Preliminary Report
Analysis Track Testing of CAISO MRTU Pricing and Dispatch

Scott M. Harvey, Matthew Kunkle, Benjamin Hagberg, Alexis Maharam, Shaun Glassman and Christine Offerman[1]

April 16, 2008

EXECUTIVE SUMMARY

LECG was retained by the California ISO to review the results of the CAISO's analysis track testing of its MRTU dispatch and pricing software for the day-ahead market, real-time pre-dispatch, and real-time dispatch. The purpose of the CAISO analysis track testing was to test the software that has been developed for operating the CAISO MRTU electricity markets under the pricing rules described in the CAISO tariff.

The analysis track testing allowed the CAISO and LECG to test the day-ahead market (IFM), real-time pre-dispatch and unit commitment (RTUC) and real-time dispatch (RTD) software and associated pricing modules that will be used to coordinate the CAISO day-ahead and real-time electricity markets under MRTU. LECG's assignment was to assess the economic consistency of the results produced by the day-ahead market, real-time pre-dispatch and real-time dispatch software and pricing modules, and verify that any inconsistencies identified did not arise from errors in the calculation of settlement prices or reflect substantial deviations from the least-cost dispatch. This report summarizes the results of our analysis to this point in the testing process.

The CAISO MRTU software systems are designed to make optimal commitment and dispatch decisions based on market participant bids, subject to a variety of physical equipment constraints and power system reliability considerations. We have taken advantage of this property in testing the software, as the prices and schedules developed by the software should satisfy a series of internal consistency and equilibrium conditions if the software is functioning properly in both calculating prices and developing schedules. Inconsistencies are then reviewed to determine whether they reflect an error in the calculation of prices, an error in the process of determining the least cost unit commitment and dispatch, a data export error or other factors.

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Based on the analyses we have performed, we have not observed substantial unresolved problems that would prevent the CAISO software systems from calculating prices consistent with the CAISO tariff and LMP pricing methodology and have not observed material unresolved problems that would prevent the software systems from committing and dispatching load and generation based on least bid cost. There are a number of minor unresolved issues with the calculation of prices and the optimality of the dispatch that appear to arise from differences in rounding and modeling issues that we and the CAISO are continuing to review. In most of these cases we believe we have identified the source of the issue, but the relevant software and modeling changes have not yet been implemented and tested. In addition, in any unit commitment software there is a tradeoff between the optimality of the unit commitment and dispatch and the number of iterations (hence performance), the CAISO and we are continuing to review this tradeoff across several test cases and to review the formulation of the objective function. The current evaluation has focused on analysis track testing of day-ahead market and pre-dispatch software. We have not evaluated any analysis track cases of the current real-time dispatch software.

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I. INTRODUCTION

LECG was retained by the California ISO to review the results of the CAISO's analysis track testing of its MRTU dispatch and pricing software for the day-ahead market, real-time pre-dispatch, and real-time dispatch. The purpose of the CAISO analysis track testing was to test the software that has been developed for operating the CAISO MRTU electricity markets under the pricing rules described in the CAISO tariff.

The analysis track testing allowed the CAISO and LECG to test the day-ahead market (IFM), real-time pre-dispatch (RTPD) and real-time dispatch (RTD) software and associated pricing modules that will be used to coordinate the CAISO day-ahead and real-time electricity markets under MRTU. LECG's assignment was to assess the economic consistency of the results produced by the day-ahead market, real-time pre-dispatch and real-time dispatch software and pricing modules based on the analysis track test cases provided to us by the CAISO and verify that any inconsistencies identified did not arise from errors in the calculation of settlement prices or reflect substantial deviations from the least-cost dispatch. This report summarizes the results of our analysis to this point in the testing process. This report describes the scope of the testing we have carried out and that is covered by this report, relative to other testing carried out by the CAISO that may be reported elsewhere.

The CAISO MRTU software systems are designed to make optimal commitment and dispatch decisions based on market participant bids, subject to physical equipment constraints and power system reliability considerations. We have taken advantage of this property in testing the software, as the prices and schedules developed by the software should satisfy a series of internal consistency and equilibrium conditions if the software is functioning properly in both calculating prices and developing schedules. Inconsistencies are then reviewed to determine whether they reflect an error in the

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calculation of prices, an error in the process of determining the least cost unit commitment and dispatch, a data export error or other factors. These tests do not assess the accuracy of the underlying transmission grid model, the accuracy of the powerflow solution, or the accuracy of the generation shift factors or loss penalty factors used in the dispatch.

The test process also serves to identify gaps in the data saved by the MRTU software that would hinder price validation and analysis of market performance under MRTU operation.

Based on the analyses we have performed, we have not observed substantial unresolved problems that would prevent the CAISO software systems from calculating prices consistent with the CAISO tariff and LMP pricing methodology and have not observed material unresolved problems that would prevent the software systems from committing and dispatching load and generation based on least bid cost. There are a number of minor unresolved issues with the calculation of prices and the optimality of the dispatch that appear to arise from differences in rounding and modeling issues that we and the CAISO are continuing to review. In most of these cases we believe we have identified the source of the issue, but the relevant software and modeling changes have not yet been implemented and tested. In addition, in any unit commitment software there is a tradeoff between the optimality of the unit commitment and dispatch and the number of iterations (hence performance), the CAISO and we are continuing to review this tradeoff across several test cases and to review the formulation of the objective function. The current evaluation has focused on analysis track testing of day-ahead market and pre-dispatch software. We have not evaluated any analysis track cases of the current real-time dispatch software.

II. TESTS OF MRTU SOFTWARE

We conducted several rounds of tests on CAISO analysis track test cases[3] in order to validate the price calculations, unit commitment and dispatch solutions and identify potential economic inconsistencies in the prices and schedules produced by the CAISO day-ahead market, and real-time pre-dispatch and unit commitment software. We have partially tested the prices and schedules produced by the real-time dispatch software (RTD).

The initial round of analysis track testing entailed evaluation of 51 cases. The results of our evaluation were reviewed with the CAISO and problems with the initial software version were identified for correction by Siemens. A second partial round of

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[3] A description of Analysis Track Testing scope of work can be found on the CAISO website at: http://www.caiso.com/1f8d/1f8d80dc2c580.pdf

analysis track testing was carried out between November 20 and December 18 on 7 IFM and 5 RTUC cases to assess whether the problems identified in the initial round of testing had been corrected and to verify that the process of correcting these problems had not introduced new problems. During January, February, March and early April a single IFM and RTUC base case were tested and retested on each software patch until all anomalies were resolved. Finally, a third round of analysis track testing was carried out beginning on April 2, 2008.[4] The April 2008 testing has been completed to date for 8 IFM cases and 1 RTUC case.[5]

A. Test Methodology

We carried out a series of tests on the analysis track cases in order to validate the price calculations, unit commitment and dispatch solutions and identify potential economic inconsistencies in the prices and schedules produced by the MRTU software. We then reviewed the inconsistencies to determine whether they reflected errors in the calculation of prices or material departures from the least cost unit commitment and dispatch. As described below, our tests of the day-ahead market and predispatch software included a review of energy and ancillary service prices and schedules. We also tested the energy schedules produced by the real-time dispatch software. The ancillary services included in the testing were regulation up, regulation down, 10-minute spinning reserves and 10-minute (or non-spinning) reserves.

Our tests of the economic consistency of the day-ahead market and real-time predispatch software verified that the correct relationship existed between resource and load schedules (including imports and exports), energy and ancillary service prices, and energy and ancillary service bid and offer prices.[6] Our tests of the economic consistency of the real-time interval dispatch software verified that the correct relationship existed between the schedules of dispatchable resources, their offer prices, and real-time energy prices. In those instances in which the tests detected anomalies, we worked with CAISO staff and/or Siemens to determine whether the anomalies reflected incorrect software performance, incorrect data, reflected false positives (i.e., the anomalies in fact reflected

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4 The 21 cases tested in the third round of analysis track testing were designed to cover all 51 of the cases included in the initial round of testing. The initial 51 cases included many cases with very minor differences to facilitate identification of the source of software performance issues. This level of disaggregation was not necessary in the third round which was intended to verify that the software was operating as intended.

5 Some cases have been reviewed at more than one MIP gap level and run on more than one computer system. The CAISO has run a number of additional IFM and RTUC cases that we are in the process of reviewing.

6 These tests were generally based on the prices and resource schedules in the pricing dispatch, rather than the physical dispatch. However, in the case of resources not eligible to set prices, we verified that their schedule in the pricing dispatch was identical to their schedule in the physical dispatch and that their schedule in the physical dispatch was consistent with the prices in the physical dispatch.

the correct operation of the software), or reflected isolated instances of imperfect optimization over integer variables (termed MIP gap, discussed further below).[7] As a general matter, the tests were designed to find flaws in the dispatch and pricing logic, not to systematically test the underlying transmission system data or powerflow solutions. In practice, however, the tests also identified other types of flaws, such as incorrect data modeling for some generation.

1. Replicate LMP Energy Prices

For the day-ahead market, real-time predispatch and real-time interval dispatch software, this test verifies that we can replicate the calculation of the LMP prices from the components. For each generator and load bus for which a LMP price is calculated (Pnodes) and each aggregated generator or load bus for which a LMP price is calculated (Apnodes) we verify that we can calculate the LMP price from the distributed reference bus price, constraint shadow prices and penalty factor and generation shift factors for that location, as calculated by the day-ahead market, real-time predispatch and real-time dispatch models based on the underlying transmission grid model. This test not only serves to identify potential errors in the calculated prices, it also serves to verify that the correct shift factors, constraint shadow price, and penalty factors are being saved and exported, and thus will be available for analysis of performance issues.

2. Validate LMP Energy Prices Based on Marginal Generators

This test verifies that the appropriate number of marginal generators can be identified for the determination of LMP energy prices for each hour (in the day-ahead market), each 15-minute interval (in the real-time predispatch) and each 5-minute dispatch interval in the real-time dispatch. In an interval with no binding transmission constraints, at least one generator or price capped load bid should be on the margin (i.e., partially dispatched and not ramp constrained or at an upper or lower operating limit)[8] and the LMP price at

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[7] False positives in the initial testing were in part an intentional design feature to facilitate identification of problems and in part reflected limitations in the software output which in some cases made it difficult to verify that resource schedules were affected by certain kinds of constraints. For example, we initially have screened for anomalies without regard to ramp rate constraints and manually verified that units were ramp rate constrained. This process served to test the accuracy of the indicator for ramp constrained units.

[8] This condition will hold unless a load balance constraint or ancillary service requirement is not satisfied, in which case all resources could be at their upper or lower limits. We understand that at present, prices would be set in these situations by the highest cost accepted offer; however, we also understand that the CAISO is considering using shortage factors to set prices in these situations. As discussed below, neither of these circumstances were observed during analysis track testing. Units with binding energy limits are on the margin if the sum of their offer price and the shadow price of the energy constraint is equal to the LMP price at their location. We have applied tests to verify that the daily schedules of energy limited resources do not exceed their maximum energy limit nor fall below the minimum energy limit and to verify that the constraint shadow price is correctly reflected in prices when the energy limits are binding.

this location should be equal to the energy offer price of the marginal generator or the bid of the marginal price capped load at its dispatch level plus any relevant opportunity costs.[9] Similarly, in an interval with n binding transmission constraints, at least n+1 generators or price capped load bids should be on the margin.[10] The marginal generators and load bids are identified in the pricing dispatch in which some resources have schedules fixed in the physical dispatch and are not eligible to set price and in which fixed block units such as gas and combustion turbines are treated as if they are dispatchable at any level between zero and their upper operating limit. If the number of marginal units is less than the number of binding transmission constraints plus one, this is reported by the price validation tool for further review.

Because of the complexity and number of the potential tradeoffs between energy and ancillary service schedules, units that are marginal due to these trade-offs are not directly identified by the price validation software. Trade-offs between energy and ancillary service schedules are validated by verifying that the energy dispatch and ancillary service schedules correctly reflect the opportunity cost of energy ancillary service tradeoffs.

3. Evaluate Energy Schedules for Consistency with LMP Energy Prices

This test reviews the energy schedules for generating units and loads submitting price capped bids in the day-ahead market, real-time pre-dispatch and real-time dispatch and verifies that they are consistent with the LMP prices at those locations. For the purpose of this test, generating units and price capped load bids are divided into five categories based on their schedules: (1) generating units or load bids that were on the margin;[11] (2) generating units that were scheduled to operate at their upper limit (given their ancillary service schedules) or were ramp constrained up; (3) price capped load bids that were dispatched down to their lower limits; (4) generating units that were scheduled to operate at their lower limit (given their ancillary service schedules) or were ramp constrained down; and (5) price capped load bids that were dispatched to their upper limit.

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[9] In the IFM and real-time pre-dispatch, energy prices can reflect the opportunity cost of providing energy instead of ancillary services and can also reflect the opportunity cost of using energy limited resources with binding daily energy limits.

[10] This condition should hold unless a transmission constraint cannot be solved in which case all resources could be at their upper or lower limits on one or both "sides" of the constraint. Constraint shadow prices would then be determined by constraint violation costs and energy and ancillary services prices could be determined in part by these constraint violation costs. We have applied tests to verify that constraint shadow prices are set to $3000/MW when a transmission constraint cannot be solved. Units with binding energy limits are on the margin if the sum of their offer price and the shadow price of the energy constraint is equal to the LMP price at their location.

[11] This could include generation or load self-schedules that were curtailed at the penalty value in the pricing pass of the IFM or RTUC software.

The next step is to verify that: (1) the LMP at the location of each marginal resource or price capped load bid was equal to the resource or load's energy bid at its dispatch point (the same as test 2);[12] (2) the LMP at the location of each resource scheduled at its upper limit or that was ramp-constrained up was greater than or equal to the unit's energy bid at its dispatch point; (3) the LMP at the location of each price capped load scheduled to its lower limit was greater than or equal to the load's bid at its dispatch point; (4) the LMP at the location of each unit scheduled at its lower limit or that was ramp-constrained down was less than or equal to the unit's energy bid at its dispatch point; and (5) the LMP at the location of each priced capped load scheduled at its upper limit was less than or equal to the load's bid at its dispatch point.

4. Replicate Ancillary Service Prices from Shadow Prices

This test verifies that ancillary prices could be replicated from appropriately calculated shadow prices. The application of this test evolved in the course of testing with changes in the number and nesting structure of ancillary service regions and with changes in the way ancillary service shadow prices are reported.

5. Validate Ancillary Service Prices Based on Marginal Suppliers

For the day-ahead market and real-time pre-dispatch, this test identifies the marginal ancillary service suppliers whose offers determined the market-clearing prices for spinning reserves, 10-minute reserves, regulation up and regulation down, in each ancillary service region in each hour, and validates the cascaded market clearing prices for each ancillary service. The offer of the marginal ancillary service supplier may have an energy market opportunity cost that sets the ancillary service price.

6. Examine Ancillary Service Schedules for Consistency with Prices

For the day-ahead market and real-time pre-dispatch, this test verifies that the ancillary service schedules for ancillary service suppliers were consistent with the market clearing prices for energy, spinning reserves and 10-minute reserves, regulation up and regulation down in each region and in each hour or pre-dispatch period. This evaluation includes verification that the sum of the ancillary service offer price and energy market opportunity cost is less than or equal to the price of ancillary services for all resources scheduled to provide each ancillary service.

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[12] In the case of energy limited units with binding energy constraints, we verify that the sum of their offer price and the shadow price of the energy constraint is equal to the LMP price at their location.

7. Examine Unit Commitment for Consistency with Prices

The day-ahead market unit commitment results are validated by applying two tests to generating unit schedules. First, we determine whether there were units that were not committed that could have profitably operated at the day-ahead LMPs, taking into account the resource's minimum load cost and start-up costs over the commitment period. Second, units whose schedules would require uplift payments because their day-ahead energy and ancillary service revenue is less than their as bid costs are identified. These tests were also applied, but less comprehensively, to the real-time unit commitment decisions by RTUC.

Because of the non-convexities inherent in unit commitment decisions, not all anomalies identified by these tests indicate software flaws or limitations. Our review focused on identifying material anomalies or patterns involving a large number of smaller anomalies within a single test case. We did not attempt to definitively resolve individual small discrepancies within a given test case that would be consistent with small changes in loss factors or prices associated with changes in the unit commitment.

B. Scope of Testing

This report covers the testing of certain elements of the CAISO market software that we have carried out. It does not cover all testing that has been carried out by the CAISO. In particular, this report does not cover the performance of various associated systems. For the purpose of the testing covered in this report:

- The IFM Cases analyzed have not been run in conjunction with RUC or market power mitigation.
- The real-time cases have been run in a test environment without market power mitigation, without going through SIBR, without real-time events such as operator actions and generator and transmission outages.
- The RTUC and RTD cases have been tested independently of the IFM cases so we have not tested issues relating to the relationship between IFM, RTUC and RTD schedules.
- We have not tested associated processes such as the load forecaster.

The results of testing these other elements of the CAISO market software will be covered elsewhere.

C. Test Cases Analyzed

In the third stage of analysis track testing, LECG has reviewed eight IFM cases: (1) base case .5% and .01% MIP gap, _ 0; (2) high load base case; (3) pc_ifm_ a2 test7a_e032408_ s91727126 (referred to as case 7a below); (4) _fc_ifm_t3_test108_ e032208_s617263382 (referred to as case 108 below);[13] (5) fc_ifm_t3_case104_p197_ e032808_S617263462 (referred to case 102 below); (6) fc_ifm_t3_test102_e032808_ S617763443 (referred to as case 104 below); (7) case fc_ifm_a2_case106_ e032408_s917271280 (referred to as case 106); and (8) case fc_ifm_a2_case107_ e032408_s917271240 (referred to as case 107).

LECG has to date only reviewed the RTUC base case: fcmrtpdwt3.patch208_ e302808_ mipgap.01% and mipgap .5%.

LECG has not reviewed any RTD cases in the final round of testing (as of this draft report), and limited review was undertaken of RTD cases in the earlier rounds of analysis track testing.

The test cases we have reviewed to date have a number of features that have helped verify that particular features of the CAISO software are working as intended. The conditions we have observed in testing, and in which the pricing software operated correctly, include:

- Unsolved internal transmission constraints with shadow prices equal to $3000 (IFM case 108).
- Binding external tie-line scheduling constraints with shadow prices in excess of $477 (IFM case 108).
- Regional ancillary service prices reflecting minimum ancillary service requirements.
- Price-capped load bids setting prices in the day-ahead market.
- Binding intertemporal limits on energy limited resources in the day-ahead market.

Not all elements of the market software have been tested by the conditions included in the test cases reviewed for this report. Some of the conditions not verified in this report include:

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13 This case was initially run with a .5% MIP gap and was subsequently rerun with a .01% MIP gap.

- No RTUC test cases have included uneconomic gas turbines running due to minimum run time constraints, with substantial differences between physical and price setting dispatch for a variety of units.

- No test cases have included reserves shortages within particular ancillary service subregions in the day-ahead market, real-time pre-dispatch or real-time dispatch.

- No test cases have included CAISO wide reserve shortages in the day-ahead market, real-time pre-dispatch or real-time dispatch.

- No test cases have included exports curtailed at the price cap in the day-ahead market or real-time pre-dispatch.

- There were no test cases in which firm load could not be met.

- There were no real-time pre-dispatch test cases with changes in transmission limits over the analysis period.

- Forbidden region constraints were turned off for the April tests.

- No wheels have been present in the April test cases.

D. Test Results

1. Replicate LMP Energy Prices

IFM

Pnode LMP Replication

We are able to replicate the congestion component and overall LMP price for all prices reported by the IFM software in the .5% MIP gap base case, the high load base case, and cases 102, 104 and 108. Our replication of LMP prices has been based on the unrounded shift factors and loss factors exported from the IFM and RTUC software.

We are unable to replicate the congestion component of prices reported by the IFM software for IFM cases 7a, 106 and 107 using shift factors, offsets, and transmission constraint shadow prices reported by the IFM software for seven Pnode IDs. The prices we calculate differ from the prices reported by the IFM software by as little as a few cents or as much as $48/MWh in case 7a, as much as $95/MWh in case 106, and as much as $523/MWh in case 107. We observed price calculation errors on the same seven Pnodes in the base test case run with patch 157. The message files for these cases indicate that these seven Pnodes were electrically disconnected from the grid in these cases, while connected in the remaining cases in which the Pnode prices for these locations could be replicated. It appears to us that we have been unable to replicate the prices from the shift factors and offsets because the shift factors exported from the IFM for these seven locations are non-zero, while the prices reported by the IFM software for these locations have been calculated with a zero shift factor (presumably reflecting the disconnection from the grid) and a non-zero offset.[14]

Apnode LMP Replication

We have been unable to recalculate certain Apnode LMPs in the base cases, cases 7a, 102, 104, 106, 107 and 108 due to missing data for the relevant load weights. The affected Apnode LMPs are those for LAPs and LAFs.[15] The missing Apnode data does not necessarily indicate the existence of a price calculation error; rather it concerns an inability to confirm that the prices were calculated correctly in these cases due to incomplete IFM data output provided to LECG.

The CAISO provided us with data from IFM case 2001 which included the load weights required to replicate Apnode prices. We recalculated the SCE, PG&E and SDG&E LAP prices from the component Pnode prices and were able to replicate the SCE and SDG&E LAP prices. We were not able to replicate the PG&E LAP price in any hour. The differences ranged from a penny up to about $.75/MWh. In some hours the congestion component of the PG&E LAP price was zero and the price different arose from differences in the calculated the loss component, in other hours both the calculated loss and congestion components differed from those reported by the IFM software.

We were not able to carry out replication of all of the aggregated generator nodes for case 2001 because the relevant Apnode prices were not correctly exported, resulting in the export of zero prices for Apnodes that clearly had non-zero prices. We were able to replicate the trading hub prices for case 2001.

RTUC

Pnode LMP Replication

When we carried out the replication of Pnode prices using unrounded shift factors for the RTUC base case, we were able to replicate the prices at all but 1455 Pnodes. If we

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14 The penalty factor for these locations is non-zero and we are able to replicate the loss component of these prices using that penalty factor, so these locations do not appear to be disconnected from the grid in determining the loss factor.

15 The emm_scuc_imm_laf.csv and emm_scuc_imm_lap.csv files for the IFM test cases other than case 2001 are blank.

carried out the replication of Pnode prices using shift factors rounded to 6 decimal places we were able to replicate the prices at the 1455 Pnodes but could not replicate prices at 7787 other Pnodes. It therefore appears to us that shift factors are being rounded in the calculation of prices for some but not all Pnodes. We also analyzed a rerun of this case with patch 199 reinstalled, but continued to observe this problem. This kind of problem has existed since the fall testing but only surfaces in cases with unsolved transmission constraints and very high constraint shadow prices. Since the errors identified are only in the range of one or two cents per megawatt in a case with transmission constraint shadow prices in the thousands of dollars, the errors are not material; however, it is desirable to identify the source of the discrepancy and resolve it to ensure that the root problem does not have other manifestations that could lead to larger errors in other circumstances. Siemens has determined that this difference has been arising because shift factors at locations used in the optimization were being rounded to 6 decimal places, while the shift factors for other locations were not being rounded. This difference should be readily corrected, although the changes have not yet been implemented and tested.

Apnode LMP Replication

We are unable to recalculate Apnode LMPs for a number of Apnodes in the RTUC base case that are composed of Pnodes whose prices cannot be recalculated as noted above. In addition, we were unable to recalculate the LAP prices due to a lack of mapping data. None of the RTUC Apnode issues shows the existence of a software error; they reflect a current inability to confirm that the prices are calculated correctly.

2. *Validate LMP Energy Prices based on Marginal Offers/Constraint Violation Costs*

Analysis of marginal units determining LMP prices was not carried out for the November cases, but was included in the evaluation of the April 2008 analysis track cases.

IFM

The number of marginal units appropriately exceeded the number of binding transmission constraints in every hour of the base cases, and analysis track cases 7a, 102 and 104, 106, 107, and in all hours of case 108 except hours 22, 23 and 0. The appropriate number of marginal units also appears likely to exist in the remaining three hours of case 108; however, because of the shift factor rounding issues discussed in Subsection 3 below, there are a number of units which should be marginal whose offer prices appear to differ by a penny or so from the LMP price at their location.

In case 108 the 30970_MIDWAY_230_30973_SUNST _230_BR_1 _1 flowgate is violated and appears in the emm_scuc_output_flowgate_v.csv file with a shadow price of $3000. This constraint violation cost correctly sets prices in several hours.

In case 108 some flowgates that are not violated, but are exactly at their limit, have shadow prices in excess of $3000. For example, the METCALF_MORGANHL_BG flowgate in HB 15 PST is binding with a shadow price of $12,993.90. Our interpretation of the MRTU tariff is that the IFM solution should violate this constraint, incurring the appropriate violation cost, instead of solving the constraint at such a high cost. It appears from discussion with the CAISO and Siemens that in the current design constraints that are not violated in the scheduling run pass are not eligible to be relaxed at the constraint violation cost in the pricing pass and this accounts for the observed outcome. The CAISO has indicated that this treatment of constraint violation costs in the pricing run will be reviewed and modified if necessary to ensure that constraints with shadow prices in excess of $3,000 will be relaxed in the pricing run.

RTUC

The number of marginal units plus violated transmission constraints appropriately exceeded the number of binding transmission constraints in the RTUC base case. As in IFM case 108, there were transmission constraints that could not be solved and were violated in the RTUC base case. The same issues that were identified in IFM case 108 were present in this base case, in particular, there were a number of constraints that were violated or binding with shadow prices in excess of $3,000. We believe these outcomes are the expected result of the way constraints are currently relaxed. One distinct issue in the RTUC base case is instances of constraints being violated at a shadow price of $1,000, rather than $3,000.

3. Examine Energy Prices for Consistency with Energy Dispatch

IFM

We have verified that in the cases we reviewed resources are being dispatched consistent with their bids and the CAISO market design in almost all instances. The exceptions are identified below. In case 108 we observed instances in which generating units are dispatched to a point on their bid curve that is uneconomic by more than $0.01, but less than $0.02. The threshold that LECG, the CAISO and Siemens have agreed should be applied to distinguish dispatch and pricing issues from the effect of rounding conventions is $.01, so these errors, while small, are outside the bounds we have used to identify software issues for review. The very high transmission constraint shadow prices in this case raise the possibility that this discrepancy is a result of a difference in shift factor rounding within the IFM software that only becomes apparent with such high shadow prices. As explained above, Siemens has determined that the shift factors used for the optimization are being rounded to six decimal places while our replication of prices is based on unrounded shift factors. This rounding does not account for the dispatch inconsistencies in case 108, however, as the prices we use for the comparison are based on the rounded shift factors used in the optimization and the rounding in case 108 only changes prices by a fraction of a cent. While the observed differences are very small, since they cannot so far be attributed to rounding conventions, it is desirable to identify the source of the discrepancies to ensure that the errors would not be larger in other circumstances. These price and dispatch inconsistencies were present in both the .5 and .01% MIP gap runs for this test case.

There were no load schedule anomalies in the base cases or cases 102, 104, 106 or 107.

In case 7a, we observed a price-capped load bid scheduled to a level that is inconsistent with the bids and prices. This load has a bid price of $5/Mwh and a LMP of $0.00 at its location, but the schedule in the pricing run is 0.033 MWs below the unit's bid MW value, when it should be fully dispatched. The dispatch inconsistency is very small, but it should not exist and it does not appear to be related to any of the other issues that have been identified. The load bid is scheduled to the appropriate level in the scheduling run. The CAISO indicated they would investigate this anomaly and open a variance with Siemens.

We also observed instances in case 108 in which load bids are dispatched to a place on their bid curve that is uneconomic by more than $0.01, but less than $0.02. This pattern is likely related to the observation regarding generation units and shift factor rounding noted above.

There were no wheeling transactions in the base cases, or in analysis track cases 7a, 102, 104, 106, 107, or 108 so no wheeling transaction anomalies were identified.

We identified a data issue in the base cases and cases 7a, 102, 104, 106, 107, and 108 in which units are committed for regulation and are ramp constrained using their regulation ramp rate, but are not flagged in the data as ramp constrained. This issue does not reflect any price calculation error or dispatch issue but should be corrected prior to market implementation to speed price verification.

We observed a number of instances in the base cases and cases 7a, 102, 104, 106, 107, and 108 in which units were dispatched to a breakpoint on their ramp capability curve, rather than to the point at which price equaled incremental cost or at which the unit would have been ramp constrained.[16] Thus, it would have been profitable to dispatch

16 .5% mip gap base case – 9 instances; high load base case – 13 instances; Case 7a – 4 instances; case 102 – 10 instances; case 104 – 6 instances; case 106 – 31 instances; case 107 – 3 instances; case 108 – 62 instances.

these resources to a different location on their energy bid curve.[17] These outcomes appear to be the outcome of the specified MIP gap, given the design of the software and the shape of the ramp rate curve submitted by these units. As a result of the complexities in the ramp rate curves, these units are treated as ramp constrained in the optimization although they actually should not be ramp-constrained at those dispatch points. In some instances, units are treated as ramp constrained in the dispatch without any change in dispatch from hour to hour.[18] All of the units treated as ramp constrained in this manner submitted ramp rate curves that can be described as W shaped, many associated with combined cycle modeling.

In the .5% MIP gap base case there are also two instances of MIP gap issues involving the scheduling of units for regulation. The units in question have different ramp rates depending on whether they are providing regulation and their commitment to provide regulation causes them to forgo larger profits in the energy market by reducing their ramp rate. One of these instances remained in the .01% MIP gap base case; the other resource was correctly scheduled in the case run at the lower MIP gap.

The instances of non-optimal dispatch identified above have been attributed to "MIP gap." The underlying issue is that when there are integer choices in the unit commitment and dispatch optimization problem, there is an inherent potential, given the resulting non-convexities, for the optimization to select a solution which is optimal given the choice of these zero one variables, but is not globally optimal. In the Siemens day-ahead market and RTUC software there are a number of such integer choices, involving unit commitment state, the ability of the resource to provide particular ancillary services, and the unit's ramp range. As a result, as noted above, there are a number of instances in which the solution is not globally optimal, and instances in which the dispatch is not optimal given the unit commitment. Virtually all of the MIP gap issues identified in this report arise, directly or indirectly, from the degree of flexibility in specifying ramp rates provided by the CAISO market design, and in many cases arises from the shape of the ramp rate curve specified by the market participant.

Our review has verified that these dispatch inconsistencies do not reflect erroneous price calculations, but simply reflect limitations on the optimality of the dispatch given the trade-off between performance and additional iterations. The prices are correctly calculated given the unit commitment, the ramp rate used in the dispatch solution, and the constraints which were binding in the dispatch solution. The calculation of LMP prices

17 This both includes instances in which units ramp to a break point and stop when it would have been optimal to ramp further and instances in which it would have been optimal to not ramp as far in that interval.

18 At present, none of these units was flagged as ramp constrained in the output data, indicating that the ramp constrained flag is still not completely reliable.

from a dispatch which is not fully optimal has precedent in PJM's operation from 1998 into 2002, when PJM had a limited set of dispatch tools and PJM calculated prices based on the dispatch, but the settlement prices were not everywhere consistent with the dispatch because the dispatch was not fully optimal.

The CAISO testing has included runs of test cases using both 0.5% and 0.01% MIP gap and we and the CAISO are continuing to review the differences between these cases and the effect of the way the objective function is specified on software performance. In particular, we are reviewing the way self-schedule penalty values are accounted for in the objective function and whether the targeted MIP gap value is currently inflated by the inclusion of self-schedule penalties in the value of the objective function.

RTUC

We observed that a unit ramped up to 246 MW when its bid was more than $0.01 above the LMP, which is outside the rounding tolerance. We observed one import whose schedule was set in the scheduling run and treated as though it were marginal, but its bid offer differed from the LMP by more than $0.01, which is outside the rounding tolerance. Since there are small errors in replicating LMP prices in this case, both of these dispatch inconsistencies may reflect the impact of those price calculation errors.

There were no wheel transactions modeled in the RTPD base case so no issues were identified.

There continue to be resources that appear to be dispatched correctly in the base case and that we can manually calculate to be ramp constrained, but that are not listed as ramp constrained in the emm_scuc_output_valid_ramp.csv file. These are not pricing errors but these kinds of omissions will slow price validation once MRTU is implemented.

We observed 10 units that were dispatched to breakpoints in their ramp rate curve, rather than to their economic dispatch point, in the .5% MIP gap case and 4 such units in the .01% MIP gap case. As discussed above in the context of IFM, these reflect the effect of the non-convexities in these ramp rate curves.

4. Replicate Ancillary Service Prices from Shadow Prices

IFM

A manual process was used to replicate the ancillary service prices for the .5% MIP gap base case, the high load base case, cases 7a, 102, 104, 106, 107, and 108. [19] This manual calculation derived prices for regulation up by subtracting the SAS generated spinning reserve price from the regulation up price, and arrived at a spinning reserve price by subtracting the non-spinning price from the spinning reserve price. We then compared these calculated prices with the prices presented in the CAISO's emm_scuc_output_bid.csv file. No errors were identified when we performed this analysis on the base cases, case 7a, 102, 104, 106, 107, or 108.

There has been an outstanding issue regarding the reporting of incorrect $0 ancillary service clearing prices in the emm_scuc_output_bid.csv file for units that were not scheduled to provide ancillary services. In cases 7a, 102, 104 and 108 this file is populated with the correct clearing prices for all commodity types that were offered by a resource. This issue therefore appears to be resolved.

In verifying that the cascading of ancillary service prices was working as intended, we observed that on-line units are able to submit offers to provide both spinning reserve and non-spinning reserve at distinct offer prices. Moreover, the entire rampable capacity of such a unit could be offered either to provide spinning reserve or non-spinning reserve with the overall ramp limit enforced when the market was cleared. Price cascading therefore operated somewhat differently than in other markets, as rampable capacity on an on-line unit could clear either as spinning or non-spinning reserve and would only trigger cascading if cleared as spinning reserve, but price cascading operated correctly in the base cases, case 7a, 102, 104 and 108, given these features. We observed instances in the test case bid data in which non-spinning reserves were offered at higher offer prices than spinning reserves on the same unit and instances in which non-spinning reserves were offered at lower offer prices than spinning reserves.

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[19] Starting with patch 176, ancillary service shadow price data is reported differently than in the past. Prior to patch 176, the shadow prices of each ancillary service commodity type were additive (i.e., the regulation up price = regulation up shadow price plus spinning reserve plus non-spinning reserve shadow price), as were the regional shadow prices (i.e., the non-spin price for a resource in regions 0 and 9 = non-spinning shadow price region 0 plus non-spinning shadow price region 9).[19] The ancillary service shadow price data are now reported in a format in which the ancillary service commodity type shadow prices are not additive; however, regional shadow prices by ancillary service commodity are still additive. The ancillary service commodity regional shadow price is no longer reported in the emm_scuc_output_ market.csv file. These changes have made it impossible to run the automated replication of ancillary service prices for the April 2008 test cases.

RTUC

We were able to recalculate all ancillary service prices in the RTUC base case, however, all spin and non-spin shadow prices were equal to zero.

5. Validate Ancillary Service Prices based on Marginal Offers

We were able to identify the correct number of marginal ancillary service suppliers in IFM case 106. The remaining cases have not yet been analyzed.[20]

6. Examine Ancillary Service Prices for Consistency with Ancillary Service Schedules, Energy Schedules and Energy Prices

IFM

Our review of the base cases and analysis track cases determined that resources scheduled to provide ancillary services are being scheduled to provide an amount that is consistent with the ancillary service prices, and energy market opportunity costs, in almost every instance. The exceptions are noted below.

We observed seven instances in case 108 in which the co-optimization of energy and ancillary services appears to be incorrect by more than $0.01, but less than $0.02, based on the reported energy and ancillary service prices. These anomalies may be related to the large constraint shadow prices in case 108, combined with the rounding of transmission constraint shift factors discussed above in Section 3.

We observed instances in case 108 in which units are not being scheduled for their full self schedule for non-spin, because they have an economic bid with a larger margin than the self-schedule modification penalty for non-spin. We believe that the software is scheduling these units correctly based on economics

While resources scheduled to provide ancillary services are almost always scheduled to provide the correct amount of ancillary services, we have identified many instances in which resources were not scheduled to provide ancillary services when it would have been economic for them to have done so. These MIP Gap issues in the base case, and cases 7a, 102, 104, 106, 107, and 108 arise from the binary commitment decision for regulation (commitment = 0 or 1), as well as the commitment decision for non-spinning reserves when the unit is offline (commitment = 0 or 1). These binary decisions can cause units not to be scheduled for regulation or non-spin when they are in

[20] Recent changes in the way ancillary service prices are reported will require changes to the SAS price validation tool to complete this analysis within the tool.

fact economic to provide that ancillary service. In the base cases, and cases 7a, 102, 104 and case 108, a varying number of units were scheduled to provide 0 MWs of an ancillary service, were not committed to provide that ancillary service, but it would have been profitable for the units to have provided that ancillary service.[21] These generally appear to be instances of non-optimal commitment due to the MIP gap.

One of these instances in case 108 included a resource that was forgoing a margin of nearly $1000/MWh by not being scheduled to provide regulation. This rather large departure from the optimal dispatch may be a result of the value of the objective function for this case. The CAISO has rerun this case at a .01% MIP Gap level to determine if these instances of non-optimal scheduling disappear. The number of instances of non-optimal ancillary service scheduling in case 108 fell from 113 to 28 at the lower MIP gap level, and the instance of the unit forgoing the large regulation margin that was present in the .5% MIP gap case was eliminated with the unit correctly scheduled to provide regulation.

RTUC

We observed in the RTUC base case that there continues to be an issue with resources that are in their minimum down time being scheduled to provide non-spinning reserves.

As in the IFM, we observed instances of non-optimal commitment of resources to providing ancillary services. There were four such MIP gap issues in the RTUC base case.[22]

7. Examine Unit Commitment for Consistency with LMP Prices

IFM

The calculation of uplift costs by resource was not carried out for the November cases, but was included in the final evaluation of analysis track cases. The uplift evaluation was carried out considering both pricing run and scheduling run prices.

There were no instances of substantial uplift costs on units committed on economics in either of the base cases, cases 7a, 102, 104 or 108. There were instances of self-scheduled units being committed uneconomically based on their pricing run penalty values, but all of these units were correctly committed based on their self-schedules in the

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21 9 instances in the base case, 92 in the high demand base case, 7 in case 7a, 25 units in case 102, 7 in case 104, 38 in case 106, 29 in case 107 and 113 in case 108.

22 The number of such instances fell from 4 in the .5% MIP gap base case to 2 in the .01% MIP gap base case.

scheduling run pass. Uplifts on other units were within the range that we would normally expect to see in such a unit commitment problem.

We have calculated large forgone energy revenues for one resource in case 107 and 7 resources in case 106. All of these resources are among the resources for which we were unable to replicate the calculated LMP prices and all are indicated in a message file as being electrically disconnected from the grid. In some instances, the resources were scheduled to provide non-spinning reserves despite not being connected to the grid. As noted above, the CAISO and Siemens are reviewing various aspects of the modeling of these resources.

RTUC

There was one unit with a must run operating mode that was not committed for energy in the RTUC base case. We understand that this appears to have been the result of a data issue in which the unit was not modeled as connected to the grid.

E. Review of Unresolved Issues

The key issues that need to be resolved are: 1) resolution of the small price recalculation and or dispatch consistency errors apparently related to the truncation of shift factors; 2) correction of the constraint violation modeling so that all transmission constraints are violated when their shadow price reaches $3,000 in IFM and RTUC; and 3) resolution of modeling and data issues for the 7 resources whose prices cannot be replicated when they are reported as not connected to the grid in several cases and the other related anomalies; and (4) replication of the PG&E LAP prices. In addition, the CAISO and LECG will continue to review the differences in the dispatch and scheduling between .5 and .01% MIP gap cases, and the manner in which the MIP gap threshold is calculated.