UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	**)** **)**	**Docket No. ER14-2017-000**

ANSWER OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION TO COMMENTS AND LIMITED PROTEST

The California Independent System Operator Corporation ("ISO")[1] files this answer to the comments and limited protest submitted in the captioned proceeding[2] in response to the ISO's May 22, 2014 tariff amendment to implement modeling enhancements in the ISO markets ("May 22 filing").[3]

The Commission should accept the ISO's proposed tariff amendment with the one change proposed by the ISO in this answer in response to Southern

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1 Capitalized terms not otherwise defined herein have the meanings set forth in appendix A to the ISO tariff, as revised by the proposed tariff changes contained in the filing the ISO submitted in the captioned proceeding. Except where otherwise specified, references to section numbers are references to sections of the ISO tariff as revised by the proposals in that filing.

2 The following entities filed motions to intervene and/or comments in the proceeding: the Balancing Authority of Northern California; Bonneville Power Administration ("BPA"); California Department of Water Resources State Water Project; California Municipal Utilities Association; City of Redding, California, and M-S-R Public Power Agency; City of Santa Clara, California d/b/a Silicon Valley Power ("SVP"); Imperial Irrigation District ("IID"); Modesto Irrigation District; Northern California Power Agency; NRG Power Marketing LLC and GenOn Energy Management, LLC; Pacific Gas and Electric Company ("PG&E"); Powerex Corp. ("Powerex"); Sacramento Municipal Utility District ("SMUD"); Southern California Edison Company ("SCE"); and Transmission Agency of Northern California. In addition, Powerex filed a limited protest.

3 The ISO files this answer pursuant to Rules 212 and 213 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.212, 385.213. The ISO requests waiver of Rule 213(a)(2), 18 C.F.R. § 385.213(a)(2), to permit it to make an answer to the limited protest filed by Powerex. Good cause for this waiver exists here because the answer will aid the Commission in understanding the issues in the proceeding, provide additional information to assist the Commission in the decision-making process, and help to ensure a complete and accurate record in the case. *See, e.g.*, *Equitrans, L.P.*, 134 FERC ¶ 61,250, at P 6 (2011); *California Independent System Operator Corp.*, 132 FERC ¶ 61,023, at P 16 (2010); *Xcel Energy Services, Inc.*, 124 FERC ¶ 61,011, at P 20 (2008).

California Edison's proposal to adopt an accuracy metric that would trigger the temporary suspension of modeling of unscheduled flow in the day-ahead market and with certain minor clarifications the ISO commits to make in this answer in response to various comments.

I. Summary

In the May 22 filing, the ISO proposes tariff amendments to implement important modeling enhancements which include the authority to model unscheduled flow in the ISO's day-ahead market, the enforcement of power flow constraints in the day-ahead market, and the expansion of the full network model topology to include information on resources, load, and interchange schedules in other balancing authority areas. These enhancements will provide significant reliability and market efficiency benefits.

Many commenters support most or all of the ISO's filing.[4] The most significant concern raised by intervenors relates to the extent of the ISO's discretion to determine when to model unscheduled flow in the ISO's day-ahead market. As explained in the May 22 filing, the discretion sought by the ISO is consistent with precedent, including the discretion the Commission has previously afforded other independent system operators and regional transmission organizations addressing unscheduled flow issues. In light of the concerns raised by a number of commenters, however, the ISO is prepared – if directed by the Commission – to adopt as a transitional mechanism a refined version of the accuracy metric proposed by SCE that if met would cause the ISO

4 *See* PG&E at 3-4; SCE at 2.

to temporarily suspend modeling of unscheduled flow in the day-ahead market. The details of this refined mechanism are described below. The refined metric ensures that the ISO will model the total unscheduled flow in the day-ahead market only when the modeling is sufficiently accurate and reliable, thereby ensuring that the market outcomes are no worse than they would have been absent the modeling of such flows. The addition of the refined metric to the ISO tariff in a compliance filing will address commenter concerns that the ISO will have unlimited discretion in determining when to model unscheduled flow in the day-ahead market. The ISO will implement this mechanism in a transparent manner, with daily updates on the metric and notice to the market when the metric results in the temporary suspension of the consideration of unscheduled flow in the day-ahead market and when such suspension is lifted. The ISO proposes to adopt this metric for a transitional period of one year after October 1, 2014, the effective date of the proposed amendment, after which the ISO proposes to sunset this requirement once it has demonstrated that it has met the metric for six consecutive months.

The ISO addresses comments on other issues. To address concerns about maintaining protections for sensitive reliability data, the ISO is prepared to revise the tariff in a compliance filing to make clear that unscheduled flow data is only available to parties that have also signed the Western Electricity Coordinating Council ("WECC") Universal Non-Disclosure Agreement. The ISO also reiterates that it will enhance its modeling of integrated balancing authority areas as part of the ISO's proposal.

One commenter questions the ISO's proposal to enforce physical flow constraints at intertie interfaces in the day-ahead market similar to how it enforces such constraints in the real-time market today, claiming that the ISO's proposal is not "necessary." The ISO is not required to show that a beneficial change is "necessary" in order to show that it is just and reasonable, and the ISO already has demonstrated that the enforcement of physical flow constraints in the day-ahead market is a just and reasonable approach to ensuring uniformity between the day-ahead and real-time markets.

The same commenter opposes the ISO's implementation of a full network model containing the topology, sources and sinks external to the ISO's balancing authority area. As explained in the May 22 filing and below, the proposed expansion of the full network model and other modeling enhancements are responsive to the joint recommendations of the staffs of the Commission and the North American Electric Reliability Corporation ("NERC") following the September 8, 2011 outage event. The modeling enhancements proposed in the May 22 filing address the recommendation that the ISO and other balancing authority areas should better coordinate their day-ahead planning. By incorporating a more accurate representation of flows on the interconnected grid, the ISO will produce more feasible day-ahead schedules that align more closely with actual system conditions. The expansion is also supported by both the Market Surveillance Committee ("MSC") and the Department of Market Monitoring ("DMM"). The Commission should accept the ISO's proposed expansion of the full network model effective September 8, 2014. Being able to implement the expanded full network model on that day will support the ISO's transition to the energy imbalance market on October 1, 2014.

This commenter expresses general support for the objectives of the ISO's filing but argues that the ISO should only be permitted to implement modeling enhancements in its markets or to respond to the recommendations of the staff report on the September 8, 2011, outage event as part of an inter-regional effort supported by all balancing authorities in the Western Interconnection. The arguments of this commenter are misplaced. The ISO will continue to engage in ongoing inter-regional coordination efforts. While such efforts are underway, it is entirely reasonable for the ISO, as the only organized market in the western United States, to take measures to ensure that its modeling produces feasible schedules that support both the reliable operation of the ISO controlled grid and efficient operation of the ISO markets. There is no reason based on either precedent or policy considerations to require the ISO to ignore the clear impacts of the interconnected nature of the Western interconnection in establishing schedules and prices on its system.

The proposed modeling enhancements will complement the new energy imbalance market recently approved by the Commission that will allow other balancing authority areas in the West to participate in the ISO's real-time market for imbalance energy.[5] The enhanced model will provide improved power flow solutions for the combined ISO and energy imbalance market footprint, thereby improving the quality of market solutions and supporting the feasibility of energy

[5] *California Independent System Operator Corp.*, 147 FERC ¶ 61,231 (2014).

imbalance market schedules. The proposed modeling enhancements support more accurate dispatch and pricing once the energy imbalance market is implemented.[6]

For all the reasons explained in the May 22 filing and below, the Commission should accept the ISO's tariff amendment to implement modeling enhancements as submitted in this proceeding, subject only to the modifications the ISO commits to make in this answer, including the commitment to implement, if directed by the Commission, a transitional mechanism under which the ISO would model unscheduled flow in the day-ahead market only if an accuracy metric is satisfied.

II. Answer

A. The ISO Is Prepared to Model Unscheduled Flow in the Day-Ahead Market Only If an Accuracy Metric Is Satisfied

A number of commenters express concerns over the degree of discretion the ISO seeks to have to determine when to model unscheduled flow in the day-ahead market. SCE generally supports providing the ISO with flexibility in modeling unscheduled flows, but argues that the Commission should direct the ISO to adopt a framework to ensure that the ISO's incorporation of unscheduled

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[6] The Commission's order conditionally accepting the energy imbalance market recognizes the benefits of the modeling enhancements while noting that Commission action on the May 22 filing is still pending. *California Independent System Operator Corp.*, 147 FERC ¶ 61,231 at P 181 ("CAISO's proposal includes a mechanism to incorporate expected EIM results into the day-ahead market. The quality of this modeling effort may determine the extent to which price separation between the day-ahead and real-time market occurs. Further, existing modeling and market price separation can be affected by conditions, such as loop-flow, arising outside CAISO's borders. Enhanced insights into markets outside CAISO from the addition of balancing authorities in the EIM, as well as CAISO's full network model proposal, may improve CAISO's modeling and convergence of prices in the two markets").

flow estimates in the day-ahead market is reasonable.[7] Similarly, SMUD's principal concern with the May 22 filing is that it reserves broad discretion to the ISO as to when, whether, and to what extent it will enforce intertie flow constraints in the day-ahead market.[8] Other commenters raise similar concerns.[9]

SCE asks that the Commission require that the ISO only model unscheduled flow in the day-ahead if such modeling improves the overall modeling relative to not modeling these flows. SCE proposes a metric that, if not satisfied, would result in the temporary suspension of such modeling until the ISO demonstrates that unscheduled flow measurements improve above the specified metric.[10]

The ISO is not seeking discretion as to when to model unscheduled flow in the day-ahead market beyond the discretion the Commission granted the ISO in the past for the real-time market and that has been exercised by other independent system operators and regional transmission organizations in considering unscheduled flow.[11]

Nonetheless, in order to address the concerns raised by commenters on the May 22 filing, the ISO is prepared to adopt a transitional mechanism under which the ISO would model unscheduled flow in the day-ahead market only if a

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7 SCE at 3.

8 SMUD at 3.

9 *See* Powerex at 23-24; IID at 8.

10 SCE at 3-7 and attachment.

11 Transmittal letter for May 22 filing at 23-24.

metric measuring the accuracy of the estimates is satisfied.[12] The ISO views this as an extraordinary measure to address the pre-implementation concerns of some commenters and believes such a metric should be in place for no more than a year once there is evidence that the ISO's modeling enhancements are working as intended. The ISO proposes a number of refinements to the SCE proposal that provide a better measurement of the accuracy of unscheduled flow estimates. The ISO will adopt this mechanism if directed by the Commission and is prepared to submit tariff changes to implement this mechanism in a compliance filing.

The metric proposed by SCE is generally reasonable, but the ISO has concluded that some elements of the test proposed by SCE would need to be refined to be an effective mechanism that the ISO can implement on October 1, 2014. The following is an overview of the refined metric that the ISO is prepared to implement if directed by the Commission:

- The ISO will compare the magnitude of the difference between actual unscheduled flow on the interties and the ISO's modeled unscheduled flow per hour in MWhs under two scenarios: one in which the ISO does model external unscheduled flow and one in which the ISO does not. Under both scenarios, the ISO will reflect the expanded full network model topology where the interties are non-radial.

- Unscheduled flow measured for this metric is the flow due to external base schedules.

- Data will be compared over a rolling three week period.

- If the metric shows that the scenario where the ISO models unscheduled flow is not closer to actual flow than the scenario where the ISO does not model unscheduled flow (*i.e.*, does not satisfy the accuracy standard), the ISO will

[12] Even if the metric is satisfied, the ISO would retain the discretion to elect not to consider unscheduled flow in the day-ahead market based on operational or reliability considerations.

suspend the consideration of unscheduled flow due to external schedules in the day-ahead market.

- The ISO will accomplish such suspension by disabling the impact of net scheduled interchange between external balancing authority areas. During such suspension, the expanded topology of the full network model will remain in effect and there will still be unscheduled flow resulting from ISO market schedules.

- The ISO will need to show that the three week rolling total satisfies the accuracy standard before reintroducing unscheduled flow from external base schedules. The ISO will also provide market participants with advance notice when the ISO disables or enables the consideration of unscheduled flow in the day-ahead market.

- The metric will be calculated on an intertie-by-intertie basis but summed up across the ISO market to apply the metric. To promote transparency, the ISO will publish daily updates on its metric calculations for interties and on an aggregate basis.

- The ISO will exclude from the metric the impact of the following unforeseen real-time events: the loss of direct current transmission lines, unexpected outages of generators over 1,000 MW, or a derate of over 1,000 MW at any intertie.

- The ISO proposes to adopt this mechanism for a transitional period of one year after October 1, 2014, after which the mechanism will cease to be effective once the accuracy standard has been satisfied for six consecutive months.

Based on conversations with SCE prior to filing this answer, the ISO has received reasonable assurances that SCE supports the refined metric proposed by the ISO with the exception of the sunset provision. The ISO believes it is critical that this mechanism be adopted on only a transitional basis. The overwhelming majority of enhancements to the ISO's market design are implemented without a need for an ongoing mechanism to confirm that they produce just and reasonable results. Requiring such affirmation on an ongoing basis would introduce significant administrative costs. The ISO is prepared to adopt such a mechanism for a limited period in these circumstances in recognition of the pre-implementation concerns of some commenters. Once the metric has been satisfied for six consecutive months at any time more than a year after implementation of the modeling enhancements, there will be no need for the trigger to remain in effect. At that time, other metrics will be available for all parties to confirm that the modeling enhancements continue to produce just and reasonable market results. The ISO therefore urges the Commission to accept the metric proposal with the sunset provision.

The following is a description of the other refinements to the SCE proposal that SCE does support. SCE proposes that the ISO measure and compare two sets of modeling errors every hour, defined as the difference between modeled flow and actual flow for each inter-tie over a rolling two week period. To the extent the total accuracy metric (over a two week period in the SCE proposal) demonstrates that the ISO's forecasting of unscheduled flow is closer to the actual flow than "doing nothing," the ISO would continue to model unscheduled flow in the day-ahead market. If the total for the two week rolling period does not satisfy the standard, the ISO would continue to forecast the unscheduled flow but would not include such unscheduled flow in the day-ahead market.

SCE defines a metric that measures the magnitude of the difference between actual unscheduled flow and the ISO's modeled unscheduled flow per hour in MWhs, and refers to this difference as the "modeling error." The total error is the sum of the individual hourly modeling errors which SCE refers to as the "Error With Forecasting" or "EWF." SCE then considers a scenario in which the ISO does not model unscheduled flow, which it characterizes as the "default ‘forecast’ is thus zero” and the error measures the magnitude of the difference between zero and the actual unscheduled flow, which it labels as the “Error Without Forecasting” or “EWoF.” SCE’s metric would then compare the “Error With Forecasting” to the “Error Without Forecasting.” SCE’s proposal to base the metric on the Error Without Forecasting where the unscheduled flow is zero reflects the notion that the ISO interties are radial, which would be inconsistent with the ISO’s actual modeling approach after October 1. Therefore, the ISO proposes to clarify SCE’s EWF and EWoF metrics to reflect the presence of the expanded full network topology where the interties are non-radial under both scenarios, which is also consistent with how the ISO would actually suspend modeling of unscheduled flows at the interties. The EWoF metric therefore would eliminate the potential uncertainty associated with the ISO’s forecasting of net interchange.

SCE’s proposal would compare data over a rolling two week period. The ISO believes this time period is likely too short to develop a meaningful pattern and to see the impact of potential tuning. The ISO proposes to apply the accuracy metric over a rolling three week period.

The ISO agrees that, if its forecast of unscheduled flow does not satisfy the accuracy metric, the ISO will stop considering unscheduled flow in the day-ahead market. SCE proposes that, should the forecast of unscheduled flow fail to satisfy the accuracy measure, “the CAISO should stop modeling loop flow until it can improve upon its forecasting ability.”[13] SCE does not explain how the

[13] SCE at 12.

suspension is accomplished. The ISO clarifies that the ISO would accomplish such suspension by disabling the impact of net scheduled interchange between external balancing authority areas. During such suspension, the expanded topology of the full network model will remain in effect, and there will still be unscheduled flow resulting from ISO market schedules. In order to maintain the power flow solution, the ISO may still need to model the demand and generation for each external balancing authority area (again, the impact of the net scheduled interchange impact will be disabled).

SCE proposes that:

> . . . the CAISO should continue to forecast loop flow via an ‘outside the market’ process, but this forecasted flow should not be included in the [day-ahead market] DAM. Then, once the two week metric shows benefits of being better than ‘doing nothing’ (the two week data could include both modeled and forecast loop flow if the CAISO could resolve the issue quickly) the forecasting accuracy has improved sufficiently that loop flow should once again be modeled and included in the DAM.[14]

The ISO proposes that, in the event the accuracy metric for modeling of unscheduled flow does not satisfy the standard specified in the tariff, the ISO would not incorporate the impact of unscheduled flow resulting from external base schedules into the day-ahead market as described above, but would continue to measure the accuracy metric offline. The ISO will not reintroduce the modeling of unscheduled flow in the day-ahead market until its offline metric demonstrates that it has passed the metric standard over a total three week rolling period. The ISO will then reintroduce the modeling of unscheduled flow in

[14] SCE at 12.

the day-ahead market within the timeline made possible by the ISO's market and pre-market process requirements.

SCE proposes application of its proposed metric to each intertie without specifying how the "trigger" to discontinue modeling unscheduled flow in the day-ahead market would apply on an intertie-by-intertie basis. The ISO proposes that the "trigger" be based on the market as a whole, rather than based on individual interties. This is more appropriate since disabling the impact of external base schedules will impact all of the ISO market (as compared to other tuning parameters which can be more limited in scope and application). The metric will be calculated by intertie but summed up as an overall ISO metric. The ISO will exclude from the metric the impact of the following unforeseen real-time events: the loss of direct current transmission lines, unexpected outages of generators over 1,000 MW, or a derate of over 1,000 MW at any intertie. In these circumstances, the ISO would not have been able to project the occurrence of the real-time event to include in forecasts. The hours removed from the metric will be documented when the ISO publishes its daily updates on the metric. The metric will use the absolute value of differences between projected and actual as compared to actual and weighted by the capacity of each intertie. However, the suspension of modeling of unscheduled flow in the day-ahead market would apply market-wide rather than on an intertie-by-intertie basis. In order to promote transparency, the ISO will publish the results of the accuracy metric analysis for the interties with daily updates but will also provide daily updates of the aggregate analysis which will serve as the trigger. The ISO will also provide market participants with advance notice when the ISO disables or enables the consideration of unscheduled flow in the day-ahead market.

Although the ISO believes that its proposed modeling enhancements could be accepted without such a mechanism, adoption of the refined metric should address the most significant concerns raised in response to the May 22 filing. Adoption of the metric will address many of the concerns raised by Powerex, the only party to protest the ISO's filing. For example, implementing the refined metric will:

- Provide a means specified in the tariff for the ISO to determine when to model unscheduled flow in the day-ahead market, rather than leaving that determination to the ISO's discretion;[15]
- Provide transparency to market participants as to the ISO's determinations on whether to model unscheduled flow;[16]
- Alleviate concerns that the ISO's pre-implementation plan will not be sufficient to show that the ISO's proposal is just and reasonable;[17]
- Provide further assurances to the Commission that the proposal to model unscheduled flow in the day-ahead market will only be implemented when it is just and reasonable;[18] and
- Better ensure that the outcomes of the ISO's proposal will be within the zone of reasonableness.[19]

The ISO notes that its willingness to adopt a mechanism under which the ISO would model unscheduled flow in the day-ahead market only if an accuracy

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15 *See* Powerex at 23-24.

16 *See id.* at 4.

17 *See id.* at 19-22.

18 *See id.* at 8.

19 *See id.*

metric is satisfied is in addition to the commitment the ISO has already made to provide the Commission and stakeholders with the results of a pre-implementation analysis of the ISO's modeling of unscheduled flow during a test period which will demonstrate the effectiveness of such modeling before the ISO actually implements the modeling of unscheduled flows in the day-ahead market. In addition, the ISO has committed to several benchmarking metrics to compare the market flows to actual flows, to track the use of compensating injections in the real-time, and to track the real-time congestion imbalance offset costs.[20] These metrics are designed to help the ISO and interested parties to measure the effectiveness of the modeling enhancements, improve its modeling, and indicate areas for further analysis both before and after the sunset of the transitional metric mechanism.

B. The ISO's Proposal Is Consistent with Inter-Regional Non-Disclosure Agreements

IID expresses concern that the ISO's proposal will result in breach of the WECC Universal Non-Disclosure Agreement because the ISO proposes to disclose unscheduled flow estimates reflecting data provided to the ISO under this Universal Non-Disclosure Agreement.[21] IID's concerns are unwarranted. First, the unscheduled flow data to be disclosed by the ISO will be highly aggregated and will not be the actual data received by the ISO under this Universal Non-Disclosure Agreement. Moreover, under the ISO's proposal, the

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20 Draft Final Proposal at 39.

21 IID at 9-10.

ISO only intends to provide unscheduled flow data under new tariff section 6.5.10.1.5 to those parties that have also signed the WECC Universal Non-Disclosure Agreement. The ISO intended to implement that requirement through existing provisions in tariff section 6.5.10, which requires parties to sign a non-disclosure agreement as a prerequisite to being provided protected data by the ISO. Upon further consideration of the matter, the ISO notes that the existing provisions in section 6.5.10 may not be sufficiently specific about the requirement to sign a WECC Universal Non-Disclosure Agreement. If directed by the Commission, the ISO is prepared to clarify section 6.5.10.1.5 in a compliance filing to state that unscheduled flow data is only available to parties that have also signed the WECC Universal Non-Disclosure Agreement.

C. The ISO Will Include Integrated Balancing Authority Areas in Its Enhanced Modeling

SVP argues that the ISO should include integrated balancing authority areas ("IBAAs") in its modeling proposal.[22] SVP's concerns are misplaced. The statement that SVP cites to support their concern that integrated balancing authority areas will not be part of the modeling is from an appendix to the ISO's draft final proposal. The draft final proposal clearly notes that the discussion in

[22] SVP at 2-6. Integrated balancing authority areas are interconnected with the ISO. Each integrated balancing authority area has power flows that have been determined to significantly affect power flows within the ISO balancing authority area. Therefore, the network topologies of integrated balancing authority areas are modeled in the full network model in greater detail than the modeling of interties in a radial fashion that applies to other interconnected balancing authority areas. Currently the integrated balancing authority areas are: (1) SMUD, which includes the transmission facilities of (a) Western Area Power Administration – Sierra Nevada Region, (b) Modesto Irrigation District, (c) City of Redding, and (d) the City of Roseville; and (2) Turlock Irrigation District. Tariff section 27.5.3.1; tariff appendix A, definition of "integrated balancing authority area."

the appendix was not part of the current stakeholder initiative and was therefore not presented to the ISO Board or discussed in the May 22 filing. The ISO further refined certain aspects of its proposal before submitting the May 22 filing. The transmittal letter for the May 22 filing makes it clear that the ISO will enhance its modeling of integrated balancing authority areas:

> The ability to use the same network model for the base market model and the energy management system will allow the ISO to replace the base market model's separate representation of the looped transmission grid in the Balancing Authority of Northern California and Turlock Irrigation District balancing authority areas with the energy management system's network model. This will better allow the ISO to reflect outages in these areas and improve the management of the ISO controlled grid.[23]

SVP's comments ask that the Commission direct the ISO to model integrated balancing authority areas, which the ISO has already agreed to do. The ISO notes that SVP does not ask for a change in pricing points for integrated balancing authority areas and the ISO does not propose to change those points in the May 22 filing. SVP does reference the market efficiency enhancement agreement ("MEEA") the ISO has entered into with SMUD. The market efficiency enhancement agreement is the means by which integrated balancing authority area pricing changes can be pursued. The ISO stands ready to discuss these issues with SVP but notes that the ISO's proposal in this proceeding does not involve the market efficiency enhancement agreement.

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[23] Transmittal letter for May 22 filing at 18-19.

D. The ISO's Proposed Methodology for Forecasting Unscheduled Flows Is Just and Reasonable

Some commenters suggest that the ISO's methodology for forecasting unscheduled flows in the day-ahead does not provide a representative estimate because the ISO will obtain the information to perform a "snapshot" forecast via the WECC interchange tool at approximately 9:00 a.m. of the day prior to delivery, but BPA does not begin to offer hourly transmission service on its network until 9:00 a.m. or later and day-ahead interchange schedules in the WECC are not due until 3:00 p.m.[24]

These comments improperly disregard the ISO's explanation in the May 22 filing that, while no methodology can guarantee perfect predictions, the ISO's methodology will provide the best possible estimate of unscheduled flow based on available external load, generation, and interchange data prior to running the day-ahead market. The ISO will not simply take a snapshot of data available at 9:00 a.m. and assume that the unadjusted data reflects actual day-ahead transactions. Instead, the morning data will be validated and adjusted to the forecasted level of interchange, and the ISO will track the accuracy of the morning projections against historical tag data. In analyzing the historical tag data, the ISO will look at both historical data based on the day-ahead tag submission deadline (at 3:00 p.m.) and all tags submitted by the real-time deadline (20 minutes before flow).[25]

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[24] Powerex at 16-19; BPA at 4-5; SMUD at 4-5.

[25] Transmittal letter for May 22 filing at 26, 38.

The ISO will not use schedule data for modeling unscheduled flow in the base market model that the ISO believes are not sufficiently accurate. The ISO will compare the demand forecasts to a historical analysis of actual demand, and the ISO can fine-tune the demand forecasts if needed by scaling the forecasts up or down. Similarly, net scheduled interchange(s) and/or entire schedule(s) may be adjusted to neutralize their impact. The ISO will have the flexibility to make adjustments for one, multiple, or all interconnected balancing authority areas as the situation requires.[26]

Also, as discussed above, the ISO is prepared to implement a mechanism to assess the accuracy of its modeling of unscheduled flow in the day-ahead market and will suspend modeling of unscheduled flow in the day-ahead market if the ISO's modeling falls below an accuracy metric threshold. These measures may be triggered when the ISO's forecasts, as adjusted, are not sufficiently accurate.

Powerex argues that the ISO's proposed methodology for forecasting unscheduled flows in the day-ahead ignores generation and/or loads that deviate from scheduled quantities. Powerex asserts that WECC has determined that such quantities are an important root cause of unscheduled flow.[27] The WECC committee reports that Powerex cites do not support Powerex's argument, instead being analyses of the performance of the Reliability Based Control field trial, and not of unscheduled flow. Coordinated operation of phase shifters has

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[26] Transmittal letter for May 22 filing at 26-27.

[27] Powerex at 15-16.

been one of the first steps in WECC's procedure for managing unscheduled flow, and the reports found that although the number of hours of coordinated operations of phase shifters increased dramatically in 2011 for Path 36 and in 2012 for Path 66, a relationship to the field trial could not be established because the anomalies appeared in only one of the four field trial years and are more likely due to other factors.

BPA argues that Peak Reliability should lead the coordination between utilities in the West on, among other things, developing modeling enhancements, the use of interconnected system data, and loop flow prediction.[28] BPA presents no evidence that Peak Reliability could perform these functions or plans to develop this capability, thus rendering BPA's comments meaningless for the foreseeable future. The ISO intends to use the same data available to Peak Reliability as part of its modeling enhancement efforts. Moreover, day-ahead regional reliability studies using data provided by balancing authority areas to Peak Reliability are not available before the start of the ISO's day-ahead market. Peak Reliability does not currently set or verify day-ahead schedules within or between balancing authority areas, or otherwise develop forecasts of conditions that balancing authority areas may consider in preparing their own day-ahead operating plans, as are needed to implement the ISO's proposal.[29] The ISO, conversely, has extensive experience with developing and using such forecasts as part of its responsibilities for market administration and system operation. It is

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[28] BPA at 4.

[29] *See* https://www.peakrc.com/whatwedo/Pages/default.aspx.

possible that Peak Reliability may take on forecasting responsibilities in the future, and the ISO would be prepared to consider how best to work with Peak Reliability at that time, but for the present only the ISO has the ability and experience to undertake these efforts. As discussed further in Section II.F below, the ISO should not be prevented from enhancing its own markets and operations until regional coordination efforts in the West have made more progress.

E. More Accurate Modeling of Unscheduled Flows Will Significantly Reduce Real-Time Congestion Offset Costs

Powerex argues that the ISO fails to show that more accurate modeling of unscheduled flows will reduce real-time congestion offset costs to a significant degree. Powerex cites a DMM statement that real-time congestion offset costs in 2013 were primarily due to unpredictable real-time conditions rather than unscheduled flows.[30] However, Powerex overlooks the fact that unscheduled flows are a significant contributor to real-time congestion offset costs, even if they are not the primary cause.[31] Had DMM's analysis indicated that unscheduled flows did not contribute to real-time congestion costs, the DMM likely would have raised issues with the ISO's modeling enhancement proposal. Instead, the DMM explained in a memorandum to the ISO Governing Board that it "strongly supports" the modeling enhancements, in part because they will provide "the opportunity for increased market efficiency from more accurate pricing of

[30] Powerex at 10-11 (quoting DMM, 2013 Annual Report on Market Issues and Performance at 81).

[31] *See* transmittal letter for May 22 filing at 14 ("While the congestion offset costs are not solely caused by unscheduled flow, more accurate modeling of such flows would address one of the root causes of the uplift and would reduce the overall amount of such costs.").

schedules <u>and lower congestion uplifts</u>."[32] Further, the MSC agreed that a "benefit of better loopflow modeling in the day-ahead market will be reductions in real time congestion rent shortfalls."[33]

Powerex also cites the reduction in real-time congestion offset costs from 2012 to 2014 to support a claim that there is no need for the ISO to address unscheduled flow.[34] Although these costs have gone down over that time, congestion uplift costs still amounted to $31 million for 2014 as of the submittal of the May 22 filing, *i.e.*, $31 million over less than the first half of 2014.[35] This is a significant amount of uplift that the modeling enhancements will help to reduce. Given the ongoing presence of congestion uplift costs of this magnitude, it is entirely reasonable for the ISO to make modeling enhancements that will reduce the amount of uplift costs even further.

F. The ISO's Proposal Is Consistent with Commission Precedent

Powerex argues that the ISO's proposed approach to addressing unscheduled flows is inconsistent with Commission policy that purportedly

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32 Memorandum from Eric Hildebrandt, Director, DMM to ISO Governing Board at 1 (Jan. 30, 2014) (emphasis added) ("DMM memorandum"). *See also id.* at 3 ("In addition to increasing reliability, this expanded network model may help reduce real-time congestion imbalance offset costs that are incurred when unscheduled real-time flows create the need to reduce flows created by schedules awarded in the day-ahead market."). This DMM memorandum is provided in attachment A to this answer and is available on the ISO website at http://www.caiso.com/Documents/DepartmentMarketMonitoringReport-Memo-Feb2014.pdf.

33 MSC opinion, attachment E to May 22 filing, at 5.

34 Powerex at 11.

35 Transmittal letter for May 22 filing at 13.

requires a regional approach to address such flows.[36] However, the only orders cited by Powerex to support this claim do not mandate a regional approach to address unscheduled flow issues.[37] Nor is the ISO aware of any Commission precedent or policy which would prevent the ISO from ensuring that the ISO's day-ahead processes are updated to reflect next-day operating conditions external to the ISO system.

The May 22 filing explained why the ISO is now taking steps to address unscheduled flow from other parts of the West, which still follow a contract path transmission service framework.[38] As the only organized market in the region, the ISO must take measures to ensure that its modeling creates feasible schedules that support the reliable operation of the ISO controlled grid and efficient operation of the ISO markets. The ISO is now able to improve its modeling due to recent regional coordination efforts among utilities in the West that have given the ISO access to more and better data regarding day-ahead system conditions.

Powerex argues that the WECC Interchange Tool, which will be the source of the ISO's information regarding imports and exports between balancing authorities, has been available for years.[39] Although it is true that the WECC

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[36] Powerex at 30, 37 & n.62. Similarly, BPA and IID argue that unscheduled flows should be addressed on a regional basis. BPA at 3-4, 5; IID at 7-9.

[37] *Sierra Pac. Power Co.*, 86 FERC ¶ 61,198, at 61,697 (1999); *East Kentucky Power Coop., Inc.*, 112 FERC ¶ 61,160, at P 27 (2005), *final order*, 114 FERC ¶ 61,035, *order on reh'g*, 115 FERC ¶ 61,247 (2006).

[38] Transmittal letter for May 22 filing at 2, 4-5, 25, 30-31, 42-43.

[39] Powerex at 15 n.27.

Interchange Tool has existed for years, Powerex ignores the fact that it has become feasible to access data from the WECC Interchange Tool only since the most recent WECC Universal Non-Disclosure Agreement was implemented. Prior to that time, the means for balancing authorities to readily obtain the data had not been developed.

Now that such data are available, there is no reason to delay making the ISO's proposed improvements. Making them now is also consistent with the April 2012 Commission and NERC staff report the September 8, 2011, outage event, which recommended that transmission operators should share data in order to improve reliability and should ensure that their next-day studies are updated to reflect next-day operating conditions external to their systems. That report does not include a recommendation that transmission operators should only make such improvements as part of a broader regional coordination effort.

This does not mean, however, that the ISO is disregarding other regional coordination efforts. The ISO is actively participating in those efforts. For example, the ISO is an active member of two groups within the WECC that are examining the issue of unscheduled flows in the real-time.[40] The ISO also continues to accommodate the continued reliance on contract path scheduling in WECC and to apply unscheduled flow mitigation procedures adopted for rated paths. But because the ISO's proposal is ahead of other regional coordination efforts, the ISO anticipates that it will be some time before regional coordination

[40] Transmittal letter for May 22 filing at 14. The two groups are the Unscheduled Flow Administrative Subcommittee ("UFAS") and the Path Operator Task Force ("POTF").

measures can move forward. The ISO should not be required to wait to make improvements that enhance reliability and promote market efficiency until the ISO can coordinate with other portions of the West to make similar improvements. The decision to move towards improved modeling in the day-ahead market should not be based on whether the rest of the West is prepared to adopt measures to better address unscheduled flows. Rather, the decision is based on the benefits to the ISO market of including such modeling. Fundamental market design principles support efforts to improve the consistency between the network models used in day-ahead and real-time markets. Greater consistency will promote improved price convergence.[41] Now that the ISO has access to data that enhances its modeling accuracy, the ISO should not be prevented from enhancing its own markets and operations. The proposal to adopt the accuracy metric further ensures that the ISO will not degrade the integrity of ISO market results by including such modeling.

G. The Potential for Joint Operating Agreements or Similar Arrangements Should Not Delay Beneficial Markets and Operations Enhancements

Powerex argues that the ISO should enter into joint operating agreements with other entities to address and account for loop flow, instead of taking the measures to enhance the ISO's modeling proposed in the May 22 filing.[42] Powerex erroneously frames the issue as a binary choice between those two approaches. In fact, the ISO believes it should implement the approach set forth

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41 *See* transmittal letter for May 22 filing at 42.

42 Powerex at 37-40.

in the May 22 filing and should explore further regional coordination measures, including the possibility of entering into agreements with willing counterparties that are comparable to the joint operating agreements cited by Powerex.[43] However, it does not make sense for the ISO to wait until it can identify willing counter-parties and negotiate the details of such agreements before the ISO takes steps that are already available to enhance reliability and promote market efficiency.

H. Enforcement of Physical Flow Constraints on the Interties in the Day-Ahead Market Is Just and Reasonable

Powerex argues that it is not necessary for the ISO to enforce physical flow constraints on the interties in the day-ahead market.[44] The Commission should find no merit in these arguments.

The relevant legal standard is not whether enforcement of such constraints is necessary, but whether enforcing such constraints is just and reasonable. As a public utility, the ISO is permitted by statute to propose changes to the rates and conditions for jurisdictional service under Section 205 of the Federal Power Act and has no obligation to prove that such changes are necessary. The explanations provided in the May 22 filing, along with the materials submitted in support of that filing, including the opinion of the MSC, amply demonstrate that it is just and reasonable to enhance the ISO's modeling

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43 Most of the joint operating agreements cited by Powerex are between independent system operators and regional transmission organizations that are adjacent to one another. The ISO is not adjacent to any other independent system operator or regional transmission organization. Therefore, those joint operating agreements may not be adequate models for the ISO to use.

44 Powerex at 26.

in order to improve its reliability and congestion management efforts.[45] The Commission has already found that it is just and reasonable for the ISO to enforce physical flow limits in both the day-ahead and the real-time within the ISO balancing authority area and in the real-time at the interties.[46] There is no legitimate basis to claim that it is unjust and unreasonable to apply the same practice to the day-ahead.

Powerex asserts that the ISO does not provide sufficient detail in its proposed tariff revisions describing how the physical flow limit will be determined.[47] That assertion is incorrect. Proposed tariff section 31.8.2, which concerns the physical flow constraint, contains the same level of detail as (and is actually longer than) the existing tariff language which addresses the scheduling constraint.[48] This level of detail compares favorably to the level of detail in other independent system operator tariff provisions address loop flow issues.[49]

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45 Transmittal letter for May 22 filing at 28-32.

46 *Id.* at 30-31 (citing *California Independent System Operator Corp.*, 137 FERC ¶ 61,025, at PP 7, 20 (2011)).

47 Powerex at 27.

48 See May 22 filing, attachment B, at tariff sections 31.8.1, 31.8.2. In the May 22 filing, the ISO broke out existing tariff section 31.8, which already addressed the scheduling constraint, into sections addressing the scheduling constraint and the physical flow constraint. Transmittal letter for May 22 filing at 28.

49 *See, e.g.*, NYISO Market Administration and Control Area Services Tariff, Section 17.1.1.1.1 ("In the Real-Time Market, expected unscheduled power flows will ordinarily be determined based on current power flows, modified to reflect expected changes over the real-time scheduling horizon."); PJM OATT, Attachment K, Section 5.3 ("When there are agreements between the LLC and others for compensation to be paid or received for unscheduled transmission service (loop flow) into or out of the PJM Region, the net compensation received shall be included in the Total Congestion Charges that are distributed in accordance with Section 5.2.").

Moreover, it is just and reasonable to provide additional detail in the business practice manual.[50]

Powerex argues that existing tariff section 6.5.10.1.1, which requires the ISO to provide information on the transmission constraints it will or will not enforce in the next day-ahead market, will not require the ISO to disclose the value it will use as the physical constraint limit.[51] The ISO intends to disclose the physical constraint limit value in accordance with section 6.5.10.1.1 and proposes to eliminate any potential ambiguity by making a clarification to section 6.5.10.1.1 in a compliance filing.

I. The Modeling Enhancements Will Not Lead to Effective De-rates of Interties

Powerex argues that the ISO's modeling enhancements will lead to effective de-rates of its interties, but only on the ISO side of the interties and without coordination with adjacent transmission providers.[52] The MSC opinion provided in attachment E to the May 22 filing demonstrates that this argument is without merit.

As the MSC explained, if there is a particular intertie on which the ISO finds that it cannot approximate the real-time physical flows with interchange modeled as sourced on the intertie, in some cases the best decision may be to not enforce the physical constraint on the intertie. However, this decision should

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50 *See California Independent System Operator Corp.*, 119 FERC ¶ 61,313, at P 42 (2007); *California Independent System Operator Corp.*, 126 FERC ¶ 61,262, at PP 70-72 (2009).

51 Powerex at 27-28.

52 Powerex at 31-34.

be made only when it is determined that there is a modeling problem on that intertie and only if it is the best way to address the modeling problem.[53]

It is appropriate for the ISO to take into account both flows on physical constraints and scheduling constraints in determining day-ahead or real-time prices. The ISO already takes into account the impact of interchange flows on physical constraints on lines internal to the ISO. The ISO simply proposes to extend that same treatment to the interties.[54]

The interchange flows used to enforce scheduling limits and physical constraints are not the same. The "flows" used to enforce scheduling limits are the contract path schedules that are simply assumed to flow entirely over the scheduled interties to facilitate interchange between balancing authority areas. The flows used to enforce physical constraints are the physical flows of energy through the AC transmission network, determined through power flow modeling as reflected in the full network model. In the full network model, not all of the scheduled interchanges will actually flow over the designated intertie, and the flows on the physical constraint may also be impacted by the scheduled interchanges on other interties and by the dispatch of internal generation within each balancing authority area. Therefore, unlike the scheduling limit, the physical limit is not an absolute limit on the net interchange scheduled on a particular intertie. Rather, if the physical limit binds, the price of the imports scheduled on this path falls to reflect the cost of redispatch required to

[53] MSC opinion at 12.

[54] MSC opinion at 12.

accommodate those flows. As a result, enforcement of the physical constraint will generally not preclude interchanges from being scheduled up to the scheduling limits, but the cost of any required redispatch would reduce the value of and be reflected in the price of those imports. This is entirely appropriate. The ISO should not pay more for imports than their economic value, after taking into account the redispatch required to accommodate their impact on the ISO's transmission constraints.[55]

Modeling physical constraints in combination with loop flows will not necessarily cause the physical constraint to bind at a lower level of interchange than the scheduling limit. Because the flows on physical constraints will be calculated based on the full network model, the physical flows associated with interchange schedules will not be the same as the contract path flows used to enforce scheduling limits. Although it is possible that implementation of the ISO's enhanced modeling will provide evidence suggesting that particular scheduling constraints are set too low, this would be evidence of problems with the WECC process for setting scheduling limits, not problems with the ISO's enhanced modeling.[56]

J. Extending the Full Network Model Is Just and Reasonable

Powerex argues that the ISO fails to show that extending the full network model will result in more accurate representations of imports than the current

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[55] MSC opinion at 13.

[56] MSC opinion at 13. It is also possible that interchange flows on some interties may be overstated due to the way that interchange is modeled under the ISO's enhanced modeling. But this is a situation that would need to be addressed only if and when it arose. *Id.*

approach. In particular, Powerex argues that the MSC's view that extending the full network model "will likely provide some improvement" should not be given much weight.[57] As the Commission is well aware, however, the MSC has extensive experience in evaluating and independently assessing the merits of proposed enhancements to the ISO's markets as well as experiences in eastern ISOs and RTOs. As such, it is fully appropriate to give significant weight to the MSC's view of this issue and to the MSC's "strong support" for the modeling enhancements.[58]

Similarly, the DMM has explained that it "strongly supports the ISO's proposal to improve modeling on the ISO system by expanding the topology" of the full network model.[59] The DMM stated that expanding the full network model to include other balancing authority areas will allow the ISO to "reflect outages and other reliability parameters on those external systems and analyze how they may affect the ISO market," and thus "provides the opportunity for substantial reliability benefits under scenarios such as that which led to the major southwest blackout on September 8, 2011."[60]

As the DMM notes, the proposal to expand the full network model is aligned with the recommendations of Commission and NERC staff in the April 2012 report on the September 8, 2011 outage event that transmission operators

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[57] Powerex at 29-30 (quoting MSC opinion, attachment E to May 22 filing, at 16-17).

[58] MSC opinion at 2.

[59] DMM memorandum at 2.

[60] *Id.*

should address the fact that models for external networks used by some transmission operators in the Western Interconnection have in the past not been updated to reflect next-day operating conditions external to their systems.

For all these reasons, the ISO has provided full support for its proposal to extend its full network model.

K. The ISO's Implementation Plan Is Appropriate

Powerex expresses misgivings about the ISO's plan for implementing the modeling enhancements. These concerns are unwarranted. First, the ISO notes that its proposal to adopt an accuracy metric as discussed above addresses the core of Powerex's concerns. Even without the adoption of this accuracy metric, however, the ISO believes its implementation is justified.

Powerex asserts that the ISO Governing Board decided to direct the ISO to prepare a pre-implementation plan due to the Board's own concerns.[61] Powerex ignores the fact that ISO management itself proposed the pre-implementation plan, and the Board approved that proposal.[62]

Powerex also erroneously asserts that the pre-implementation analysis will not be based on a sufficient set of data.[63] In fact, the analysis will be conducted with a focus on four interties that provide a good sample of major unscheduled flow concerns: (1) California-Oregon Intertie; (2) Palo Verde; (3) Eldorado-Mead; and (4) Victorville-Lugo. In addition, the analysis will include

61 Powerex at 19-20.

62 Board memorandum, attachment F to May 22 filing, at 5.

63 Powerex at 20.

rerunning of data for as many days as possible leading up to the reporting of results to stakeholders and the Board in September.[64] Thus, the data for the pre-implementation analysis will be sufficient.

Powerex claims that the ISO has not explained how the results of the pre-implementation analysis will be evaluated to determine whether the modeling enhancements should be permitted to go into effect on October 1.[65] Although the ISO can and will provide its own evaluation of whether the analysis indicates that the enhancements should be allowed to go into effect, ultimately that question will be up to the Board to decide. The ISO will provide the results of the analysis to stakeholders, its Board, and to the Commission in an informational filing, prior to the implementation date.[66] To the extent that any stakeholder has reservations based on that analysis, it can ask the Commission to act at that time.

Powerex claims that the ISO's proposal to submit an informational filing on its pre-implementation analysis is inconsistent with the approach the Commission has taken in previous cases, including the proceeding on the ISO's new market design that went into effect in 2009.[67] Powerex is incorrect on this point as well. In the proceeding on the new market design, the Commission found that the new

[64] Addendum to draft final proposal, attachment D to May 22 filing, at 2-3.

[65] Powerex at 20-21.

[66] Transmittal letter for May 22 filing at 39. As the ISO has explained, there is no need to make acceptance of the proposed tariff revisions contingent on the results of the pre-implementation analysis, because the ISO's requested authority includes the discretion to make adjustments where justified by the analysis. *Id.* at 39-40.

[67] Powerex at 23 & n.40 (citing *California Independent System Operator Corp.*, 116 FERC ¶ 61,274, at PP 1380, 1414 (2006), *order on reh'g*, 119 FERC ¶ 61,289 (2006)).

market design was just and reasonable but required the ISO to submit an informational filing prior to the implementation date to demonstrate whether the tariff revisions were ready to go into effect.[68] In this proceeding, the ISO has demonstrated the justness and reasonableness of its tariff revisions, but proposes to submit an informational filing prior to the implementation date which will show that the ISO is ready to implement the proposed modeling enhancements. Thus, the ISO's approach in this proceeding is consistent with the approach taken in the proceeding on the new market design.

L. The Modeling Enhancements Are Consistent with Commission Policy Regarding Coordination of ATC Calculations

Powerex argues that the ISO's proposal is inconsistent with Commission policy stated in Order No. 890 regarding coordination of available transmission capacity ("ATC").[69] In making this argument, Powerex ignores the ISO's explanation in the May 22 filing that the ISO intends to continue its practice of coordinating ATC with neighboring regions and providing this information on the ISO's OASIS.[70] The ISO does not propose any changes to the coordination or calculation of ATC in the May 22 filing. The ATC calculation is separate from the physical flow constraint that the ISO proposes to enforce on the interties in the

[68] *California Independent System Operator Corp.*, 116 FERC ¶ 61,274, at PP 25, 1380, 1414.

[69] Powerex at 36-37.

[70] Transmittal letter for May 22 filing at 44.

day-ahead market in order to reflect actual congestion when the constraint is binding.[71]

M. Other Issues

IID asks how operational disputes about unscheduled flows or flow limits between balancing authorities would be resolved.[72] The ISO notes that such operational disputes would involve actual real-time flows, not flows that are modeled in the ISO's day-ahead market. There are existing procedures in place for dealing with actual real-time flows. Nothing in the ISO's proposal will affect such existing operating procedures.

IID requests clarification as to whether the May 22 filing will result in the denial or cutting of schedules of transmission owners that are using transmission ownership rights.[73] Transmission ownership rights have scheduling priority over transmission constraints under the ISO tariff.[74] Therefore, the modeling of transmission constraints pursuant to the May 22 filing will not result in such schedules being denied or cut.

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[71] *Id.*

[72] IID at 7-9.

[73] IID at 2.

[74] *See* ISO tariff section 27.4.3.5.

III. Conclusion

For the foregoing reasons, the Commission should accept the ISO's May 22 filing as submitted in the captioned proceeding, subject only to the modifications and clarifications on compliance proposed in this answer, including the commitment to implement, if directed by the Commission, a transitional mechanism under which the ISO would model unscheduled flow in the day-ahead market only if an accuracy metric is satisfied.

Respectfully submitted,

Roger E. Collanton
General Counsel
Anthony Ivancovich
Deputy General Counsel
Anna McKenna
Assistant General Counsel
California Independent System Operator Corporation
250 Outcropping Way
Folsom, CA 95630

Sean Atkins
Bradley R. Miliauskas
Alston & Bird LLP
The Atlantic Building
950 F Street, NW
Washington, DC 20004

Counsel for the California Independent System Operator Corporation

Dated: June 27, 2014

Attachment A

Memorandum

To: ISO Board of Governors

From: Eric Hildebrandt, Director, Department of Market Monitoring

Date: January 30, 2014

Re: **Market Monitoring report**

This memorandum does not require Board action.

EXECUTIVE SUMMARY

This memo provides analysis and comments of the Department of Market Monitoring (DMM) on three issues.

- **Full network model expansion**. DMM strongly supports the ISO's proposal to improve modeling of the ISO system by expanding the topology and inputs used to project actual power flows in the day-ahead and real-time market models. While most of the discussion throughout this initiative has focused on the market efficiency impacts of this modeling enhancement, it is important to note that the primary driver of this initiative is the reliability benefits that will stem from increased visibility and co-ordination with other balancing areas, and the ability to enforce more reliability constraints and feasible schedules in the ISO. The initiative also provides the opportunity for increased market efficiency from more accurate pricing of schedules and lower congestion uplifts. However, as discussed in detail in the opinion of the Market Surveillance Committee (MSC), accurately projecting unscheduled flows using a full network model is a complex task. Consequently, DMM joins the MSC in recommending the ISO commit the resources necessary to analyze, validate, and benchmark the full network model before and after implementation to ensure this feature provides the intended benefits. DMM will continue to work closely with the ISO and MSC in this important effort.

- **Market competiveness in 2013.** As noted in prior Board memos, overall prices in 2013 increased about 30 percent due to higher gas prices and costs associated with the state's cap-and-trade program for greenhouse gases. However, analysis by DMM completed for our 2013 annual report indicates prices were even more competitive than in 2012, after taking into account the impact of higher gas prices, greenhouse gas compliance costs and other supply and demand conditions. Prices in 2013 were in the range expected in an extremely competitive market, and were consistent with the highly competitive prices observed in 2010 through 2012.

- **Implementation of 15-minute market**. DMM is working closely with the ISO before and after implementation of the new 15-minute market this spring to monitor market performance and make any adjustments that may be appropriate to manage and ensure the efficiency of this new market. In our report on performance in the third quarter of 2013, DMM identified a long term trend of relative high prices in the ISO's current 15-minute pre-dispatch process, which are currently non-binding and not used in any financial settlement. However, since that report, 15-minute prices have tracked more closely with other market prices, and the ISO has identified the cause of the price divergence and steps that may be taken to mitigate any trend of high average 15-minute prices that might re-occur after implementation of the new 15-minute market this spring.

FULL NETWORK MODEL EXPANSION

DMM strongly supports the ISO's proposal to improve modeling of the ISO system by expanding the topology and inputs used to project actual power flows in the day-ahead and real-time market models. By expanding the full network model to include other balancing areas, the ISO will also be able to reflect outages and other reliability parameters on those external systems and analyze how that may affect the ISO market. This provides the opportunity for substantial reliability benefits under scenarios such as that which led to the major southwest blackout on September 8, 2011.

These modeling enhancements should also improve market efficiency by allowing better management of congestion. Including these modeling improvements in the day-ahead and real-time markets will help the ISO create feasible schedules, enforce reliability, and accurately price market transactions. Expanding the ISO's network model to a regional level that includes other balancing authority areas is also a key component needed to ensure the efficiency and future expansion of the ISO's energy imbalance market.

The ISO's initial proposal was modified significantly as the result of input from DMM, the Market Surveillance Committee and stakeholders. Specifically, major changes involving how pricing of imports and exports would be affected by assumptions about actual physical sources or sinks of these transactions were deferred for consideration in a later phase. DMM strongly supported deferral of this aspect of the proposal. The final proposal will still affect the pricing of some import and export transactions. However, under the final proposal, the price for imports and exports will only be higher or lower based on the ISO's own modeling of the impact and value of these schedules given actual power flows.

As explained in Management's memo, the key feature of the final proposal is that the ISO's network model will be expanded to include the other balancing areas in the Western Electricity Coordinating Council area. This expanded model will be used to model the unscheduled electrical flows that will occur within the ISO balancing area caused by the load, generation, and interchanges forecast for other balancing areas in the western interconnection. The goal of this is to produce day-ahead and real-time schedules and prices that more accurately reflect actual system constraints and the impact schedules have on these constraints.

In addition to increasing reliability, this expanded network model may help reduce real-time congestion imbalance offset costs that are incurred when unscheduled real-time flows create the need to reduce flows created by schedules awarded in the day-ahead market. One potential limitation of this effort is that the ISO may not have data on schedules outside the ISO that are complete, timely, or accurate enough to sufficiently project next-day base schedules used in the full network model.

Even with this information, the accuracy with which unscheduled flows can be projected will depend on a variety of other modeling assumptions that must be made, such as which generation schedules in other balancing areas are ultimately increased or decreased as a result of imports or exports with the ISO. Consequently, monitoring the impact that this has on projections of unscheduled flow and congestion in the day-ahead and real-time market models – and modifying these models in response to this monitoring – will be critical.

DMM strongly supports the opinions and recommendations of the MSC on this issue which have been stressed throughout the stakeholder process and are summarized in their final opinion on Mangements' proposal. As noted in the MSC opinion, creating and testing the full network model is likely to be a difficult and complex task, and other ISOs have experienced serious challenges in improving the accuracy of their estimates of unschedled flows. Consequently, DMM joins the MSC in recommending that the ISO analyze, validate, and benchmark the full network model before and after implementation to ensure this feature provides the intended benefits.

The ISO has committed to performing a variety of studies as part of pre-implementation testing and to report on these results to stakeholders and the Board. DMM supports this approach, but also emphasizes that this pre-implementation testing be viewed as the first step in an ongoing process of monitoring, analysis, refinement and improvement of the full network model. More specifically, DMM provides the following recommendations on this process:

- Analysis and benchmark studies of the performance of the full network model in terms of accounting for unscheduled flows should be performed in advance of implementation and should continue after implementation of the model to provide timely feedback and adjustments to improve performance tuning.

- As part of this pre-implementation analysis and testing, DMM recommends development of a variety of automated metrics that can be used to assess the impact that modeling inputs and assumptions are having on market congestion in the day-ahead and real-time. Automation of metrics that can flag the most critical aspects of performance is critical due to the massive amount of data involved in assessing unscheduled flows.

- Unless the estimated or actual flow on a line is actually near a limit in the day-ahead or real-time market, there may be little or no consequences of any improvement of projected flows in terms of reliability or market costs. Therefore, DMM recommends that these automated metrics focus on the impact that the full network model is having on estimated flows on specific constraints which are at or near their limits in the day-ahead and real time markets based on estimated or actual flows.

- DMM also recommends that the ISO's metrics and analysis focus on constraints on which the actual market impact of congestion is highest. As identified in prior reports by DMM, the bulk of real-time energy congestion offset costs that have been incurred in the past are associated with a relatively small number of constraints on any given period. Automated metrics can be used to quickly identify these constraints and allow resources to be focused on modeling improvements or adjustments that have the highest value in terms of reliability and market benefits.

DMM looks forward to continuing to work closely with the ISO and MSC in development of such metrics and other analysis both before and after implementation of the full network model.

MARKET COMPETITIVENESS IN 2013

As noted in prior Board memos, overall prices in 2013 increased about 30 percent due to higher gas prices and costs associated with the state's cap-and-trade program for greenhouse gases. However, analysis by DMM indicates prices were even more competitive than in 2012, after taking into account the impact of higher gas prices, greenhouse gas compliance costs and other supply and demand conditions.

To assess the competitiveness of the ISO energy markets, DMM compares actual market prices to *competitive benchmark* prices we estimate would result under highly competitive conditions. DMM estimates competitive baseline prices by re-running the day-ahead market software with bids reflecting the actual marginal cost of gas-fired units and actual system loads.[1] DMM calculates the overall *price-cost mark-up* based on the difference between actual market energy prices and the competitive benchmark price. For instance a markup of 5 percent would indicate overall average energy prices 5 percent above the average competitive baseline price.

Figure 1 compares this competitive baseline price to average prices in the day-ahead and 5-minute real-time markets. When comparing these prices, it is important to note that baseline prices are calculated using the day-ahead market software under highly competitive conditions, which does not reflect all of the system conditions and limitations that impact real-time prices.

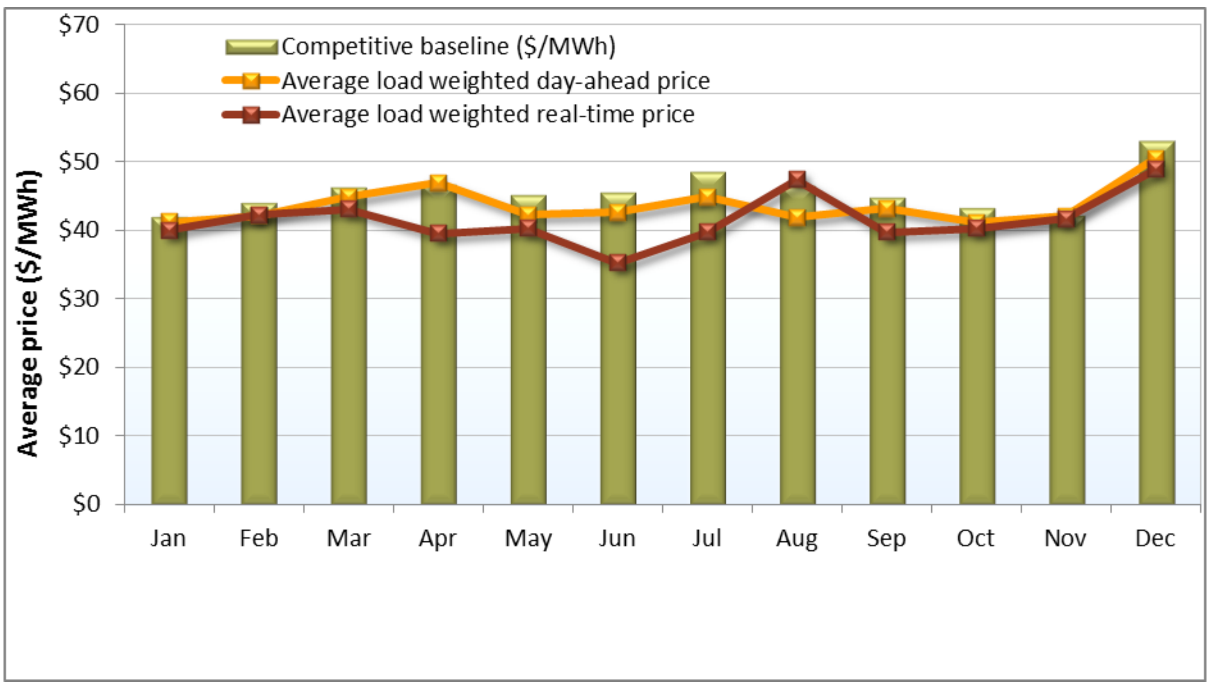
As shown in Figure 1, day-ahead market prices tracked very closely with competitive baseline prices during most months. In the real-time market, average prices were lower

[1] This analysis is performed using physical supply bids and actual system demand only (excluding virtual supply and demand bids). This scenario represents the combination of perfect load forecast with competitive bidding of gas-resources that typically set price in the ISO system setting resources. For January through April, DMM used an alternative model of the ISO market (PROBE) since data needed to run the day-ahead market software was unavailable.

than the competitive baseline in 2013 in most months except for August. A major factor contributing to these lower real-time prices was the substantial amount of real-time energy that was not scheduled in the day-ahead market.[2]

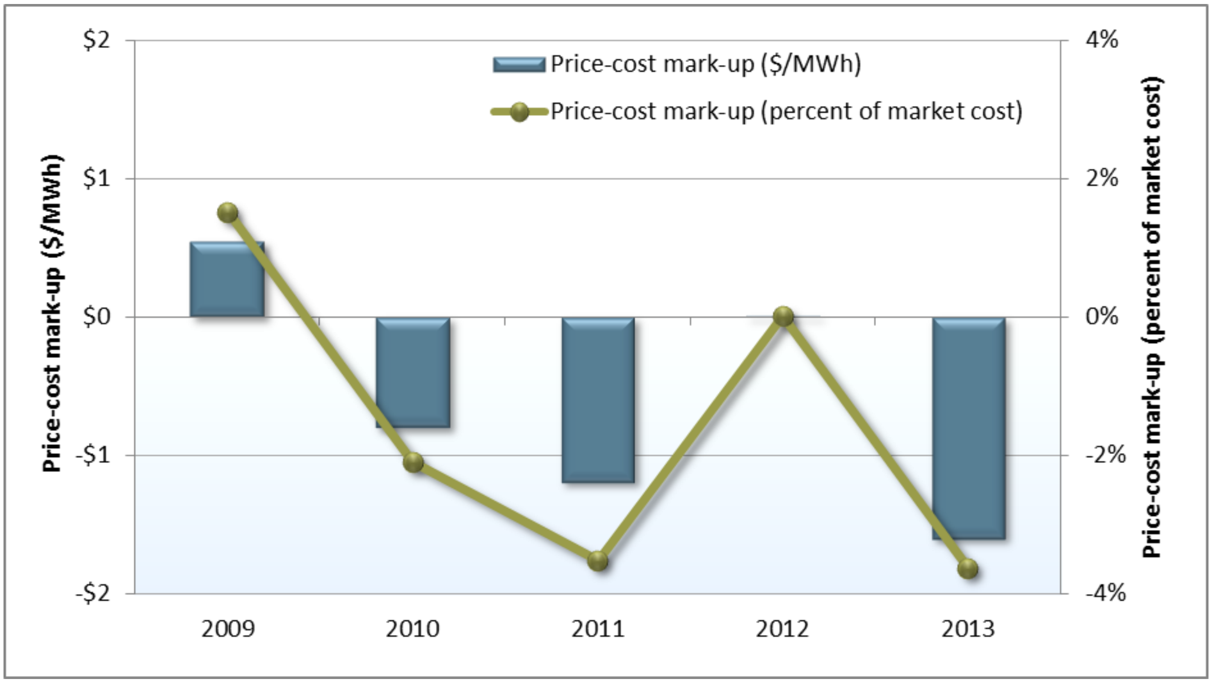
As shown in Figure 2, the overall combined average of day-ahead market and real-time prices were about $1.50/MWh or about 3.8 percent lower than the competitive baseline price. This represents a slight drop in the price-cost markup in 2013 and is consistent with the slightly negative price-cost markups observed in 2010 and 2011. Slightly negative price-cost markups reflect the fact that many suppliers bid somewhat lower than their default energy bids – which include a 10 percent adder above estimated marginal costs. Another factor contributing to the slightly negative price-cost mark-up in 2013 is the additional sources of supply that are available in the ISO's real-time market which are not available in the day-ahead market model used to calculate the competitive baseline price.

Figure 1. Comparison of competitive baseline with day-ahead and real-time prices



2 This unscheduled energy was the combined result of a variety of factors, rather than being driven by any single source. Various sources off additional real-time energy included minimum load energy from units committed after the day-ahead market through the residual unit commitment process and exceptional dispatches, additional self-scheduled energy from thermal generating resources, and unscheduled energy from intermittent renewable energy. A detailed analysis of this issue will be provided in DMM's 2013 Annual Report.

Figure 2. Price-cost mark-up index (2009-2013)



IMPLEMENTATION OF 15-MINUTE MARKET

FERC Order No. 764 requires that all FERC-jurisdictional transmission providers provide the opportunity for intra-hour schedule changes in 15 minute increments.[3] This requirement is instrumental to facilitating proposed enhancements that will create a market structure oriented around renewable resources while also eliminating existing market inefficiencies.

The ISO has taken the opportunity created by FERC Order No. 764 to make additional changes in the hour-ahead and real-time markets in spring 2014. Specifically, the ISO is proposing to change inter-tie scheduling and settlement from an hourly to a 15-minute basis, and to also establish a 15-minute settlement for internal resources and convergence bids. The ISO proposal also includes retaining the existing 5-minute dispatch to provide real-time balancing.

The ISO's 15-minute real-time pre-dispatch market already produces energy prices for each 15-minute interval which are non-binding (i.e. not used in any financial settlement). In DMM's report on the third quarter of 2013, DMM provided a comparison of these 15-minute

[3] On June 22, 2012, FERC approved Order 764 to remove barriers to the integration of variable energy resources by requiring each transmission provider to: (1) offer an option to schedule energy with 15-minute granularity; and (2) require variable energy resources to provide meteorological and forced outage data for the purpose of power production forecasting. Draft Final Proposal - FERC Order No. 764 Market Changes. For more information, see http://www.caiso.com/informed/Pages/StakeholderProcesses/FERCOrderNo764MarketChanges.aspx.

non-binding prices to day-ahead and 5-minute real-time prices. This comparison showed that these 15-minute prices had been consistently significantly higher than day-ahead and real-time prices dating back to at least 2012.

As a result, DMM recommended that the ISO look into the cause of this difference and closely monitor these prices leading up to implementation of the 15-minute market in spring 2014.Since that time, the ISO and DMM have performed additional analysis of the causes of these higher 15-minute prices, monitored these prices, and identified factors and steps that could mitigate any trend of systematically high or low 15-minute prices once the new market design is implemented.

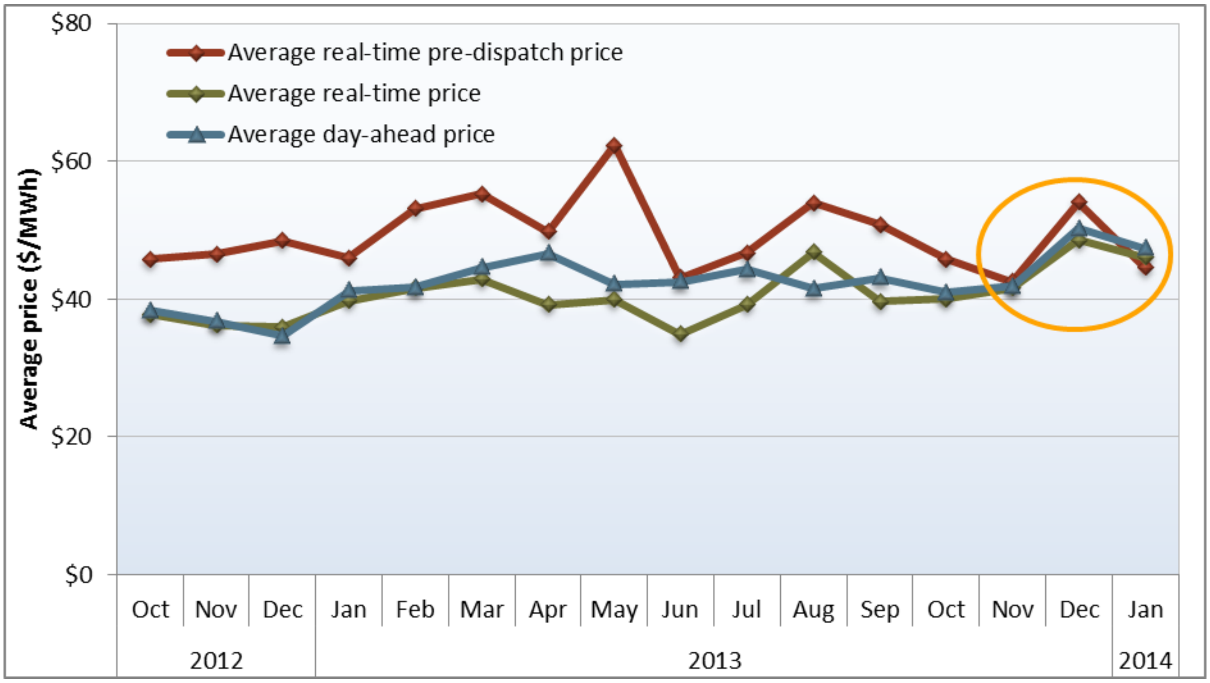
Analysis by the both the ISO and DMM confirms that the primary cause of higher average 15-minute prices in 2013 has been the flexible ramping constraint (or price at which this constraint is relaxed rather than resulting in an extreme re-dispatch of resources), which is enforced in the 15-minute pre-dispatch process but not the 5-minute market. Although this constraint binds and cannot be met during a relatively small percentage of intervals, when this constraint does bind it creates high 15-minute prices.

As shown in Figure 3, the trend of higher 15-minute prices has changed significantly starting in November. This appears to be driven in large part by a decrease in the number of intervals when the flexible ramping constraint cannot be met and results in very high prices. This may be due largely to seasonal factors that result in additional supply of flexible capacity in recent months.

Prices in Figure 3 represent prices for the first 15-minute interval after the current pre-dispatch process is performed, since these are the only 15-minute prices that have been saved historically. When the 15-minute market is implemented, market prices will actually be based on the second 15-minute interval after the 15-minute process is performed. Prices in this second 15-minute interval should be marked by fewer price spikes driven by the flexible ramping constraint, since there will be much more ramping capacity and flexibility available over this additional 15 minute period. The ISO has modified the software to save prices from this second 15-minute interval under the current process and will monitor these prices up to implementation of the new 15-minute market.

Another factor that is expected to help mitigate extreme price spikes in the 15-mintue market with implementation of the new 15-minute market is a reduction in the penalty price for the flexible ramping constraint. The ISO is currently evaluating how to reduce this value from $247/MW.

Figure 3. Comparison of average 15-minute real-time prices to day-ahead and real-time prices



The ISO is also prepared to closely monitor, manage and modify operating practices as the new 15-minute market is implemented to help achieve an efficient balance between the day-ahead, 15-minute and 5-minute market prices. For example:

- The requirement that is set for flexible ramping capacity will be closely monitored and adjusted if necessary as the new 15-mintue market is implemented. If this requirement is set at levels that cannot be met by the available ramping capacity, the requirement can be reduced to levels that may be binding and result in additional flexible ramping capacity, while avoiding extreme price spikes that are created when the requirement cannot be met.
- The ISO will also monitor and adjust the use of the any load bias in the 15-minute market. Grid operators may address reliability concerns by increasing the projected system load in the 15-minute pre-dispatch process to ensure commitment of additional short start units. When the new 15-minute market is implemented, this can also have the impact of raising the 15-minute prices that will now be used for financial settlement. Thus, the use of load bias and the impacts it has on pricing will be closely monitored as the new 15-minute market is implemented.

DMM will continue to work closely with the ISO before and after implementation of the new 15-minute market this spring to monitor market performance and make any adjustments that may be appropriate to manage and ensure the efficiency of this new market.

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon all of the parties listed on the official service list for the above-referenced proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Washington, DC this 27th day of June, 2014.

/s/ Bradley R. Miliauskas
Bradley R. Miliauskas