UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	Docket Nos. ER06-615-002

COMMENTS OF THE
CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
ON ISSUES TO BE DISCUSSED AT SEAMS TECHNICAL CONFERENCE

On September 21, 2006, the Commission issued an order in this proceeding conditionally approving the tariff to implement the Market Redesign and Technology Upgrade ("MRTU") initiative of the California Independent System Operator Corporation ("CAISO").[1] In the September 21 MRTU Order, the Commission directed the "Commission staff to convene a technical conference to assist the CAISO and parties outside the CAISO Control Area to identify seams issues that require resolution."[2] On October 24, 2006, the Commission issued a Notice of Technical Conference ("October 24 Notice") in this proceeding scheduling the conference on seams issues for December 14-15, 2006, in Phoenix, Arizona. The October 24 Notice encouraged participants to file comments on or before November 15, 2006, identifying operational seams issues and possible solutions for discussion at the technical conference.[3]

On November 14, 2006, the CAISO requested a two day extension of time to submit comments on seams issues for discussion at the December 14-15 technical conference. On

---

[1] *California Independent System Operator Corp.*, 116 FERC ¶ 61,274 (2006) ("September 21 MRTU Order").

[2] *Id.* at P 490.

[3] "Participants are encouraged to file comments with the Commission on or before November 15, 2006 that identify specific alleged operational seams issues (particularly quantitative examples) and possible solutions for discussion at the conference. These comments should be filed in Docket No. ER06-615-002." October 24 Notice.

November 15, 2006, the Commission granted this extension. The CAISO now submits its comments on issues it believes should be discussed at the December 14-15 technical conference. Specifically, the CAISO requests that the following two issues be discussed at the technical conference: (1) Reduction of unscheduled Real-Time loop flows through the Day-Ahead exchange of scheduling data among western Control Areas; and (2) Modeling of embedded Control Areas and adjacent Control Areas within California under MRTU.

I. COMMENTS

The CAISO agrees with the Commission that seams at the borders between the CAISO and other regions within the West exist today, and MRTU does not create new seams with the bilateral markets in the West.[4] The CAISO further agrees that it is important to identify and explore ways to resolve any seams issues that could hinder competitive markets in the West.[5] Lastly, the CAISO agrees that the West will benefit from a well-functioning California market that eliminates existing market design flaws.[6] Consistent with these observations, the CAISO identifies two issues related to the CAISO's exchanging of data with neighboring Control Areas and the modeling of Control Areas under MRTU that the CAISO believes should be discussed at the December 14-15 technical conference. First, the CAISO believes that, in parallel with the development and implementation of MRTU, new procedures for the exchange of Day-Ahead scheduling data among Control Areas can be developed that will benefit all Western Control Areas. Second, the CAISO believes that achieving the greatest reliability benefits of MRTU requires detailed modeling of those Control Areas that are either embedded within the CAISO Control Area or adjacent to the

[4] September 21 MRTU Order at P 8.
[5] *Id.* at P 490.
[6] *Id.* at P 485.

CAISO Control area and within California, and that certain Day-Ahead scheduling data are required in conjunction with such modeling.

A. Background

The CAISO's MRTU program is a comprehensive effort to address the structural flaws in the CAISO's current electricity markets. These flaws include a Congestion Management system that has led to excessive Congestion costs and inefficient use of the CAISO Controlled Grid, a market structure that has provided opportunities for manipulation and has failed to ensure that the resources necessary for reliability are made available through market mechanisms, and the lack of an adequate forward Energy market in California since the California Power Exchange ceased operation. The MRTU market design addresses these flaws through a comprehensive overhaul of the electricity markets administered by the CAISO and the adoption of a new network model that will accurately reflect the operational realities of the CAISO Controlled Grid. The primary objectives of the MRTU project are to: (1) perform effective Congestion Management in the CAISO's Day-Ahead Market by enforcing all transmission constraints, so as to establish feasible forward Schedules to enhance reliable grid operations; (2) re-establish a Day-Ahead Market for Energy; (3) automate Real-Time Dispatch so as to balance the system and manage Congestion in an optimal manner with minimal need for manual intervention; and (4) ensure consistency across market time frames (from release of transmission rights through Day-Ahead and Real-Time) in the allocation of transmission resources to grid users and in the pricing of transmission service and Energy. These objectives require that physical flows within the CAISO Control Area be modeled realistically and accurately in all CAISO markets. The element of MRTU most central to achieving these objectives is the Full Network Model

("FNM"), which is the detailed, accurate model of the transmission grid that is used in all CAISO markets.

In developing the FNM for the MRTU market redesign, a key decision was how to represent the interties between the CAISO Control Area and neighboring control areas, as well as the more extensive network operated by the other Control Areas in the Western Energy Coordinating Council ("WECC") interconnected system. A fundamental characteristic of the interconnected system in the west is that power injections and withdrawals in one part of the grid typically create Unscheduled Flows across other parts of the grid. Traditional methods of interaction between Control Areas have consisted of scheduling contractual deliveries at intertie Scheduling Points between Control Areas in a manner that does not attempt to minimize the unscheduled or "loop" flows just mentioned, and then making adjustments in real time to mitigate any discrepancies between these schedules and actual physical flows.[7] In some cases, these "unscheduled" differences between contractual deliveries and physical flows are relatively small and readily manageable in real time by the grid operators of the CAISO and other control areas; in other cases they can create a significant reliability issue.

Substantive improvement on the unscheduled flow problem requires both the use of a realistic west-wide network model for scheduling, and the sharing of day-ahead scheduling data (i.e., generation, load quantities and locations) to allow all control area operators to develop a realistic estimate of the expected real-time interchange flows. On its own the CAISO could under MRTU utilize a more detailed network model for the western region, but absent the day-ahead scheduling data the network model alone would not improve upon the

[7] The accepted approach for mitigating such discrepancies in the west is the WECC Unscheduled Flow ("USF") procedure, which the CAISO believes should remain in effect and should not change under MRTU.

more limited FNM approach adopted for the start-up of MRTU. Under the MRTU Release 1 approach, external Control Areas, such as the Bonneville Power Administration ("BPA") or the Nevada Power Company, are not modeled in the FNM. Instead, the interconnections with external Control Areas are modeled through radial interties to external network buses, such as the connection to BPA at Malin.[8] The more extensive external west-wide network beyond the Scheduling Points is ignored in the FNM.

B. Reduction of Unscheduled Real-Time Loop Flows Through Day-Ahead Exchange of Scheduling Data Among Western Control Areas

As described above, in developing the FNM for the MRTU project, the CAISO decided to model the interties with neighboring control areas radially for the initial release. This decision was based on the observation that in the absence of data on Day-Ahead generation and load schedules outside the CAISO, modeling external transmission more accurately in the FNM would not improve – and might even degrade – the correspondence between Day-Ahead interchange schedules and Real-Time flows. This radial model for external Control Areas has limited accuracy because it ignores the loop flow effects of CAISO Schedules on congestion within the CAISO Controlled Grid, as well as the loop flow effects on the CAISO of external Energy transactions among the interconnected Control Areas in the WECC. Furthermore, the radial model does not allow for contingency analysis in the nearby external network that may have an impact on the simultaneous transfer capability on the interconnections with external Control Areas, or on the CAISO Controlled Grid. To a certain degree, this impact is captured by nomograms and dynamic Operating Transfer Capacity ("OTC") limits on the radial interties, which are determined by offline

---

8 These buses are referred to as Scheduling Points because these buses are where Import and Export Bids and Schedules from/to the external Control Areas are modeled. More specifically, Import and Export Bids are represented in the CAISO Markets as Bids from logical generating units connected at the relevant Scheduling Points.

power system analysis studies using the entire WECC interconnected network model. For these reasons, the radial model is considered satisfactory for external Control Areas, at least for the time being, until more inter-regional scheduling coordination ensues in the WECC.

Although this decision was appropriate for the start-up of MRTU, the CAISO described in its previous filings with the Commission its intention to work with other Control Areas to develop procedures to exchange Day-Ahead schedule data so that all Control Areas could utilize a west-wide network model to develop a realistic Day-Ahead picture of Real-Time interchange flows.[9]

In 2003, under the auspices of the Western Interconnection's Seams Steering Group ("SSG-WI"), the CAISO worked with participants in the WestConnect and RTO-West initiatives to develop a conceptual proposal for such a Day-Ahead process. The resulting proposal, which is provided as Attachment A to this filing, remains a useful starting point to pursue this effort today.

The CAISO emphasizes that the issues associated with the lack of information on external Control Area Day-Ahead schedules exist today and are unrelated to the implementation of MRTU. Initially, MRTU would have no impact on either the magnitude of unscheduled loop flows or on how they are managed. The FNM would retain today's radial representation of interties between the CAISO and Control Areas in neighboring states, so it would not provide a basis for more accurate Day-Ahead estimation of Real-Time loop flows. Nor does MRTU impact or modify the WECC Unscheduled Flow ("USF") procedure, which is the approach western Control Areas use today to manage Real Time loop flows. Even if Control Areas in the West do move to a more accurate Day-Ahead approach as

[9] *See* the CAISO's February 9, 2006, MRTU Tariff filing, Exhibit No. ISO-1 at 17-18; the CAISO's July 22, 2003, filing in Docket No. ER02-1656 at 46-47.

described here, the USF procedure would remain in place to manage the effects of post-Day-Ahead schedule changes, but would have vastly reduced flow volumes to have to mitigate.

The CAISO proposes to work with other Control Areas in the West to develop procedures to share Day Ahead schedule data on a daily basis, which all participating control areas could then use in conjunction with the WECC west-wide network model to develop more realistic Day-Ahead estimates of Real-Time interchange flows than are possible today. The CAISO further proposes that the parties to this effort develop Day-Ahead procedures to manage any identified intertie congestion in a coordinated manner and settle appropriately for any schedule adjustments to mitigate such congestion. The attached SSG-WI paper offers a proposal for how all of these activities might be implemented.

C. Modeling of Embedded Control Areas and Adjacent Control Areas within California

In contrast to the purely radial modeling approach for interties between CAISO and most Control Areas outside California, an accurate network model within the CAISO Control Area, and in neighboring Control Areas whose networks are closely interrelated with the CAISO's and therefore affect physical flows within the CAISO Control Area, is important for MRTU to fully achieve its reliability objectives. For this to work well, the CAISO requires Day-Ahead information about generation schedules and load patterns in these Embedded Control Areas ("ECAs") and Adjacent Control Areas within California ("ACAs").

ECAs are Control Areas totally surrounded by the CAISO Control Area, or more generally, Control Areas that have direct interconnections exclusively with the CAISO Control Area, and no other Control Area. ACAs are a more general concept; ACAs are tightly interconnected with the CAISO Control Area, but they also have direct interconnections with other Control Areas, possibly including other ACAs. The ECA concept was originally developed to address the modeling of SMUD, and was later expanded to the ACA concept when WAPA (Mid-Pacific region) joined the SMUD Control Area. The SMUD Control Area is now directly interconnected with BPA through the California-Oregon Transmission Project ("COTP"), in addition to interconnections with the CAISO and the Turlock Irrigation District ("TID") Control Areas. TID is another ACA. Currently, the only ECA is the Comision Federal de Electricidad ("CFE"), which is interconnected with only the CAISO Control Area, through the CFE transmission interface. The Imperial Irrigation District ("IID"), which is also interconnected with Arizona Public Service, and the Los Angeles Department of Water and Power ("LADWP"), which has several interconnections, also have the characteristics of ACAs and are candidates for to be modeled as an ACA. Other areas may be added as the CAISO develops sufficient modeling information.

For example, the CAISO's network is so closely linked to the networks of its neighboring ECAs and ACAs that, assuming that contractual deliveries to and from the CAISO Control Area strictly flow based on the Scheduling Point delivery is scheduled at, erroneous congestion management by the CAISO could result. As a consequence, the CAISO could fail to recognize some congestion until Real-Time, when its options are limited for managing the congestion, while some congestion could appear to be present during Day-Ahead scheduling but not materialize in Real-Time because the physical flows deviated from the scheduled flows.

Conditions within ECAs and ACAs cannot be ignored in the FNM, as is currently the case with external Control Areas, because their transmission network is embedded in, and/or runs in parallel with, major parts of the CAISO network, thus having significant impacts on the operation of the CAISO Controlled Grid. Loop flow through the ECAs/ACAs is significant and may have large impacts on the optimal resource scheduling, grid reliability and efficient real-time dispatch. Locational Marginal Prices ("LMPs") can also be impacted in the CAISO's MRTU markets, as they are a function of the accuracy of the model. Furthermore, accurate contingency analysis requires an accurate model for ECAs/ACAs. For these reasons, ECAs/ACAs should be modeled accurately in the FNM, which presents several challenges, not only in the market applications and information systems, but also in the coordination of information between the ECAs/ACAs and the CAISO.

The CAISO is preparing a more detailed whitepaper on modeling of ECAs and ACAs under MRTU, which it intends to use to facility discussions with candidate ECAs and ACAs. The CAISO is optimistic that it will be able to work out arrangements with neighboring ECAs/ACAs to share necessary data to facilitate the modeling of ECA/ACA under MRTU. However, to the extent such arrangements cannot be resolved, the CAISO also will pursue alternatives to obtain the data necessary to achieve the objectives of MRTU by forecasting the generation and load patterns within the ECAs and ACAs. While additional scheduling data from ECAs and ACAs would be optimal, at a minimum the CAISO should be allowed to forecast load and generation patterns within each ECA and ACA in the Day-Ahead market from relatively current ECA or ACA operations data. For the Real-Time market, the CAISO should be allowed to utilize State Estimator results for the load and generation pattern in each ECA and ACA in order to more accurately reflect the flows of system.

The CAISO looks forward to working with neighboring Control Areas and other interested parties at the December 14-15 technical conference and through ongoing seams resolution and stakeholder meetings to resolve these issues.

II. CONCLUSION

Wherefore, for the reasons discussed above, the CAISO respectfully requests that the following two issues be discussed at the December 14-15 seams technical conference: (1) Reduction of unscheduled Real-Time loop flows through the Day-Ahead exchange of scheduling data among western Control Areas; and (2) Modeling of embedded Control Areas and adjacent Control Areas within California under MRTU.

Respectfully submitted,

/s/ Sean A. Atkins

Sidney M. Davies
Assistant General Counsel
Anna McKenna
Counsel
The California Independent
System Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630
Tel: (916) 351-4400
Fax: (916) 608-7296

Sean A. Atkins
Petra A. Walsh
Alston & Bird LLP
The Atlantic Building
950 F Street, N.W.
Washington, D.C. 20004
Tel: (202) 756-3300
Fax: (202) 756-3333

Dated: November 17, 2006

Certificate of Service

I hereby certify that I have this day served a copy of this document upon all parties listed on the official service list compiled by the Secretary in the above-captioned proceedings, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated this 17th day of November, 2006 at Washington, D.C.

Rafael Lopez

Rafael Lopez
Paralegal
Alston & Bird LLP
The Atlantic Building
950 F Street, NW
Washington, DC 20004

Attachment A

SSG-WI Congestion Management Alignment Working Group (CMAWG)

Straw Proposal for Inter-RTO Day Ahead Scheduling and Congestion Management

REVISED DRAFT – October 3, 2003

SSG-WI Congestion Management Alignment Working Group (CMAWG)

Straw Proposal for Inter-RTO Day Ahead Scheduling and Congestion Management

INTRODUCTION

This paper describes a straw proposal for performing day-ahead scheduling and congestion management for the western inter-connected transmission system. This proposal was developed by a sub-team of the CMAWG in the course of meetings held on July 22-23 in Portland and August 7-8 in San Diego.[1]

This straw proposal assumes three functioning Regional Transmission Organizations (RTOs) in the western region:

> (1) the California ISO ("CAISO"), which is assumed to be operating under its MD02 design as filed with FERC on July 22, 2003;
>
> (2) RTO West ("RTOW"), which is assumed to be operating under its FERC-approved design; and
>
> (3) WestConnect ("WC"), which is assumed to be operating under its FERC-approved tariff.

Although the sub-team recognizes that there will likely be some "non-participating" transmission in the western region operated by entities not belonging to an RTO, the incorporation of non-participants has been identified as a topic for further work and is not yet addressed in this straw proposal.

In coordination with the Single Market Interface Working Group (SMIWG) of SSG-WI, the CMAWG effort attempts to achieve two principal functional objectives:

1. Create a single interface through which users of the western inter-connected transmission system can, on a day-ahead basis, schedule use of the transmission system and bid into markets operated by the RTOs (the "Single Market Interface" or "SMI"); this objective has often been referred to as "one-stop shopping"; and
2. Perform effective day-ahead, region-wide congestion management resulting in final day-ahead schedules that:

   (a) are feasible with respect to the use of transmission facilities both within and between RTOs,

---

[1] Participating in these meetings were Jerry Smith, Buddy Crill and George Kelly from WestConnect, Wally Gibson (CMAWG chair), Steve Walton from RTO West, Alan Davis representing independent generators, Lorenzo Kristov and Farrokh Rahimi from CAISO, and Linda Brown of Sempra Energy. In addition Karen Shea of the CPUC and John O'Connor of the California EOB attended a portion of these meetings.

(b) explicitly recognize and account for parallel path or loop flows resulting from day-ahead schedules, and

(c) provide an accurate and transparent basis for inter-RTO settlements where appropriate.

This paper focuses primarily on the second objective, but along the way does identify some of the functionality needed for an adequate SMI.

The sub-team set out to achieve the two objectives subject to the constraint of respecting the design differences of the three RTOs. If this proved impossible, the sub-team's task would then have been to identify specific elements of any of the RTO designs that prevented reaching a solution, and to examine potential design modifications that could reduce the obstacles. The sub-team is pleased to report that this straw proposal appears thus far to offer a way to achieve the above functional objectives within the context of the current RTO designs. At the same time, we point out that this straw proposal is still quite far from a finished product. There are significant questions that have not yet been addressed and areas where further work is needed, summarized at the end of this document. For example, in developing this straw proposal the sub-team needed to simplify the problem by deferring consideration of day-ahead markets for reserves or ancillary services (A/S). All three RTOs propose to operate day-ahead A/S markets, however, so this additional realism will need to be addressed as the CMAWG effort continues.

Finally, the sub-team also set out to identify specific areas or questions where it would be productive either to engage the services of a consultant or to procure some modeling capability to test aspects of the proposal. Although the sub-team has identified areas requiring further work, we have not yet delineated specific questions that might comprise a scope of work for a consultant (rather than be performed internally by the CMAWG) or a list of requirements for a computer model. The sub-team hopes to address this task in the near future.

OVERVIEW OF THE STRAW PROPOSAL

The straw proposal is structured as a series of steps, numbered 0 through 5. Steps 0 through 3 may be viewed as "set-up" steps. Step 4 is the actual "convergence" step whereby the accepted schedules of the three RTOs are adjusted for mutual consistency and region-wide feasibility. Step 5 is the inter-RTO settlement step. It is important to note that there are no iterations with Scheduling Coordinators (SCs)[2] during this sequence of steps; i.e., once SCs submit their schedule and bid information in Step 1 there are no opportunities for them to revise their schedules or bids prior to publication of the final DA schedule for the region at the conclusion of Step 4.

The straw proposal makes the necessary assumption that there will be a somewhat simplified model of the western regional network (a "common network model") that each RTO will use to represent the grid external to its own control area, in conjunction with a fully detailed model of its own control area ("RTO-specific model") for purposes of its own scheduling, congestion

[2] We have adopted the term Scheduling Coordinators (SCs) to refer generically to the parties who submit schedules and bids and are responsible for the settlements associated with using the RTO-operated transmission systems and participating in any of the RTO markets.

management, dispatch, etc. The sub-team's current thinking is that the common network model should include all transmission facilities rated 230 kV and above, any other transmission facilities that are significant for west-wide congestion management, all generator locations (without necessarily distinguishing among multiple units at a single node or in close proximity, electrically speaking), and all load locations based on yet-to-be-determined aggregation conventions.[3]

The six steps may be summarized as follows.

Step 0. Initial sharing or posting of pre-DA system information for each RTO, particularly load forecasts and network status.

Step 1. Submission of DA schedule and bid information by SCs to the Single Market Interface (SMI) and distribution of appropriate information to the three RTOs. RTOW and WC require that SCs submit balanced schedules, whereas CAISO will accept unbalanced schedules as well as bids to buy and sell energy.

In Steps 2-3 each RTO will perform its own scheduling and congestion management procedures as needed, using the common network model for its external areas in conjunction with a more detailed "RTO-specific" model for its internal area.

Step 2. CAISO runs its DA Integrated Forward Market (IFM). Step 2 is a CAISO-only step, which needs to go first in order to clear the CAISO DA energy market and determine fixed MW quantities consistent with the schedules accepted by the other RTOs. As a result of the IFM the CAISO now has a balanced schedule for its system, which it shares with RTOW and WC in the form of injection and withdrawal locations and quantities.

Step 3. Given the information from Step 2, RTOW now runs its DA congestion management and WC updates its DA schedule with final dispatch quantities for resources in its area that had bid into the CAISO energy market. (Both RTOs also run their DA A/S markets, though as noted above this straw proposal does not yet address issues related to the A/S markets.) As a result of Step 3 all three RTOs have their own DA schedules which are individually feasible from each RTO's perspective.

Step 4. Congestion Management Convergence Process (for converging the three RTOs' DA schedules). Several options for how to structure this process are under consideration and are illustrated with flow diagrams later in this document. The desired result of the convergence process is a final DA schedule that is consistent across the three RTOs, is feasible with respect to inter-RTO flows as well as each RTO's internal network, accurately reflects inter-RTO parallel path (loop) flows, and provides a transparent basis for inter-RTO settlements.

Step 5. Inter-RTO settlements. The RTOs will settle among one another based on the final DA scheduled inter-RTO energy flows for each operating hour. Transparent and accurate inter-RTO settlements require mutually acceptable and reliable methods to:

---

[3] Based on the discussions of the Single Market Interface (SMI) Working Group, the target structure of the detailed (RTO-specific) and common network models is such that there would be a many-to-one relationship between the busses in each detailed model and the nodes in the common network model. Thus schedules and bids submitted to each host RTO (i.e., RTO where a SC's resources and loads are located) can be simply aggregated to provide equivalent schedules and bids at the common network nodes (sources and/or sinks) as observed by the other RTOs.

- quantify the scheduled flow on each inter-RTO interface, and
- determine financial values for those flows (i.e., consistent pricing at the seams).

Figure 1 of the attachment provides a schematic overview of Steps 0 through 5.

SOME TERMINOLOGY

Before describing the details of the steps it is important to clarify some potentially confusing terms.

- A "preferred schedule" or simply a "schedule" is a set of MW injections and withdrawals, with specified locations, as submitted by a SC prior to the running of the RTO-specific and inter-RTO congestion management procedures. In RTOW and WC each SC's schedule must be balanced (i.e., total injections equal total withdrawals) at the time it is submitted, whereas in CAISO this is not required. By itself a preferred schedule does not have associated prices, although in RTOW and WC it may be accompanied by "adjustment bids" for congestion management as noted below. Specifically, the CAISO design distinguishes "bids" from "self schedules," such that the latter are price takers in the CAISO market and are adjusted for congestion only if economic bids are exhausted. In RTOW and WC, because these RTOs do not have forward energy markets in their designs, SCs may submit explicit adjustment or INC-DEC bids to be used for congestion management.
- A "bid" is an offer by a SC to buy or sell energy or A/S capacity. As such a bid will consist of MW quantities at a specific location with associated prices. Under the three proposed RTO designs a DA energy bid is relevant only to the CAISO. DA A/S bids are relevant to all three RTOs, but as noted earlier this straw proposal does not yet deal with A/S bids.
- An "adjustment bid" is an offer by a SC to have its preferred schedule at a particular location incremented (INC'd) or decremented (DEC'd) for the purpose of congestion management by the RTO or the inter-RTO process. All three RTO designs accept and use bids to adjust or "re-dispatch" preferred schedules to manage congestion. The CAISO design differs from the other RTOs, however, in the fact that it operates a DA energy market integrated with congestion management and therefore does not distinguish between energy bids and adjustment bids.
- A "final schedule" is a set of accepted injection and withdrawal quantities and locations as established by an individual RTO or the inter-RTO congestion management process. Some parties also call this a "dispatch" to distinguish it from a preferred schedule, but it is important to recognize that it refers to the forward time frame and not to the dispatch of resources in real time. In this document we use the term "final schedule" to refer to the schedule resulting from either an individual RTO's congestion management or the inter-RTO convergence process; hopefully the context will make the usage clear.
- Trading Hubs, and Inter-SC Trades at Trading Hubs **[brief explanation to be added, per request made at 8/19 meeting]**

- Physical Plane and Commercial Plane **[brief explanation to be added, per request made at 8/19 meeting]**

DETAILS OF DAY AHEAD INTER-RTO SCHEDULING AND CONGESTION MANAGEMENT STEPS

STEP 0

RTOs provide initial information to each other, e.g., updated network status and load forecasts.[4] This information would be provided well ahead of (e.g., 12 hours before) the closing of the day-ahead schedule and bid submission periods. All or part of this information could also be published through the SMI as Public Market Information.

STEP 1

Submission by SCs to SMI, with information distributed to RTOs as appropriate after any validation or processing incorporated in the SMI functionality.

- As noted above, to make the problem manageable initially this proposal ignores day-ahead A/S markets. Thus the only kinds of SC submissions considered in this document are:
  - fixed MW quantities of energy with injection and/or withdrawal locations (also referred to as "preferred schedules" or simply "schedules"),
  - bids to buy or sell energy in the CAISO day-ahead energy market, and
  - INC-DEC "adjustment" bids associated with fixed MW energy schedules that may be used for congestion management.[5]
- At the end of Step 1 each RTO should receive from the SMI:
  - preferred schedule injection and withdrawal MW and locations for the entire region, in accordance with the common network model;
  - adjustment bids on resources and loads within its own control area; and
  - bids submitted to its own markets, which may have been submitted by resources located in other RTOs where permitted.
- Validation by the SMI. The sub-team expects the SMI to perform some validation of SC preferred schedules prior to transmitting information to each RTO. The specifics of SMI validation require further elaboration and this topic is noted among the open issues at the end of this document, but the sub-team has considered the following elements.
  - With respect to preferred schedules (injection and withdrawal quantities and locations, without associated bid prices):

[4] Other useful forecast information such as estimates of transmission loss factors may be added as needed.

[5] Note that the CAISO MD02 design, which features a forward energy market integrated with congestion management, does not distinguish between (2) and (3).

    - Schedules that source or sink within a given RTO must pass validity checks for consistency with the requirements of those RTOs (e.g., each SC's schedule must be balanced for RTOW and WC; schedules must be attached to commensurate FTRs for WC; etc.).
    - Schedules may utilize "trading hubs" as points of delivery and receipt of energy, rather than actual generator or load locations. However, any such schedule submitted by a SC must be complemented by a counter-party schedule submitted by another SC, so that the net injection or withdrawal at each trading hub is zero for each operating hour. This ensures that trading hub transactions will have no effect on congestion or on the prices determined in the congestion management process.[6] The SMI should validate that each preferred schedule that utilizes a trading hub has a matching counter-party schedule that results in zero net energy at that hub for that hour.[7]
  - Bids, flagged as targeted to a specific RTO. Clearly, DA energy bids would have to be designated for CAISO, since only the CAISO proposes to run a DA energy market. With regard to adjustment bids, as a starting place for this straw proposal the sub-team agreed that adjustment bids associated with a specific resource or load schedule would be made available only to the RTO in which the resource or load is physically located (i.e., the "host" RTO).[8]
    - Supply resources located in RTOW or WC may bid into the CAISO DA energy market. At the time the SC submits such a bid, the SC would be able to indicate its willingness for an energy bid accepted by the CAISO to be used as a DEC bid for congestion management by the host RTO. In addition, any unused energy bids submitted to the CAISO market would be available by default as INC bids for congestion management by the

---

6 The two SCs on either side of a trading hub transaction may utilize an "Inter-SC Trade" as a mechanism to schedule their transaction with the RTO. Such a schedule will have settlement implications for the parties, so it is important to establish transparent, stable procedures for setting the prices and charges associated with trading hub schedules. Such schedules cannot in themselves affect these prices or charges, however, because the zero net energy requirement allows them to be ignored by the congestion management procedures.

7 The counter-party to a hub trade scheduled by a SC must be another SC. In particular, a SC cannot force a RTO to be the counter-party to an arbitrary hub delivery or receipt designated by the SC. In case the SC bids from its physical resource(s) into a RTO energy market, the point of delivery in the recipient RTO is presumed to be based on pre-specified load distribution factors agreed upon by all three RTOs. Any Inter-RTO hub trading will be based on Inter-RTO agreements. At this time, our working assumption is that settlement of Inter-RTO trades would be based on the converged Inter-RTO flows and prices associated with SC schedules (within or between RTOs), and/or SC schedule adjustments for market clearing or congestion management, including acceptance of energy bids or congestion-specific INC and DEC bids, as computed by the converged congestion management and pricing solution. For all practical purposes, because SC-to-SC trading hub trades are purely financial and do not entail any injections or withdrawals, they can be submitted after the close of the DA market, once the parties to a trading hub transaction know the published hub prices.

8 Bids to supply A/S capacity must be designated for a particular RTO, which could be a non-host RTO that accepts A/S import bids. As noted earlier, however, issues associated with A/S bids and markets are deferred for future discussion.

host RTO.[9] This provision is important to guard against physical withholding of supply. **[Clarifying example to be added, per request of parties at 8/19 meeting.]**

- Market bids, e.g., energy bids into CAISO, including import bids.[10] (An issue regarding the modeling of import energy bids is described at the end of this paper.)

There is one final point that must be emphasized. All of the bid and schedule information that will be used by the three RTO congestion management procedures, the CAISO's integrated DA energy market, and the inter-RTO congestion management procedure, will represent injection and withdrawal quantities (with or without bids) at the locations of physical resources and loads on the common network model or, for the individual RTOs, at nodes of their more detailed internal models. In particular, supply resources in RTOW or WC that bid into the CAISO energy market will be evaluated in that market based on their physical locations on the common network model, rather than today's practice of bidding to supply energy at an inter-tie into the CAISO control area.[11] Similarly, schedules that utilize trading hubs rather than specifying physical resources or loads must net to zero, and thus may be ignored in each RTO's forward markets and congestion management procedures. The overall effect of this design principle is that DA scheduling, bidding and congestion management will be performed completely on a "source-to-sink" basis, with reference to actual resource and load locations and without retaining any vestiges of the "contract path" approach. As a result, the DA scheduling and congestion management process will reflect the physics of energy flows more accurately than was possible under the contract path approach.[12]

STEP 2

CAISO only. The DA CAISO market clears to establish injection and withdrawal quantities. Because CAISO is the only RTO that accepts unbalanced schedules and DA energy bids, the accepted supply and demand bids have to be determined in order to establish a balanced schedule

---

9 At the August 18, 2003 CMAWG meeting, some parties noted that a supplier may not be indifferent to which entity buys its energy and therefore may not be willing to have its unused energy bids made available to a second entity. There is, however, a countervailing concern about physical withholding that may become an issue without this rollover provision, particularly if such withholding impedes the ability of the host RTO to perform efficient congestion management.

10 There are some further questions to be addressed regarding validation of import bids and schedules. For example, if a generator located in WC bids into the CAISO DA energy market, will CAISO know whether or not the generator has the needed FTRs within WC to deliver energy from its location to the CAISO boundary? Perhaps the simplest answer is for CAISO not to validate this ex ante, and instead to assume that the bidder has the FTRs and thus hold the bidder responsible to either deliver the energy sold in the DA market or to buy it back in a subsequent market if it does not have the FTRs. This is still an open issue, however.

11 The CAISO notes that such an approach is beyond what has been proposed in the MD02 filing submitted to FERC on July 22, 2003, but that such an approach appears to be a feasible extension of MD02 once the other RTOs and the inter-RTO procedures envisioned in this straw proposal become operational.

12 Another implication of this provision is that there will be no portfolio bidding into RTO markets. Third parties may develop portfolio clearing markets similar to APX or the former California PX. The need for portfolio clearing in RTOs is minimized by RTOs that offer a unit commitment service. Further discussion of portfolio bidding and "virtual" supply bidding is provided in the section on open issues below.

for the CAISO system and to determine preferred schedule quantities for resources and loads within RTOW and WC that have bid into the CAISO energy market. As noted earlier, such resources and loads will be evaluated in the CAISO market based on their physical locations on the common network model. As a result, Step 2 will also produce locational prices at common network model nodes within the RTOW and WC systems in addition to within the CAISO system and at its interfaces with RTOW and WC. Those prices may or may not be relevant to the CAISO settlement process, depending on the mode of Inter-RTO settlements adopted.

STEP 3

Results of Step 2 are passed to other RTOs. All RTOs will have balanced injections and withdrawals at this point, plus adjustment bids to be used for congestion management, plus locational prices at the interfaces with CAISO that were calculated by the CAISO in Step 2. In addition CAISO will have done its initial CM run and will have determined a feasible final schedule for its own control area. Next, Steps 3A and 3B below occur simultaneously.

- STEP 3A. RTOW does its CM run, utilizing its own internal adjustment bids, plus the energy bids of its internal resources that have bid into the CAISO market (subject to the provisions described above). In this process, RTOW is not required to maintain balance within each SC's schedule (i.e., there is no "market separation" rule such as exists in the CAISO's design today.) As a result, for each SC RTOW will maintain both the balanced preferred schedule as it was prior to congestion management, and the final schedule or "dispatch" as determined in the CM process. Although RTOW will retain both for its settlement purposes, only the final schedule will reflect actual anticipated energy flows and thus will be relevant to the inter-RTO CM process.
- STEP 3B. WC adjusts its expected DA schedule with the generation quantities resulting from the CAISO IFM run in Step 2 for any WC generators that had bid into CAISO's market. Further internal congestion management by WC should not be necessary at this time since the feasibility of schedules on its system are ensured through the acquisition and use of physical rights.

This step ends with each RTO having established its own final DA schedule without necessarily having considered the impact of its schedules on other RTO systems nor its potential financial liability because of parallel flows its schedules may have created in other RTO systems, and without attempting to obtain quantity and price consistency at the RTO boundaries. At the same time, because each RTO is utilizing the common network model to represent the transmission system external to its own control area, and sees the all the preferred schedule injection and withdrawal MW and locations for the entire region, Steps 2 and 3 are expected to produce reasonably accurate schedules of parallel path flows. Indeed, this is one of the key objectives in requiring that all bidding and scheduling occur on a source-to-sink basis rather than a contract-path basis.

In summary, in both STEP 2 and STEP 3

- Each RTO will use only its own internal adjustment bids to resolve congestion in its own control area;
- Each RTO will see its own internal quantities and adjustment bids, but only fixed quantities at locations in the other RTOs;

- Incremental energy bids submitted into the CAISO energy market but not taken in that market can be used by the host RTO for congestion management. Energy bids that were accepted by CAISO to establish resource schedules may be used by the host RTO as decremental bids only if so designated a priori by the bidder.

STEP 4

This is the convergence step, which is intended to produce a final DA schedule that is consistent across the three RTOs, is feasible with respect to inter-RTO flows as well as each RTO's internal network, accurately reflects inter-RTO parallel path (loop) flows, and provides a transparent basis for inter-RTO settlements. Several different process designs were discussed by the sub-team, and these are illustrated in flow diagrams that accompany this paper. Different designs derive from such considerations as: (1) creating an over-arching CM system that sees the whole system and makes optimal adjustments, versus maintaining all adjustment at the RTO level and achieving convergence through an iterative process; (2) under an iterative process, having only one RTO make adjustments at a time and share the results before the next RTO makes adjustments, versus having successive rounds of simultaneous adjustments by all three RTOs. At this time the sub-team does not have a preferred design for the convergence step. There are several observations that can be made, however.

- The results of Steps 2 and 3 will be the inputs to Step 4.
  - This may include other information that will help the process converge, e.g., locations of binding constraints, sensitivity of RTO boundary prices to inter-RTO incremental import/export quantities, range of applicability of prices (to help avoid hunting or oscillation in convergence).
  - In addition to each RTO's DA schedules, RTOs may also share their expected real-time imbalance energy dispatch (resource locations and quantities) to the extent that their final DA schedules vary significantly from their load forecasts.
  - RTOW and CAISO will produce LMPs over the entire common network model and will provide these to the convergence process. At this stage the LMPs produced by RTOW and CAISO at any particular node will probably be different.
  - RTOW and CAISO may also see prices at their interfaces with WC that can be used in the congestion management iteration process. WC may provide these as resource adjustment bids at actual internal locations, or as derived adjustment bids at the interfaces that are based on the underlying resource adjustment bids.[13]
- Several alternative approaches to the design of the convergence process are being considered by the sub-team (see flow charts at the end of this document).
  - With RTOs performing the iterative steps:

---

[13] Depending on how WC prefers to do this, CAISO and RTOW may need to modify their treatment of the WC network in their congestion management procedures. Under some options for the iterative process, each RTO may use a radial external network coupled with shift factors representing flows of INCs and DECs on different internal transmission paths and ties, rather than the common network model with external INCs and DECs at specific nodes. This question will be a significant part of the continued effort in developing the details of Step 4.

    - Strictly Sequential (e.g., CAISO, then RTOW, then WC, etc.)
    - Sequential/parallel (e.g., combined CAISO/RTOW, then WC)
    - Strictly Parallel
  - "Simultaneous", i.e., with an umbrella solution process replacing the iterative, individual RTO actions (with the solution algorithm implicitly doing either strictly sequential, parallel sequential, or strictly parallel processing as above).

- Required results of the convergence process are:
  - Feasible final DA schedule for the region
  - Loop flows explicitly accounted for, and
  - An accurate, transparent basis for inter-RTO settlements (i.e., quantification of scheduled inter-RTO energy flows and associated prices for valuing those flows).

STEP 5[14]

As noted above, accurate and transparent RTO to RTO settlement requires a commonly accepted and reliable approach for determining the inter-RTO flows that result from the DA scheduling and congestion management process, and for placing a dollar value on such flows. The dollar value aspect of this problem is commonly referred to as the problem of "consistent prices at the seams."

The actual basis of inter-RTO settlements can be traced back to particular aspects of the DA scheduling and congestion management process, such as (1) re-dispatch costs to alleviate congestion, including congestion resulting from loop flows, and (2) settlement of trading hub transactions that cross RTO boundaries.

This straw proposal does not attempt to resolve all of the complexities of inter-RTO settlement, but the sub-team did consider a couple of examples that help to illustrate the issues. The starting point of the two examples is the distinction between a generator within RTOW bidding into and being accepted in the CAISO forward energy market (Example 1), versus a balanced schedule from a generator within RTOW serving load within CAISO (Example 2). The examples are presented in detail in an Appendix at the end of this paper, based on the use of shift factors to decompose the inter-RTO transactions into flow components at the inter-RTO interfaces.[15]

As exploration of these examples proceeded it became apparent that the significant issues derived to some extent from the distinction between energy market bids versus balanced schedules, and also depended on the choice of inter-RTO settlement approach. The following

---

[14] The discussion of settlements in this document does not attempt to incorporate recovery of embedded costs of transmission infrastructure, i.e., the "access charges" in CAISO and RTOW, or the "transmission usage charges" in WC.

[15] This is one possible approach to measuring the quantity of scheduled flow on each inter-RTO interface from a transaction. Other methods may be considered as the details of this proposal are developed. The examples deal only with inter-RTO transfers. The treatment of internal-only transactions effect on other RTOs would need to be determined as well.

discussion therefore also explores four different inter-RTO settlement approaches, based on two binary design choices.

- First, is inter-RTO settlement based
  - (A) purely on net inter-RTO scheduled flows without regard to the inter-RTO flow effects of individual SC schedules, or
  - (B) on the inter-RTO flow effects of individual SC schedules?
- Second,
  - (C) does each RTO settle directly with some resources and loads located within the other RTO control areas, or
  - (D) does each RTO fully manage the settlements with entities physically located within their own areas, and thus not have to settle directly with entities located in other RTO areas?

1. Inter-RTO settlement based on total inter-RTO flows only, and each RTO settles with all SCs within its own area. (A-D)

2. Inter-RTO settlement based on inter-RTO flows due to each SC; each RTO settles only with SCs inside its own area. (B-D)

3. Inter-RTO settlement based on inter-RTO flows due to each SC; each RTO may settle with some SCs within other RTO areas. (B-C)

At this point it is not clear whether all combinations (A-C), (A-D), (B-C) and (B-D) are potentially viable options. The examples provided here demonstrate the feasibility of (A-D) and (B-C), and hint at the feasibility of (B-D).

It is important for the reader of this document to understand that the sub-team is just beginning to explore these issues and the alternative approaches. Thus these examples are provided only to illustrate the issues and stimulate further discussion, not to suggest that the sub-team has agreed on a particular approach.

Example 1. Scheduling Coordinator SC1 with generation at point A inside RTOW bids 100 MW at $50 into the CAISO DA energy market. The CAISO market procures all 100 MW from SC1, and produces a LMP of $50 at point A and a LMP of $70 at the load location B inside CAISO (assume for simplicity that all load inside CAISO is aggregated to a single node). Assume that these results stand unadjusted at the conclusion of Step 4. That would mean among other things that the LMP at point A as seen by RTOW is also $50. Using approach (B-C) mentioned above, CAISO then collects $7,000 from its load and pays $5,000 to SC1. The remaining $2,000 represents congestion revenues that must be paid out to: (1) holders of CRRs inside CAISO, (2) RTOW and WC for the usage of their transmission system to deliver the power to their tie points with the CAISO control area. The transmission usage charges will be based on the pattern of MW flows on the interfaces attributed to this specific transaction as computed by the set of shift factors of the source and the sink of the transaction.

Approach (A-D) would perform inter-RTO settlements based on computed net inter-RTO flows and converged prices. Each RTO would then settle with all SCs having supply or demand scheduled within their control area regardless of whether the intended sink or source is in the same or a different RTO control area. Under such settlement scheme, in this example, RTOW would pay the supplier at the locational price of $50, and then collect the boundary price times the corresponding boundary net flow quantities from the respective RTOs regardless of which transaction caused what portion of each tie-line flow. With converged prices, the financial result would be the same, but the settlement process would be simpler. The amount of $ going back and forth among the RTOs would be larger, however, since each RTO would no longer settle directly with generators or loads within the other RTOs. Basically, the point of view under this type of settlement would be that the power supplied at point A is used by RTOW and RTOW delivers power to the neighboring RTOs.[16]

Example 2. SC1 submits a balanced schedule of 100 MW injected at point A inside RTOW to serve load at the CAISO load aggregation point B. Assume this schedule is accepted, and that when Step 4 is concluded the LMPs are $50 at point A and $70 at B. Under this scenario, using settlement approach (A-D) mentioned above, CAISO does not pay $5000 to SC1 as in the previous case, nor does it collect $7000 from the internal load. Instead, in this case SC1's balanced schedule must be distributed to the various inter-RTO interfaces based on agreed upon shift factors.[17] CAISO then assesses congestion usage charges to SC1 based on the differences between the LMP at B and the various interface prices and interface flow quantities associated with this transaction as computed by the shift factors, and pays congestion revenues to holders of CRRs within the CAISO. RTOW and WC charge SC1 for the use of their transmission system in a similar manner.

If approach (B-C) is used, however, CAISO is designated as the responsible RTO to settle with SC1. CAISO then computes and assesses usage charges to SC1 for this transaction based on LMPs at B and A, and pays RTOW and WC their share of usage charges based on the source schedule at A, the inter-RTO flows associated with this transaction, and the converged prices.

Note that the SC would collect CRR revenues wherever it has such rights. Whether or not it has acquired CRRs to adequately hedge against congestion usage charges is the SC's responsibility.

The comparison of these examples raises a few points:

- **[For discussion 10/1-2]** The distinction between a market energy bid into the CAISO market versus a balanced schedule between two RTOs may or may not drive any differences in settlement, depending on the designated sink of the accepted bid. Once the CAISO market clears, an external sale or purchase into the CAISO market gets converted into a balanced schedule. Since a balanced schedule requires designation of the balanced source(s) and sink(s), under a B-type settlement it is important to designate the sink for the schedule derived from the energy bid appropriately. For energy that is bid into the CAISO market the seller cannot designate the sink; rather, the sink would be distributed throughout the CAISO control area in a manner consistent with other bids into the market. In other words, the seller can elect the sink point of a transaction only if it self

---

[16] One way to think about this is to imagine that the AGCs are simulated in the day-ahead time frame, with zero frequency bias or no frequency deviation.

[17] The choice of the reference location for the shift factors does not have an impact on the outcome of either of the two examples. This is always the case as long as the source and the sink of the schedule under consideration are balanced (i.e., the same quantity is injected at A and withdrawn at B).

schedules, i.e., has a willing non-RTO buyer or its own loads to accept delivery at the designated sink. Under an A-type settlement the specification of sink nodes for an energy bid accepted in the CAISO market is not required for accurate inter-RTO settlement. In this case it is necessary only to calculate inter-RTO flows accurately, which can be done based on the total energy that cleared in the CAISO market.

- Determining the proper settlement using approach (B-C) or (B-D) requires agreement among the RTOs regarding the shift factors to apply to a resource schedule, or some other convention for decomposing individual SC schedules into flows on the various inter-RTO interfaces. This is a consequence of trying to settle each transaction separately with respect to its impacts on each RTO, rather than settling based on total net inter-RTO flows for each interface.
- Under any of the settlement approaches, the three RTOs should utilize the common network model in their processes for releasing transmission rights (CRRs, FTOs, FTRs). This is needed to bring as much consistency as possible between the release of rights and the daily scheduling and congestion management processes. From the viewpoint of RTOW and CAISO participants, such consistency is necessary to enable them to hedge the congestion charges associated with the approach set out in this straw proposal. From the viewpoint of WC participants, such consistency will enable them to procure the rights they need to submit their daily schedules to WC.

OPEN ISSUES AND RESEARCH QUESTIONS

The following items represent questions and issues that have been identified to date regarding limiting assumptions made in this straw proposal or desired refinements to the proposal. Some items were identified within the group based on limiting assumptions that were made to simplify the initial straw proposal, while others were added by participants in comments on earlier drafts of this proposal or in meetings of the larger CMAWG group. It is important for readers to keep in mind that the primary objective of this straw proposal is to demonstrate that is it feasible to perform day-ahead scheduling and congestion management among the three different RTO designs. To achieve this objective the Team made several simplifying assumptions to make the problem tractable. As the effort continues the CMAWG Team intends to address some of these over the coming months. All identified issues will remain on this list as long as they are open.

- Are any unintended arbitrage or gaming opportunities created by the rules, or advantages or disadvantages created when RTOs act in sequence rather than simultaneously? This question is applicable to the sequencing of Steps 2 and 3, as well as the comparison of options identified for Step 4. E.g., does it make any difference to the RTOs, or to market participants, or to the efficiency of the outcome that CAISO acts first in Step 2 and passes results to the other RTOs, who then act in Step 3?
- How much functionality should be built into the SMI, versus simply having the SMI collect the submissions of SCs and pass information to the individual RTOs? For example, how much and what kinds of validation or other pre-processing of submitted schedule and bid information should the SMI perform in Step 1? **[Does the SMI replace OASIS?] The intent of SMI is to incorporate OASIS functions so that parties can do everything at one place – move this comment to the earlier SMI footnote.**

- What are the pros and cons of the various approaches for Step 4? Does it make any difference whether the Step 4 iterations are sequential or parallel/simultaneous?
    - What network model is needed to support the various options for Step 4? Will some options require a detailed regional model that combines the "RTO-specific" models used in Steps 2-3?
    - What additional information is required from each RTO to facilitate convergence under the various options for Step 4 (e.g., shadow prices on constraints)?
- How must the straw proposal be modified to incorporate day-ahead A/S markets in the three RTOs? What are the effects of A/S market design differences among the RTOs (e.g., with respect to bid structure and treatment of opportunity cost)?
- How must the straw proposal be modified to account explicitly for transmission losses?
- Trading hub schedules. This straw proposal has made some strong assumptions regarding schedules at trading hubs that must be clearly understood. This proposal assumes that trading hub transactions are purely financial transactions between two SCs, with no impacts on congestion or prices. In particular it assumes that any schedule to or from a trading hub must be matched by another equal and opposite schedule (e.g., an inter-SC trade) such that the net injection or withdrawal at the trading hub is zero. This requirement allows trading hub transactions to be ignored in the congestion management process. It also means that trading hub schedules will never be adjusted in the process; i.e., once submitted by the two SCs, such schedules will represent a fixed-MW financial commitment by the parties that cannot be adjusted based on the prices resulting from the congestion management process.[18]

  Alternatively, market participants may wish to have their hub trades adjusted to reflect physical delivery capability or congestion costs, and they may want to submit adjustment bids on the trades to limit their exposure to congestion charges.[19] Under such paradigm the market participants would want to pay the charges associated with trading hub transactions based on their final (adjusted) schedules rather than their preferred schedules. This would require direct accounting of the hub trades in the scheduling process, making it much more complicated. Although the net financial impact summed over all RTOs would be zero, huge transfers may take place among parties in one paradigm compared to the other.
- Import bids and schedules. This straw proposal has made strong assumptions about how the scheduling and congestion management process will treat bids and schedules to import from one RTO to another, and these assumptions must be clearly understood. In particular, to

---

[18] The parties to the trade may, of course, adjust the volume of the trade through a side transaction after the fact based on published prices, but that would take place outside the RTO settlement systems.

[19] The CAISO currently provides an Inter-SC Trade Adjustment Bid facility to allow the volume of an Inter-SC Trade to be adjusted based on congestion costs. The need for this is driven by the current market separation rule, which requires that each individual SC schedule be kept in balance during the forward congestion management process. With MD02 the CAISO will eliminate the market separation rule and will discontinue the Inter-SC Trade Adjustment Bid facility. The problem created by the market separation rule is not an issue for RTOW or WC. Although the RTOW design does require SCs to submit balanced schedules initially, there is no requirement for RTOW to maintain balance during congestion management. In WC there will be no need to modify submitted SC schedules because congestion will be precluded through the use of physical transmission rights.

achieve the objective of explicitly accounting for parallel path flows, all import bids and schedules must be represented in terms of actual injection and withdrawal locations on the common network model. Thus, for example, an SC located in WC who bids into the CAISO day ahead energy market must submit that bid at its actual location rather than at a specific interface between WC and CAISO. The sub-team recognizes that this represents a departure from current practices. We believe it is necessary, however, in order to resolve the long-standing problem of real-time unscheduled flows that result from the inability to account for loop flows in the forward scheduling process.

Moreover, it would severely complicate the inter-RTO process described in this document to accommodate "virtual" or "portfolio" bids or schedules at interfaces where the supply is not actually located. In particular this type of bidding and scheduling would not be compatible with consistently using a common network model to represent regional energy flows. For example, if import bids are treated as injections at the RTO border, then when they are used by the CM convergence process they must either be applied with a radial external network (rather then a common inter-RTO network model) or, if a common network is used, they would have to be balanced by phantom injections to make the interface line flows correspond to the combined effect of accepted import bid quantities and flows resulting from other source to sink schedules.

- How might phase shifters and other technologies be integrated into Steps 2-4?
- The straw proposal places limits on the target markets for SC bids (e.g., A/S bids must be targeted to a specific RTO; whereas adjustment bids can be used by the host RTO only). Does this raise problems? Given that the process from Step 1 through Step 4 does not allow SCs to change or modify their initial bids, should there be provision for SCs to specify multiple target markets, with some priorities so that bids not accepted in the first-choice market would be available to other markets? What would be the implications of this? Some have suggested that it might lead to a more efficient outcome for the region if bids are available to multiple RTO markets. At the same time, depending on such things as the market rules and mitigation procedures, allowing bids into multiple RTOs could either increase competition or increase the opportunity for the bidders to inflate their bids.
- What are bid dissemination and bid confidentiality rules? To what extent would the fact that an RTO is "for profit" or "not-for-profit" make a difference in this regard? This question is particularly applicable to Steps 1 through 3. There are a few different issues here, such as: (1) The exchange of expected real-time imbalance energy dispatch (at the end of Step 3) could simply be an estimate of how much of the forecast load did not clear the forward market, or could go further and identify the resources and their respective quantities that are expected to be dispatched to meet the shortfall in real-time. (2) Unrestricted exchange of bid information among RTOs (e.g., in Step 1) may not be appropriate if one or more RTOs are "for profit" rather than "indifferent to the wealth distribution as long as the dispatch is efficient." (3) Should the provision to allow SCs to bid into multiple RTO markets and designate a priority order be a facility to be used by the bidders voluntarily, or should bids automatically roll to the other RTOs if not used by the initially targeted RTO? (4) The requirement that a bid cannot be restricted by the bidder to be used only for a non-host RTO is appropriate as a measure against physical withholding. (5) A "bidding activity rule" that would say if a bid is

not used in one market (e.g., the day-ahead market) it should remain binding for the subsequent markets (e.g., real-time) may be considered somewhat onerous.

- Inter-RTO Settlements. What are the pros and cons of the various approaches for conducting inter-RTO settlements with regard to day-ahead scheduling and congestion management, and what is the best approach? The examples discussed above consider the very simple case of a supply resource at one node in one RTO serving load in another RTO. We need to consider, among other things, treatment of network service schedules (i.e., multiple supply nodes to multiple load nodes), and the loop flow effects of schedules that source and sink within a single RTO.
- Incorporating non-participants (i.e., owners/operators of transmission that do not belong to a RTO). For example, how to incorporate changes associated with ETC rights.
- The case of multiple Day Ahead energy markets in different RTOs (e.g., both CAISO and RTOW operate DA energy markets that run at the same time) – what bidding options can be exercised by suppliers with regard to participating in such multiple markets?
- A convergence process that includes participation by the SCs, rather than just iteration among the RTOs. For example, can there be a convergence process in which SCs get to see the results of intermediate steps and resubmit their bids? If such a process is created what kinds of bidding activity rules are required?
- Real-time inter-RTO coordination. What kinds of real-time USF procedures are envisioned under the CMAWG proposal? Exclusive focus of this group to date has been on day ahead; may decide to look at RT issues later. **[Ra]**
- Consider the UFAS (Unscheduled Flow Administrative Subcommittee of WECC) designation of zones for use in USF procedures. How do these zones related to the level of detail required in the common network model envisioned in the CMAWG proposal?
- Allowing portfolio energy bids in DA instead of requiring all unit-specific bids. Some parties want to continue today’s practice of bidding imports at inter-ties without specifying actual source of energy. Some suppliers are interested in this as a way to manage uncertainty about actual operating conditions and/or costs that will pertain in real time.
- Post-day-ahead schedule changes prior to RT operations.
- Staggered RTO scheduling timelines. Consider the case where one RTO does not conduct a DA process, but only performs scheduling and congestion management on an hourly basis several hours prior to each operating hour.
- Linkage between unit-specific bid requirement and RTO unit commitment. If portfolio energy bids are not allowed – i.e., SC must commit specific resources in DA process – then should each RTO be willing to provide unit commitment cost compensation (i.e., along the lines of CAISO’s proposal to guarantee start-up and minimum load costs for units it commits)? This appears not to be an issue, since CAISO is the only DA energy market, and CAISO already incorporates SU/ML cost compensation. Alternatively, if parties want to pursue SU/ML cost compensation it is probably outside the scope of this group.

NEXT STEPS

1. Finish DA settlements proposal.

2. Incorporate DA A/S markets. Each RTO to provide draft of its AS proposal.

3. Incorporate DA accounting for transmission losses. Each RTO to provide draft of its losses proposal.

4. Details of SMI processing & validation for Step 1.

QUESTIONS

Do we have enough specificity after the above topics to prepare a SOW for consultant.

Handoff business rules & other directions for input to SMI group.

5. Portfolio Bidding (including Trading Hub bidding, Virtual Bidding). – **Restructure this issue in the issues list.**

6. Non-participants – specifically an LADWP-like entity.

7. Incorporating phase shifters in DA.

APPENDIX

EXAMPLES TO ILLUSTRATE INTER-RTO SETTLEMENT

The actual basis of inter-RTO settlements can be traced back to particular aspects of the DA scheduling and congestion management process, such as (1) re-dispatch costs to alleviate congestion, including congestion resulting from loop flows, and (2) settlement of trading hub transactions that cross RTO boundaries.

The following examples, expanding upon the brief discussion of Step 5 above, are provided to illustrate some possible approaches to the inter-RTO settlement issues. These examples use shift factors to measure the quantity of scheduled flow on each inter-RTO interface. This approach was adopted in these examples in lieu of carrying out a power flow solution. In practice, once a converged solution is obtained, the inter-RTO scheduled flows and prices are available from the converged solution with no need to resort to the shift factors. To determine the impact of individual (source-to-sink) SC schedules on inter-RTO flows (regardless of whether the source and the sink are in the same or different RTOs) requires an additional step, however. For this it is convenient to adopt a common reference bus (agreed upon by all three RTOs) and use shift factors that relate the injection at each point in the common network model to the inter-RTO flows. The set of shift factors may be derived off-line based on normal network state (all lines in service), or on the fly based on the network topology used in the common network model at the time. Selecting a method for measuring the impact of individual SC schedules on inter-RTO flows is another open issue to be pursued in future work.

Example 1. Scheduling Coordinator SC1 with generation at point A inside RTOW bids 100 MW at $50 into the CAISO DA energy market. The CAISO market procures all 100 MW from SC1, and produces a LMP of $50 at point A and a LMP of $70 at the load location B inside CAISO (assume for simplicity that all load inside CAISO is aggregated to a single node). Assume that these results stand unadjusted at the conclusion of Step 4. That would mean among other things that the LMP at point A as seen by RTOW is also $50.[20] Using approach (B-C) mentioned earlier, CAISO then collects $7,000 from its load and pays $5,000 to SC1.

The remaining $2,000 represents congestion revenues that must be paid out to: (1) holders of CRRs inside CAISO, (2) RTOW and WC for the usage of their transmission system to deliver the power to their tie points with the CAISO control area. The transmission usage charges will be based on the pattern of MW flows on the interfaces attributed to this specific transaction as computed by the set of shift factors of the source and the sink of the transaction. For example, suppose that a location in WC is adopted as the reference for the shift factors by all RTOs, and that there are 5 inter-RTO ties as follows:

[20] The nodal aggregation used in constructing the common network model from the detailed RTO-specific models guarantees that the LMP as seen by RTOW at the different RTOW internal nodes comprising the common network node seen by CAISO are practically the same (slight variations may exist due to looped network structure). Moreover, since all final schedules are the same as seen by all RTOs (same source and sink quantities, with the source and sink represented by aggregated nodes for external RTOs), price convergence at the seams would mean price convergence at all nodes.

- TRC, from RTOW to CAISO
- TRW1 and TRW2, two ties from RTOW to WC
- TWC1 and TWC2, two ties from WC to CAISO

Assume that the shift factors for location A (in RTOW) and location B (in CAISO) are as follows:

Shift Factors

Tie	TRC	TRW1	TRW2	TWC1	TWC2
Location A	+ 0.42	+ 0.40	+ 0. 18	- 0.11	- 0.31
Location B	- 0.38	+ 0.28	+ 0.10	- 0.16	- 0.46

Then, for a schedule of 100 MW from A to B, the injection at A is + 100 MW and the injection at B is – 100 MW. Multiplying by the shift factors and adding results in the tie flow quantities shown in the first row of the following table. Assume that the converged prices at the interfaces are as shown in the second row:

Tie	TRC	TRW1	TRW2	TWC1	TWC2
Scheduled Flow[21]	80 MW	12 MW	8 MW	5 MW	15 MW
Converged Prices	$60	$56	$54	$64	$66

Then, the usage charges are computed as follows:

Transmission Usage Charge Computation

From	A	A	A	TRW1/TRW2	TRC	TWC1	TWC2	Total
To	TRC	TRW1	TRW2	TWC1/TWC2	B	B	B	-
$	$800	$72	$32	$206	$800	$30	$60	$2,000
Subtotals	RTOW = $ 904			WC = $206	CAISO = $ 890			$2,000

Approach (A-D) would perform inter-RTO settlements based on computed net inter-RTO flows and converged prices. Each RTO would then settle with all SCs having supply or demand scheduled within their control area regardless of whether the intended sink or source is in the same or a different RTO control area. Under such settlement scheme, in this example, RTOW would pay the supplier at the locational price of $50, and then collect the boundary price times the corresponding boundary net flow quantities from the respective RTOs regardless of which transaction caused what portion of each tie-line flow. With converged prices, the financial result would be the same, but the settlement process would be simpler. The amount of $ going back

[21] The scheduled flow represents the flow on the tie associated with the schedule from A to B. It is computed as (Injection at A)*(Shift Factor of A) + (Injection at B)* (Shift Factor of B) = 100*SFA – 100*SFB.

and forth among the RTOs would be larger, however, since each RTO would no longer settle directly with generators or loads within the other RTOs. Basically, the point of view under this type of settlement would be that the power supplied at point A is used by RTOW and RTOW delivers power to the neighboring RTOs.

Alternative Settlement Process

RTO	Buy at	Sell at	MW	Price	$	Net $
RTOW	A	-	100	$50	($5,000)	$904
RTOW	-	TRC	80	$60	$4,800	
RTOW	-	TRW1	12	$56	$672	
RTOW	-	TRW2	8	$54	$432	
WC	TRW1	-	12	$56	($672)	$206
WC	TRW2	-	8	$54	($432)	
WC	-	TWC1	5	$64	$320	
WC	-	TWC2	15	$66	$990	
CAISO	TRC	-	80	$60	($4,800)	$890
CAISO	TWC1	-	5	$64	($320)	
CAISO	TWC2	TWC1	15	$66	($990)	
CAISO	-	B	100	$70	$7,000	

Revised Convergence Process (10/1-2)

Step 0 – as before

Step 1 – as before

Step 2 – as before – CAISO IFM

Step 3A – as before – RTOW scheduling & CM incorporating CAISO IFM results

Step 3B – as before – WC scheduling incorporating CAISO IFM results

SNAPSHOT A after Step 3B – All dispatch quantities resulting from Steps {2, 3A, 3B} based on independent processes of each RTO, and the implied inter-tie flows resulting when the quantities are applied to the common network model (QA). Since each RTO's process ignores congestion inside the other RTOs this snapshot is probably not feasible for the system because of parallel flows created by the separate processes. These quantities become the benchmark for flows that are subtracted off the inter-tie flows resulting from Step 4 to determine the incremental flow changes used for inter-RTO settlement.

Step 4 – Convergence process – re-dispatches for CM and produces prices (P = {PG, PI, PL}) common to all RTOs at all common network model nodes including inter-tie points. These will all be LMPs including at the inter-tie points.

SNAPSHOT B – Injection & withdrawal quantities and inter-tie flows, feasible for whole system (QB).

Step 5 – Settlements

RTO-SC Energy Settlements = PG * QA where PG is the generator node LMP and QA is the generator dispatch level. This refers specifically to CAISO settlement with external generators that sell into CAISO IFM.

CAISO CM Settlements PI * QIA – PG * QGA

RTO-RTO Flow Settlements (inter-tie points) = PI * (QB – QA), due to inter-RTO convergence adjustments.

RTO-SC CM Settlements = PG * (QB – QA) for generators internal to each RTO, where PG, QB, QA refer to specific generator (although different RTOs may choose to perform this settlement differently).

Settlement example.

Qga in RTOW = 100 MW sale into CAISO @ P = $26

Qia into WC = Qia from WC into CA = 40 MW

Qia into CA from RTOW = 60 MW