California Independent
System Operator Corporation

Review of California ISO MRTU Structured Market Simulation Results Trade Days - December 9-12, 2008

Department of Market Monitoring

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I. Executive Summary

This report provides a follow-up assessment of certain market performance issues raised by the California Independent System Operator Corporation (CAISO) Department of Market Monitoring (DMM) in its October 22, 2008, report (October Report) assessing the results of the market redesign and technology upgrade (MRTU) market simulations during September 2008.[1]

Based on this follow-up analysis, DMM believes the MRTU markets have performed reasonably well overall in the structured market simulations performed in December, and we have not seen any performance issues that would warrant a delay in MRTU implementation. However, we do recommend that the CAISO continue to work with DMM and market participants over the next six weeks to conduct a more in-depth assessment of some of the more extreme pricing outcomes in the December structured simulations to better explain and confirm the root cause of these results. Additionally, we recommend the CAISO closely track and mitigate the root cause of potential failures that have periodically prevented the running of local market power procedures prior to the Real Time Market, and establish pricing provisions when such failures occur under actual market operation.

Summary of October DMM Report

In the October Report, we identified five specific areas for further review and analysis:

1. **Extreme real-time market locational marginal prices (LMPs) –** Our assessment of the real-time market (RTM) performance in September found that roughly 2 percent of the real-time market clearing quantities cleared at LMPs greater than $1,000/MWh. A significant share of these extreme prices were reviewed by the CAISO and found to be due to software or technical glitches in the simulation environment that have since been corrected. DMM recommended that the CAISO continue conducting in-depth analysis of the root cause of extreme LMPs to identify and correct any erroneous modeling or software issues that may be causing these prices.
2. **Price divergence between day-ahead and real-time markets –** Our analysis of September market simulation results found that prices for imports and exports on inter-ties with other control areas tended to be significantly higher in the Real Time Market than in the Day Ahead Market. This divergence was part of a more general trend of much higher prices in the real-time market. We noted that if such significant and systematic price divergences persisted under MRTU, it could result in market inefficiencies and potential implicit virtual bidding at the inter-ties. We recommended the CAISO run structured market scenarios to further examine and test for price divergences between the Day Ahead and Real Time Markets.
3. **Reliance on non-resource adequacy units in the residual unit commitment (RUC) process –** Results from the September market simulations showed that the RUC process consistently awarded RUC capacity to non-resource adequacy units at fairly high average RUC prices. An effective resource adequacy program should generally provide sufficient

[1] The October Report can be found on the CAISO website at: http://www.caiso.com/2068/2068ad206a9b0.pdf

capacity in RUC such that reliance on non-RA units is minimal; therefore, RUC prices would generally be low if not zero. If non-RA resources are routinely awarded large amounts of RUC capacity at relatively high prices in actual market operation, this could have significant market power and price distorting implications for other markets that would in our view necessitate changes to the RUC market design and/or market power mitigation rules. We committed to undertake additional analysis to better assess whether sufficient resource adequacy (RA) capacity is being offered to the day-ahead market.

4. **Effectiveness of local market power mitigation (LMPM) –** Our analysis of the September market simulations found that the LMPM procedures appear to be working as intended and are effectively mitigating local market power. However, we indicated that we would continue to review LMPM performance.
5. **Skipped or Failed LMPM Procedures -** Importantly, our September analysis found that the LMPM procedures fail to run in the real-time market or have been skipped in as much as 5 percent of the hours. We committed to continue to monitor the frequency of any failures of RTM market power mitigation runs during market simulation, and recommended that these failures be formally tracked by the CAISO as a basic market performance metric.

In response to the DMM recommendations, as well as similar requests from market participants, the CAISO completed a structured market simulation for trade days December 9-12.[2] We used the results from these structured simulations to further assess the five issues noted above. A summary of the key finding from our updated assessment of these issues is provided below.

Summary of Structured Simulation Findings

Residual Unit Commitment (RUC)

More recent market simulation results – including the structured market simulations discussed here – show much smaller amounts of RUC capacity being awarded to non-RA capacity and in much fewer hours. Moreover, the RUC prices paid for this capacity are generally moderate. Consequently, we are less concerned about this issue and do not believe that any changes in the RUC design are necessary prior to MRTU go-live. We will be closely monitoring the performance of the RUC market after go-live. We also strongly encourage the load-serving entities (LSEs) to mitigate reliance of non-RA resources in RUC through proactively managing their RA portfolio to ensure sufficient RA capacity is being made available to the CAISO Day Ahead Market.

Finally, we also recommend that the CAISO consider alternatives to the current RUC design for implementation after MRTU go-live. Importantly, we believe the current RUC design may be incompatible with nodal convergence bidding. As the CAISO works towards finalizing its convergence bidding market design it should consider the implications and compatibility of that design with RUC – among other things.

[2] In November, the CAISO initially tried to perform structured base-case analysis separate from the market simulations but this approach proved to be difficult to complete for the hour-ahead scheduling process (HASP) and Real Time Market. Consequently, an alternative approach was adopted in December.

Real Time Market Performance – Extreme Prices & Price Convergence

The structured market simulations performed in December were designed to assess both the frequency and root cause of extreme real-time prices and price convergence. However, while the structured market simulations in December were of better quality in terms of the submitted bids and schedules and constructed scenarios, they were far from perfect and ultimately suffer from the unavoidable fact that until real dollars are at stake, market participants are not going to exert the level of thought and effort and reaction to observed prices that they would in actual market operation. Consequently, we remain cautious in inferring too much from these simulations. With this caveat, our general assessment of the December structured market simulations is that they produced – in most hours – more realistic and explainable real-time market outcomes.

- With the exception of December 12, extreme real-time market prices were less frequent than observed in the September simulations but still need further analysis to understand their root causes. The CAISO is currently working with DMM and market participants in undertaking a deeper analysis of a subset of extreme prices observed in the structured market simulation.

- Extreme real-time market prices observed on December 12 appear to be due to a combination of reduced supply bids and increased demand, the combination of which resulted in severe system shortages. We do not consider the structured scenario for this day to be very realistic and the extreme results observed are more reflective of the limitations of the simulation as opposed to what we would expect in actual market operation. Specifically, if the CAISO experienced such a significant increase in real-time energy demand in actual operation on a peak summer day, we believe that there would be a significant market response of increased supply, particularly at the inter-ties, which would mitigate extreme prices, whereas the structured simulation had essentially no supply response. Moreover, such an extreme event would likely trigger demand response programs, which did not happen under the structured simulation. The extreme prices observed in the simulation for this day appear to reflect various transmission constraint violations. However, we recommend that the CAISO closely examine a sample of these extreme prices to confirm their root cause.

- Day-ahead and real-time load aggregation point (LAP) prices generally showed better price convergence than observed in the September simulations, particularly during shoulder hours of the day. Real-time prices during the peak hours were still fairly volatile and higher than day-ahead prices but this likely has more to do with deficiencies in the simulation environment than some systematic bias or problem in the market software.

- Prices at the inter-ties also generally showed better convergence than observed during the September simulations – though not at a level that we would expect under actual market operation. As expected, prices at the inter-ties generally diverged more under the load under-scheduling scenario that was executed on December 10.

Effectiveness of Local Market Power Mitigation Procedures

The structured market simulation scenario for the December 11 trade date was specifically designed to test the effectiveness of local market power mitigation (LMPM) procedures. Under this scenario, bids for a significant portion of capacity within several transmission-constrained areas were set at relatively high prices in order to test LMPM performance. The results of this single scenario indicate that LMPM mechanisms are functioning as designed in the integrated forward market (IFM) and effectively mitigating market power. However, DMM plans to further "stress test" LMPM procedures in both the IFM and HASP/RTM through off-line market simulations.

While our review indicates that LMPM mechanisms functioned properly during all of the structured market simulation scenarios, results of the December 11 scenario for the San Diego area highlight the importance of making sure that sufficient time is provided for the IFM to reach an optimal solution – even if that means significantly delaying the close of the Day Ahead Market. Specifically, on the December 11 scenario, although one of the key criteria for measuring the quality of IFM solution (or "MIP Gap"[3]) was not met, the Day Ahead Market was closed in order to provide market participants with sufficient time to structure and submit real-time bids. Under this less optimal solution, a Reliability Must Run (RMR) unit within San Diego that was committed in the market power mitigation procedures was not committed in the IFM. As a result, LMPs within the San Diego area during the peak hours of this scenario exceeded $500/MW (compared to mitigated bid prices of less than $100/MW).

The CAISO subsequently re-ran the same IFM scenario (with an off-line version of the IFM software) and provided additional time to reach a better solution. Under this more optimal solution, one additional RMR unit was dispatched in the San Diego region, and LMPs were lowered to levels reflecting mitigated bids. We recommend that in the event a similar situation should occur under actual market operations, the CAISO should be prepared to extend the solution time of the market software and re-run the software prior to closing the IFM.

Finally, as noted in our October Report, DMM found that the Real Time Market LMPM procedures failed to run or were skipped in as much as 5 percent of the hours during the September simulations. Such failures are generally caused when the software fails to reach a solution in the required amount of time. DMM's review of market simulation logs for December indicates that these failures continue to be occurring in about 5 percent of hours. Thus, we are again recommending that the CAISO track and investigate the root causes of LMPM failures and pursue system enhancements/modifications to reduce their frequency. In addition, DMM has recommended that the CAISO establish pricing provisions that may be applied in cases where the LMPM procedures are not completed in the Real Time Market in actual market operation.

Summary

In summary, this updated analysis of the structured simulations has largely addressed the five issues identified in our October Report. Overall, the MRTU markets have performed reasonably well in the structured market simulations and we have not seen any performance issues that would warrant a delay in MRTU implementation. However, we do recommend that the CAISO continue to work with DMM and market participants over the next six weeks to conduct a more in-depth assessment of some of the more extreme pricing outcomes in the December structured simulations to better explain and confirm the root cause of these results. Additionally, we recommend the CAISO closely track and mitigate the root cause of market power mitigation

[3] For an explanation of the "MIP Gap" metric used to assess the optimality of the market solution, see page 82 of this report.

failures in the Real Time Market and establish pricing provisions when such failures occur under actual market operation.

II. Overview

This report provides a follow-up assessment to certain market performance issues raised by DMM in its October 22, 2008, report (October Report) assessing the results of the MRTU market simulations during September 2008.[4] In the October Report, we identified five specific areas for further review and analysis:

1. **Extreme real-time market locational marginal prices (LMPs) –** Our assessment of the real-time market performance in September found that roughly 2 percent of the real-time market clearing quantities cleared at LMPs greater than $1,000/MWh. A significant share of these extreme prices have been reviewed by the CAISO and found to be due to software or technical glitches in the simulation environment that have since been corrected – though occasional glitches in the real-time simulation environment do still occur. The rest appear to be correct market optimization outcomes associated with extreme conditions – some of which are induced by particular scenarios. DMM recommended that the CAISO continue conducting in-depth analysis of the root cause of extreme LMPs to identify and correct any erroneous modeling or software issues that may be causing these prices.
2. **Price divergence between day-ahead and real-time markets –** Our analysis of September market simulation results found that prices for imports and exports on inter-ties with other control areas have tended to be significantly higher in the HASP than in the IFM. This divergence was part of a more general trend of much higher prices in the real-time market than the IFM. However, we noted that if such significant and systematic price divergences for imports and exports persisted under MRTU, it could result in market inefficiencies and potential implicit virtual bidding where market participants submit IFM bids and schedules on the inter-ties with no intent or ability to deliver (or receive) and instead intend to buy or sell back their position in the HASP. The observed price divergence between the IFM and the HASP during the September market simulations may have been simply due to the fact that market clearing load quantities in the IFM were consistently well below the simulated forecasted load, which increases demand in HASP and necessitates dispatching higher cost resources. To make sure that this persistent divergence was not due to other factors, we recommended the CAISO run structured market scenarios where a larger fraction of load clears the IFM (e.g., 95 percent) and examine the level of price divergence between the real-time market and IFM under this scenario. Additionally, to the extent there are any simulated days in October where a larger proportion of forecasted load cleared the IFM, these days should also be closely reviewed to assess the level of price convergence.
3. **Reliance on non-resource adequacy units in RUC –** Results from the September market simulations showed that the RUC process consistently awards RUC capacity to non-resource adequacy units at fairly high average RUC prices. This result is counter to expectations in that an effective resource adequacy program should generally provide sufficient capacity in RUC such that reliance on non-RA units is minimal; therefore,

[4] The October Report can be found on the CAISO website at: http://www.caiso.com/2068/2068ad206a9b0.pdf

RUC prices would generally be low if not zero.[5] If non-RA resources are routinely awarded large amounts of RUC capacity at relatively high prices in actual market operation, this could have significant market power and price distorting implications for other markets that would in our view necessitate changes to the RUC market design and/or market power mitigation rules. We noted that it is difficult to gauge whether this market outcome is likely to persist in actual market operation or is simply an artifact of the simulation, which may be resulting in less RA capacity being made available to the market than would occur in actual market operation and indicated that we would undertake additional analysis to better assess whether sufficient RA capacity is being offered to the day-ahead market. We also recommended the CAISO carefully review the RUC optimization to determine whether any of its features or input assumptions are overly restrictive or conservative, thereby causing an over-reliance on non-RA resources.[6] Additionally, we also recommended the CAISO publish RUC awards to non-RA resources on a sub-regional level (e.g., local capacity areas). Currently, only the RUC LMPs are posted on the MRTU OASIS. Posting the approximate location and quantity of non-RA RUC awards will provide better information to LSEs on the source of the RA deficiencies and potential options for addressing them.

4. **Effectiveness of local market power mitigation –** Our analysis of the September market simulations found that the LMPM procedures appear to be working as intended and are effectively mitigating local market power. However, we indicated that we would continue to review LMPM performance and that additional analysis would include:
    a. Assessing the LMPM effectiveness with nomogram constraints identified as "competitive" enforced in the competitive run of the market power mitigation procedures. Currently no competitive nomograms are enforced in the competitive run of the market power mitigation.
    b. Performing additional stress testing of the LMPM procedures by running special bidding scenarios (e.g., manually increasing the bids of resources in constrained areas and testing the LMPM effectiveness).
    c. Continuing to review and monitor default energy bids (DEBs), including DEBs developed under the consultative DEB option.
    d. Continuing to review and monitor other resource characteristics that may be submitted by participants to the CAISO Master File and/or as part of market inputs, such as:
        i. Ramp rates;
        ii. Start-up and minimum load data; and

[5] Under the MRTU market design, available capacity from RA resources is considered at a $0 price in the RUC optimization, and RA resources are not eligible to receive RUC payments.

[6] The CAISO has already undertaken some analysis of the RUC optimization and tested an alternative optimization set-up, which did not yield any appreciable difference in RUC market outcomes. It is also important to note that the CAISO typically procured additional RUC capacity beyond the forecasted load in the September market simulations to compensate for certain simulation deficiencies in the real-time market that were overstating the real-time imbalance demand. These additional RUC capacity demands, which were sometimes as high as 10 percent of forecasted demand, likely contributed to higher RUC prices.

iii. Requests for treatment as a use-limited energy resource.

5. **Skipped or failed LMPM procedures** - Importantly, our September analysis found that the LMPM procedures fail to run in the real-time market or have been skipped in as much as 5 percent of the hours.[7] Such failures are generally caused when the software fails to reach a solution in the required amount of time. We recommended the CAISO track and investigate the root causes of LMPM failures and pursue system enhancements/modifications to reduce their frequency. We committed to continue to monitor the frequency of any failures of RTM market power mitigation runs during market simulation, and recommended that these failures be formally tracked by the CAISO as a basic market performance metric. In addition, we recommended that the CAISO establish pricing provisions that may be applied in cases where the LMPM procedures are not completed in the RTM in actual market operation.

In response to the DMM recommendations, as well as similar requests from market participants, the CAISO successively conducted a structured market simulation for trade days December 9-12.[8] We used the results from these structured simulations, as well as results from other market simulation days, to further assess the five issues noted above.

The structured market simulations that were run on December 9-12 began with a realistic base-case scenario that utilized cost-based bids and reasonable assumptions about self-scheduled generation and net-imports. This base-case (Base – 0) ensured the load bids were structured such that 90-95 percent of the load forecast clears the IFM. Several variants of this base case were then run in subsequent days to test certain aspects of market performance. These and the original base-case (Base – 0) are summarized in Table 1 below.

Table 1. Summary of Structured Market Simulation Scenarios

Case	Trade Date	Description
Base - 0	December 9	Cost-based bids, 90-95% load cleared in IFM, DA forecast equals RT actual load. **Purpose:** - Examine price convergence between the IFM, HASP and RTD markets.
Base - 1	December 10	Same as Base – 0 except only 85% of the load clears the IFM. **Purpose:** - Test RUC & RT Market Performance (e.g., occurrence of extreme prices)

[7] We noted that this assessment may be over-stating the frequency of LMPM failures as the data available for this analysis may not distinguish between cases where the LMPM ran successfully but did not identify any need for bid mitigation and cases where the mitigation procedures simply failed to work. DMM has requested that the CAISO provide a more accurate metric going forward for tracking and discerning actual mitigation failures from cases where no mitigation was required.

[8] In November, the CAISO initially tried to perform structured base-case analysis separate from the market simulations. However, this approach proved to be difficult to complete for the HASP and Real Time Market. Consequently, an alternative approach was adopted in December.

		- Examine price divergence between IFM, HASP, RTD
Base - 2	December 11	Same as Base – 0 except submit extreme generator bids in load pockets **Purpose:** - Test LMPM Effectiveness
Base - 3	December 12	Same as Base – 0 except real-time load forecast 5% higher in all IOU territories (PG&E, SCE & SDG&E) **Purpose:** - Test RT Market Performance (e.g., occurrence of extreme prices) - Test LMPM Effectiveness - Examine price divergence between IFM, HASP, RTD

As noted earlier, while the structured market simulations in December were of better quality in terms of the submitted bids and schedules and constructed scenarios, they were far from perfect and ultimately suffer from the unavoidable fact that until real dollars are at stake, market participants are not going to exert the level of thought and effort and reaction to observed prices that they would in actual market operation. Consequently, we remain cautious in inferring too much from these simulations.

III. General Market Performance

Residual Unit Commitment (RUC)

This section reviews the performance of the Residual Unit Commitment (RUC) market in the structured simulations with particular focus on the availability of Resource Adequacy (RA) capacity in the day-ahead market. As noted in the overview, in our October Report, we raised a concern about the level and frequency of RUC awards to non-RA resources and pointed out that if this were to occur in actual market operation, it could have significant market power and price distorting implications for other markets that would in our view necessitate a change to the RUC design. This concern was based on the market simulation results for September. More recent market simulation results, including the structured market simulations discussed here, show much smaller amounts of RUC capacity being awarded to non-RA capacity and in much fewer hours. Moreover, the RUC prices paid for this capacity are generally moderate. Consequently, we are less concerned about this issue and do not believe that any changes in the RUC design are necessary prior to MRTU go-live.

We will be closely monitoring the performance of the RUC market after go-live. We also strongly encourage the Load Serving Entities to mitigate reliance on non-RA resources in RUC through proactively managing their RA portfolio to ensure sufficient RA capacity is being made available to the CAISO Day Ahead Market.

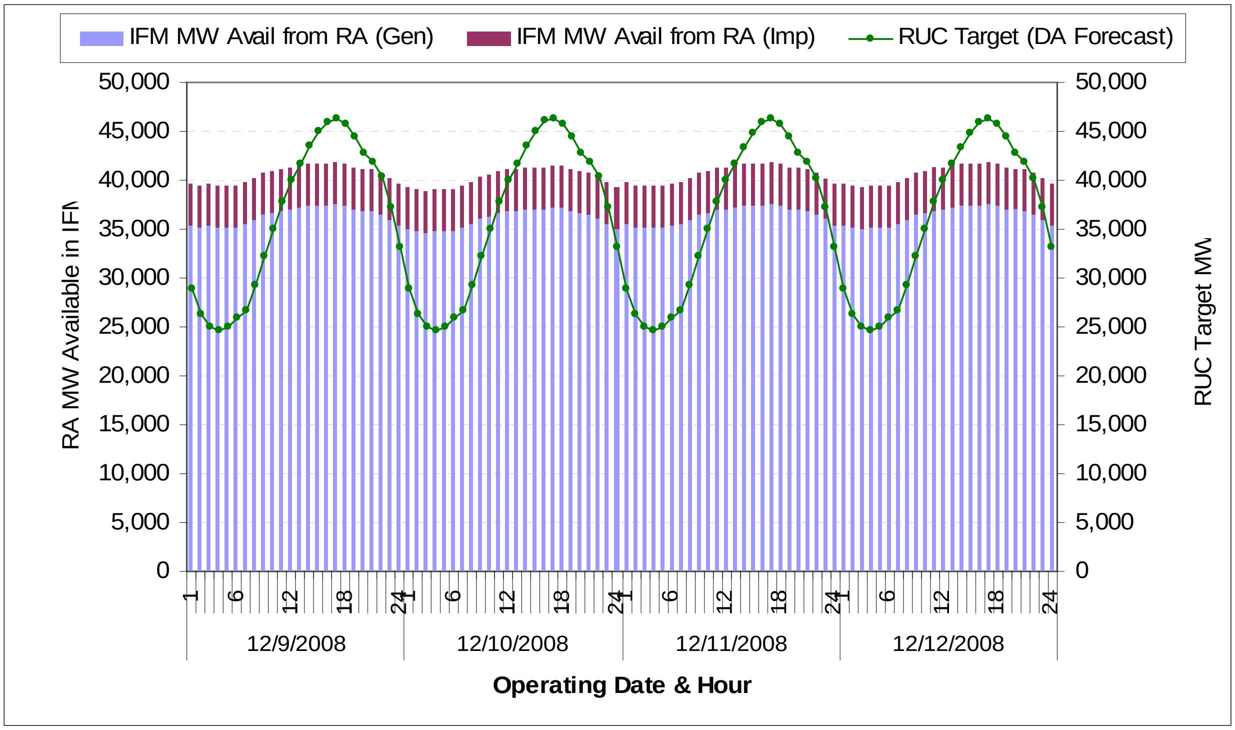
Finally, we also recommend that the CAISO consider alternatives to the current RUC design for implementation after MRTU go-live. Importantly, we believe the current RUC design may be incompatible with nodal convergence bidding and could create gaming opportunities where suppliers use virtual bidding strategies in the IFM to cause reliance on non-RA capacity in RUC. As the CAISO works towards finalizing its convergence bidding market design it should consider the implications and compatibility of that design with RUC – among other things.

A detailed review of the RUC results for the structured market simulations is provided below.

Resource Adequacy and RUC

Figure 1 compares the total RA capacity (generation and imports) made available to the IFM to the day-ahead load forecast used in RUC. The peak load forecast in the structured simulation was approximately 46,000 MW, and, as can be seen in Figure 1, the identified RA capacity available to the IFM (import and generation resources) was considerably less than that – by approximately 5,000 MW across the peak hour. Having insufficient identified RA capacity to meet forecasted load does not necessarily mean that non-RA capacity will be procured in RUC. To the extent energy from non-RA capacity from internal generation and imports clears against load in the IFM, there could be sufficient unloaded capacity from RA resources to meet any residual capacity requirements in RUC. Nonetheless, the shortage does increase the likelihood that non-RA capacity will be needed in RUC.

Figure 1. Comparison of RA Capacity to DA Load Forecast (December 9-12)



A more detailed examination of the RA capacity available to the IFM is provided in Table 2. Specifically, Table 2 provides a breakdown of the various types of RA capacity, showing for each type of capacity:

- The amounts identified in the July 2008 RA showings to the CAISO, which was the assumed RA month for the structured simulations (column 2).
- The amounts identified in the CAISO MRTU Master File used for the structured simulations (column 3).
- The amounts ultimately offered to the IFM in the structured simulation for December 10, Hour 16 (left three columns).

In comparing the RA showings to what was registered in the CAISO Master File, we see that essentially all of the resource-specific RA capacity identified in the July 2008 RA showings (generation and imports) was identified in the CAISO Master File used for the structured simulation. However, a significant share of the July 2008 RA showing (approximately 9,400 MW or 18 percent) is comprised of non-specific resources (e.g., liquidated damages (LD) contracts) for which the CAISO market systems have no ability to identify. The total amount of energy bids submitted to the IFM from identified RA generation capacity was 37,030 MW – roughly 94 percent of the total RA generation capacity identified in the RA showing. There were 4,251 MW of energy bids were provided from RA import resources, representing approximately 86 percent of the 4,900 MW of imports identified in the RA showing.

Table 2. Summary of RA Availability (Dec 10, 2008, Hour 16)

Type of Resource	July 2008 RA Showings (MW)	RA Capacity in Structured Simulation Master File (MW)	Bid Quantity Included in IFM (Dec 10, 2008 HE 16)		
			MW	Percentage of Struc. Sim MF RA Cap.	Percentage of July 2008 RA Showing
Gas Generation - Must Offer		22,624	22,059	98%	
Gas Generation - Non-Must Offer		1,587	1,247	79%	
Hydro Generation - Non-Must Offer		6,255	5,325	85%	
Other Generation - Must Offer		760	758	100%	
Other Generation - Non-Must Offer		8,217	7,641	93%	
Total Gen	38,682	39,442	37,030	94%	96%
Imports	4,916	4,921	4,251	86%	86%
Other RA Resources - (DWR contracts, LD contracts, etc)	9,388	Non-Resource Specific	?	?	?
Total	52,986	44,363	41,281	93%	78%

The amount of incremental capacity that is procured in RUC is largely dependent on how much load clears the IFM relative to the load forecast. Figure 2 shows the hourly percentage of day-ahead forecasted load that cleared the IFM in each hour of the structured simulation (Dec 9-12). With the exception of December 10, the IFM generally cleared approximately 95 percent of forecasted load during the peak hours. The market simulation for December 10 was structured to only clear 85 percent of the load-forecast during the peak hours.

Figure 2. IFM Load Clearing Quantities (December 9-12)

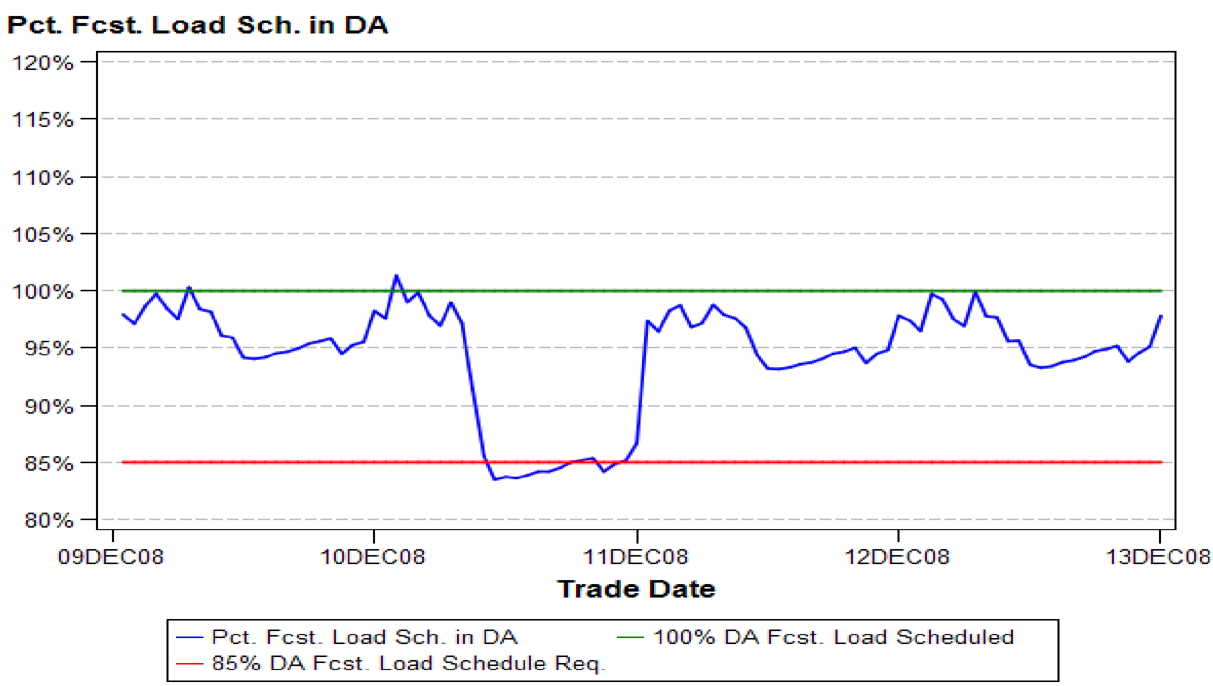


Figure 3 compares the RA capacity available to the IFM (green line) to the amount of RA capacity that was taken for energy or ancillary services in the IFM (blue column) and the amount of available RA capacity in RUC (red column). Importantly, the figure demonstrates that not all of the RA capacity that was made available to the IFM was made available to RUC. Approximately 2,500-3,000 MW of RA capacity available to the IFM was not made available to RUC. This shortfall appears to be primarily attributable to bids that are submitted for hydro and use-limited resources to the IFM but not submitted to RUC.

Figure 3. Comparison of Available RA Capacity in IFM and RUC (Dec 9-12)

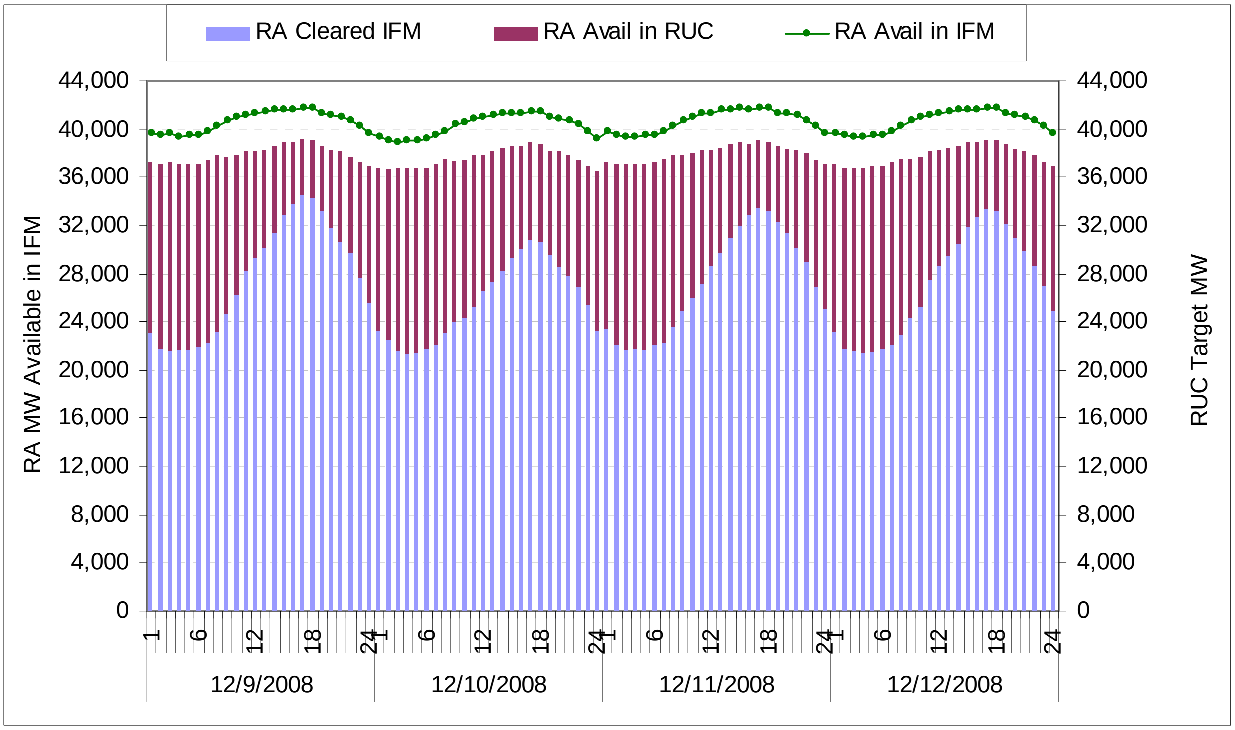
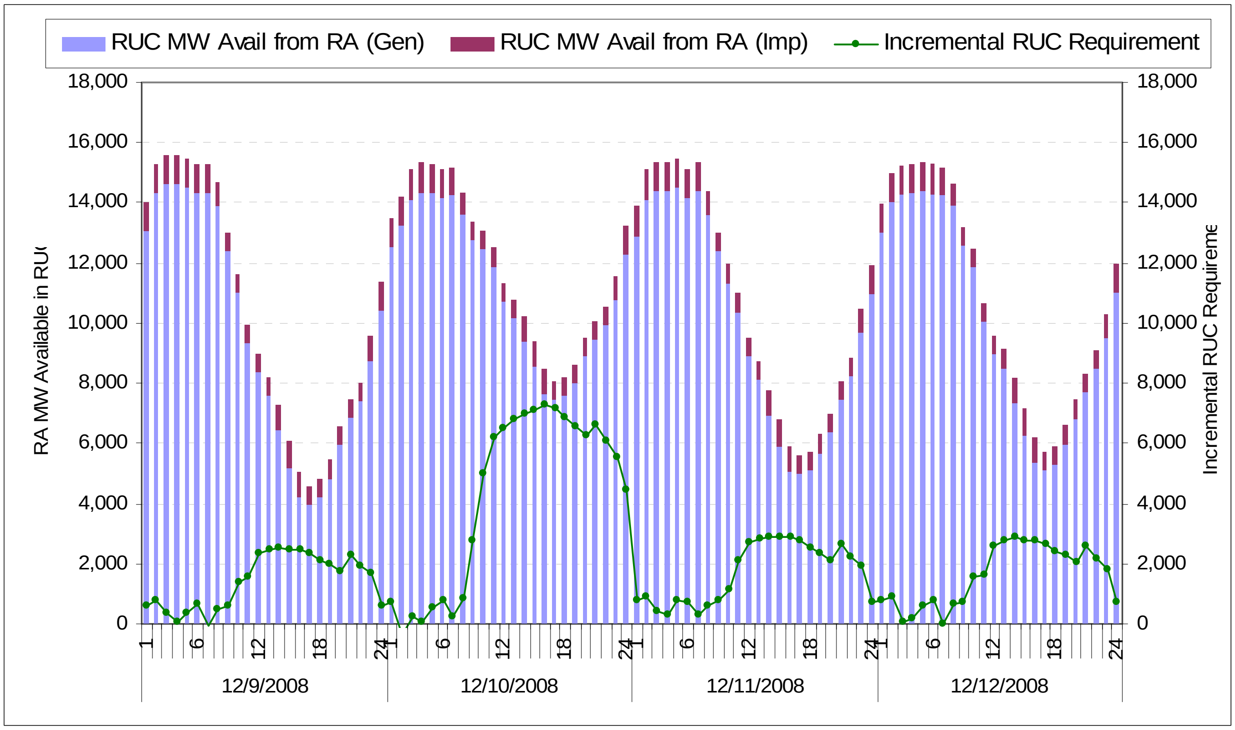


Figure 4 compares the incremental RUC system capacity requirement (i.e., load forecast less the amount of energy cleared in the IFM (generation and net-imports)) and the RUC capacity available from RA resources (i.e., RA capacity not taken for energy or ancillary services in the IFM that was made available to RUC). This comparison suggests there was sufficient RA capacity in RUC to meet the incremental system RUC requirements. However, since some of this capacity may be transmission or ramp constrained, reliance on non-RA capacity in RUC occurred in this hour and several others during the structured simulation. Moreover, some of this RA capacity may be associated with generating units that were not committed in the IFM and consequently the RUC optimization may find it more optimal to award RUC to already committed non-RA capacity than to incur the cost of committing an RA unit. Nevertheless, the CAISO is planning to conduct a more detailed review of the resources available in RUC and RUC commitments.

Figure 4. Available RA Capacity and Incremental RUC Requirements (Dec 9-12)



RUC Results

Figure 5 shows the hourly quantities of RUC awards to non-RA capacity and the average and maximum RUC LMPs paid for that capacity. The results show that RUC awards to non-RA capacity were relatively minor compared to the incremental RUC requirements shown in Figure 4. Average and maximum RUC LMPs paid for non-RA capacity were at or below $25/MW in most hours with the exception of four hours that experienced relatively high RUC LMPs in excess of $100/MW, and, in some cases, in excess of $200/MW. These prices and RUC awards are examined more closely below.

Figure 5. RUC Procurement from Non-RA Capacity (December 9-12)

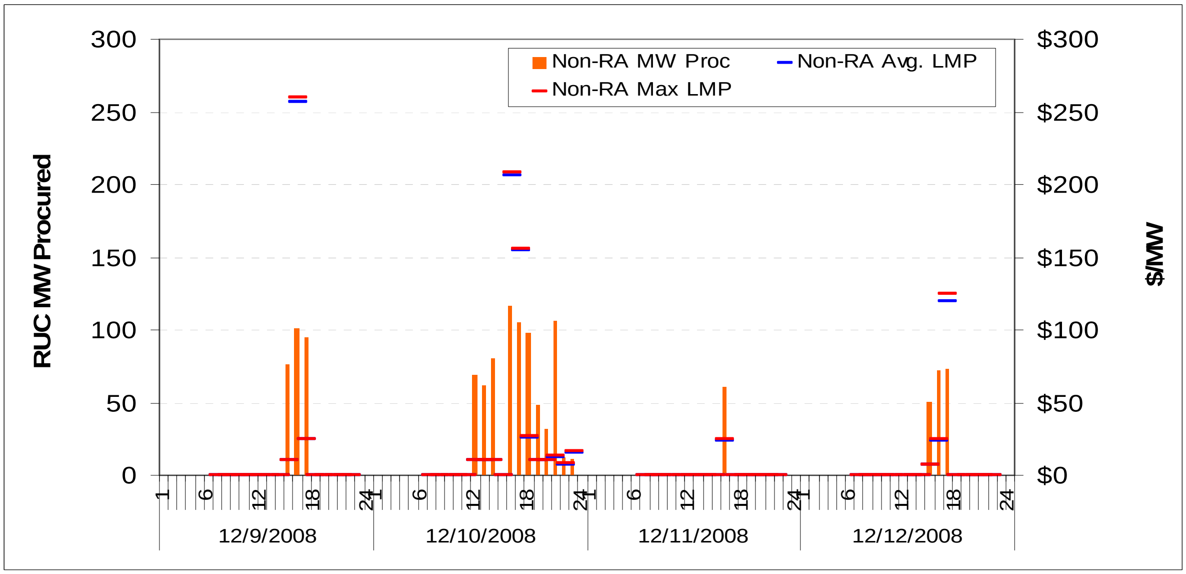


Table 3 provides additional details on the three hours of the structured simulation where RUC LMPs paid for non-RA capacity were in excess of $150/MW. Specifically, Table 3 shows the range of RUC LMPs paid to non-RA capacity from various generating units, which in total amounted to approximately 100 MW of capacity procurement in each hour. Table 3 also shows the energy component of the RUC LMPs and the ranges of the congestion and marginal loss LMP components. The very high system energy component of RUC LMPs observed in these hours strongly suggests that the RUC capacity procured from these resources was for system needs as opposed to local constraints.

Table 3. RUC LMP Decomposition at P-Nodes with Non-RA RUC Awards

Date	Hour	RUC LMP Range ($/MWh)	RUC LMP Decomposition ($/MWh)		
			Energy	Congestion Range	Losses Range
12/9/08	16	247 – 260	259	-2.70 - 0	-12.11 - .26
12/10/08	16	198 – 208	208	-2.70 - 0	-9.72 - .64
12/10/08	17	148 – 156	155	0	-7.28 - .70

Real Time Market Performance

In our October Report, we noted that roughly 2 percent of the real-time LMPs observed in the September market simulations cleared at LMPs greater than $1,000/MWh. We further noted that a significant share of these extreme prices were due to occasional glitches in the market simulation environment and to modeling or software glitches that have since been corrected. Nonetheless, we recommended that the CAISO continue to closely review the root cause of extreme LMPs in the on-going market simulations to determine whether there are any other modeling or software deficiencies causing extreme prices.

We also raised a concern in the October Report about the observed levels of price divergence between the day-ahead and real-time markets (HASP, RTD), and noted that if such extreme levels of price divergence occurred in actual market operation, it would create incentives for implicit virtual bidding where market participants submit day-ahead bids and schedules at the inter-ties with no ability or expectation to physically deliver (or receive) energy. Instead, their intent is to sell or buy back their position in HASP. While we noted that the observed pattern of real-time prices being generally much higher than day-ahead prices was likely due to the fact that load was significantly under-scheduled in the IFM during the September market simulations, we recommended the CAISO conduct structured market simulations where a larger portion of load clears the IFM (e.g., 95 percent) to see if there is an improvement in price convergence.

The structured market simulations performed in December were designed to assess both of these issues. However, while the structured market simulations in December were of better quality in terms of the submitted bids and schedules and constructed scenarios, they were far from perfect, and ultimately suffer from the unavoidable fact that until real dollars are at stake, market participants are not going to exert the level of thought and effort and reaction to observed prices that they would in actual market operation. Consequently, we remain cautious in inferring too much from these simulations. With this caveat, our general assessment of the December structured market simulations is that they produced – in most hours – more realistic and explainable real-time market outcomes.

- With the exception of December 12, extreme real-time market prices were less frequent than observed in the September simulations but still need further detailed review to understand their root causes. The CAISO is currently working with DMM and market participants in undertaking a deeper analysis of a subset of extreme prices observed in the structured market simulation.

- Extreme real-time market prices observed on December 12 appear to be due to a combination of reduced supply bids and increased demand, the combination of which resulted in severe system shortages. We do not consider the structured scenario for this day to be very realistic and the extreme results observed on that day were reflective of the limitations of the simulation as opposed to what we would expect in actual market operation. Specifically, if the CAISO experienced such a significant increase in real-time energy demand in actual operation on a peak summer day, we believe that there would be a significant market response of increased supply, particularly at the inter-ties, which would mitigate extreme prices, whereas the structured simulation had essentially no supply response. Moreover, such an extreme event would likely trigger demand response programs, which did not happen under the structured simulation. The extreme prices observed in the simulation for this day appear to reflect various transmission constraint violations. However, we recommend that the CAISO closely examine a sample of these extreme prices to confirm their root cause.

- Day-ahead and real-time LAP prices generally showed better price convergence than observed in the September simulations, particularly during shoulder hours of the day. Real-time prices during the peak hours were still fairly volatile and higher than day-ahead prices but we suspect this has more to do with deficiencies in the simulation environment than some systematic bias in the market software.
- Prices at the inter-ties also generally showed better convergence than observed during the September simulations – though not at a level that we would expect under actual market operation. As expected, prices at the inter-ties generally diverged more under the load under-scheduling scenario that was executed on December 10.

A more detailed review and assessment of real-time market performance is provided below.

December 9, 2008

Figure 6 - Figure 8 below show the Day Ahead, HASP, and Real Time prices for the PG&E, SCE, and SDG&E Load Aggregation Points (LAPs), respectively, for December 9, 2008. As evident in these three figures, the LAP prices for all three locations followed almost identical patterns. The anomalous pricing patterns observed in the Real Time Market in the morning hours (HE 1-11) were due to data problems with the simulated resource telemetry and therefore are not valid. The telemetry issue was corrected in HE 12 and the simulation of the Real Time Market performed well for the remainder of the day. Some price spikes were observed in the Real Time Market for the peak hours of the day (HE 14-18). These 5-minute interval LAP price spikes were in the range of $400-$450/MWh for PG&E and SCE LAPs but higher for the SDG&E LAP – ranging between $400/MWh to just over $600/MWh. Also of note is that the spikes generally occurred during the later intervals of each hour, which suggests that they were caused by a depletion of ramping capability. These high LAP prices, which are discussed in greater detail below, were limited to just a few 5-minute intervals. For the rest of the day (ignoring the morning hours), the Day Ahead, HASP, and Real Time Market LAP prices showed reasonable price convergence.

Figure 6. PG&E LAP Prices (DA, HASP, RTD) - December 9, 2008

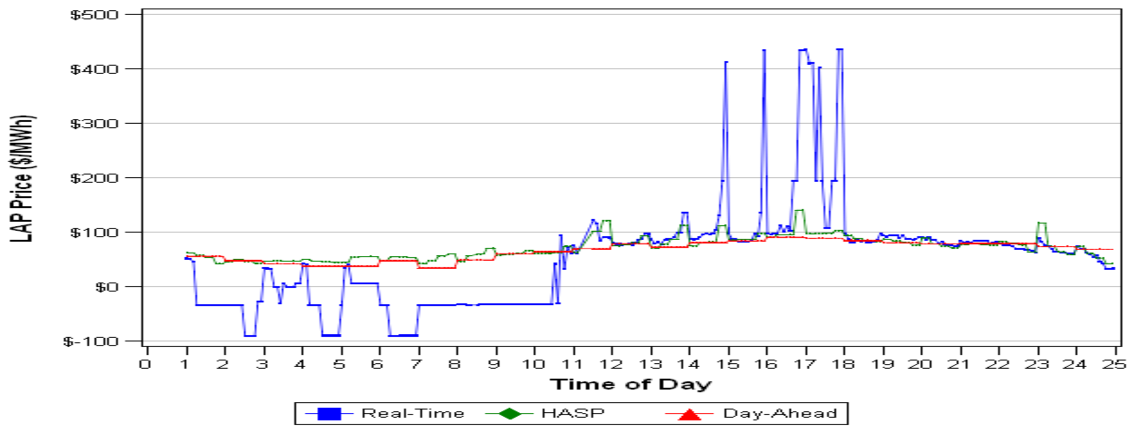


Figure 7. SCE LAP Prices (DA, HASP, RTD) - December 9, 2008

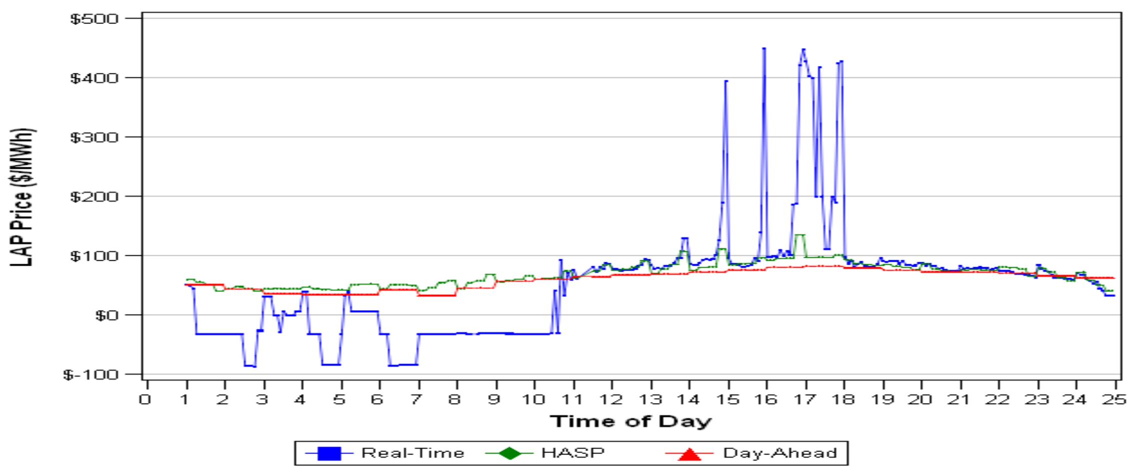


Figure 8. SDG&E LAP Prices (DA, HASP, RTD) - December 9, 2008

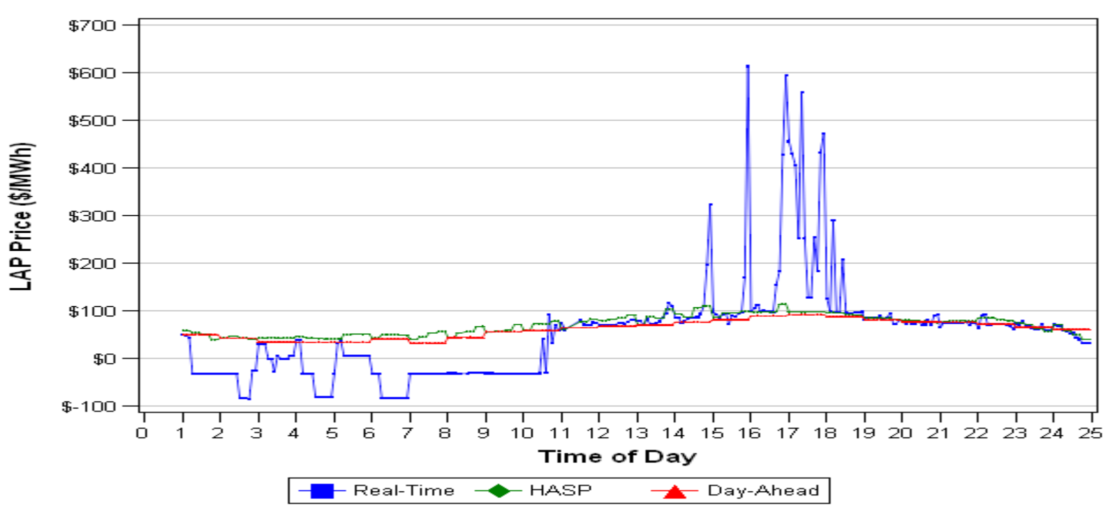


Figure 9 compares the HASP LAP prices for PG&E, SCE, and SDG&E. The HASP prices for all three LAPs tracked similarly throughout the day, particularly the PG&E and SCE LAP prices, while the SDG&E LAP prices showed some separation during the latter half of the day.

Figure 9. Comparison of HASP LAP Prices (December 9, 2008)

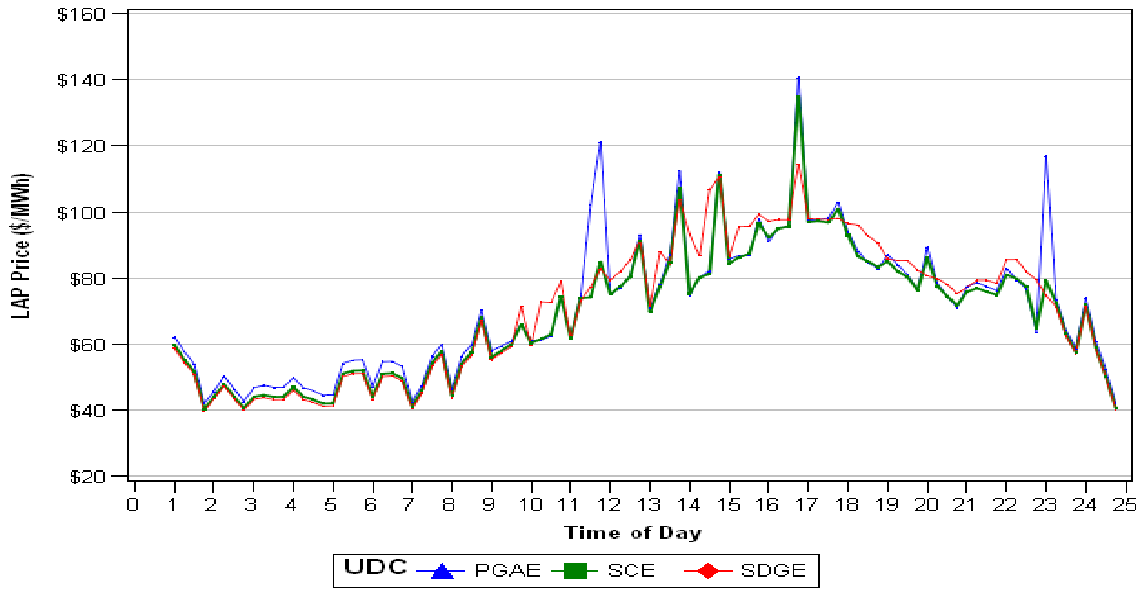


Figure 10 shows a price duration curve for all the HASP LMPs on December 9. To focus on the frequency of extreme prices, Figure 10 shows just the left and right tails of the price duration curve. As evident in the left tail of the LMP price duration curve, the frequency of extreme positive LMPs (i.e., LMPs greater than $500/MWh) was extremely limited – comprising less than a tenth of a percent of the total HASP LMPs produced for that day. The right tail of the LMP price duration curve (showing the lowest HASP LMPs) indicates that roughly two percent of LMPs were below zero and were in the range -$27/MWh to -$42/MWh.

Figure 10. HASP LMP Duration Curve (December 9, 2008)

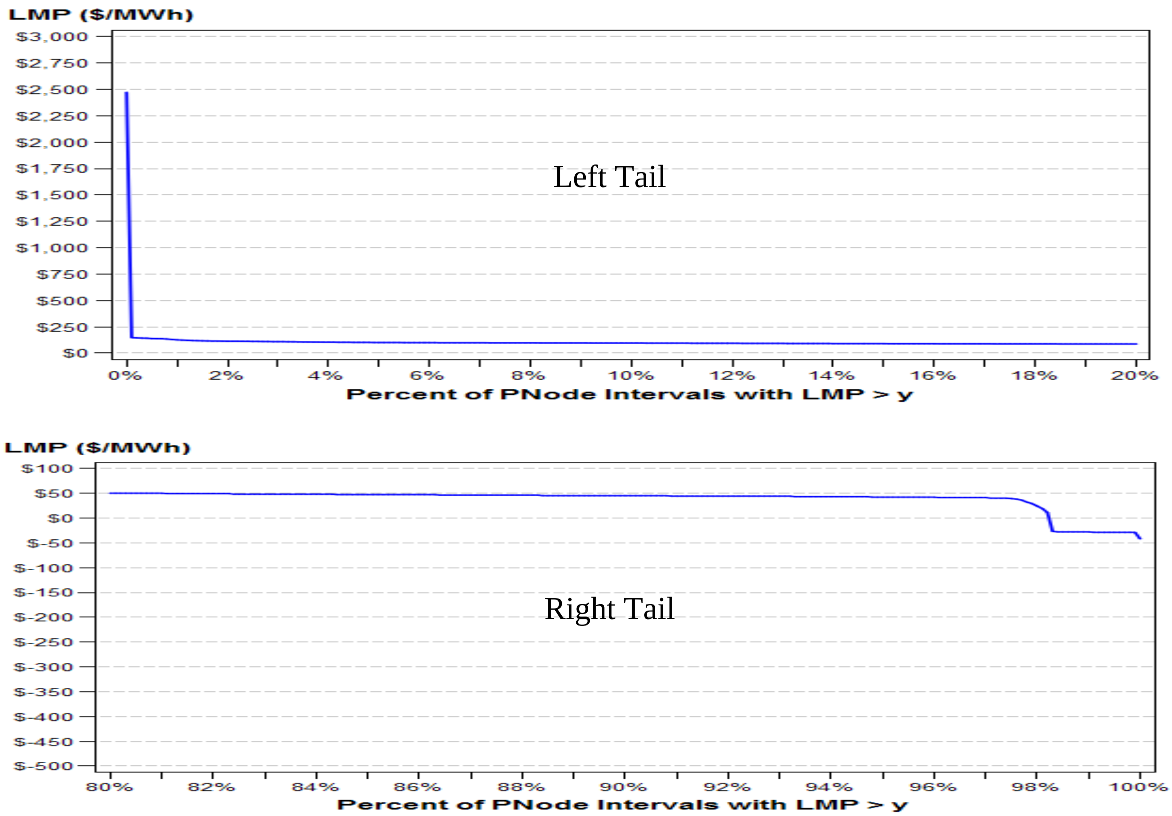


Figure 11 shows when extreme HASP LMPs occurred throughout the operating day. Negative HASP LMPs (between -$30 and -$100/MWh) occurred predominately in three specific intervals (HE 2 - Interval 2, HE 5 – Interval 2, HE 7 – Interval 2). The occurrence of negative prices in interval 2 during the morning hours could be related to inter-hour energy ramping. Since the inter-hour energy ramp is completed in interval 1, it could create a surplus of energy in interval 2 that would be mitigated through downward dispatch. Extreme positive HASP LMPs were limited predominately to three specific intervals (HE 11 - Intervals 3 & 4, HE 23 – Interval 1) and were limited to a small subset of nodes.

Figure 11. HASP LMP Frequencies by Interval (December 9, 2008)

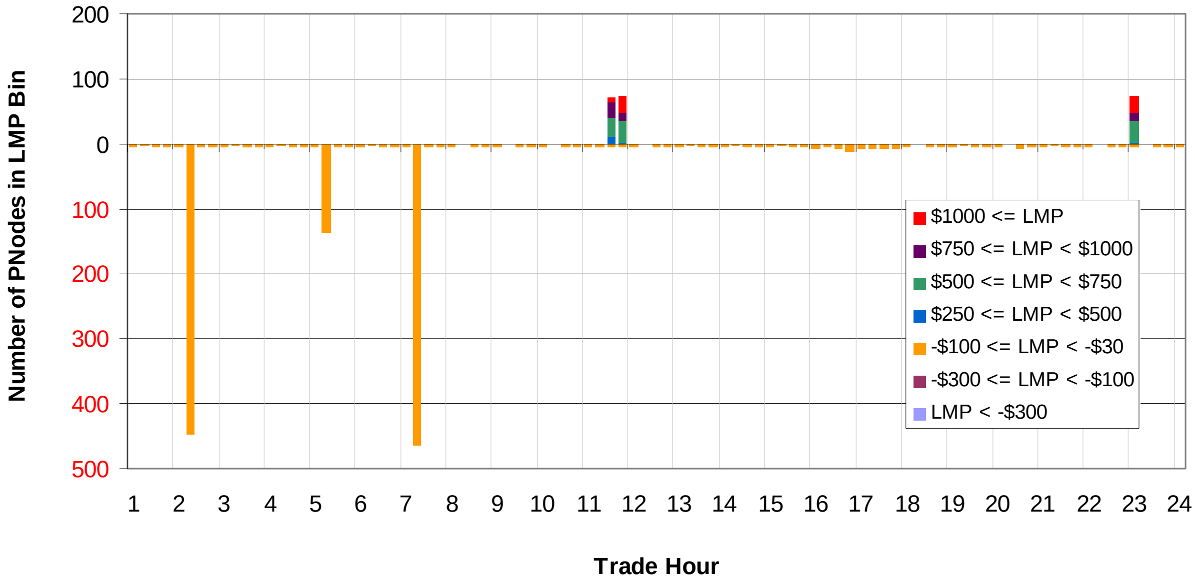
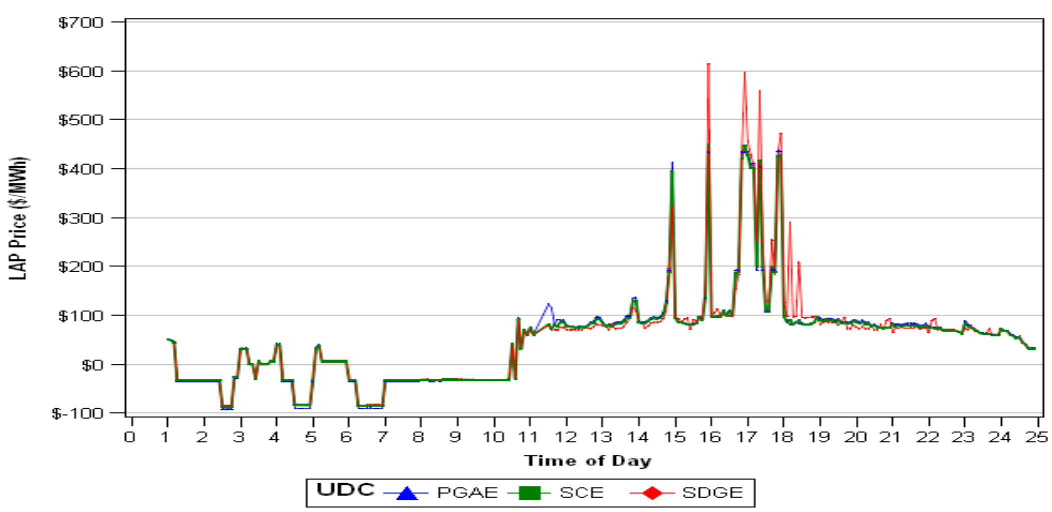


Figure 12 shows a comparison of Real Time Dispatch (RTD) prices for the PG&E, SCE, and SDG&E LAPs. Similar to the HASP, all three LAP prices tracked very closely throughout the day but the SDG&E LAP price exhibited greater separation from the other two LAP prices. SDG&E LAP prices were particularly higher in a number of intervals during the peak hours of the day. All three LAP prices showed volatility across the peak hours with a number of price spikes at or above $400/MWh.

Figure 12. Comparison of RTD LAP Prices (December 9, 2008)



Analysis of congestion and LAP prices indicates that RTD LAP prices for PG&E and SCE, including high prices, were predominately due to system energy needs, whereas the San Diego LAP price had a significant congestion component that generally pushed it above the PG&E and SCE LAP prices. Specifically, only two transmission constraints were binding during the intervals when at least one RTD LAP price exceeded $200/MWh: 1) the Miguel flowgate (located in SDG&E), and (2) the Morgan Hill to Llagas flowgate (located in PG&E). The shadow values of these constraints are shown in Table 4. The difference between SDG&E and SCE LAP prices appears to be driven by congestion on the Miguel flowgate, as evident in Table 4 and Figure 13. The Morgan Hill to Llagas congestion, which was binding under the Metcalf to Morgan Hill contingency, did not appear to have a big impact on the PG&E LAP price – though high shadow prices for this constraint were highly correlated with high LAP prices for both PG&E and SCE (Figure 14).

Table 4. RTD Binding Constraints when LAP Price > $200/MWh (Dec 9)

Hour	Interval	Constraint Shadow Prices* ($/MW)		LAP Prices ($/MWh)		
		Miguel	Morgan Hill - Llagas	PG&E	SCE	SDG&E
14	1	41	0	88	85	86
	2	40	0	87	85	85
	3	0	0	87	84	75
	4	6	0	91	88	79
	5	11	0	96	93	85
	6	12	0	98	95	86
	7	17	0	96	93	86
	8	13	0	98	95	87
	9	20	0	104	101	94
	10	7	35	131	126	110
	11	149	95	194	189	197
	12	0	302	413	395	323
15	1	54	42	98	96	98
	2	69	32	87	85	93
	3	22	32	87	86	87
	4	34	28	83	84	92
	5	89	27	82	81	95
	6	0	29	83	81	72
	7	33	27	82	83	91
	8	26	29	84	85	88
	9	27	42	98	97	95
	10	68	37	92	91	97
	11	128	78	136	139	169
	12	682	360	435	449	614
16	1	21	122	97	98	98
	2	35	121	96	98	106
	3	60	122	97	99	113
	4	24	122	97	97	99
	5	26	136	112	109	100
	6	55	125	101	99	100
	7	25	134	111	108	99
	8	41	127	103	101	98
	9	0	212	194	187	155
	10	107	213	194	188	183
	11	347	441	435	421	429
	12	624	441	435	448	596
17	1	392	441	436	427	456
	2	366	417	410	402	429
	3	325	419	412	400	407
	4	229	213	194	200	254
	5	597	411	403	417	559
	6	229	213	194	200	254
	7	79	132	108	111	129
	8	79	132	108	111	129
	9	229	212	194	200	254
	10	108	213	194	189	184
	11	350	442	437	425	432
	12	501	442	437	427	473
18	1	161	43	98	98	126
	2	88	33	88	87	98
	3	845	26	81	91	290
	4	102	27	82	81	97
	5	86	32	87	86	98
	6	509	29	84	90	209
	7	113	30	85	83	96
	8	95	27	82	81	96
	9	95	27	82	81	96
	10	96	28	83	83	97
	11	89	31	86	85	97
	12	59	42	98	96	98

* Aqua color indicates constraint violations

Figure 13. RTD LAP Prices & Miguel Congestion (Dec 9, Hours 14-18)

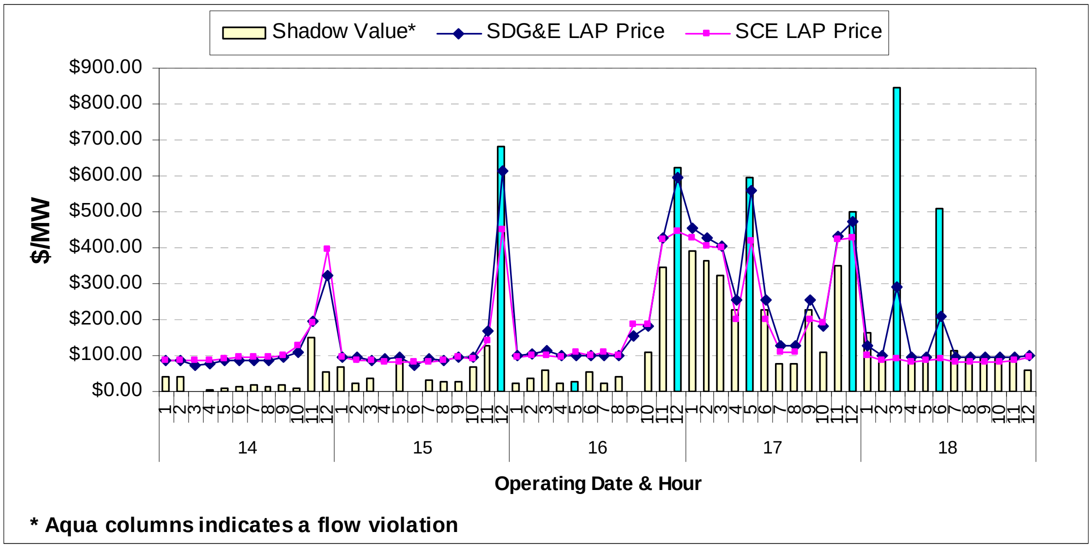


Figure 14. RTD LAP Prices & Morgan to Llagas Congestion (Dec 9, 2008, Hours 14-18)

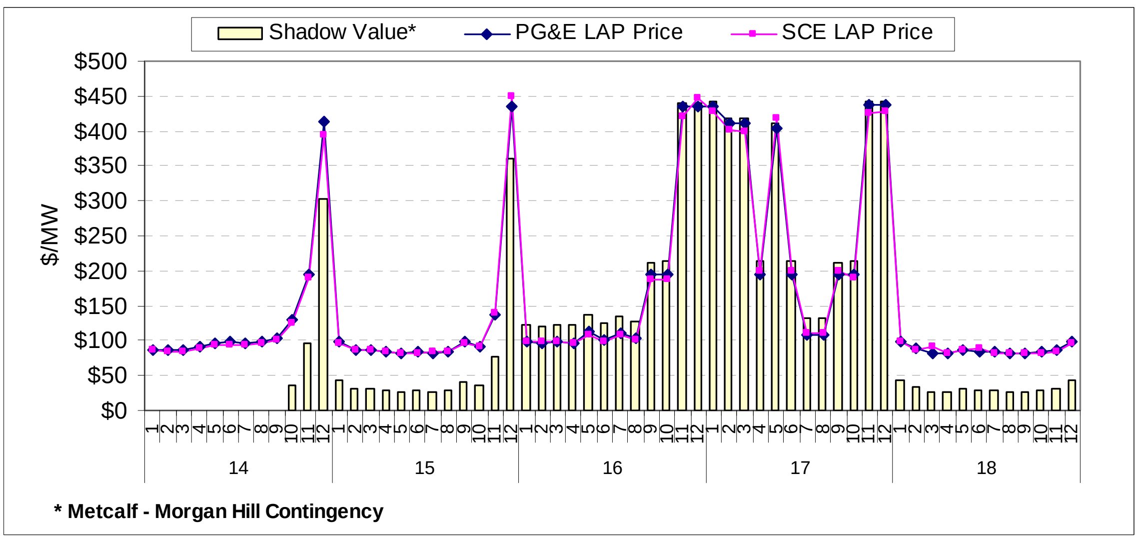
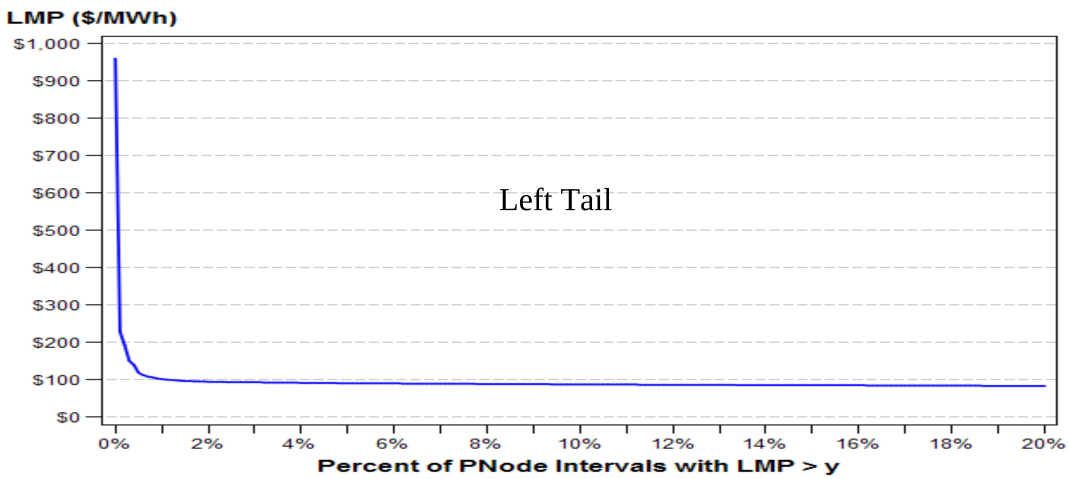


Figure 15 shows the right and left tails of the RTD LMP duration curve but excludes LMPs for Hours 1-11 due to the telemetry issues previously noted. As evident in the left tail of Figure 15, RTD LMPs in excess of $500 were extremely limited on December 9, comprising less than .25 percent of total RTD LMPs. Similarly, there were very few negative LMPs.

Figure 15. RTD LMP Duration Curve (December 9, 2008 HE 12-24)



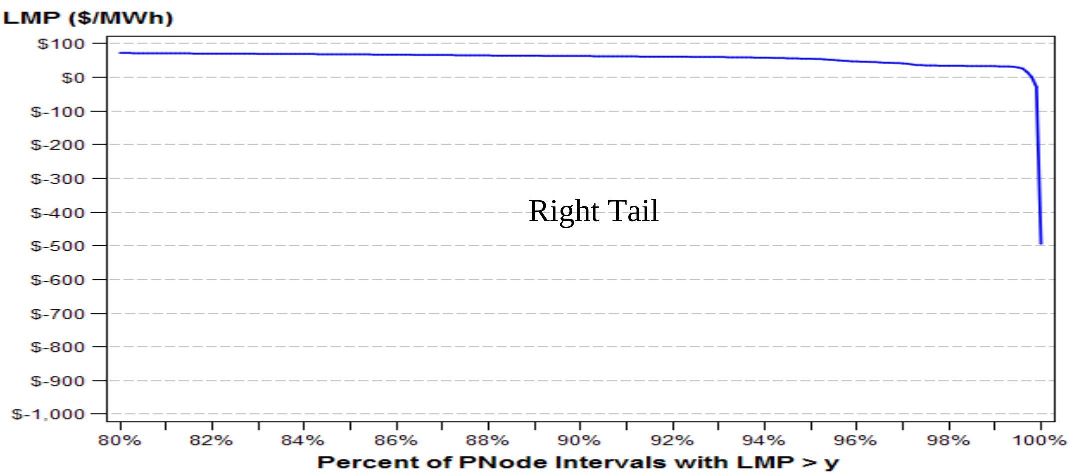


Figure 16 shows the number of P-Nodes having RTD LMPs within certain price ranges for each interval of the operating day. When relatively high LMPs occurred (in excess of $250/MWh), they tended to be system-wide – as evident by the number of P-Nodes shown in Figure 16. However, LMPs in excess of the $500 bid cap were limited to a subset of nodes. High LMPs also tended to occur in the later intervals of each hour. This trend may be due to a limitation of ramping energy in the later intervals of the hour or may also be related to two other issues, one of which relates to a problem in the way the real-time market simulation treats the regulation range of generating units and the second of which relates to a known software variance that is being corrected concerning modeling the inter-hour ramping of energy schedules. These two issues are described in greater detail below:

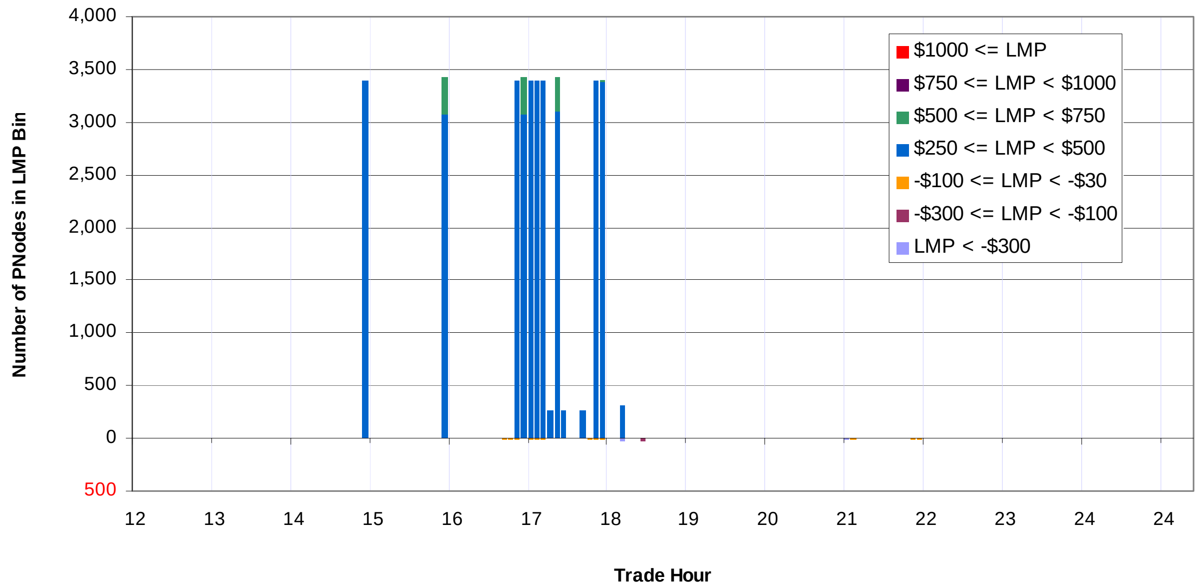
- **Regulation Range Modeling.** The RTM software is designed to constrain energy dispatches issued to units providing regulation so that these units do not operate outside of their *regulation range* (or minimum and maximum operating levels when providing regulation). For the current operating hour, the regulation range used is based on telemetered data provided by the plant. For the next trading hour, the regulation range used by the software is based on the regulation ranges established in the Master File. During market simulation, however, the current telemetered regulation range for the current hour must be simulated. This simulated regulation range is established based on the minimum and maximum operating levels (Pmin and Pmax), rather than the actual regulation range. As a result, units on regulation may be dispatched above their regulation range to provide real-time energy during the initial portion of an operating hour, and may then be constrained back into their regulation range in the last few intervals of the hour. This could contribute to or exacerbate price spikes during the last few intervals of each hour by reducing the energy available from these units during these intervals (as well as requiring that other units be dispatched to compensate for adjustments being made to enforce regulation range constraints on units providing regulation). Since this trend is caused by the simulator used to generate inputs to the RTM during market simulation, it should not occur after MRTU implementation, when the RTM software will be run using actual telemetered data from each generating unit.[9]

- **Inter-Hour Ramping Software Variance.** The RTM software design specifies that resources will be ramped up or down from their hourly self-scheduled operating levels from one hour to the next over a 20 minute period, starting 10 minutes prior to the end of the prior operating hour (*t*-10) and ending 10 minutes after the start of the next operating hour (*t*+10). However, in the RTM software currently being used in Market Simulation, resources are ramped up or down to their scheduled operating level for the next operating hour only during the first 10 minutes of that operating hour (*t* to *t*+10).[10] This software variance has been resolved and is currently being tested. It will be promoted to the production system prior to MRTU implementation. However, during market simulation, this could have the effect of contributing to or exacerbating price spikes during the last few intervals of each hour by reducing the ramping energy available during these intervals.

[9] See *Quality of Solution – Pricing Review*, Mark Rothleder, MRTU Structured Simulation – Follow-up, January 13, 2009 slide 7,(http://www.caiso.com/2335/233585cc3b090.pdf)

[10] See *Quality of Solution – Pricing Review*, Mark Rothleder, MRTU Structured Simulation – Follow-up, January 13, 2009 slide 6, (http://www.caiso.com/2335/233585cc3b090.pdf)

Figure 16. RTD LMP Frequencies by Interval (December 9, 2008)



December 10, 2008

As noted in the introduction, the December 10 simulation varies from December 9 in that Day Ahead LAP demand bids were modified so that approximately 80-85 percent of the Day Ahead load forecast clears the IFM. Figure 17 - Figure 19 below show the Day Ahead, HASP, and Real Time prices for the PG&E, SCE, and SDG&E Load Aggregation Points (LAPs), respectively, for December 10, 2008. Similar to December 9, the LAP prices for all three locations followed almost identical patterns. The anomalous pricing patterns observed in the Real Time Market in the morning hours (HE 2-3) were due to data problems with the simulated resource telemetry and therefore are not valid pricing points. The price spikes observed in the HASP and Real Time Market for the peak hours of the day (HE 14-18) were more sustained compared to December 9. LAP prices in HASP and RTD across the super peak hours were generally in the range of $400-$600/MWh with HASP LAP prices tending to be more in the high end of this range. Similar to December 9, LAP prices for PG&E and SCE were almost identical with SDG&E exhibiting greater separation. As expected, with less load clearing the IFM, LAP prices in HASP and RTD were generally higher than day-ahead prices. This is most noticeable in hours 10-15. Across the peak hours, HASP and RTD prices were also reasonably well converged.

Figure 17. PG&E LAP Prices (DA, HASP, RTD) - December 10, 2008

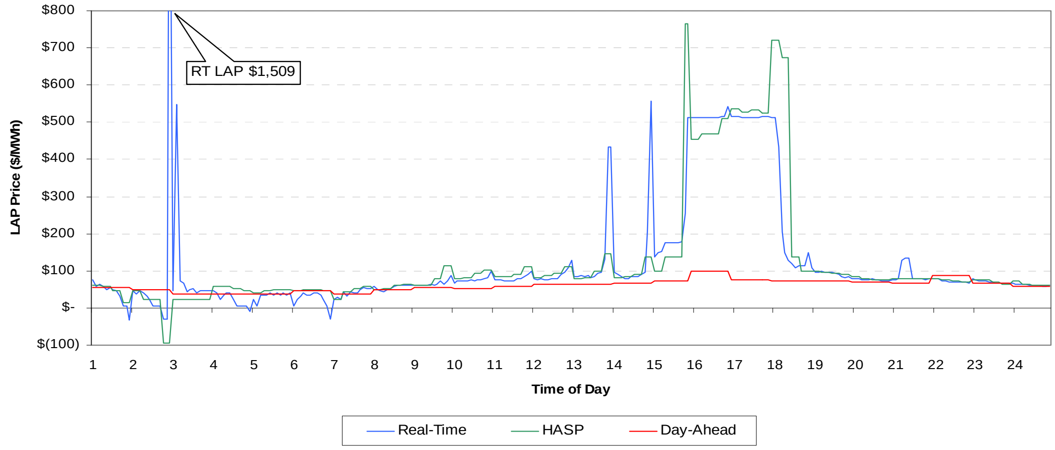


Figure 18. SCE LAP Prices (DA, HASP, RTD) - December 10, 2008

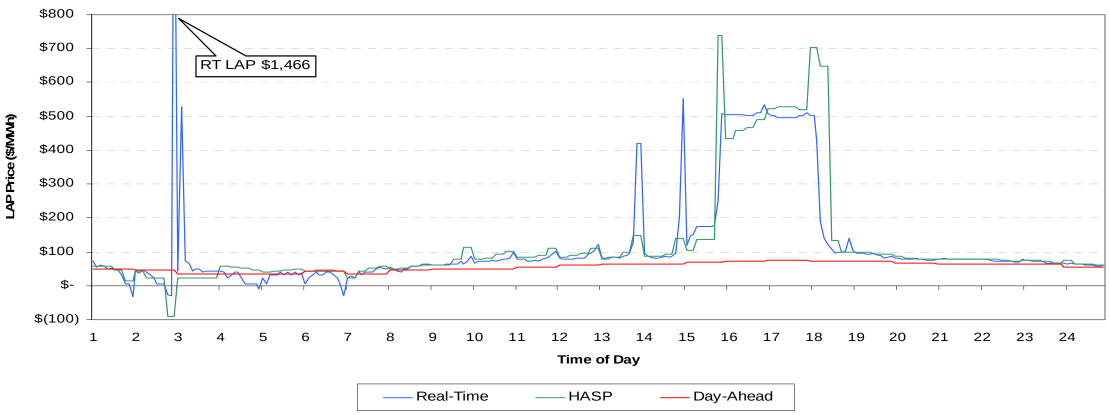
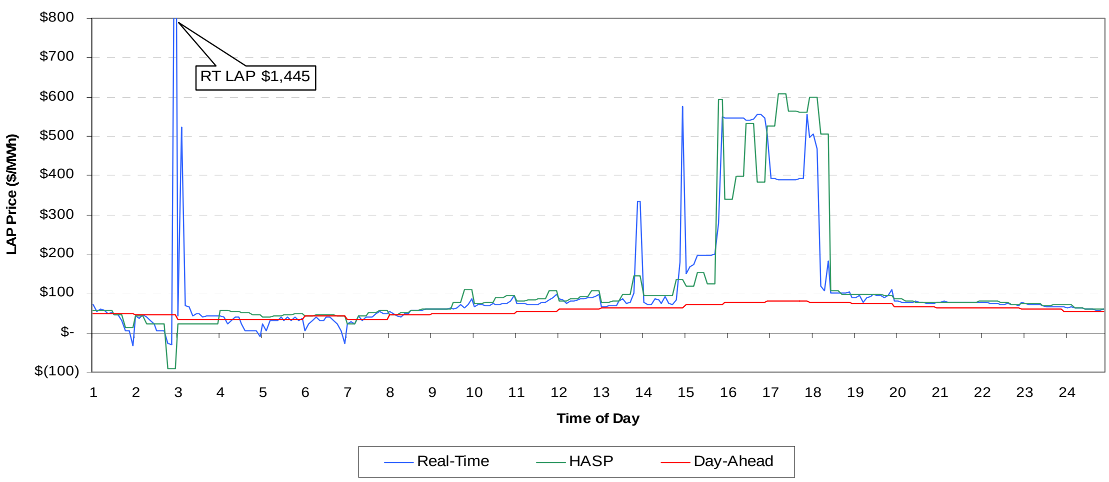


Figure 19. SDG&E LAP Prices (DA, HASP, RTD) - December 10, 2008



Given the scenario, one would expect real time prices across the peak to be generally higher. However, it is somewhat surprising that the real time prices (HASP & RTD) would stay at or above $500/MWh for more sustained periods under this scenario, particularly given that the day-ahead and real-time load forecasts were the same and RUC was committing sufficient capacity to meet the load forecast in real-time. One possible factor contributing to these high prices in HASP and RTD is that significantly less real-time energy was bid into the structured simulations on December 10 compared to December 9. This was also true for December 11 and 12, which may have exacerbated real-time price volatility for those simulations as well (Figure 20). On these days, the combined amount of energy bid from imports and some resources within the CAISO submitted by participants in the HASP was about 1,800 MW lower than on the first day of the structured simulations (December 9). This it is yet another example of the limitations of a market simulation.

Data in Figure 20 also help illustrate why prices tended to spike in the HASP and RTM on December 10-12. As shown in Figure 20, on these days bid prices during Hour Ending 17 rise sharply above $100/MW after the first 53,000 MW of potential supply for real time energy bids. During this hour, the total demand for the supply depicted in Figure 20 averaged about 52,500 MW.[11] However, the aggregated bid curve depicted in Figure 20 overestimates the actual supply of bid energy available for dispatch in the HASP and RTM, since it does not reflect internal CAISO constraints, simultaneous import limits, individual unit constraints (such as various ramping limits and special limits placed on units providing regulation), and the unavailability of any additional import bids in the RTD after the conclusion of the HASP process.[12] These factors would, if accounted for in Figure 20, have the effect of shifting the effective supply curves further to the left. Thus, data in Figure 20 indicate that during the peak hours of these days, once these other various constraints are taken into account, the aggregate supply curve actually available for dispatch in the HASP and RTD had an extremely steep upward slope, so that relatively small increases in demand could create significant spikes in LMPs system wide.

[11] CAISO Load (46,173 MW) + Exports (3,032 MW) + Ancillary Services (3,308 MW) = 52,513 MW.

[12] Aggregated supply curves in Figure 20 are approximated from HASP bids by screening out bids that are not likely to be feasible in the HASP market. These include HASP bids for non-committed units with start-up times greater than one hour, and any import bids in excess of the total available capacity on inter-ties. It should noted that it is likely this approach still overestimates the actual available supply of bid available for dispatch in the HASP and RTM, since it does not reflect internal CAISO constraints, individual unit constraints (such as ramp limits), and capacity reserved for Ancillary Services.

Figure 20. Comparison of Aggregate Real Time Supply Curves (Dec 9-12, Hr 17)

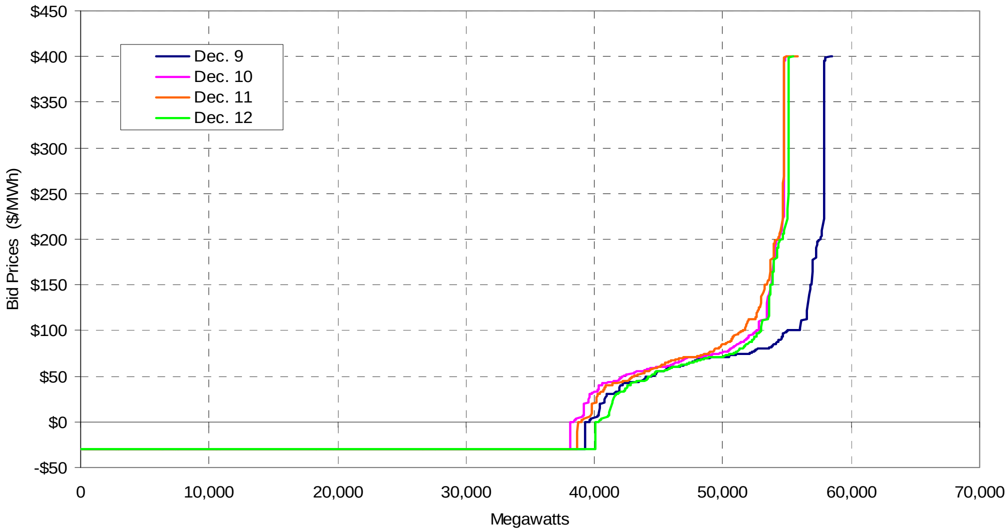


Figure 21 compares the HASP prices for the three LAPs (PG&E, SCE, SDG&E) and shows they were generally the same except for the peak hours (Hours 15-18) where the SDG&E LAP price exhibited some separation. The deviation in the SDG&E LAP price during these hours was likely due to congestion on the Miguel flowgate.

Figure 21. Comparison of HASP LAP Prices (Dec 10, 2008)

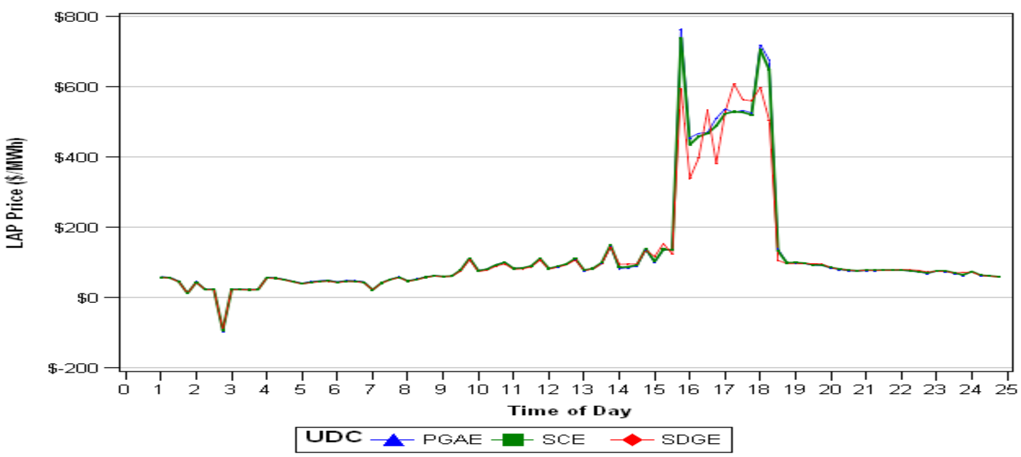


Figure 22 - Figure 24 show the decomposition of HASP LAP prices for PG&E, SCE, and SDG&E, respectively, into the three component of system energy, congestion, and losses. The congestion and loss components of the PG&E and SCE HASP LAP prices were relatively minor. The SDG&E HASP LAP prices had a more significant congestion component, which appears to be primarily related to congestion on the Miguel flowgate.

Figure 22. PG&E HASP LAP Price Decomposition (Dec 10, 2008, Hrs 13-18)

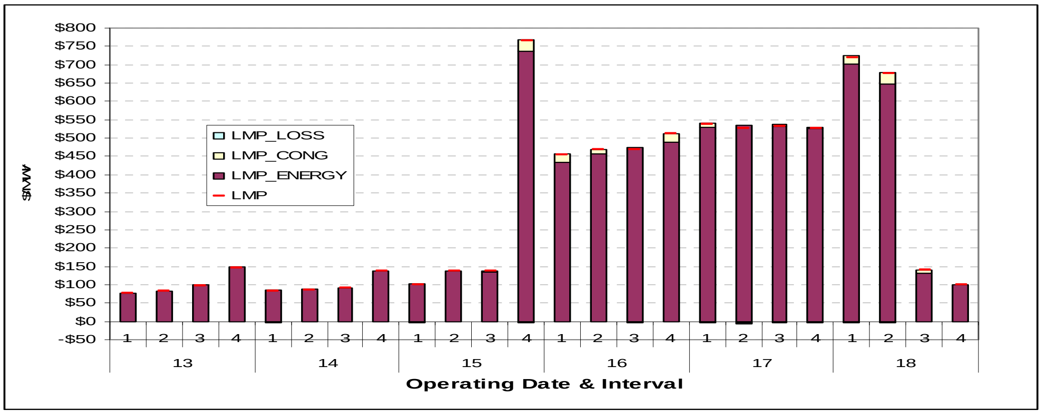


Figure 23. SCE HASP LAP Price Decomposition (Dec 10, 2008, Hrs 13-18)

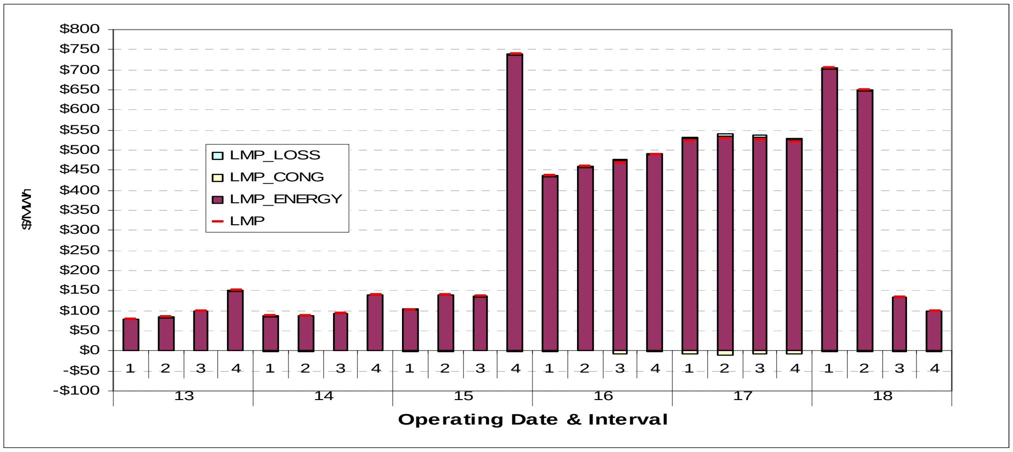


Figure 24. SDG&E HASP LAP Price Decomposition (Dec 10, 2008, Hrs 13-18)

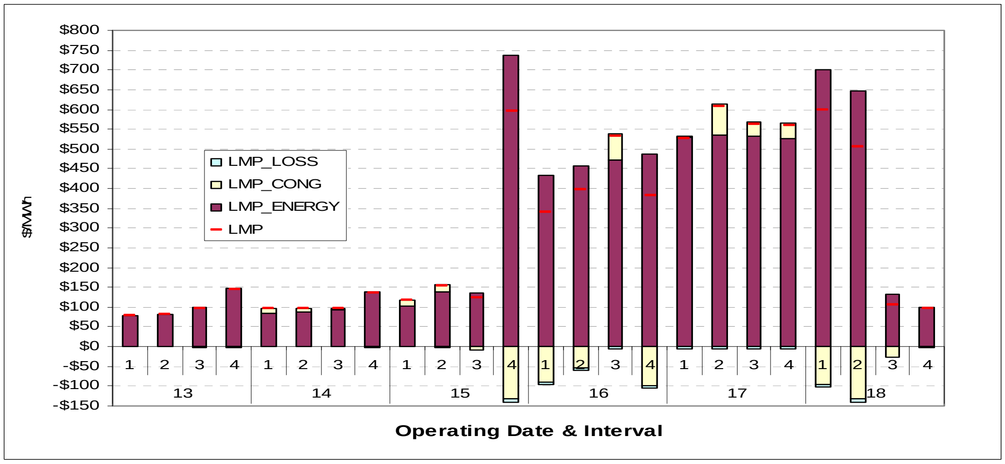


Table 5 provides a list of some of the more frequent and significant binding transmission constraints[13] in HASP during intervals where at least one HASP LAP price exceeded $200/MWh. Table cells highlighted in aqua indicate flow violations. Flow violations occurred in the HASP on several transmission constraints, Miguel and two constraints on the PG&E system (Chicago Park to Higgins and Morgan Hill to Llagas).

Table 5. HASP Binding Constraints when LAP Price > $200/MWh (Dec 10)

		Constraint* Shadow Prices** ($/MW)						LAP Prices ($/MWh)		
Hour	Interval	Miguel	Imperial Valley	Vict. Lugo Nomogram	Chicago Park - Higgins	Morgan Hill - Llagas	PACI Inter-tie	PG&E	SCE	SDG&E
15	1	65	0	0	0	5	92	100	103	117
	2	101	0	70	0	38	126	136	138	154
	3	0	59	78	0	39	126	136	136	125
	4	0	439	1351	528	627	709	764	739	594
16	1	0	206	921	0	338	423	455	436	340
	2	0	312	503	1003	347	431	467	459	397
	3	500	0	549	1003	348	432	470	467	533
	4	0	239	1035	69	383	474	511	489	382
17	1	435	0	1054	1227	411	493	537	524	527
	2	583	0	615	1203	401	484	527	529	608
	3	500	0	869	0	408	492	533	527	563
	4	500	0	834	385	401	485	526	521	560
18	1	0	488	915	1610	583	663	720	705	598
	2	0	338	1378	0	544	627	675	649	505
	3	0	18	272	0	42	128	139	133	106
	4	30	0	93	0	5	92	100	100	97

*** Binding constraints shown are not an exhaustive list**
**** Aqua color indicates constraint violations**

[13] Other binding constraints not shown in Table 5 include the following inter-ties: Standiford, Marble, IID-SCE, Cascade, Silver Peak, North Gila, and Palo Verde.

Figure 25 compares the HASP shadow values of the Miguel constraint to the SDG&E and SCE HASP LAP prices and shows that the SDG&E LAP price was higher than the SCE LAP price when Miguel was congested, but generally lower otherwise.

Figure 25. HASP LAP Prices & Miguel Congestion (Dec 10, Hrs 15-18)

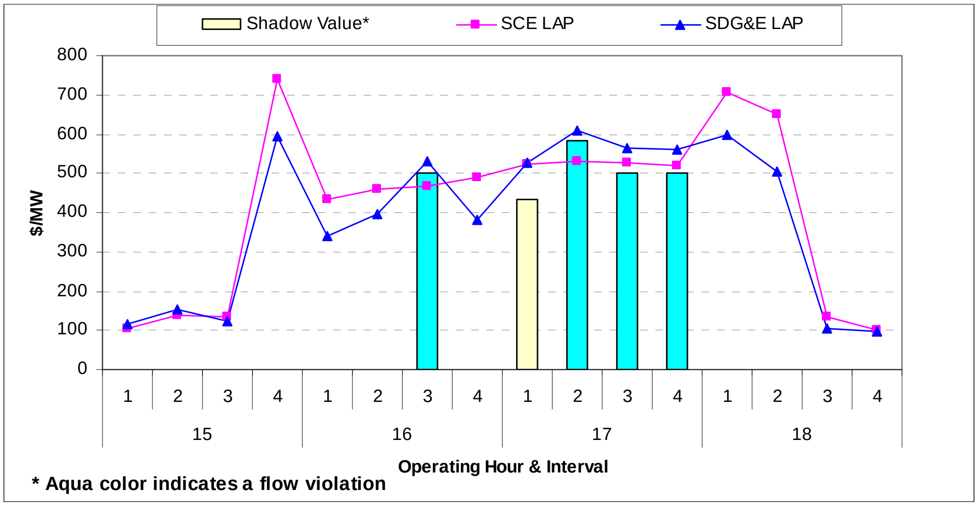
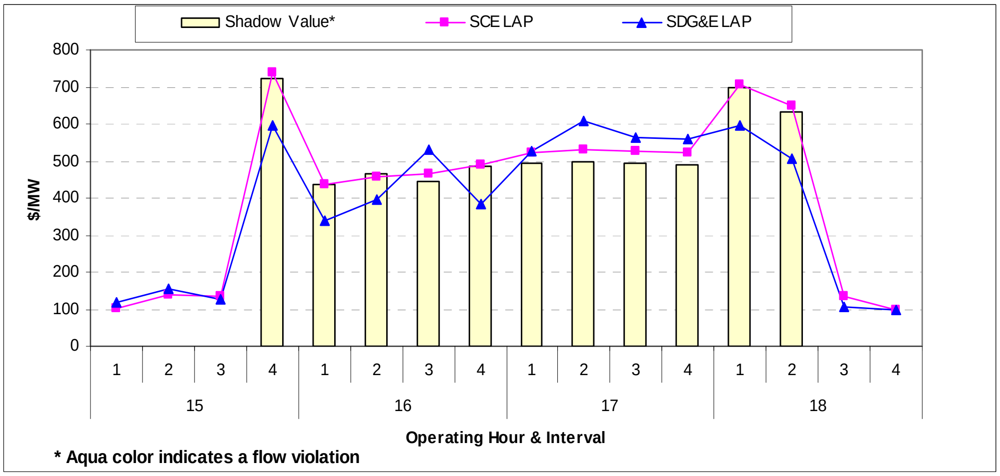


Figure 26 compares the shadow values in HASP for the Imperial Valley to SCE constraint to the HASP LAP prices for SCE and SDG&E. The SCE and SDG&E LAP prices were near identical in the first three intervals of Hour 15, when neither Miguel or Imperial Valley were congested. The SCE LAP price was generally higher than the SDG&E LAP price when Imperial Valley was congested but Miguel was not (e.g., Hour 15, Interval 4, Hour 16, Intervals 1-2).

Figure 26. HASP LAP Prices & Imperial Valley[14] Congestion (Dec 10, Hrs 15-18)



[14] IID to SCE Inter-tie Constraint

Figure 27 shows a price duration curve for all the HASP LMPs on December 10. To focus on the frequency of extreme prices, Figure 27 shows just the left and right tails of the price duration curve. As evident in the left tail, the frequency of extreme positive HASP LMPs (i.e., LMPs greater than $500/MWh) was more frequent relative to December 9 – comprising approximately 7 percent of the total HASP LMPs. The right tail of the LMP duration curve (showing the lowest HASP LMPs) indicates that only a small share of HASP LMPs (less than 2 percent) were at or below $0/MWh.

Figure 27. HASP LMP Duration Curve (December 10, 2008)

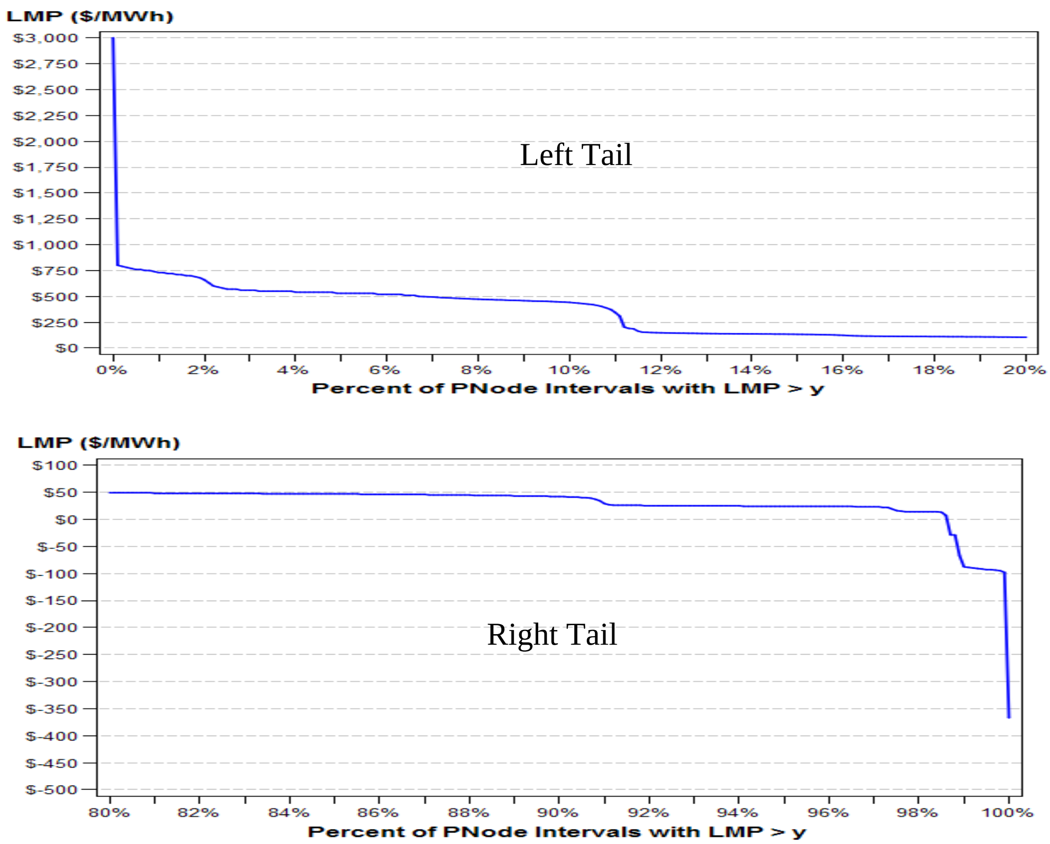


Figure 28 shows the number of P-nodes having HASP LMPs within certain price ranges for each interval of the operating day. Negative HASP LMPs between -$30 and -$100/MWh occurred predominately in Hour 2 - Interval 4. Extreme positive HASP LMPs occurred in most intervals across Hours 15-18. HASP LMPs in excess of the $500 bid cap occurred at most P-Nodes in Hour 17.

Figure 28. HASP LMP Frequencies by Interval (December 10, 2008)

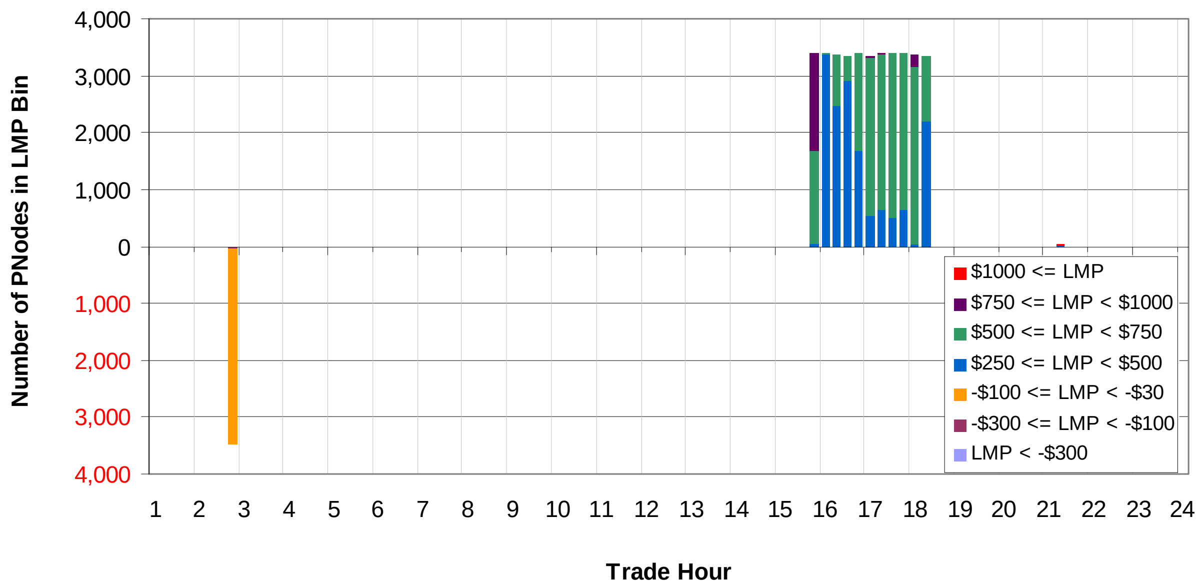


Figure 29 shows a comparison of RTD LAP prices for December 10. The spikes in RTD LAP prices observed in Hours 2 and 3 were due to a glitch in the simulated telemetry. RTD LAP prices across the peak hours were generally at or near $500/MWh, which was generally lower than what was observed in HASP. The SDG&E LAP price separated from the other LAP prices during the peak hours, which appears to be due to Miguel congestion.

Figure 29. Comparison of RTD LAP Prices (Dec 10, 2008)

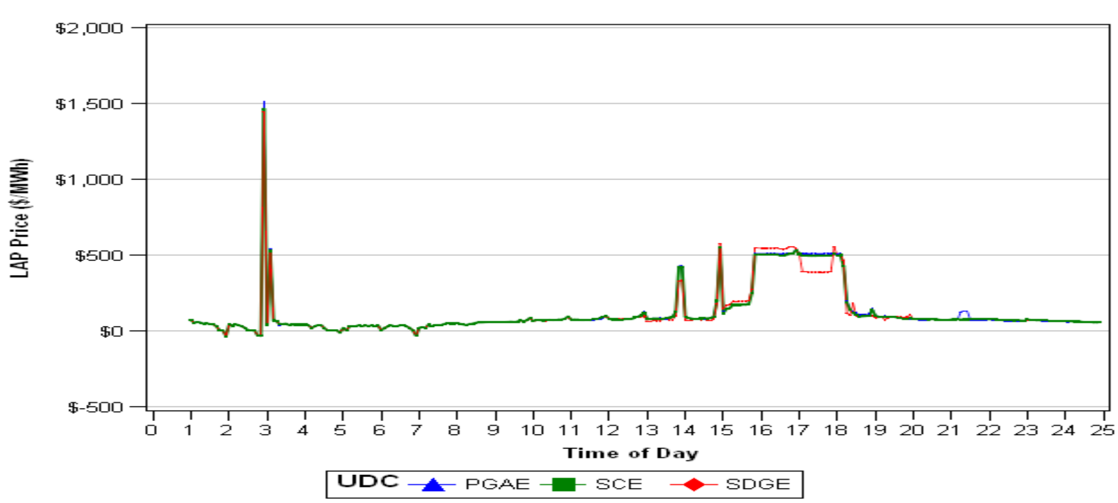


Figure 30 compares the RTD LAP prices for SDG&E and SCE to the shadow values of the Miguel flowgate and demonstrates that the SDG&E LAP price is generally significantly higher than the SCE LAP price when there is congestion at Miguel, particularly in intervals where Miguel experiences flow violations (aqua columns).

Figure 30. RTD LAP Prices and Miguel Congestion (Dec 10, Hrs 14-18)

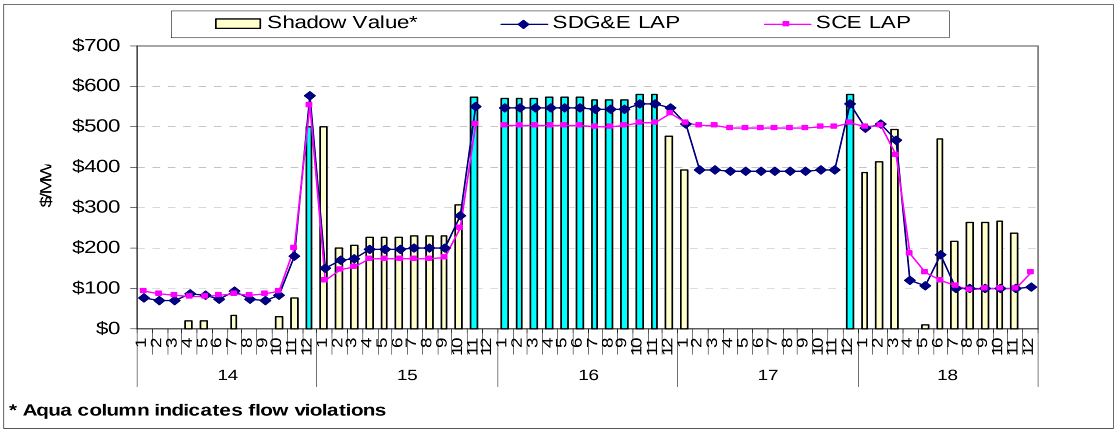


Table 6 shows the shadow values of the transmission constraints that tended to be most frequently congested during intervals of high LAP prices (i.e., >$200/MWh – highlighted in yellow). Table cells highlighted in aqua indicate shadow prices associated with a flow violation. The Miguel flowgate had high shadow prices and flow violations through most of Hour 16. A constraint on the PG&E system (Chicago Park to Higgins) had high shadow prices and flow violations in hours 16 and 17. The Victorville-Lugo nomogram was also binding through most of the peak hours with high shadow prices.

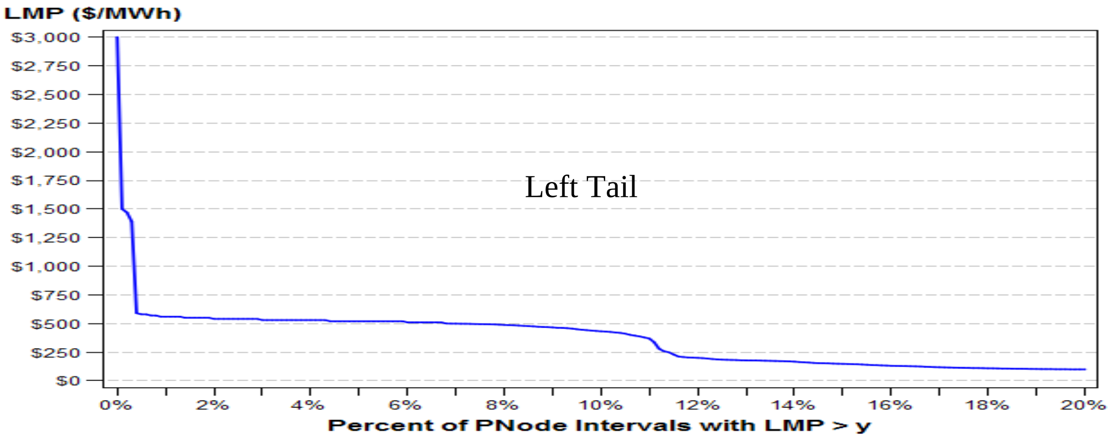
Table 6. RTD Binding Constraints when LAP Price > $200/MWh (Dec 10, Hrs 13-18)

		Constraint Shadow Prices* ($/MW)				LAP Prices ($/MWh)		
Hour	Interval	Miguel	Vict. Lugo Nomogram	Chicago Park - Higgins	Morgan Hill - Llagas	PG&E	SCE	SDG&E
13	1	0	161	0	0	84	81	66
	2	0	161	0	0	84	81	66
	3	8	167	0	0	87	84	70
	4	0	137	0	0	86	84	70
	5	0	168	0	0	87	84	68
	6	0	0	0	0	81	82	81
	7	0	0	0	0	85	87	85
	8	0	182	0	0	94	91	74
	9	0	190	0	4	98	95	77
	10	0	258	0	34	130	127	101
	11	0	888	0	319	432	421	334
	12	0	888	0	319	432	421	334
14	1	0	189	0	0	97	95	76
	2	0	175	0	0	90	88	71
	3	0	129	0	0	85	83	71
	4	21	0	0	0	79	82	86
	5	20	28	0	0	79	81	82
	6	0	108	0	0	85	85	74
	7	33	16	0	0	84	86	92
	8	0	108	0	0	85	84	74
	9	0	175	0	0	90	88	71
	10	29	186	0	3	97	95	84
	11	77	408	0	105	205	201	180
	12	500	1,018	0	436	557	553	576
15	1	500	1,010	0	40	136	119	149
	2	201	278	0	52	148	147	169
	3	205	288	0	56	153	152	174
	4	228	332	0	75	176	174	197
	5	228	332	0	75	176	174	197
	6	228	332	0	75	176	174	197
	7	229	335	0	78	177	175	198
	8	229	335	0	78	177	175	198
	9	231	338	0	80	179	177	200
	10	308	487	550	151	254	251	279
	11	574	1,005	0	396	513	507	550
	12	0	0	0	0			
16	1	571	1,001	0	395	512	505	547
	2	571	1,001	0	395	512	505	547
	3	571	1,001	0	395	512	505	547
	4	572	1,001	1,117	394	513	505	548
	5	572	1,001	1,117	394	513	505	548
	6	572	1,001	1,117	394	513	505	548
	7	565	991	1,116	388	512	501	542
	8	565	991	1,116	388	512	501	542
	9	568	996	0	390	513	503	544
	10	580	1,014	0	398	516	511	556
	11	580	1,014	0	398	516	511	556
	12	477	1,075	0	422	542	535	548
17	1	395	1,028	0	396	515	509	506
	2	0	1,061	0	396	515	502	393
	3	0	1,061	0	396	515	502	393
	4	0	1,051	1,129	392	512	497	389
	5	0	1,051	1,129	392	512	497	389
	6	0	1,051	1,129	392	512	497	389
	7	0	1,052	1,128	388	512	498	389
	8	0	1,052	1,128	388	512	498	389
	9	0	1,052	1,128	388	512	498	389
	10	0	1,059	0	395	514	501	392
	11	0	1,059	0	395	514	501	393
	12	579	1,012	0	395	514	511	555
18	1	386	1,016	1,230	393	513	502	497
	2	414	1,014	1,132	393	513	502	505
	3	493	848	0	321	434	429	467
	4	0	730	0	103	205	188	119
	5	11	367	0	50	149	141	108
	6	470	579	0	31	129	121	183
	7	217	655	0	24	120	107	100
	8	263	662	0	13	109	96	100
	9	262	688	0	17	113	100	100
	10	266	713	0	19	114	100	100
	11	236	642	0	19	114	101	100
	12	1	399	0	52	149	141	103

* Aqua color indicates constraint violations

Figure 31 shows the left and right tails of the RTD LMP duration curve for December 10. Approximately 6 percent of the total RTD LMPs for December 10 were in excess of $500/MWh. RTD LMPs in excess of $1,000/MWh were limited to less than half a percent of total RTD LMPs. Extreme negative RTD LMPs (right tail) were also less than half a percent of all RTD LMPs.

Figure 31. RTD LMP Duration Curve (December 10, 2008)



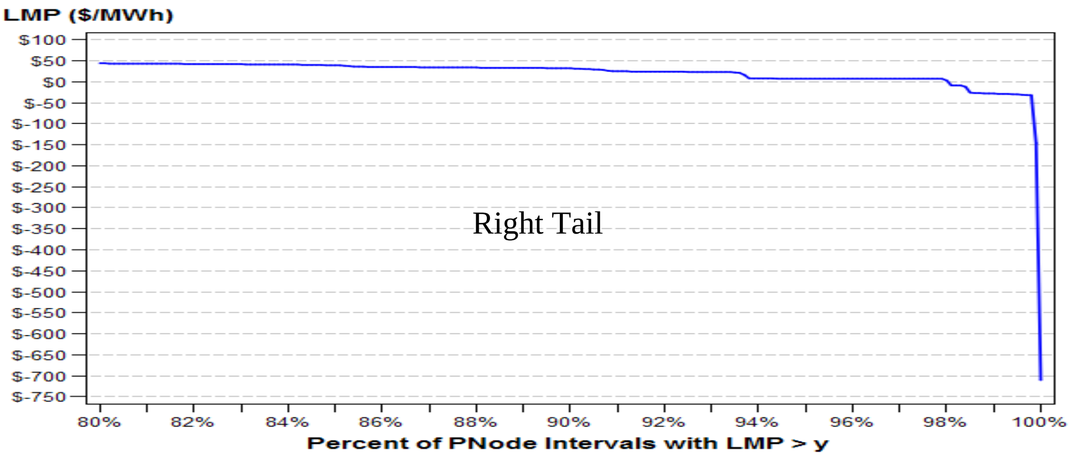
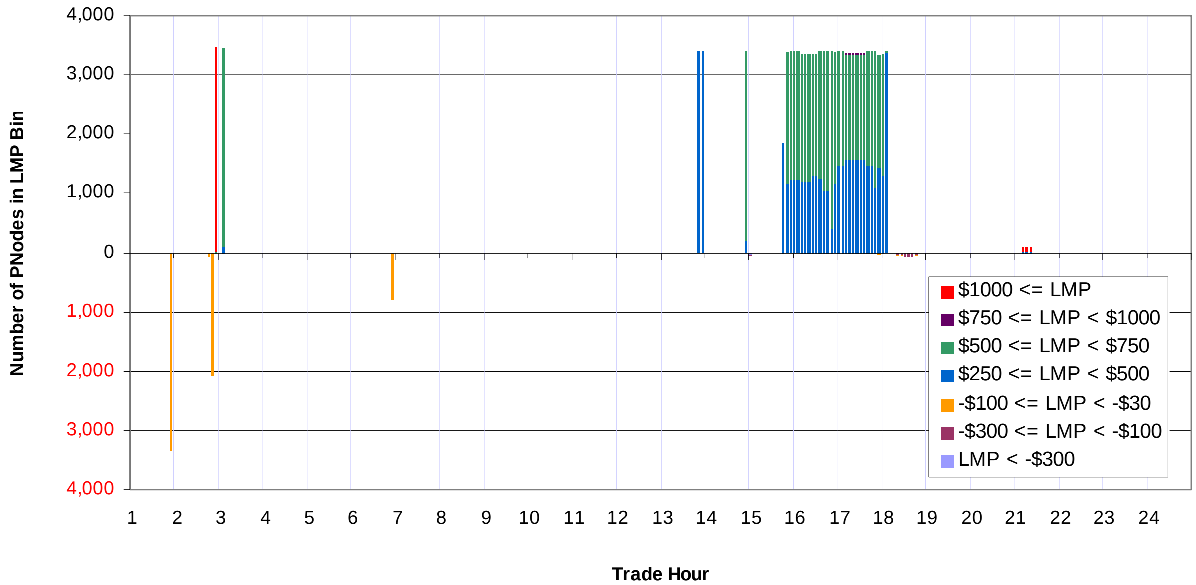


Figure 32 shows the number of P-Nodes experiencing relatively extreme prices for each RTD interval for December 10 and demonstrates that when high LMPs occurred, they tended to occur throughout the system. LMPs in excess of $1,000/MWh occurred primarily in Hour 2 and, as previously noted, these were due to a glitch in the simulated telemetry.

Figure 32. RTD LMP Frequencies by Interval (December 10, 2008)



December 11, 2008

The structured simulation for December 11 involved modeling strategic bidding at select load pockets to test the effectiveness of the local market power mitigation. Specifically, energy bids from select generating units in the Los Angeles Basin, San Francisco Bay Area, Big Creek/Ventura area, and San Diego were increased to $400/MWh. The specific details of this economic withholding scenario are described in Section IV of this report.

Figure 33 - Figure 35 compare the Day Ahead, HASP, and RTD LAP prices for PG&E, SCE, and SDG&E, respectively. The high RTD price spikes observed in hours 4 and 5 were due to a glitch in the simulation telemetry. Day Ahead, HASP, and RTD LAP prices showed reasonable price convergence for much of the day with some exceptions. Similar to the previous days, HASP and RTD LAP prices increased significantly across the peak hours but were generally not as high as the LAP prices observed on December 10. The high day-ahead LAP prices observed for SDG&E were the result of a poor quality of solution for the IFM, which resulted in not committing a specific Reliability Must Run (RMR) generating unit in San Diego that was committed under the local market power mitigation procedures. When this day-ahead scenario was re-run offline and allowed to run longer to converge to a better quality solution, an additional RMR unit was committed and the SDG&E LAP prices were more inline with the other LAP prices.

Figure 33. PG&E LAP Prices (DA, HASP, RTD) - December 11, 2008

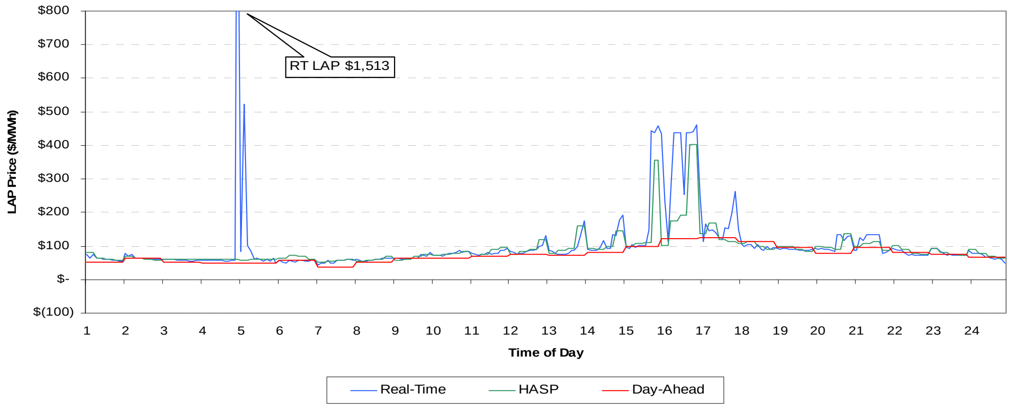


Figure 34. SCE LAP Prices (DA, HASP, RTD) - December 11, 2008

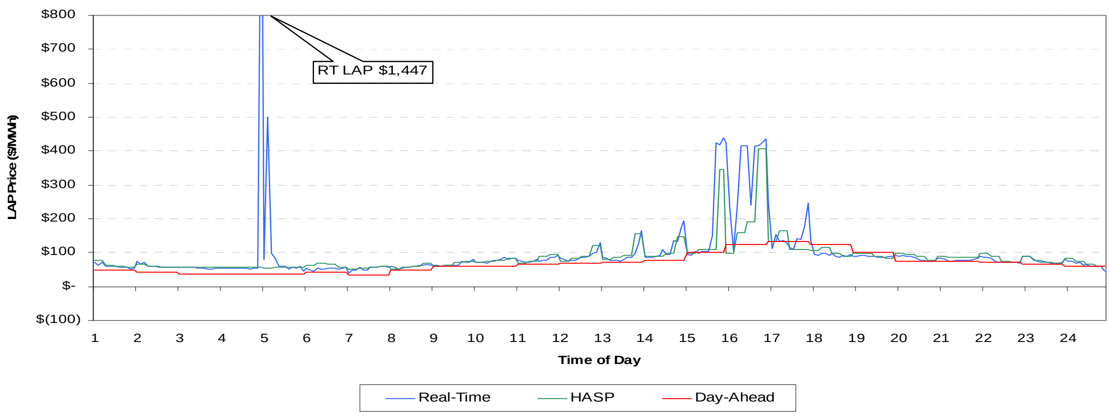


Figure 35. SDG&E LAP Prices (DA, HASP, RTD) - December 11, 2008

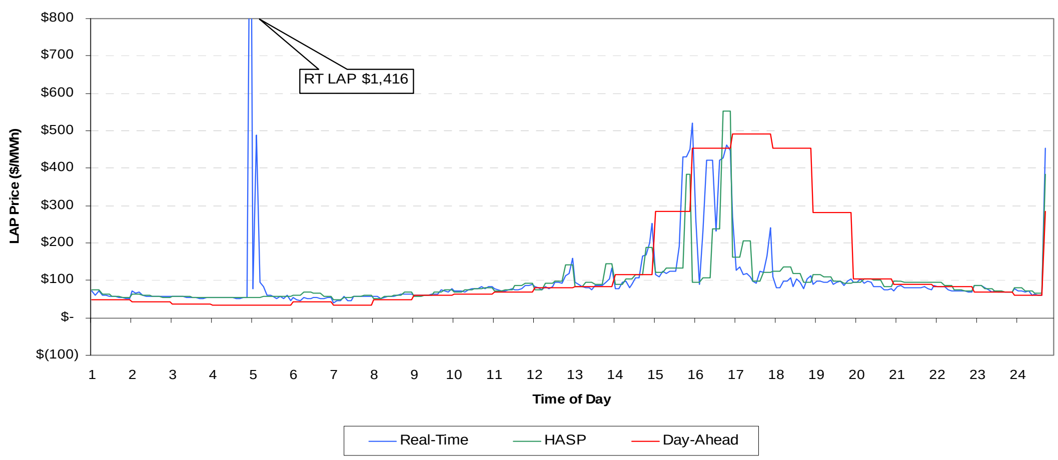


Figure 36 compares the HASP LAP prices for PG&E, SCE, and SDG&E. The PG&E and SCE HASP LAP prices were very similar for most HASP intervals. The SDG&E LAP followed a similar pattern to the other two LAPs but tended to be higher during the peak hours. Again, this trend appears to be primarily due to congestion at Miguel.

Figure 36. Comparison of HASP LAP Prices (December 11, 2008)

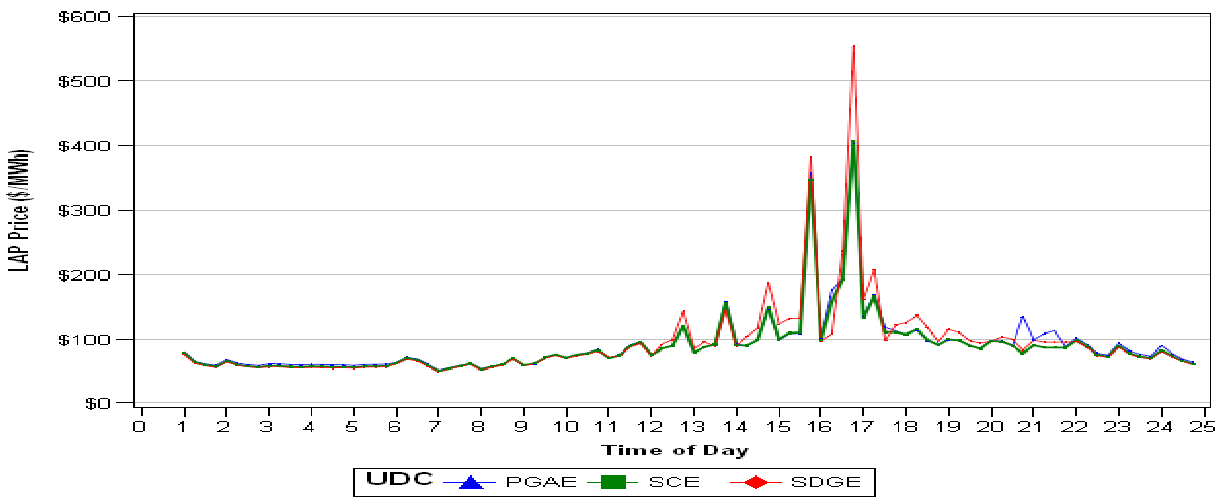


Figure 37 - Figure 39 show the decomposition of the HASP LAP prices for hours 12-18. The congestion component of the HASP LAP prices was relatively minor in comparison to the total LAP price – though the SDG&E LAP price had a more significant congestion component than the other two LAPs.

Figure 37. PG&E HASP LAP Price Decomposition (Dec 11, 2008, Hrs 12-18)

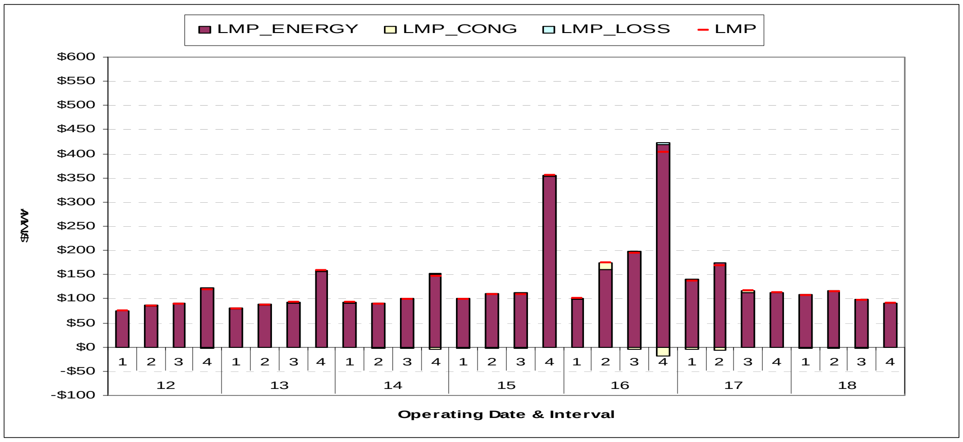


Figure 38. SCE HASP LAP Price Decomposition (Dec 11, 2008, Hrs 12-18)

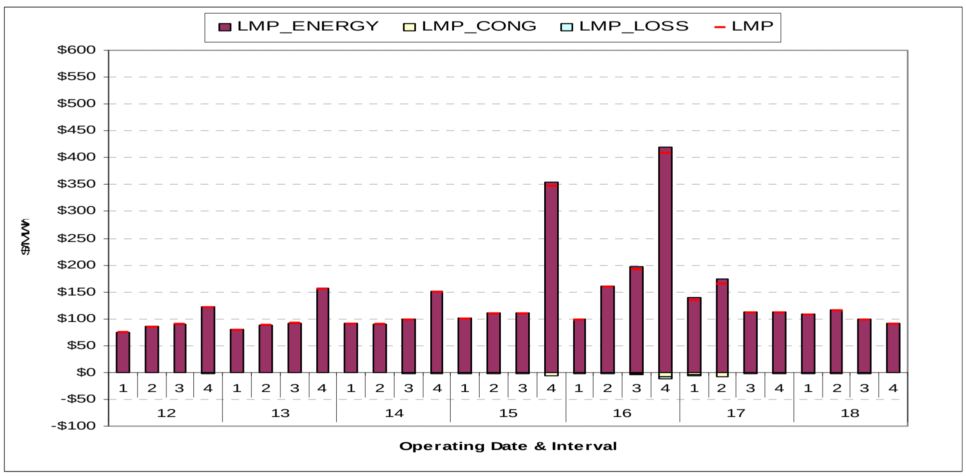


Figure 39. SDG&E HASP LAP Price Decomposition (Dec 11, 2008, Hrs 12-18)

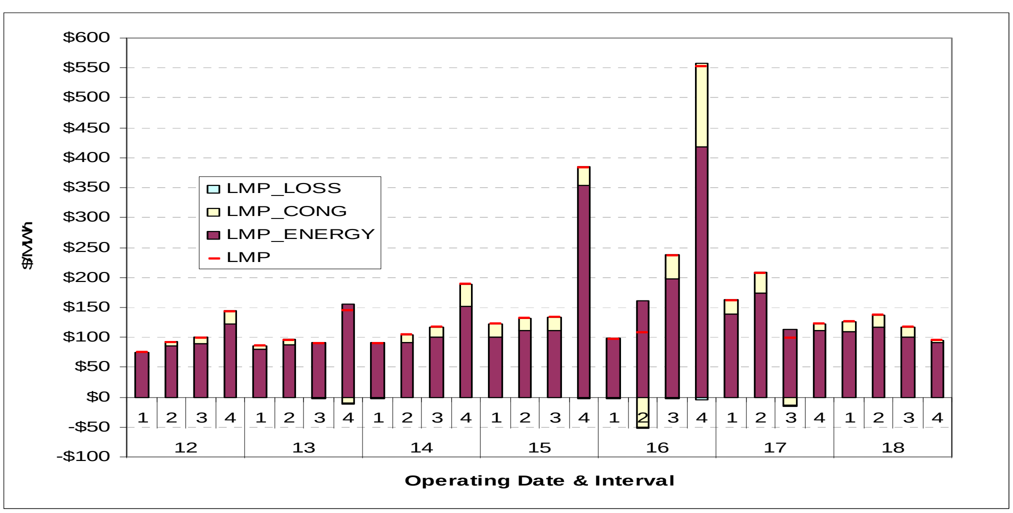


Figure 40 shows the left and right tail of the HASP LMP duration curve for December 11. There were very few extreme HASP LMPs. HASP LMPs in excess of $500/MWh comprised less than half a percent of total HASP LMPs. The same was true for the number of negative HASP LMPs.

Figure 40. HASP LMP Duration Curve (December 11, 2008)

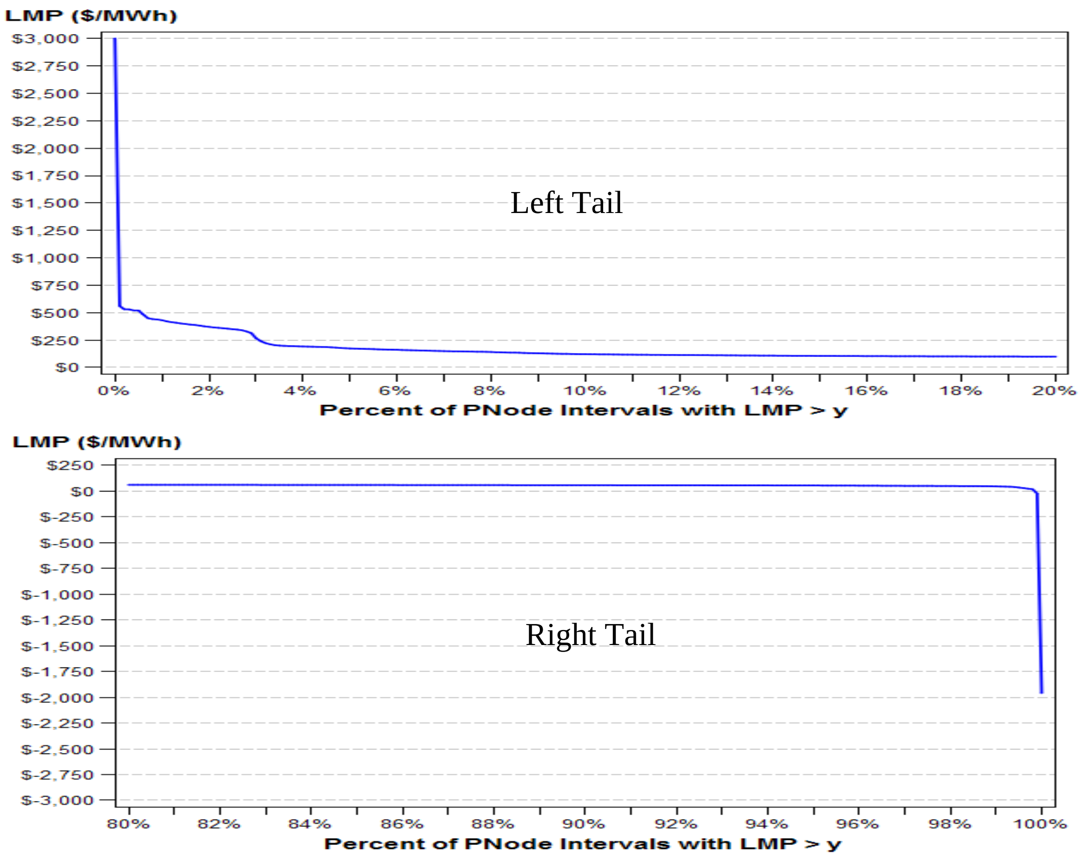


Figure 41 provides a count of the number of P-Nodes having HASP LMPs within certain price ranges for each interval of the day. Most of the HASP LMPs between $500/MWh and $750/MWh occurred in Hour 5, interval 2. The majority of HASP LMPs between $250/MWh and $500/MWh occurred across the peak hours. There were also a small number of high HASP LMPs occurring in Hours 20 and 21.

Figure 41. HASP LMP Frequencies by Interval (December 11, 2008)

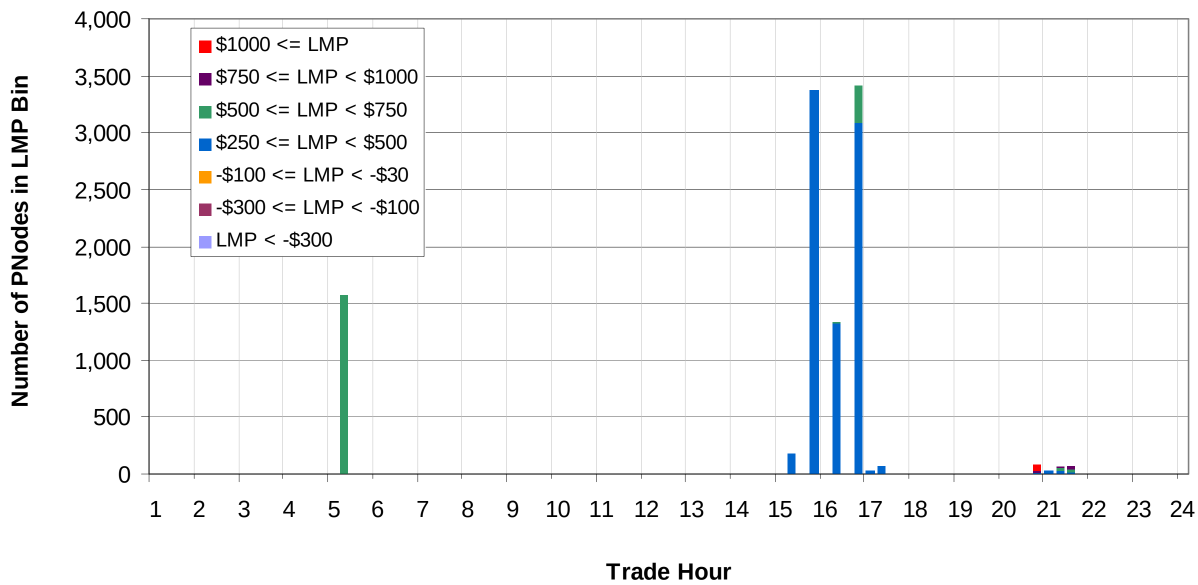


Table 7 provides a list of some of the more frequent and significant binding transmission constraints[15] in HASP during intervals where at least one HASP LAP price exceeded $200/MWh. Table cells highlighted in aqua indicate flow violations. Flow violations were observed on Miguel and on a PG&E constraint (Birds Landing to Contra Costa).

[15] Other binding constraints not shown in Table 7 include the following inter-ties: Standiford, Marble, Cascade, Silver Peak, PACI, North Gila, Parker, and Palo Verde.

Table 7. HASP Binding Constraints when LAP Price > $200/MWh (Dec 11)

Hour	Interval	Constraint* Shadow Prices** ($/MW)						LAP Prices ($/MWh)		
		Miguel	Birds Landing - Contra Costa	Vict. Lugo Nomogram	Chicago Park - Higgins	Morgan Hill - Llagas	Imperial Irrig. Distr.-SCE Inter-tie	PG&E	SCE	SDG&E
15	1	96	0	0	0	5	121	98	99	123
	2	93	0	0	0	13	132	108	109	132
	3	94	0	0	0	14	132	109	110	133
	4	328	0	482	0	246	340	356	347	383
16	1	37	0	116	0	7	121	102	98	96
	2	0	0	555	0	77	173	175	158	108
	3	204	0	59	0	93	205	194	192	237
	4	596	0	0	0	289	394	403	407	553
17	1	117	1590	0	0	52	153	136	133	162
	2	172	2421	0	0	90	182	169	165	207
	3	19	424	192	0	26	133	118	111	98
	4	64	0	48	0	17	133	112	110	122

*** Binding constraints shown are not an exhaustive list**
**** Aqua color indicates constraint violations**

Figure 42 provides a comparison of RTD LAP prices for December 11. As previously noted, the extreme RTD LAP prices observed in Hours 4 and 5 were due to a glitch in the simulated telemetry. All three RTD LAP prices were closely aligned through much of the day and peaked between $400 and $500/MWh across the peak hours of the day.

Figure 42. Comparison of RTD LAP Prices (December 11, 2008)

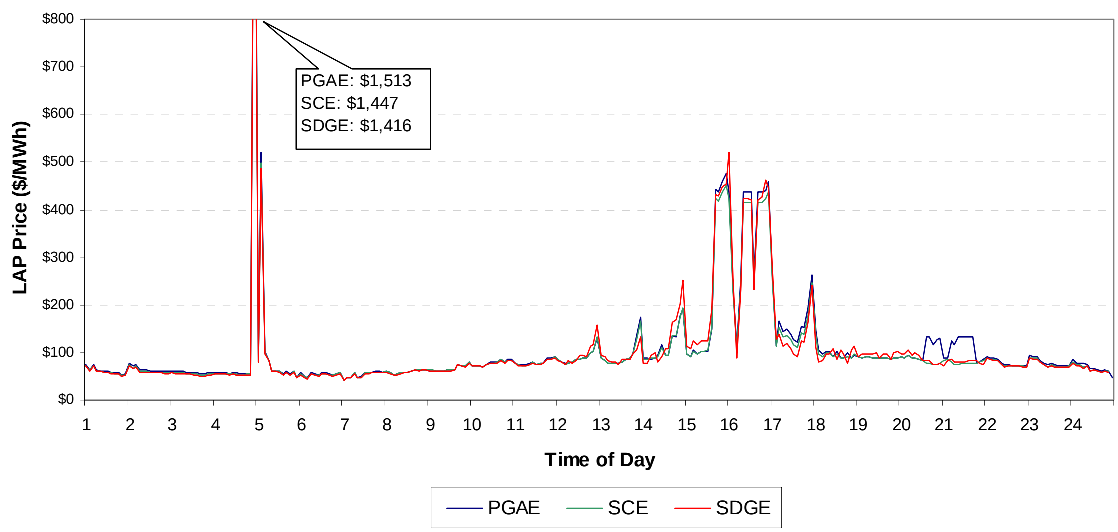


Table 8 lists the transmission constraints that were most frequently binding during periods of high RTD LAP prices (>$200/MWh) for Hours 14-15 and Table 9 provides the same data for Hours 15-16. Constraints that had flow violations are highlighted in aqua. High RTD LAP prices are highly correlated with high shadow prices for several transmission constraints, the Victorville to Lugo Nomogram, Miguel, and Birds Landing to Contra Costa.

Table 8. RTD Binding Constraints when LAP Price > $200/MWh (Dec 11, Hrs 14-15)

Hour	Interval	Constraint Shadow Prices* ($/MW)						LAP Prices ($/MWh)		
		Miguel	Vict. Lugo Nomogram	Brdsldg - C.Costa	NOB Inter-tie	Cascade Inter-tie	Morgan Hill - Llagas	PG&E	SCE	SDG&E
14	1	5	106	0	0	0	0	89	86	78
	2	0	88	0	0	0	0	88	86	78
	3	26	0	0	0	0	0	87	88	94
	4	43	0	0	0	0	0	88	89	99
	5	5	134	0	0	0	0	95	92	81
	6	0	221	1,022	0	0	0	117	110	90
	7	53	0	0	0	0	0	94	95	108
	8	53	0	0	0	0	0	94	95	108
	9	117	0	1,465	0	0	48	135	135	164
	10	137	0	0	0	0	36	132	134	169
	11	155	130	2,335	0	0	95	177	173	201
	12	231	0	2,287	0	0	109	192	193	251
15	1	72	0	0	0	0	2	96	96	114
	2	65	0	203	0	0	0	92	92	109
	3	82	0	864	131	0	16	104	103	124
	4	76	0	0	126	89	3	97	98	117
	5	83	0	0	130	92	7	101	102	123
	6	85	0	0	132	93	8	103	104	125
	7	85	0	0	0	94	9	103	104	125
	8	165	0	0	178	136	52	149	151	192
	9	341	858	649	409	389	332	442	424	431
	10	351	849	0	405	400	323	437	419	430
	11	368	884	994	421	395	349	459	438	449
	12	341	915	2,314	433	380	375	476	452	455

*** Aqua color indicates constraint violations**

Table 9. RTD Binding Constraints when LAP Price > $200/MWh (Dec 11, Hrs 16-17)

Hour	Interval	Constraint Shadow Prices* ($/MW)						LAP Prices ($/MWh)		
		Miguel	Vict. Lugo Nomogram	Brdsldg - C.Costa	NOB Inter-tie	Cascade Inter-tie	Morgan Hill - Llagas	PG&E	SCE	SDG&E
16	1	605	580	0	0	428	0	436	424	521
	2	206	250	0	245	246	0	237	230	258
	3	6	217	2,286	126	134	0	114	107	89
	4	147	486	2,267	245	232	150	253	240	233
	5	334	843	2,394	401	400	323	437	415	422
	6	334	843	2,370	401	400	323	437	415	422
	7	333	843	1,441	402	400	323	438	415	422
	8	146	486	1,446	245	232	150	254	240	232
	9	333	843	2,462	402	400	323	438	415	422
	10	348	841	2,301	401	400	323	438	415	427
	11	404	667	3,016	416	402	325	440	423	463
	12	358	886	400	420	421	344	460	437	446
17	1	213	311	0	258	262	150	254	246	270
	2	75	32	0	140	134	19	114	113	129
	3	49	304	0	166	127	84	167	153	137
	4	26	261	0	147	108	62	145	132	115
	5	30	268	0	150	108	67	148	135	118
	6	20	250	0	142	100	58	139	126	109
	7	11	232	0	134	110	40	126	116	98
	8	6	221	0	129	105	35	121	111	92
	9	36	281	0	156	112	74	155	142	125
	10	34	275	0	153	113	69	152	139	122
	11	74	353	0	188	135	114	194	178	164
	12	153	500	0	251	260	160	262	247	240

*** Aqua color indicates constraint violations**

Figure 43 shows the left and right tails of the RTD LMP duration curve for December 11. RTD LMPs in excess of $500/MWh comprised less than 1 percent of the total RTD LMPs. The same was true for negative RTD LMPs.

Figure 43. RTD LMP Duration Curve (December 11, 2008)

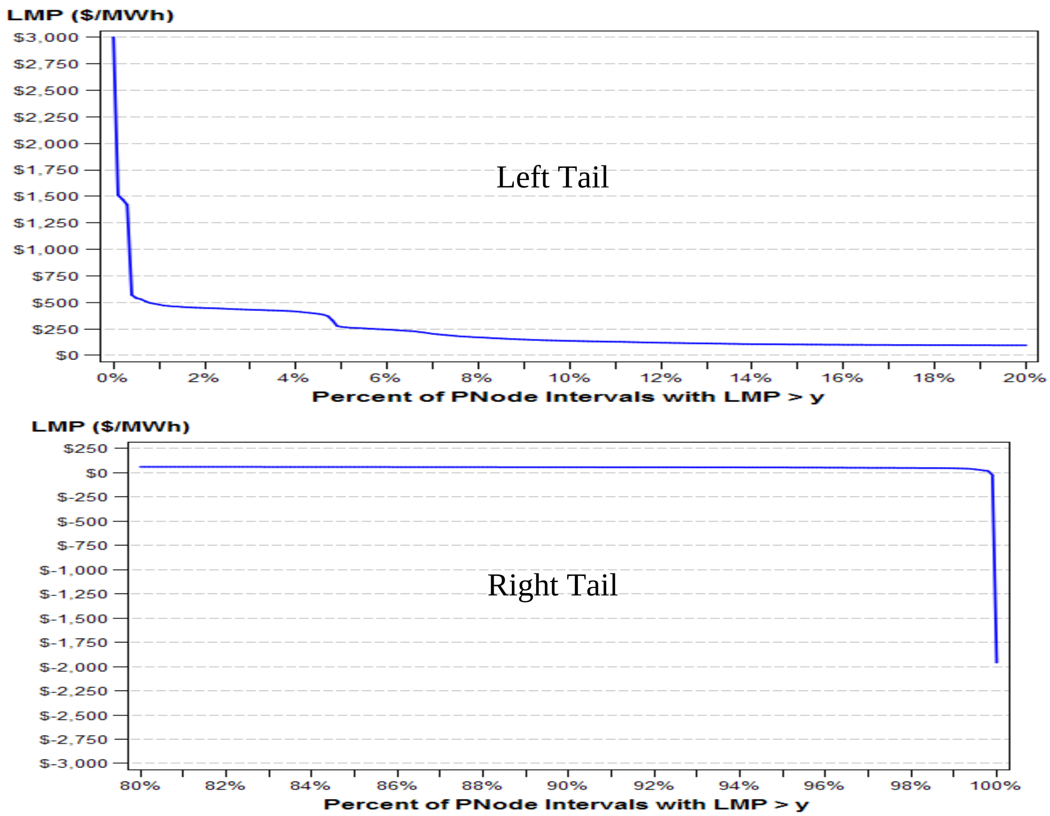
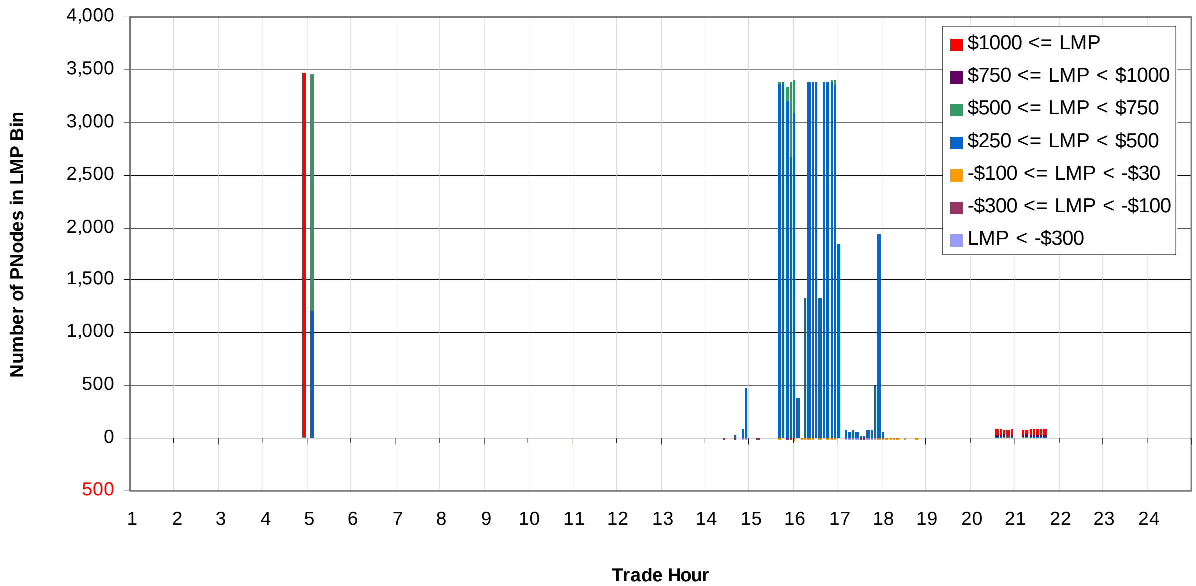


Figure 44 lists the number of RTD LMPs that occurred in specific price ranges for each interval of the day. The extreme RTD LMPs observed in Hour 4 were due to telemetry issues. The majority of RTD LMPs between $250/MWh and $500/MWh occurred across the peak hours of the day and tended to be system-wide in Hours 15-16. There were also a small number of extreme LMPs in Hours 20 and 21.

Figure 44. RTD LMP Frequencies by Interval (December 11, 2008)



December 12, 2008

The December 12 structured simulation was the same as December 9 except that the real-time load forecast was increased to be 5 percent higher than the day-ahead load forecast. This increase was imposed in both HASP and RTD. With a peak day-ahead load forecast of 46,000 MW, the 5 percent forecast increase in real-time added another 2,300 MW of real-time demand. Additionally, as was previously discussed and demonstrated in Figure 20, the amount of supply bids offered to the real-time market (HASP and RTD) on December 12 was significantly less than what was offered on December 9. The combination of these two events (higher loads, less supply) created severe shortages in the HASP and RTD and resulted in very extreme prices system-wide.

We do not consider the structured scenario for this day to be very realistic and the extreme results observed are more reflective of the limitations of the simulation as opposed to what we would expect in actual market operation. Specifically, if the CAISO experienced such a significant increase in real-time energy demand in actual operation on a peak summer day, we believe that there would be a significant market response of increased supply, particularly at the inter-ties, which would mitigate extreme prices, whereas the structured simulation had essentially no supply response. Moreover, such an extreme event would likely trigger demand response programs, which did not happen under the structured simulation. The extreme prices observed in the simulation for this day appear to reflect various transmission constraint violations.

Figure 45 - Figure 47 show the Day Ahead, HASP, and RTD LAP prices for PG&E, SCE, and SDG&E, respectively. Similar to past days, all three LAPs exhibited similar pricing patterns with very extreme LAP prices in HASP and RTD across the peak hours – often in excess of $2,000/MWh. HASP LAP prices were generally much higher than RTD LAP prices across the peak hours, with the highest HASP LAP price at approximately $7,000/MWh in Hour 20.

Figure 45. PG&E LAP Prices (DA, HASP, RTD) - December 12, 2008

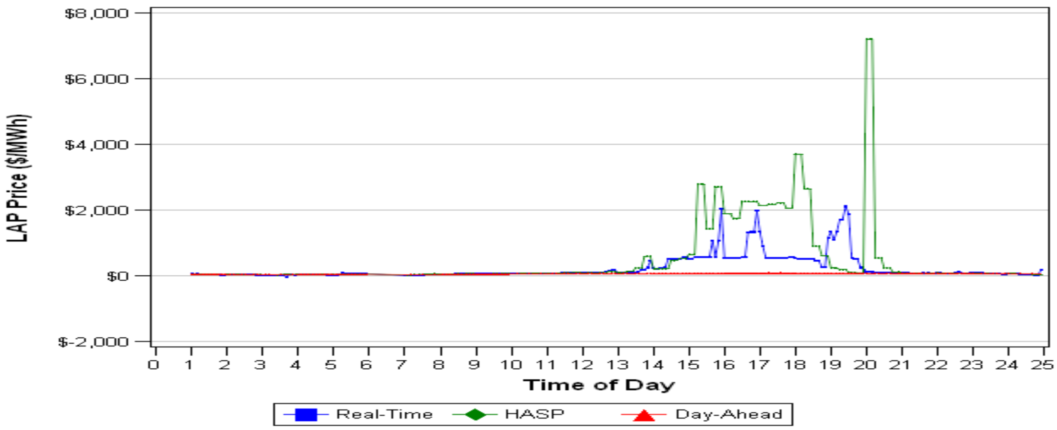


Figure 46. SCE LAP Prices (DA, HASP, RTD) - December 12, 2008

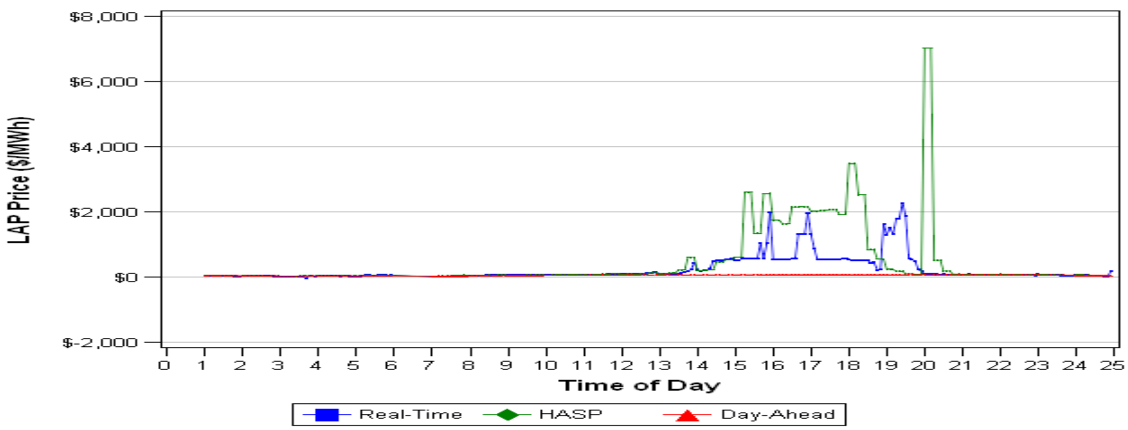


Figure 47. SDG&E LAP Prices (DA, HASP, RTD) - December 12, 2008

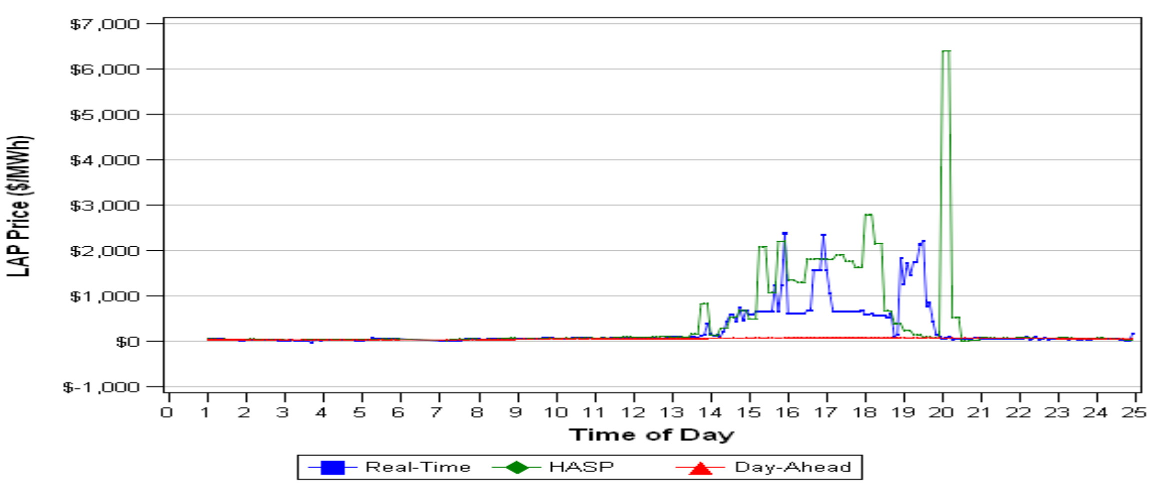


Figure 48 compares HASP LAP prices for PG&E, SCE, and SDG&E. Consistent with prior days, the PG&E and SCE LAP prices followed almost identical patterns and the SDG&E LAP price showed more separation, especially across the peak hours where the SDG&E LAP price in HASP was significantly lower.

Figure 48. Comparison of HASP LAP Prices (December 12, 2008)

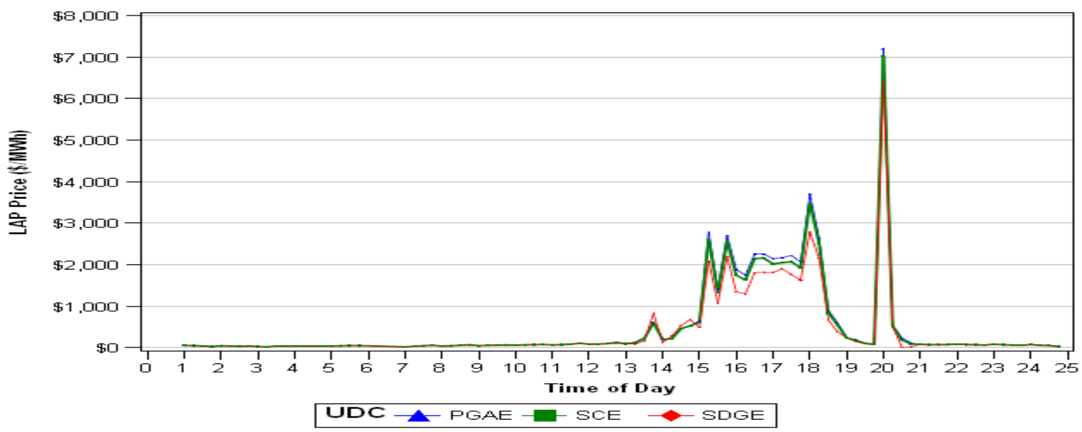


Figure 49 - Figure 51 show the decomposition of the HASP LAP prices for PG&E, SCE, and SDG&E, respectively. Though difficult to discern from the scale of the chart, the PG&E HASP LAP had a fairly significant positive congestion component during intervals with extreme prices, particularly Hour 20, interval 1. Conversely, the SDG&E HASP LAP price had a more significant and negative congestion component. The SCE HASP LAP prices had relatively minor congestion components.

Figure 49. PG&E HASP LAP Decomposition (Dec 12, 2008, Hrs 13-19)

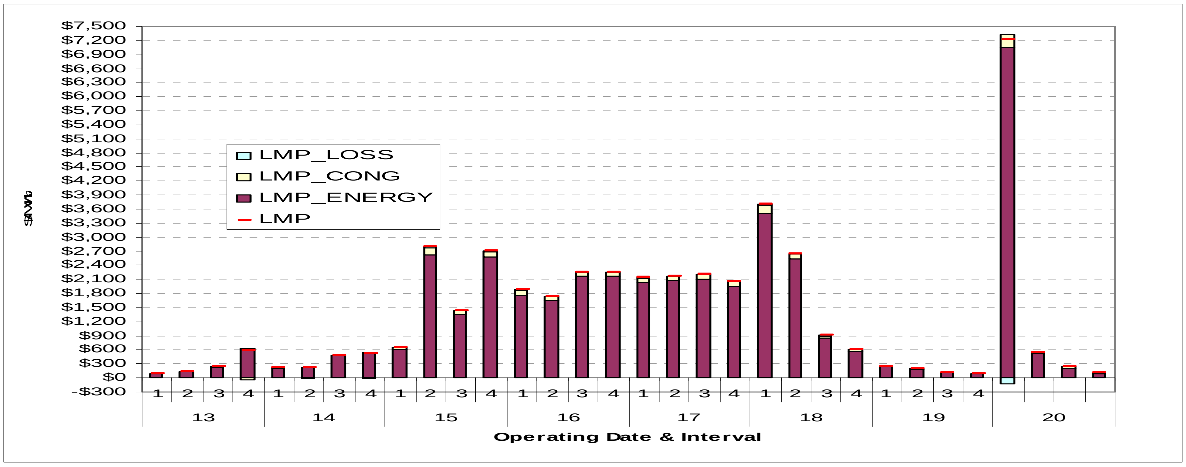


Figure 50. PG&E HASP LAP Decomposition (Dec 12, 2008, Hrs 13-19)

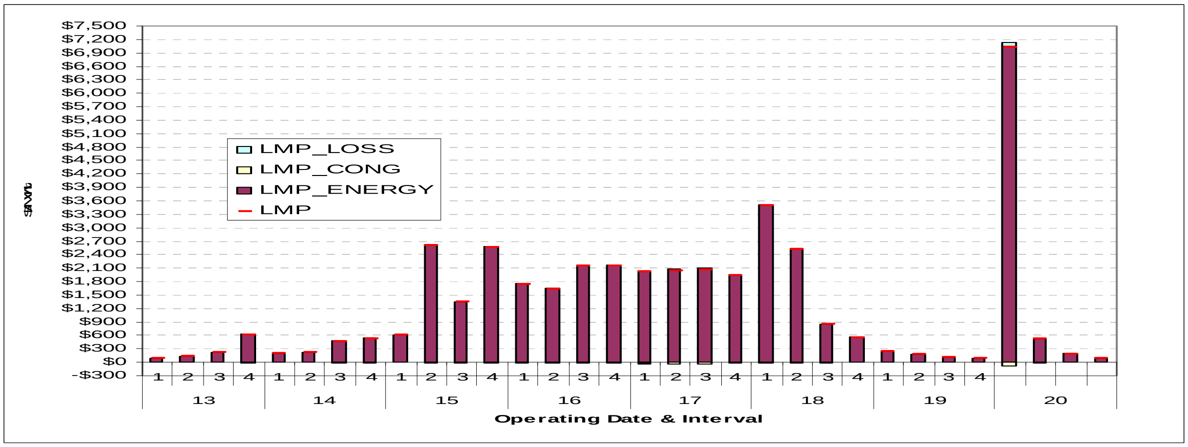


Figure 51. SCE HASP LAP Decomposition (Dec 12, 2008, Hrs 13-19)

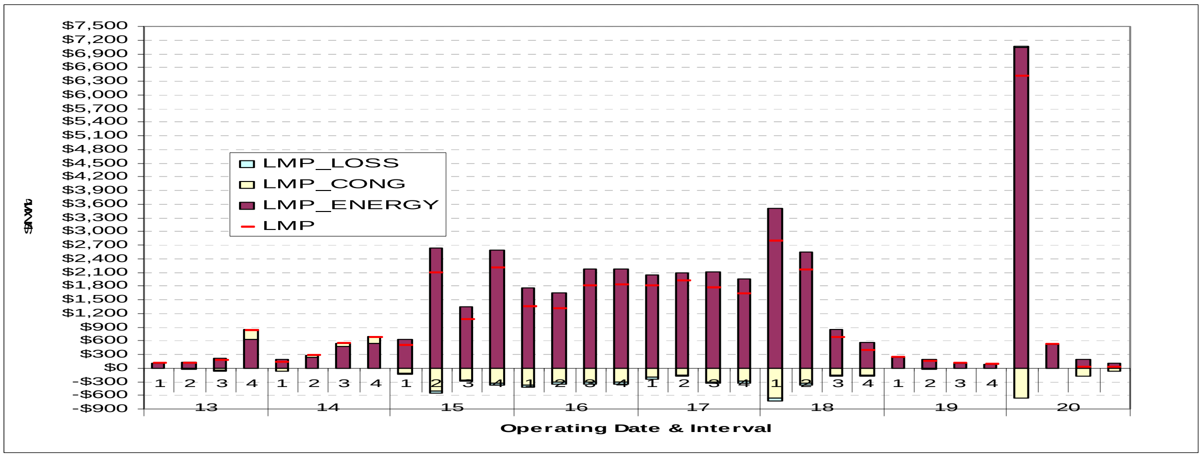


Table 10 provides a list of some of the more frequent and significant binding transmission constraints[16] in HASP during intervals where at least one HASP LAP price exceeded $200/MWh. Table cells highlighted in aqua indicate flow violations.

Table 10. HASP Binding Constraints when LAP Price > $200/MWh (Dec 12)

Hour	Interval	Constraint* Shadow Prices** ($/MW)						LAP Prices ($/MWh)		
		Miguel	Cragview - Cascade	Vict. Lugo Nomogram	Chicago Park - Higgins	Morgan Hill - Llagas	PACI Inter-tie	PG&E	SCE	SDG&E
13	1	0	631	0	0	6	121	99	97	97
	2	0	0	339	0	41	158	138	127	96
	3	34	0	733	0	138	254	242	220	162
	4	921	0	0	0	465	577	595	608	831
14	1	0	0	707	0	113	229	215	195	131
	2	267	958	0	0	114	230	218	221	286
	3	500	0	549	44	351	465	472	462	532
	4	711	0	256	1148	404	514	529	532	681
15	1	0	531	1301	1369	522	633	653	612	490
	2	0	0	5577	7105	584	2584	2794	2606	2084
	3	0	500	2859	500	613	1343	1432	1341	1073
	4	55	514	3754	5301	560	2503	2711	2561	2204
16	1	0	409	4139	8394	423	1722	1890	1746	1350
	2	0	436	3476	3655	444	1599	1746	1634	1300
	3	0	0	3467	2310	444	2074	2263	2152	1812
	4	0	420	3493	500	442	2072	2261	2158	1816
17	1	0	400	500	3973	422	1954	2143	2021	1810
	2	326	407	500	4040	431	1982	2177	2049	1906
	3	0	410	1412	4031	436	2027	2224	2072	1765
	4	0	0	1595	2754	402	1889	2064	1925	1631
18	1	0	500	7250	3969	720	3423	3705	3488	2791
	2	0	500	3726	5543	493	2447	2650	2527	2157
	3	0	500	1791	4112	500	853	904	843	670
	4	0	500	1744	1284	476	590	609	554	391
19	1	0	0	0	0	137	252	242	241	239
	2	0	0	377	0	92	208	193	182	147
	3	0	0	65	0	14	129	107	105	98
	4	0	0	131	0	0	116	94	89	77
20	1	0	500	500	1447	1572	6624	7210	7033	6399
	2	437	408	1044	12065	392	569	546	517	527
	3	0	0	1961	521	140	256	242	187	10
	4	0	0	760	1328	24	137	118	94	25

*** Binding constraints shown are not an exhaustive list**
**** Aqua color indicates constraint violations**

[16] Other binding constraints not shown in Table 10 include the following inter-ties: Standiford, Marble, IID-SCE, Cascade, Silver Peak, North Gila, Blythe, and Palo Verde.

Figure 52 shows the left and right tails of the HASP LMP duration curve for December 12. The left tail (extreme positive LMPs) is truncated at $3,000/MWh. Approximately 20 percent of the HASP LMPs on December 12 exceeded $500/MWh with roughly 12 percent exceeding $1,000/MWh. There were very few extreme negative LMPs (less than 1 percent).

Figure 52. HASP LMP Duration Curve (December 12, 2008)

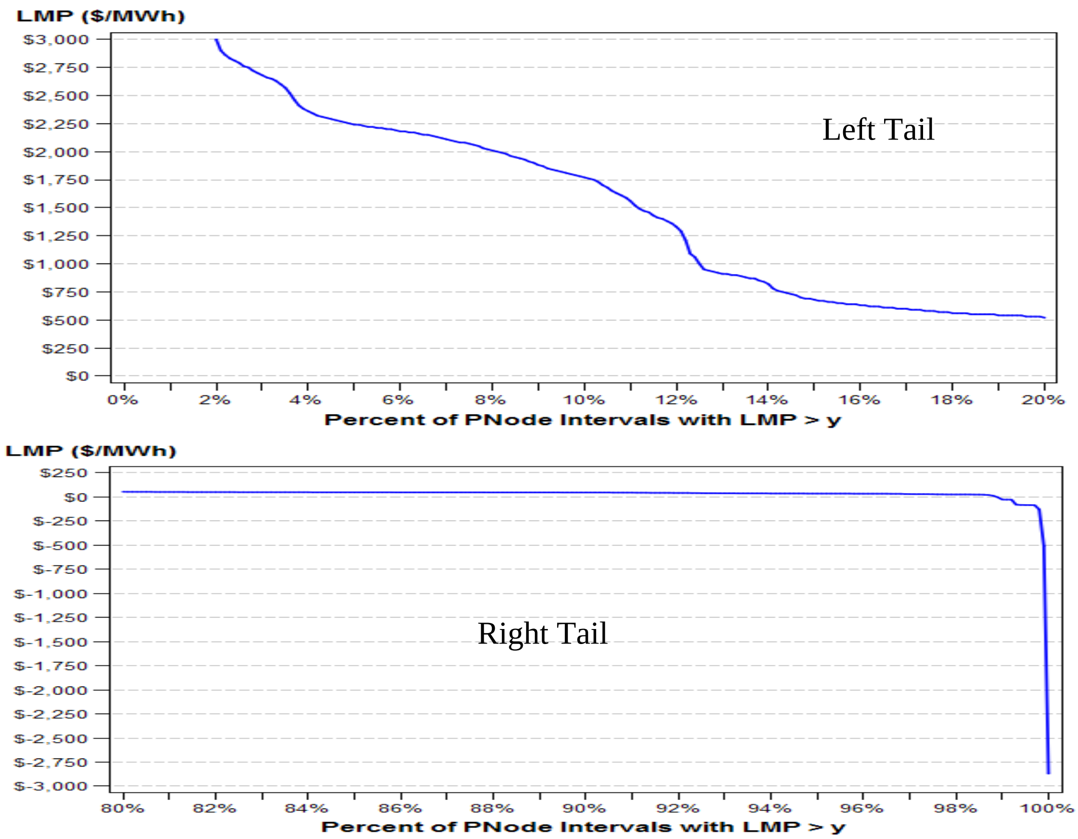


Figure 53 provides a count of the number of P-Nodes with HASP LMPs within certain price ranges for each interval of the day. HASP LMPs in excess of $1,000/MWh occurred primarily in the super peak hours of 15 to 17 and tended to occur throughout the system.

Figure 53. HASP LMP Frequencies by Interval (December 12, 2008)

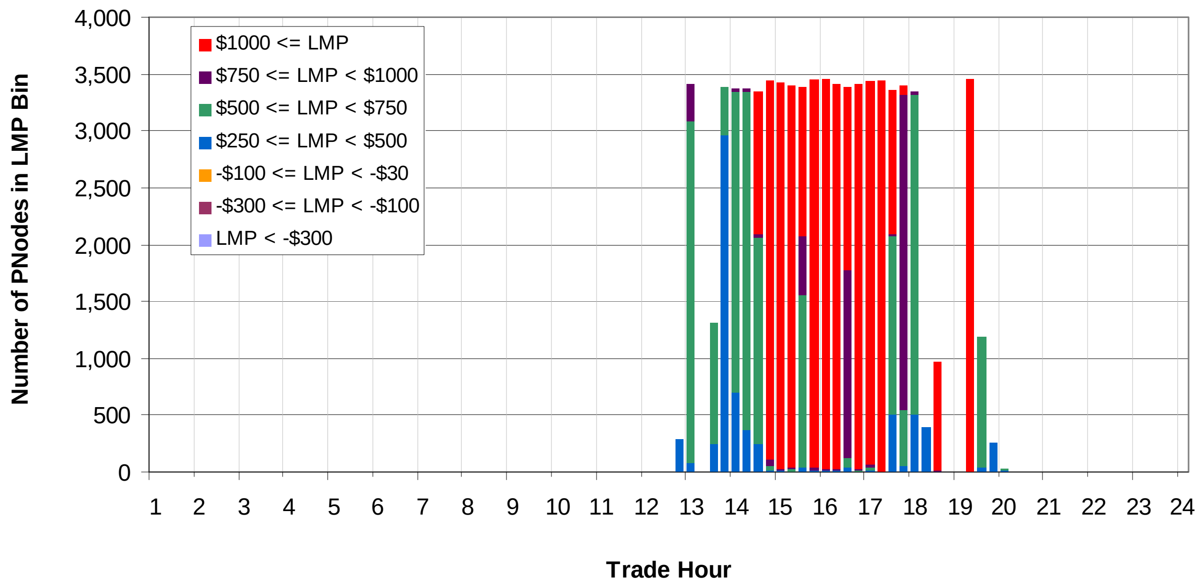


Figure 54 compares RTD LAP prices for December 12. The PG&E and SCE LAP prices were more closely aligned than SDG&E. Higher RTD LAP prices for SDG&E across the peak hours appear to be associated with Miguel congestion.

Figure 54. Comparison of RTD LAP Prices (December 12, 2008)

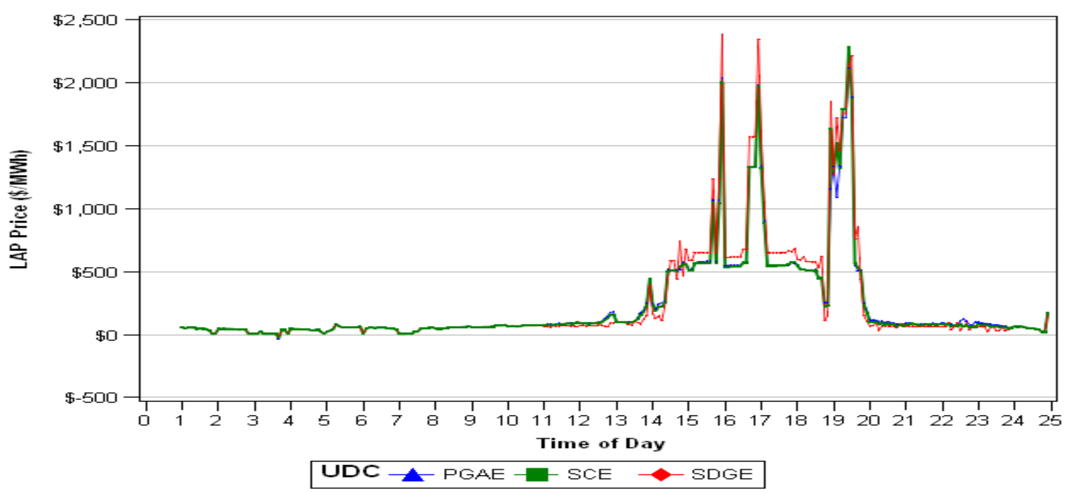


Table 11 provides a list of the transmission constraints that most frequently binding in RTD during interval where HASP LAP prices exceeded $200/MWh for Hours 13-16 and Table 12 shows the same data for Hours 17-19. Constraints that incurred flow violations are highlighted in aqua. As evident from these tables, numerous transmission constraints were binding in RTD during the peak hours of December 12 and several of them had flow violations. These binding constraints were likely a major factor in causing the extreme LAP prices. Further in-depth analysis for selected hours would be required to determine the extent to which each of these constraints contributed to extreme RTD LAP prices.

Table 11. RTD Binding Constraints when LAP Price > $200/MWh (Dec 12, Hrs 13-16)

Hour	Interval	Constraint Shadow Prices* ($/MW)									LAP Prices ($/MWh)		
		Miguel	Vict. Lugo Nomogram	IID - SCE Inter-tie	Rio-Oso	Brdsldg - C.Costa	Chicago Prk - Higgins	PACI Inter-tie	Cragview - Cascade	Morgan Hill - Llagas	PG&E	SCE	SDG&E
13	11	0	904	0	120	0	0	0	0	152	254	233	151
	12	0	571	0	276	0	997	0	0	337	450	441	388
14	1	0	693	0	115	0	0	0	0	145	247	230	167
	2	0	667	0	80	0	0	0	0	106	205	189	128
	3	0	825	0	93	2,100	497	0	0	159	247	223	147
	4	0	1,233	0	113	0	546	0	0	147	252	221	109
	5	0	345	0	119	402	562	0	0	160	262	255	222
	6	0	644	0	323	748	1,109	0	0	398	515	502	440
	7	554	633	0	328	0	1,120	0	0	391	513	509	586
	8	555	635	0	335	751	0	0	0	399	516	512	588
	9	0	646	0	335	751	0	0	0	399	516	504	442
	10	0	0	0	333	0	1,132	0	0	402	521	540	738
	11	812	939	20	370	829	1,234	0	0	458	575	555	469
	12	718	689	0	362	814	1,211	0	0	448	564	562	675
15	1	624	784	0	329	0	1,223	0	0	397	516	509	589
	2	623	783	0	324	750	1,214	0	0	403	518	509	589
	3	626	696	0	364	1,165	1,326	0	0	456	571	565	653
	4	620	695	0	367	1,413	1,340	0	0	459	579	566	650
	5	620	695	0	367	1,413	1,340	0	0	459	579	566	650
	6	620	695	0	367	1,413	1,340	0	0	459	579	566	650
	7	620	695	0	0	1,490	1,345	3	0		583	566	650
	8	620	695	0	0	1,490	1,345	3	0		583	566	650
	9	1,288	1,246	416	0	1,499	2,425	446	0		1,070	1,044	1,238
	10	619	694	0	0	1,511	1,345	4	0	463	583	566	650
	11	1,285	1,242	414	0	1,500	2,421	445	0	912	1,067	1,042	1,235
	12	2,503	2,384	1,254	0	500	500	419	0	1,810	2,037	2,000	2,380
16	1	583	661	0	354	0	1,276	0	459		551	536	613
	2	583	661	0	354	0	1,276	0	459		551	536	613
	3	586	664	0	354	0	1,273	0	459		551	540	616
	4	586	664	0	0	0	1,273	0	459		551	540	616
	5	586	664	0	0	0	1,273	0	459		551	540	616
	6	586	664	0	0	0	1,273	0	459		551	540	616
	7	718	697	0	374	0	1,329	22	482	445	574	571	677
	8	718	697	0	374	0	1,329	22	482	445	574	571	677
	9	1,622	1,575	668	995	0	2,992	716	1,195	1,152	1,335	1,330	1,567
	10	1,625	1,571	666	995	0	2,993	456	1,196	1,152	1,336	1,329	1,569
	11	1,625	1,571	666	995	0	2,993	456	1,196	1,152	1,336	1,329	1,569
	12	2,468	2,313	1,229	1,490	0	3,740	1,302	1,800	1,752	1,982	1,973	2,345

*** Aqua color indicates constraint violations**

Table 12. RTD Binding Constraints when LAP Price > $200/MWh (Dec 12, Hrs 17-19)

Hour	Interval	Constraint Shadow Prices* ($/MW)									LAP Prices ($/MWh)		
		Miguel	Vict. Lugo Nomogram	IID - SCE Inter-tie	Rio-Oso	Brdsldg - C.Costa	Chicago Prk - Higgins	PACI Inter-tie	Cragview - Cascade	Morgan Hill - Llagas	PG&E	SCE	SDG&E
17	1	1,616	1,563	660	0	0	2,986	713	1,193	0	1,341	1,321	1,560
	2	1,101	1,064	280	0	0	2,036	317	785	0	903	890	1,053
	3	690	668	0	0	0	1,275	0	459	423	551	547	649
	4	690	668	0	0	0	1,275	0	459	0	553	547	649
	5	690	668	0	0	0	1,275	0	459	0	553	547	649
	6	690	668	0	0	0	1,275	0	459	0	553	547	649
	7	692	669	0	0	0	1,275	0	0	423	550	547	650
	8	692	669	0	0	0	1,275	0	0	423	550	547	650
	9	692	669	0	0	0	1,275	0	0	423	550	547	650
	10	705	681	0	0	0	1,311	0	0	430	552	556	662
	11	691	903	0	0	0	1,366	22	0	453	577	575	658
	12	725	700	0	0	0	1,347	15	0	445	569	573	682
18	1	538	864	0	0	0	1,316	0	0	429	553	547	594
	2	626	792	0	0	0	1,239	0	0	397	519	515	591
	3	660	639	0	0	0	1,239	0	0	397	519	520	618
	4	544	630	0	0	0	1,242	0	0	390	515	509	578
	5	544	630	0	0	0	1,242	0	0	390	515	509	578
	6	544	630	0	0	0	1,242	0	0	390	515	509	578
	7	542	628	0	0	0	1,240	0	0	389	514	506	575
	8	569	554	0	0	0	1,098	0	0	330	451	445	529
	9	919	547	0	0	0	1,098	0	0	330	451	451	621
	10	0	1,201	0	0	0	658	0	0	150	257	223	112
	11	0	882	0	0	0	658	0	0	150	257	232	149
	12	500	0	500	0	0	500	462	0	0	1,161	1,635	1,846
19	1	500	1,593	708	1,011	0	3,019	722	0	1,153	1,340	1,301	1,265
	2	500	300	500	500	0	500	499	0	500	1,092	1,519	1,722
	3	500	500	691	500	0	500	724	0	500	1,339	1,319	1,465
	4	500	500	1,050	1,230	0	500	915	0	0	1,721	1,788	1,756
	5	500	500	1,050	1,230	0	500	915	0	0	1,721	1,788	1,756
	6	500	2,755	1,581	837	0	500	0	0	0	2,115	2,280	2,135
	7	2,283	2,216	1,149	0	0	500	1,234	0	1,668	1,888	1,869	2,211
	8	837	28	0	0	0	0	5	0	423	549	563	760
	9	1,330	0	0	0	0	0	0	0	389	513	535	856
	10	0	642	0	340	0	0	0	0	389	513	499	437
	11	0	891	0	121	0	82	0	0	149	255	232	150

*** Aqua color indicates constraint violations**

Figure 55 shows the left and right tails of the RTD LMP duration curve for December 12. Approximately 17 percent of the RTD LMPs were in excess of $500/MWh and roughly 5 percent were in excess of $1,000/MWh. Extreme negative RTD LMPs were rare, comprising less than 1 percent of the total RTD LMPs.

Figure 55. RTD LMP Duration Curve (December 12, 2008)

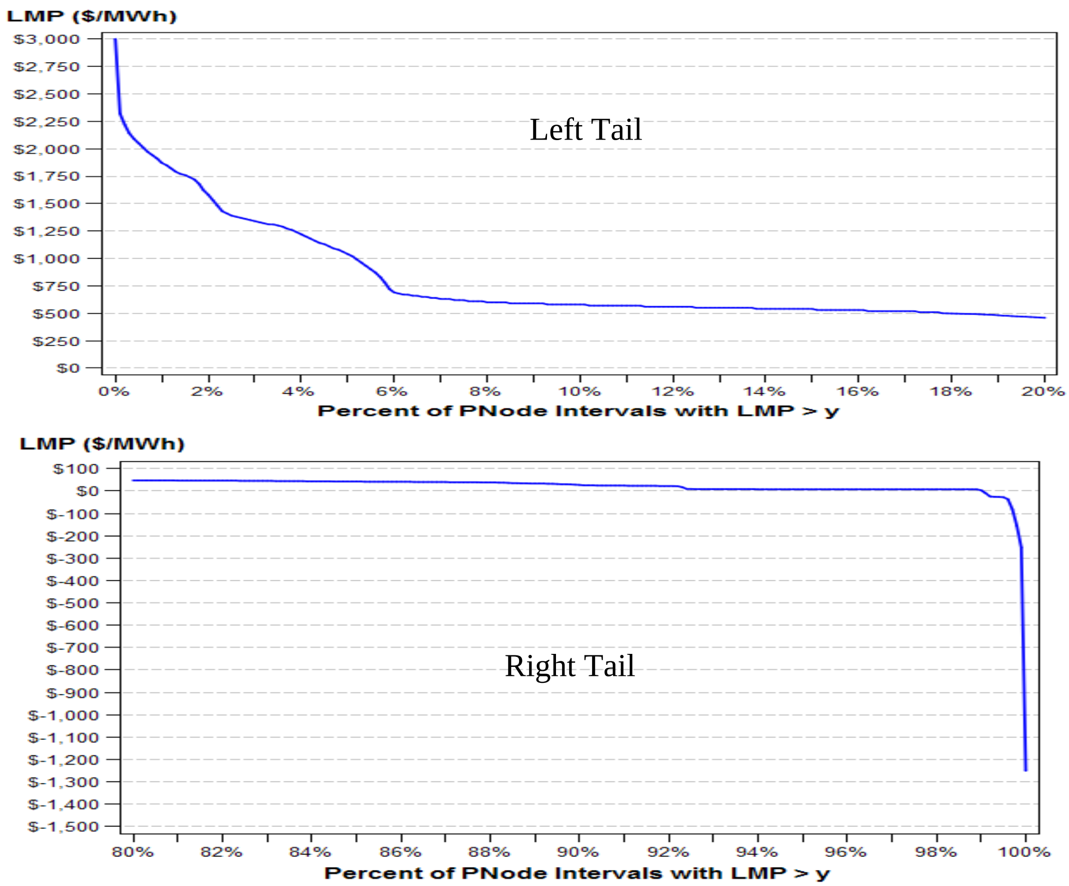
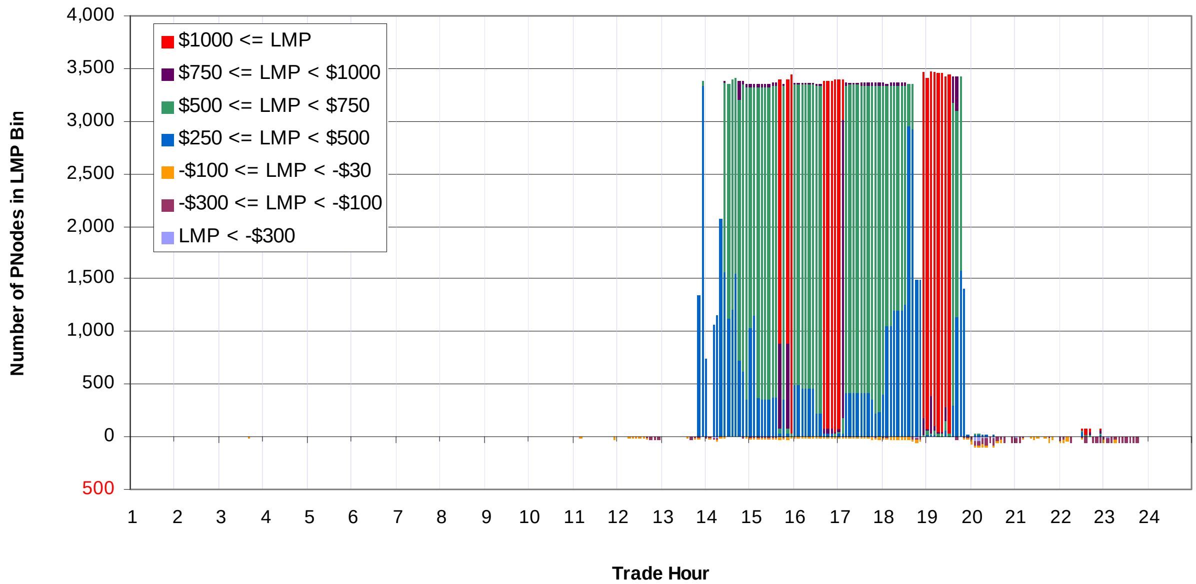


Figure 56 provides a count of the number of P-Nodes within specific price ranges for each interval of the day in RTD. Essentially all of the high RTD LMPs occurred during the peak hours. RTD LMPs in excess of $1,000/MWh occurred mostly in Hours 15, 16, and 19 and were fairly widespread.

Figure 56. RTD LMP Frequencies by Interval (December 12, 2008)



Comparison of Inter-tie Prices

This section reviews inter-tie prices in the structured simulation with a particular emphasis on a comparison of prices between the IFM and HASP markets. As noted in the overview, our analysis of September market simulation results found that prices for imports and exports on inter-ties with other control areas tended to be significantly higher in the HASP than in the IFM. We noted that if such significant and systematic price divergences for imports and exports persisted under MRTU, it could result in market inefficiencies and potential implicit virtual bidding where market participants submit IFM bids and schedules on the inter-ties with no intent or ability to deliver (or receive) and instead intend to buy or sell back their position in the HASP.

As noted in our analysis of September market simulation results, the quantity of demand clearing the IFM was consistently well below the total system load in the September simulations. This trend would tend to make HASP prices higher than IFM prices, simply because the additional demand clearing in the HASP would be met by the remaining (higher priced) portion of supply bids in the market simulation. In order to further assess the degree to which this persistent price divergence was due to load under-scheduling – rather than other factors related to the MRTU design or software – the scenarios that were run for the simulations for trade dates December 9, 11 and 12, 2008 were structured so that approximately 90 to 95 percent of load cleared the IFM. Meanwhile, the scenario for trade date December 10 was structured so that only approximately 85 percent of load cleared IFM, similar to the September simulation conditions.

The following sections review the inter-tie prices resulting from these scenarios for the Palo Verde, El Dorado, Mead, PACI (Malin), PDCI (Nob), and SMUD/WAPA tie points. As indicated below, the prices appear generally reflective of the scenarios modeled, with much better price convergence between the IFM and HASP.

December 9, 2008

As noted earlier in this report, the scenario run for December 9, 2008, resulted in approximately 95 percent of load being cleared in the IFM during peak hours. This was a much larger proportion of load cleared in the IFM than occurred in the September market simulations, when load was significantly under-scheduled in the IFM, and HASP inter-tie prices averaged as much as $100/MWh or more higher than IFM prices.

Figure 57 - Figure 62 show the Day Ahead (IFM) and HASP prices for December 9, 2008, for the Palo Verde, El Dorado, Mead, PACI, PDCI, and SMUD/WAPA tie points, respectively. As evident in these figures, inter-tie prices show much better price convergence between the IFM and HASP than was observed in the September market simulation results. Price differences between the IFM and HASP for December 9 on individual tie points generally average only about $10/MWh, with some inter-ties exhibiting higher prices in the HASP than the IFM and other inter-ties exhibiting lower prices. This improved price convergence in the December 9 results is consistent with the higher proportion of load being cleared in the IFM. HASP inter-tie prices for December 9 that are <u>lower</u> than IFM prices (i.e., El Dorado, Mead) are likely attributable to constraints in the HASP increasing the congestion component of these inter-tie prices and consequently decreasing these tie point prices. With the exception of the Palo Verde and PACI inter-ties, the prices for the inter-ties shown in Figure 57 - Figure 62 follow the general pattern of the LAP prices.

On the Palo Verde inter-tie, import self-schedules appear to have been greater than the Palo Verde scheduling limit in the IFM on December 9. This appears to have resulted in self-schedules with the $30/MWh penalty bid price used for self-schedules in the IFM pricing run setting the price on Palo Verde. In the HASP, the total quantity of import self-schedules and bids on Palo Verde appears to have been greater than the scheduling limit, which appears to have resulted in the HASP price being set by marginal $10/MWh or $30/MWh import bids on Palo Verde.

A similar situation appears to have existed for the PACI tie point, where the price remained at $30/MWh in the HASP throughout the peak hours. Under actual market conditions, prices on these inter-ties would not be expected to diverge as much from the prices for other inter-ties, as market participants would be expected to respond to the low prices paid for imports at these inter-ties by either decreasing the quantity of imports offered at these inter-ties or increasing purchases of exports. Each of these responses would decrease the net quantity of imports, and thereby raise prices to be more aligned with prices on other tie points in the HASP and IFM. However, since participants do not actually have any economic incentives in the context of a market simulation, no such price responses appear to have occurred in market simulations.

Figure 57. Comparison of Palo Verde Prices (DA, HASP) – December 9, 2008

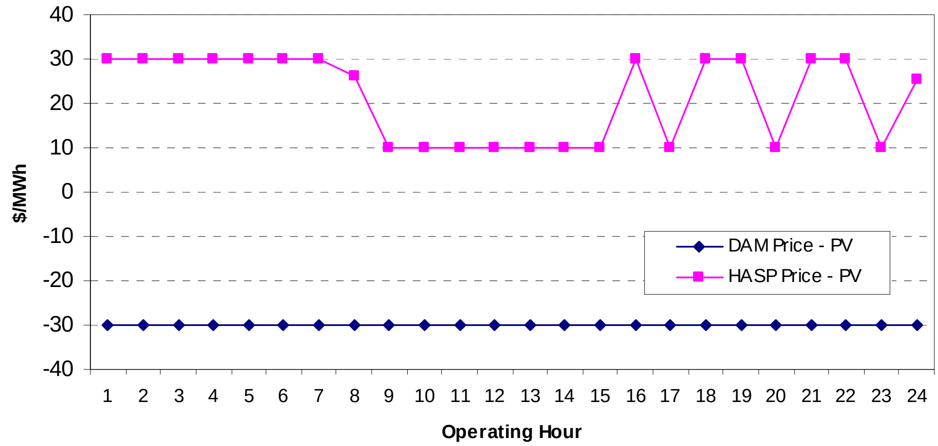


Figure 58. Comparison of El Dorado Prices (DA, HASP) – December 9, 2008

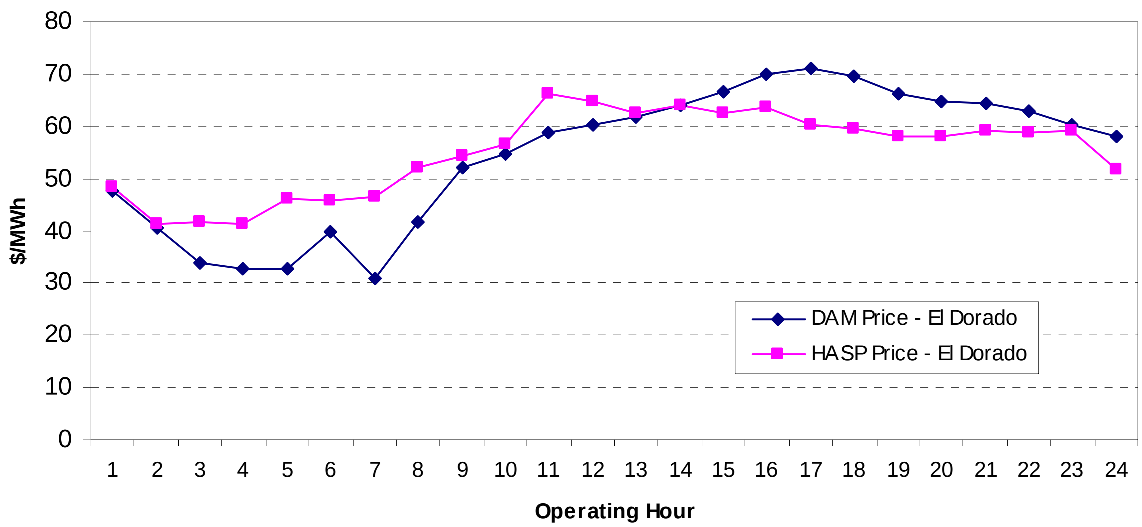


Figure 59. Comparison of Mead Prices (DA, HASP) – December 9, 2008

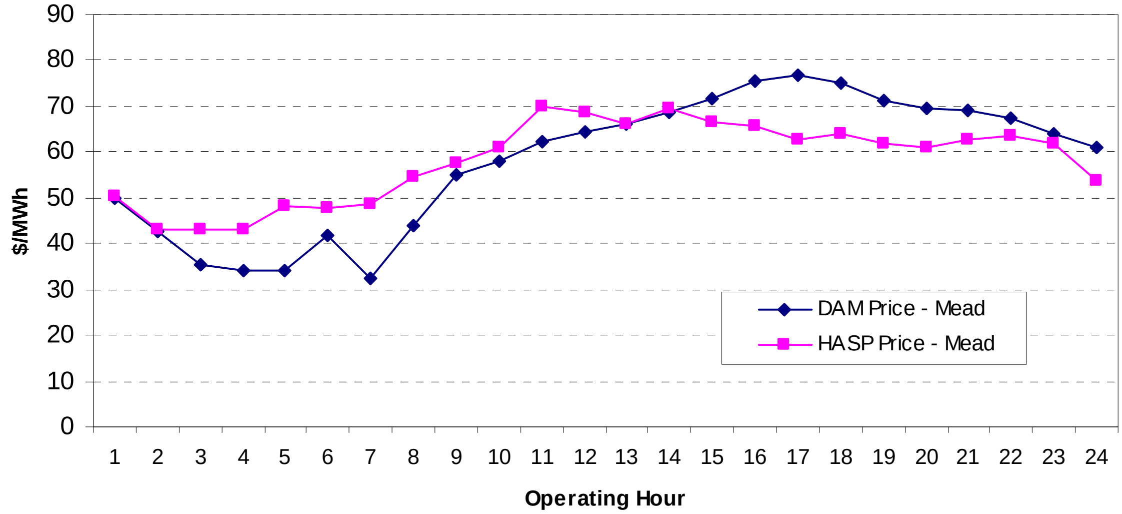


Figure 60. Comparison of PACI Prices (DA, HASP) – December 9, 2008

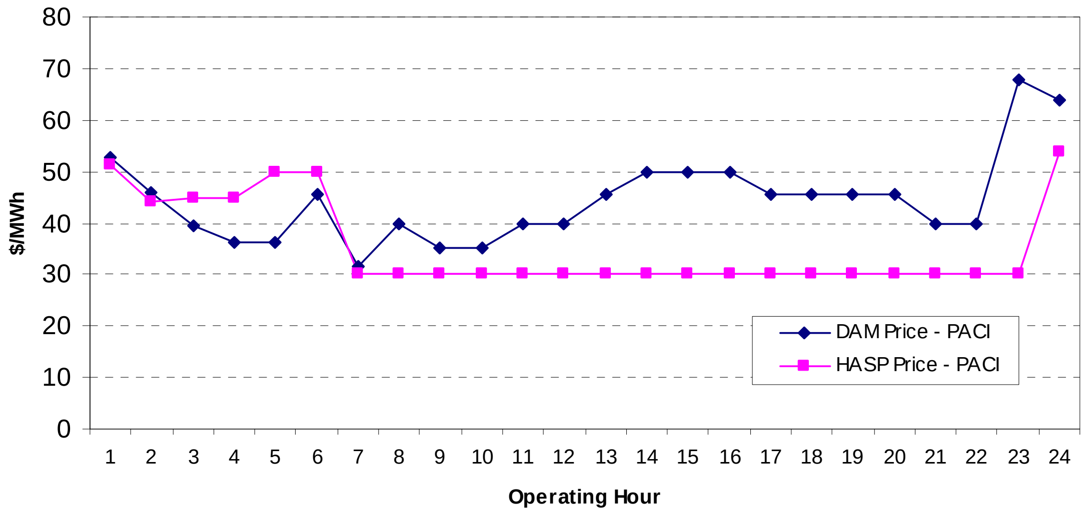


Figure 61. Comparison of PDCI (NOB) Prices (DA, HASP) – December 9, 2008

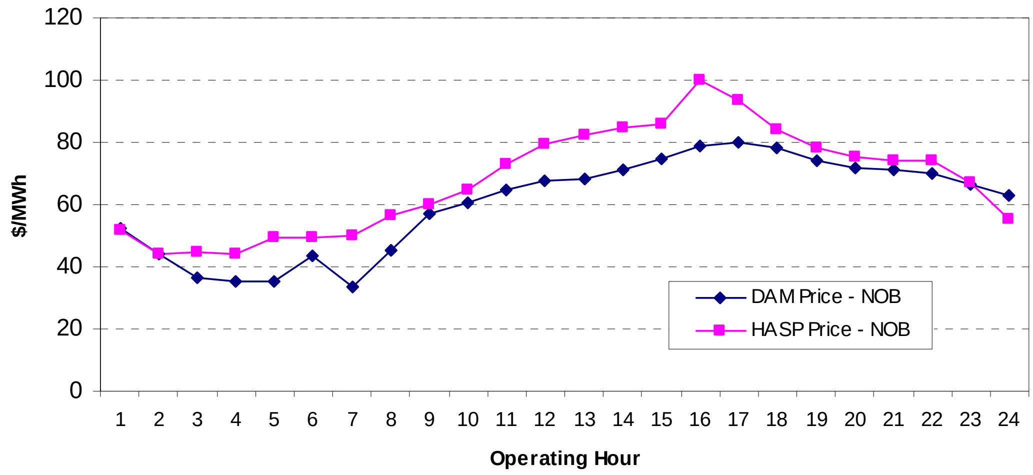
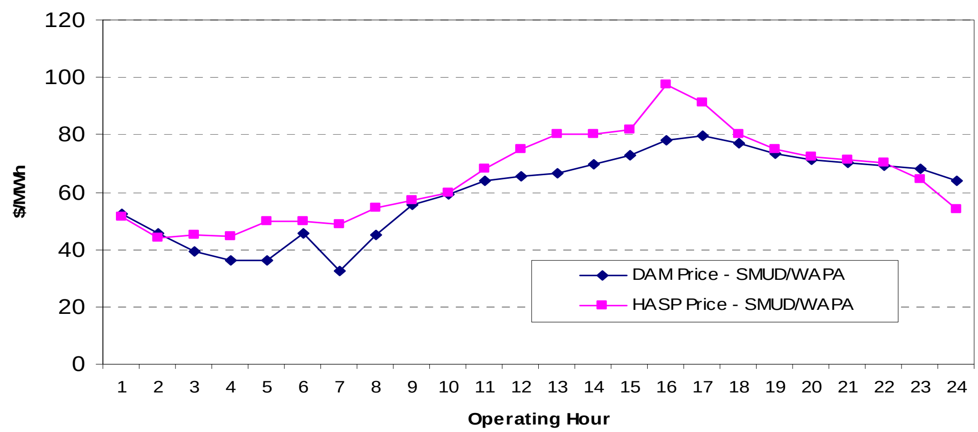


Figure 62. Comparison of SMUD/WAPA Prices (DA, HASP) – December 9, 2008



December 10, 2008

The scenario run for December 10, 2008, resulted in approximately 85 percent of load being cleared in the IFM during peak hours, as compared to the 95 percent of load cleared in IFM on December 9. Because relatively more incremental supply would need to be cleared in HASP under the scenario run for December 10, the HASP inter-tie prices would be expected to increase relative to the IFM prices and be more similar to the prices in the September market simulations, when a similar level of load under-scheduling occurred. In addition, as described earlier in this report, it appears that significantly less real-time energy bids were provided to the market simulation for December 10-12 compared to December 9, which would be expected to further increase HASP prices compared to IFM prices for these days.

Figure 63 - Figure 68 below show the Day Ahead and HASP prices for December 10, 2008, for the Palo Verde, El Dorado, Mead, PACI, PDCI, and SMUD/WAPA tie points, respectively. As

shown by these figures, the prices on these inter-ties are for the most part consistent with the under-scheduling scenario run for December 10 and decrease in supply bids submitted in the HASP during this scenario compared to the December 9 scenario. While HASP prices were at most approximately \$10/MWh more than the corresponding IFM prices for December 9, HASP prices increased for December 10 to a range of about \$20 to \$40/MWh greater than IFM prices, with much greater differences existing during HE 14-18. HASP prices were approximately \$400/MWh greater than IFM prices on the PDCI and SMUD/WAPA inter-ties during these hours, which were reflective of the price spikes seen in the LAPs during these hours, as described earlier in this report.

Meanwhile, prices on the Palo Verde and PACI inter-ties for December 10 differed from the general pattern described above. Similar to the situation that existed for Palo Verde on December 9, the prices for Palo Verde appear for the most part to be set by import self-schedules that exceed the scheduling limit. Also, as occurred during the December 9 scenario, the HASP prices for the PACI inter-tie for December 10 appear for most hours to be set by import self-schedules that exceeded the scheduling limit. Again, since the amount of import schedules on Palo Verde and PACI and the resulting prices do not appear to reflect economic incentives and actual market dynamics, these simulation results are probably not reflective of what would be expected under actual market conditions.

Figure 63. Comparison of Palo Verde Prices (DA, HASP) – December 10, 2008

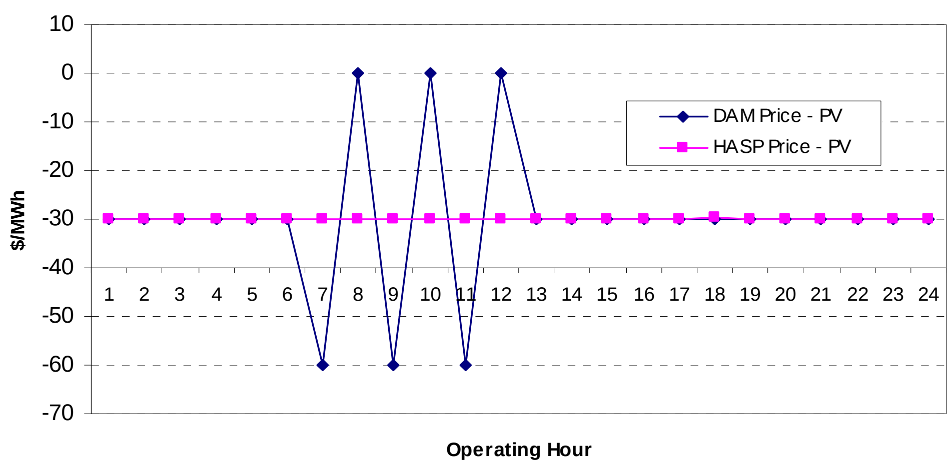


Figure 64. Comparison of El Dorado Prices (DA, HASP) – December 10, 2008

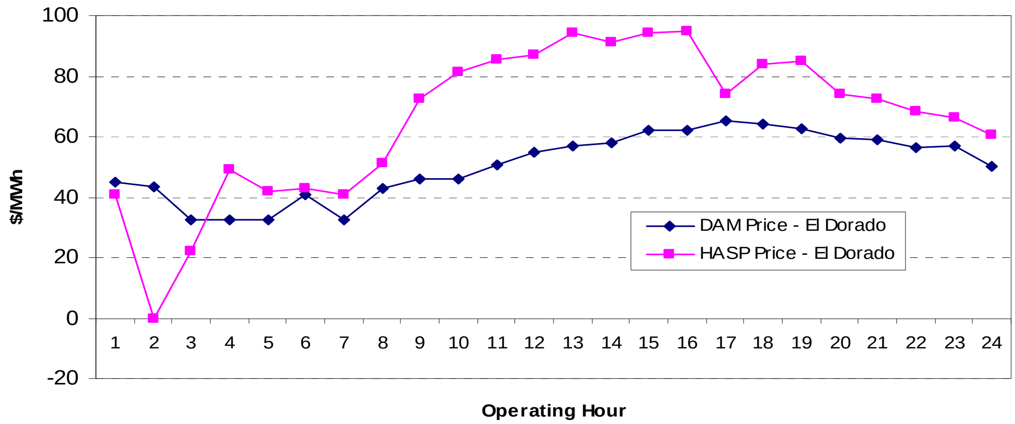


Figure 65. Comparison of Mead Prices (DA, HASP) – December 10, 2008

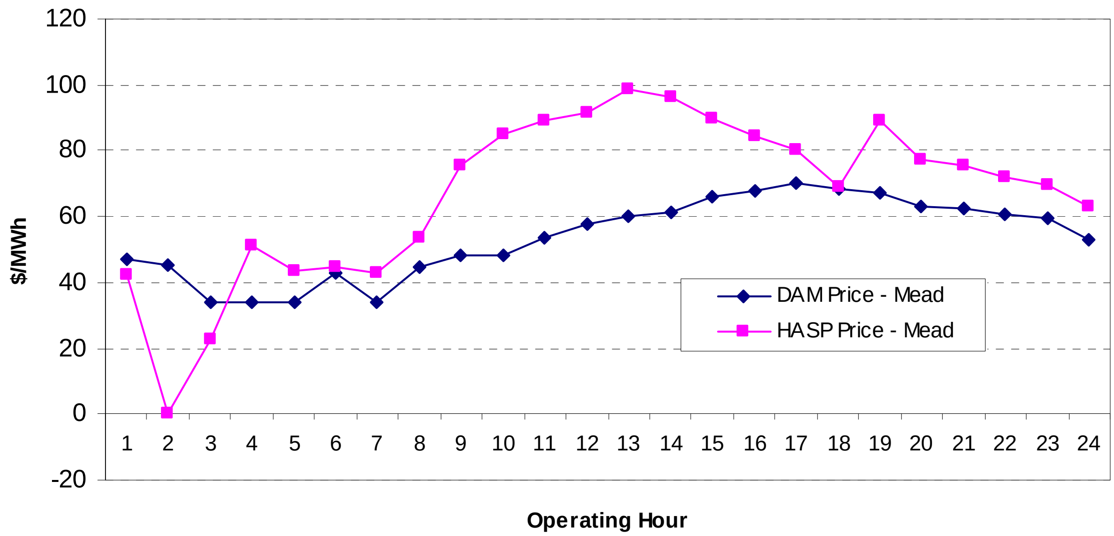


Figure 66. Comparison of PACI Prices (DA, HASP) – December 10, 2008

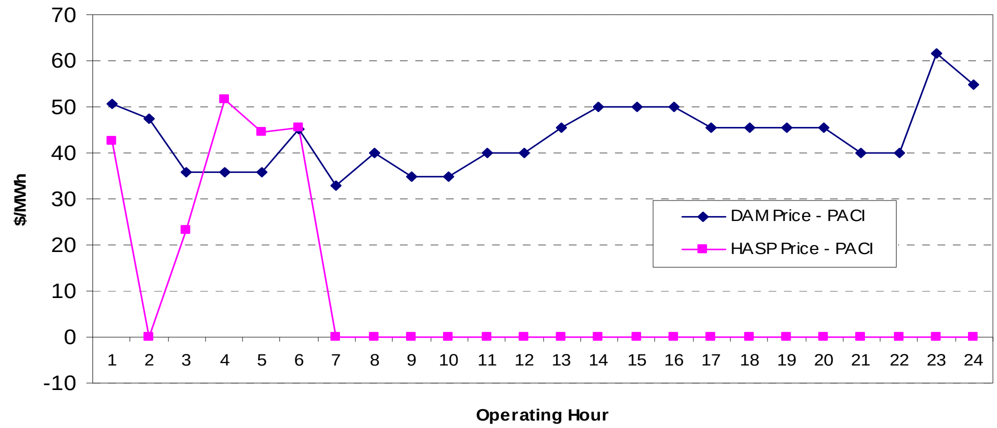


Figure 67. Comparison of PDCI (NOB) Prices (DA, HASP) – December 10, 2008

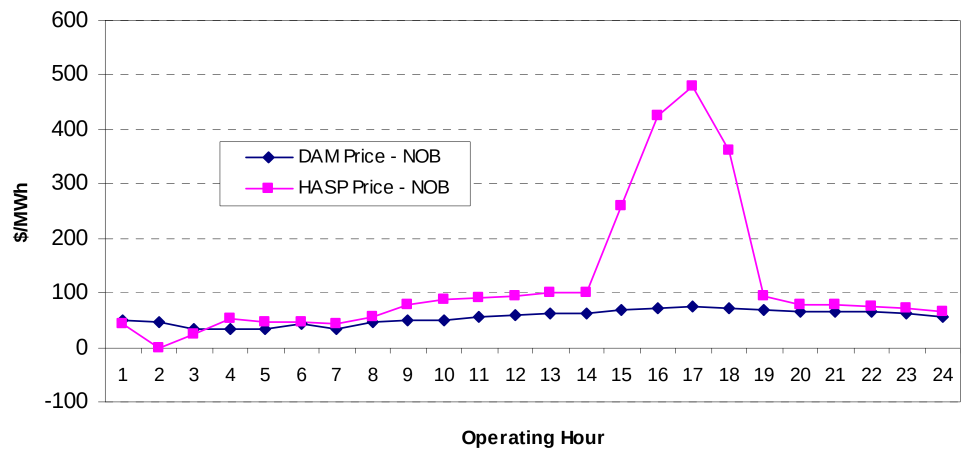
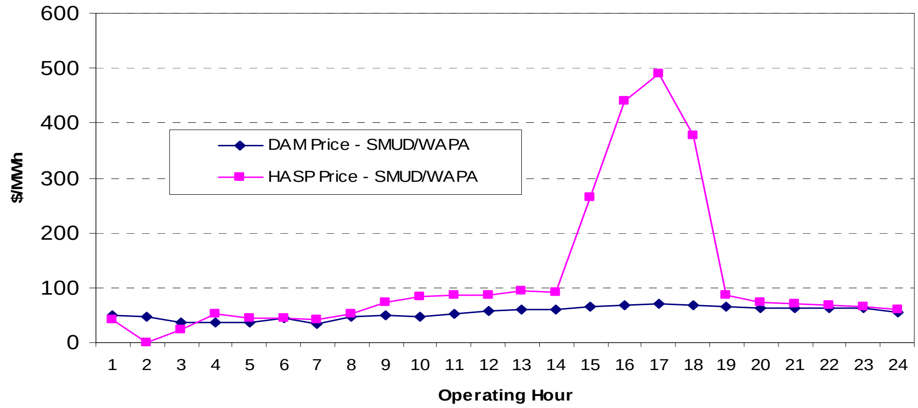


Figure 68. Comparison of SMUD/WAPA Prices (DA, HASP) – December 10, 2008



December 11, 2008

The scenario run for December 11, 2008, incorporated a significant level of potential economic withholding through relatively high priced generation bids in load pockets, with the amount of load cleared in IFM similar to December 9. Figure 69 - Figure 74 below show the Day Ahead and HASP prices for December 11, 2008, for the Palo Verde, El Dorado, Mead, PACI, PDCI, and SMUD/WAPA tie points, respectively. As shown by these figures, prices are generally similar to the prices for December 9, except that prices are somewhat higher in the HASP. These higher prices in the HASP are reflective of the price spikes seen in the LAPs during peak hours on December 10, as described earlier in this report. The prices in the IFM for Palo Verde and the El Dorado tie points differ from this general pattern. The $-30/MWh IFM prices for Palo Verde that persisted for most of the day are, similar to December 9 and December 10, likely attributable to import self-schedules that exceeded the import limit. The very low IFM prices for both Palo Verde and El Dorado for HE 14-19 were potentially due to the interaction of self-schedules and/or bids between inter-ties as these inter-ties are modeled as an external loop.

Figure 69. Comparison of Palo Verde Prices (DA, HASP) – December 11, 2008

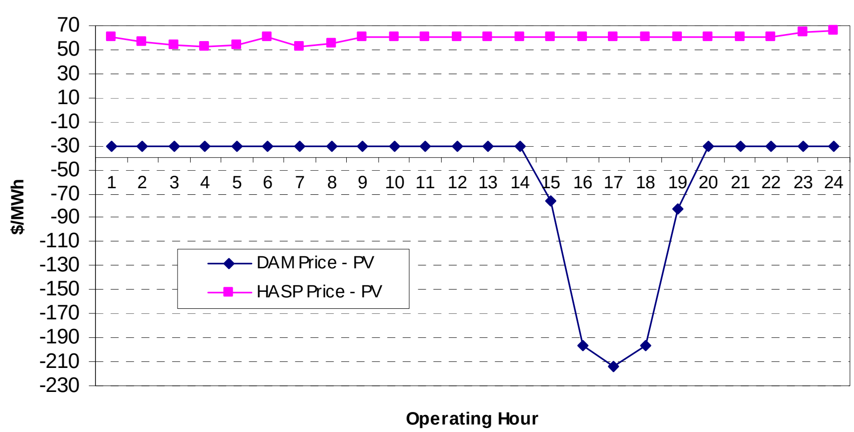


Figure 70. Comparison of El Dorado Prices (DA, HASP) – December 11, 2008

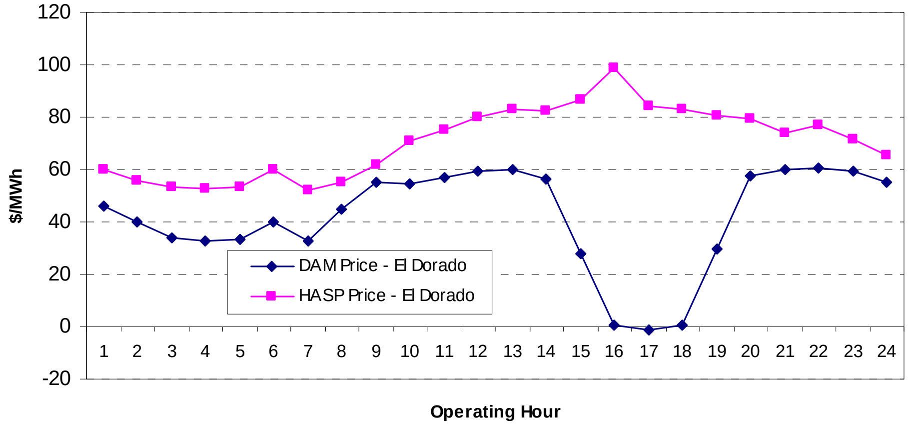


Figure 71. Comparison of Mead Prices (DA, HASP) – December 11, 2008

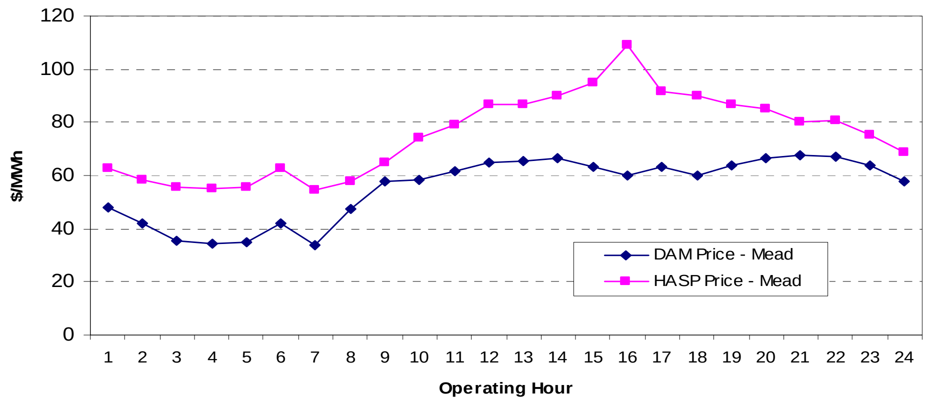


Figure 72. Comparison of PACI Prices (DA, HASP) – December 11, 2008

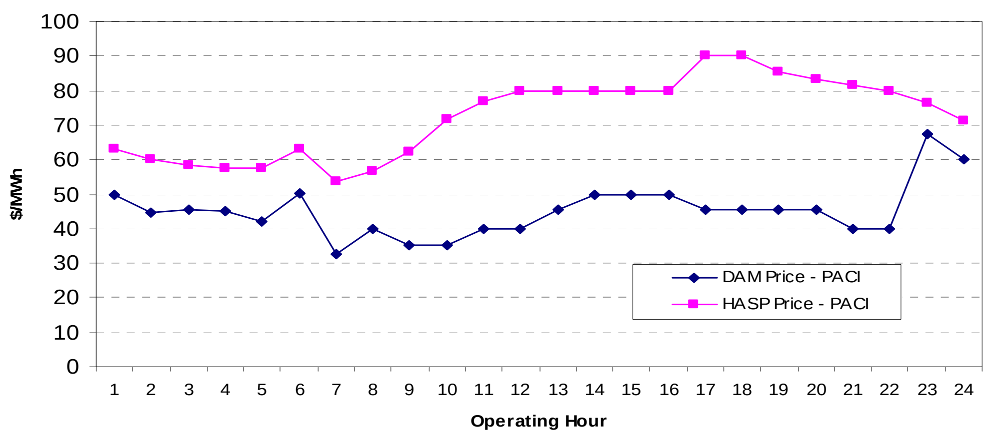


Figure 73. Comparison of PDCI (NOB) Prices (DA, HASP) – December 11, 2008

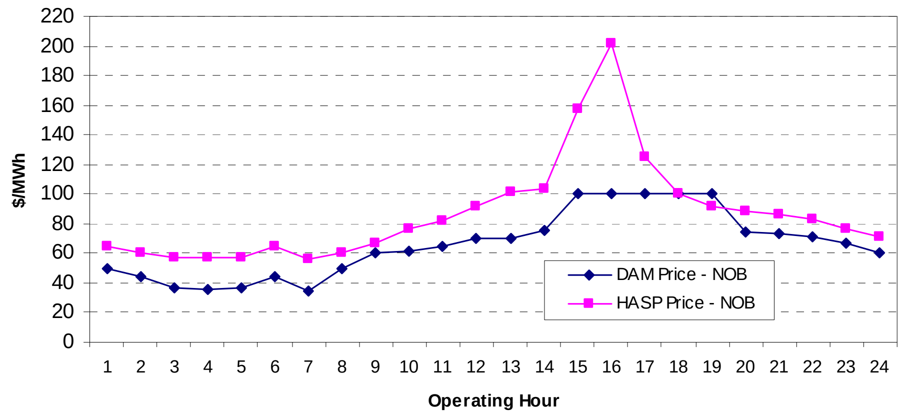
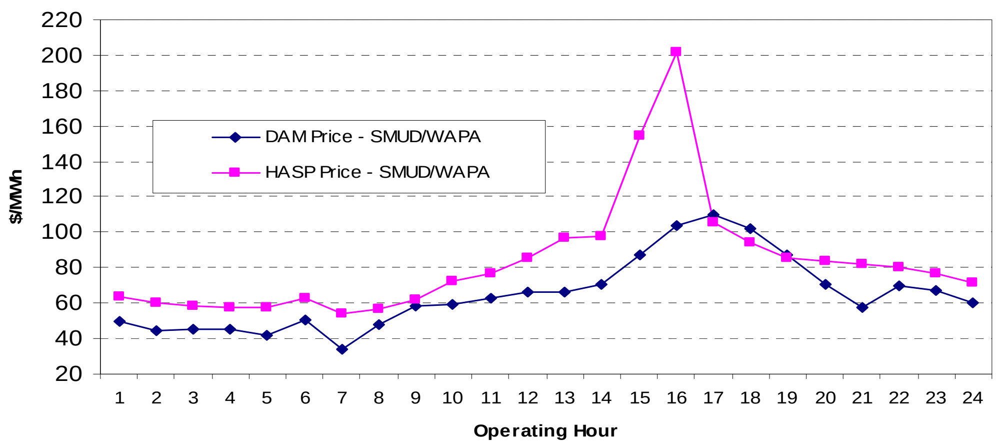


Figure 74. Comparison of SMUD/WAPA Prices (DA, HASP) – December 11, 2008



December 12, 2008

The scenario run for December 12, 2008, consisted of the real-time load forecast being 5 percent higher than the day-ahead load forecast, with the amount of load cleared in IFM similar to December 10. Figure 75 - Figure 80 below show the Day Ahead and HASP prices for December 12, 2008, for the Palo Verde, El Dorado, Mead, PACI, PDCI, and SMUD/WAPA tie points, respectively. As shown by the figures, the El Dorado, Mead, PDCI, and SMUD/WAPA inter-ties had price spikes of varying degrees in the HASP, with some very high prices occurring under this scenario. These price spikes were consistent with very high LAP prices in the HASP in these same hours. Similar to other days, Palo Verde exhibits negative prices in the IFM and HASP, and PACI had zero or negative prices in the HASP.

Figure 75. Comparison of Palo Verde Prices (DA, HASP) – December 12, 2008

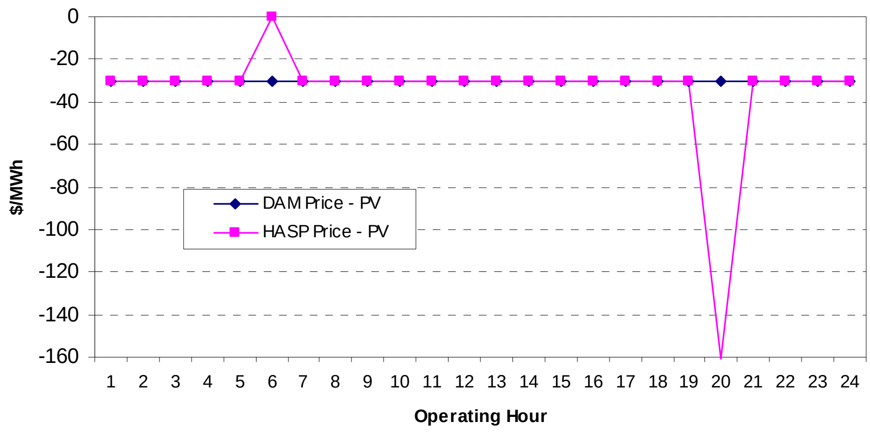


Figure 76. Comparison of El Dorado Prices (DA, HASP) – December 12, 2008

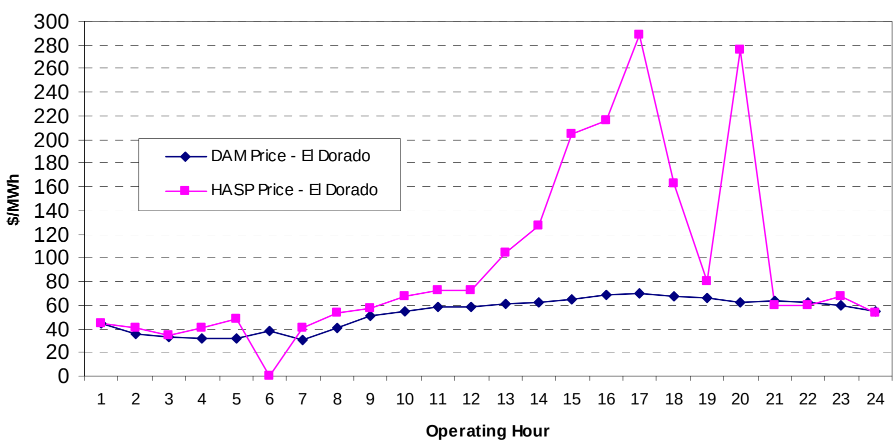


Figure 77. Comparison of Mead Prices (DA, HASP) – December 12, 2008

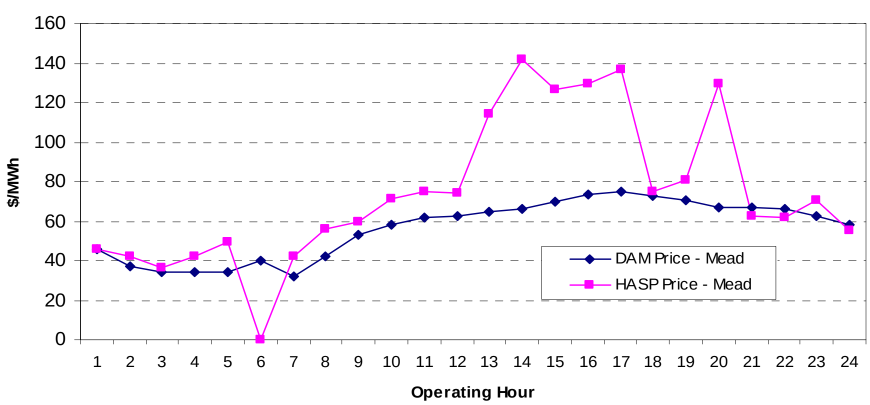


Figure 78. Comparison of PACI Prices (DA, HASP) – December 12, 2008

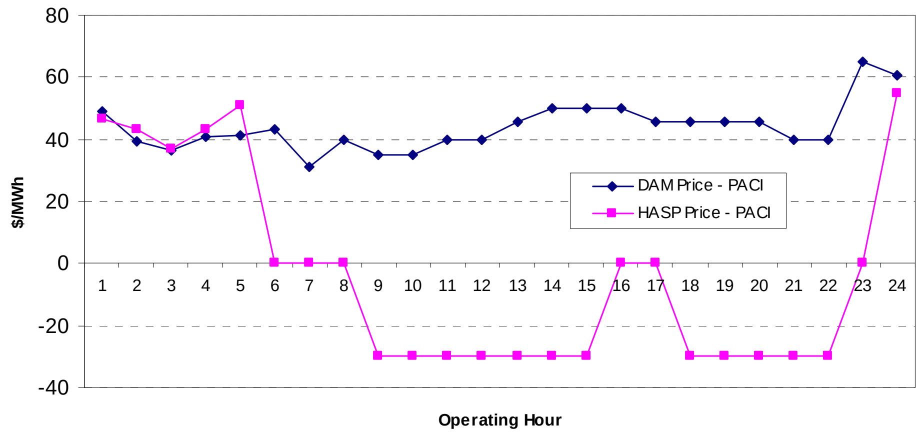


Figure 79. Comparison of PDCI (NOB) Prices (DA, HASP) – December 12, 2008

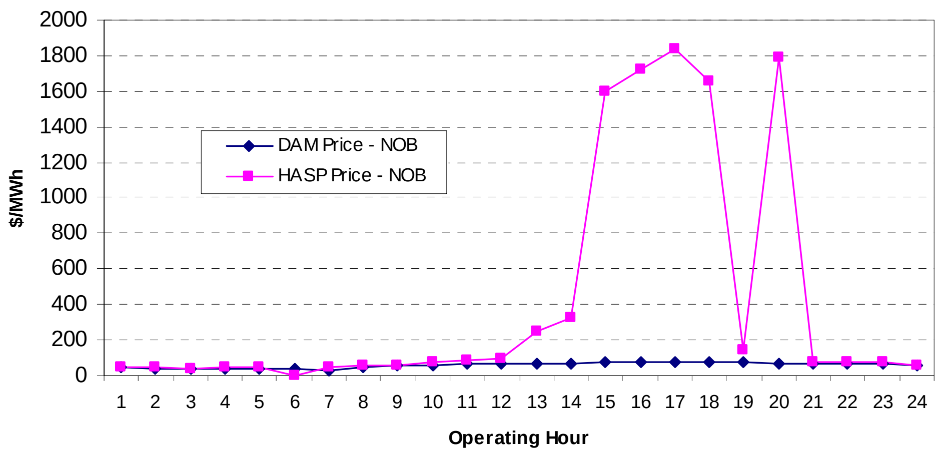
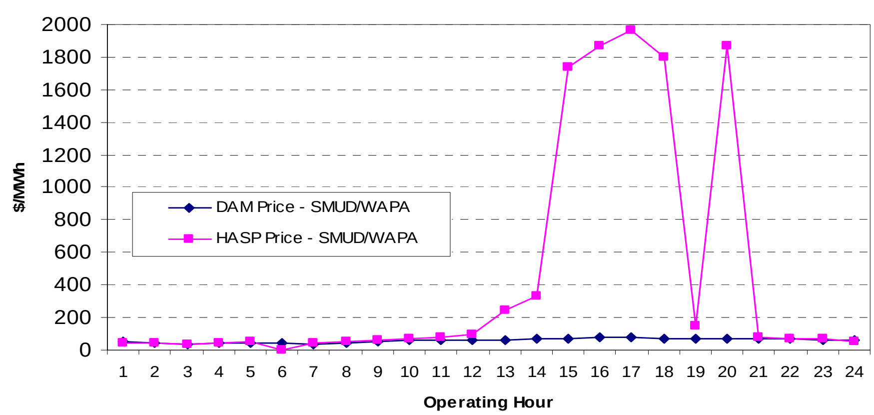


Figure 80. Comparison of SMUD/WAPA Prices (DA, HASP) – December 12, 2008



IV. Local Market Power Mitigation

Overview

This section summarizes DMM's review of the performance of the Local Market Power Mitigation (LMPM) provisions of the MRTU market design and software. As noted in our October Report, the MRTU market design relies upon a variety of LMPM provisions that are designed to work together to effectively mitigate local market power. These include:

- Identification of uncompetitive constraints through the Competitive Path Assessment (CPA), and incorporation of these results into the MRTU day ahead and real time market models.
- Establishment of Default Energy Bids (DEBs) reflective of competitive bid prices, to be used as the basis for limiting bids for resources dispatched to meet uncompetitive constraints.
- Successful execution of local market power mitigation runs and bid mitigation procedures prior to the day ahead and real time markets.

DMM has been reviewing market simulation results to ensure that each of these LMPM components is correctly implemented, and has designed metrics to monitor the effectiveness of each of these LMPM provisions after MRTU go-live.

In our October Report, DMM indicated that the LMPM features of the MRTU software were mechanically functioning as intended and effectively mitigating local market power, with one major exception:

- **Skipped or failed LMPM procedures** - During the September period covered in the October Report, DMM found that LMPM procedures failed to run or were skipped prior to the hourly HASP/RTM in as much as 5 percent of hours. Such failures are generally caused when the software fails to reach a solution in the required amount of time. Review of market simulation logs for December indicates that such problems may continue to be occurring in about 5 percent of hours. Thus, we are again recommending that the CAISO track and investigate the root causes of LMPM failures and pursue system enhancements/modifications to reduce their frequency. In addition, DMM has recommended that the CAISO establish pricing provisions that may be applied in cases where the LMPM procedures are not completed in the RTM in actual market operation.

In our October Report, DMM also indicated that we planned to complete further review of LMPM performance, including additional analysis in four areas:

- **LMPM effectiveness with nomogram constraints identified as "competitive" enforced in the competitive run of the market power mitigation procedures.** As noted in our October Report, no competitive nomograms were being enforced in the competitive run of the LMPM procedures at that time. This created the potential that LMPM procedures could be less effective once these nomogram constraints began to get enforced in the Competitive Constraints (CC) run of the market power mitigation procedures, rather than only being added in the All Constraints (AC) run. Since November, however, these competitive nomograms have been enforced in the Competitive Constraints (CC) run of the LMPM procedures. Thus, more recent market simulation results – including all of the structured market simulations for the December 9-12 period covered in this report – use the same designations of competitive vs. non-competitive constraints that would be used upon MRTU implementation under results of DMM's most recent CPA studies.[17]

- **Additional stress testing of the LMPM procedures by running special bidding scenarios.** The structured market simulation scenario for the December 11 trade date was specifically designed to test LMPM procedures under relatively high levels of economic withholding within some transmission constrained local areas. However, as discussed in this report, this single scenario primarily provides a test of LMPM effectiveness only within the San Diego area in the IFM. Thus, DMM will continue to perform additional off-line testing of LMPM effectiveness in other areas and in the RTM.
- **Default Energy Bids (DEBs).** As noted in our October Report, DMM will continue to review and monitor default energy bids (DEBs), including DEBs developed under the consultative DEB option. To date, very few market participants have engaged in discussion with the entity under contract by the CAISO to establish any special negotiated DEBs (Potomac Economics). However, DMM will continue to review and monitor DEBs established pursuant to provisions in the MRTU Tariff and Business Practice Manual (BPM) for Market Instruments.
- **Unit Operating Characteristics.** DMM has continued to review and monitor other resource characteristics that may be submitted by participants to the CAISO Master File and/or as part of market inputs, such as:
  - Ramp rates;[18]
  - Start-up and minimum load data; and
  - Requests for treatment as a use-limited resource.

  Our review of units requesting designation as use-limited resources indicates that over 1,000 MW of combustion turbine capacity under Resource Adequacy (RA) contracts have been designated as use-limited resources due to air permitting constraints (e.g., limiting units to no more than 876 operating hours and a limited number of start-ups per year). While these units are subject to a must-offer obligation if they are under an RA contract, there is no specific requirement for the amount of energy that must be scheduled or bid into the CAISO market during any specific hour. Although these units are required to submit a use plan for review and approval by the CAISO, our review of use plans indicates that such plans typically specify only a target number of operating hours per month, and do not specify whether or how a unit would be actually scheduled or offered in the CAISO markets during critical peak hours. Since many of these units are within transmission constrained areas, the portion of

[17] A list of CPA results was provided in our October Report. DMM plans on formally releasing its next CPA Report in February 2009, or at least 30 days prior to the scheduled date of MRTU implementation. Based on current data, DMM does not expect any revisions to the results in our October Report, which already reflected information on contractual ownership and control of resources during 2009 collected from market participants.

[18] As summarized in our October Report, operational ramp rates submitted for some units – particularly combined cycle units – were significantly lower than maximum ramp rates listed in the CAISO Master File. However, this was consistent with indications by some generators that ramp rates were being used to reflect operational limits of combined cycle units not captured in MRTU modeling. In addition, at that time, the lower ramp rates being submitted for some combined cycle units were not found to be a significant factor in IFM or RTM price spikes.

this capacity that is actually scheduled or offered in the CAISO markets during critical peak hours could have an impact on LMPM effectiveness. Thus, we recommend that the CAISO monitor the actual availability of these resources, and, if necessary, seek to establish more specific scheduling and bidding requirements for these units through use plans and/or other market design enhancements.

The remainder of this section summarizes our review of the performance of LMPM provisions in the structured market simulation scenarios tested during the December 9-12 trade dates. As indicated below, our review of these simulation results indicates that the LMPM features of the MRTU software are mechanically functioning as intended and effectively mitigating bids with one notable exception:

- **High MIP Gap.** During the December 11 market scenario designed specifically to test the LMPM features of the MRTU software, extremely high LMPs occurred within the San Diego area during several hours of the IFM when the software did not reach the target level of optimality as measured by the "MIP Gap".[19] However, by running this scenario offline for a greater number of iterations, DMM and Market Operations confirmed that as the MIP Gap is lowered, one additional unit would be committed within the San Diego area, and LMPs would fall within competitive levels reflecting the DEBs used to mitigate bids when LMPM provisions are triggered.[20]

This exception underscores the importance of providing sufficient time for the IFM to find an optimal solution – even if that means significantly extending the close of the Day Ahead Market.

Bid Inputs for Local Market Power Scenario (December 11)

The December 11 Market Simulation scenarios was specifically designed to test the local market power mitigation features of the MRTU software in IFM and RTM. For the local market power scenario, bids for the base case scenario performed on December 9 were modified to reflect a scenario where a significant portion of gas-fired capacity owned or contractually controlled by non-load-serving entities is economically withheld by being bid at a price of $400/MW. The capacity economically withheld in this scenario was all located within the CAISO's four largest Local Capacity Areas (LCAs):

- Greater Bay Area (in PG&E LAP)
- Big Creek Ventura (in SCE LAP)
- Los Angeles Basin (in SCE LAP)
- San Diego (in SDG&E LAP)

Figure 81 provides a comparison of energy bids for all resources within these LCAs used in the IFM in the base case scenario (December 9) and the market power scenario (December 11).

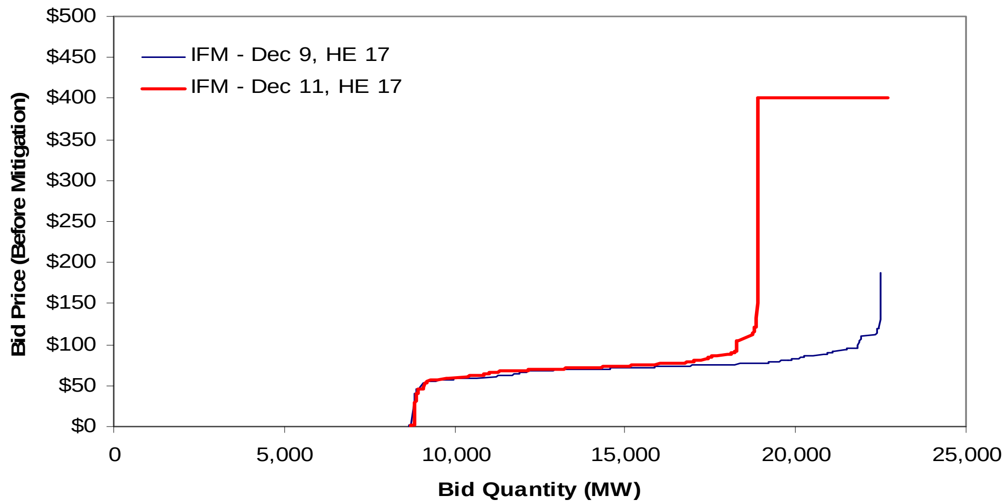
[19] For a discussion of the "MIP Gap" see *Final Report: Analysis Track Testing of CAISO MRTU Pricing and Dispatch*, October 20, 2008, prepared by Scott Harvey et. al.,(LECG) http://www.caiso.com/2067/2067769c1c5a0.pdf

[20] See *Quality of Solution – Pricing Review*, Mark Rothleder, MRTU Structured Simulation – Follow-up, December 23, 2008, slide 5-7, presentation Dec 23, 2008 http://www.caiso.com/20a6/20a67f452b390.pdf

Table 13 provides a breakdown of the capacity economically withheld in the IFM during the December 11 scenario by LCA.[21]

In the December 11 market power scenario, IFM bids were established directly by the CAISO, with all bids in the RTM being submitted by market participants. In some cases, however, RTM bids submitted by participants were not the same as the IFM bids submitted by the CAISO in the IFM. Figure 82 provides a comparison of energy bids for all resources within these LCAs used in the IFM in the base case scenario (December 9) and the market power scenario (December 11). As shown in Figure 82, a significantly greater amount of capacity was self-scheduled in the RTM in the December 11 market simulation than in the IFM for that operating day, while less capacity was bid at the $400/MW level. This change in RTM bids contributed to the lack of mitigation that occurred in the RTM under the December 11 scenario.

Figure 81. IFM Bids within Major Local Capacity Areas (December 9 and 11 Scenarios)

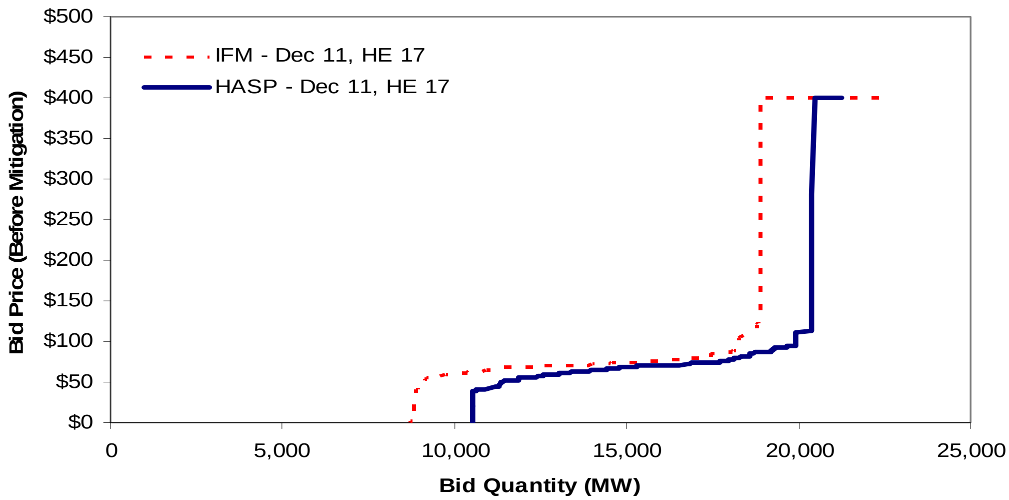


[21] As shown in Table 13, the portion of capacity economically withheld was extremely high in the San Diego LCA (56 percent), and relatively high in the Big Creek Ventura LCA (31 percent), but was relatively low in the Bay Area LCA (10 percent) and LA Basin (4 percent). The level of economic withholding within each LCA was initially designed to assume that about half of the capacity under the control of non-LSEs (i.e., excluding any capacity under tolling agreements or RMR contracts) was economically withheld. After initial market simulation results from initial tests in November indicated that very minimal mitigation would occur under these initial assumptions, the level of economic withholding in the December 11 scenario was increased to levels that would trigger a more significant level of mitigation in the San Diego LCA.

Table 13. IFM Bids within Major Local Capacity Areas (December 11 Scenario)

Area (LCA)	Self Scheduled and Minimum Load Energy (MW)	Capacity Bid at Base Case Price (Cost+20%)	Capacity Economically Withheld (MW)	Total Capacity Bid in IFM (MW)	Percent of Capacity Economically Withheld
LA Basin	4,398	5,266	364	10,028	4%
Bay Area	2,285	3,013	605	5,904	10%
Big Creek/Ventura	1,062	1,538	1,179	3,779	31%
San Diego	961	345	1,664	2,970	56%
Total	8,706	10,162	3,813	22,681	17%

Figure 82. IFM and HASP Bids within Major Local Capacity Areas (December 11 Scenario)



Market Simulation Results for IFM

Table 14 summarizes the hours in which LMPM procedures triggered bid mitigation in the IFM during the December 9-12 structured market simulation tests. As shown in Table 14:

- LMPM was triggered in the San Diego LCA during at least nine peak hours on all days. A more detailed discussion of mitigation in this LCA is provided later in this section.
- Minimal bid mitigation was triggered in all other LCAs, even under the December 11 bidding scenario.

Table 14. Occurrence of Local Market Power Mitigation in IFM

LCA	Structured Simulation Scenario			
	Dec 9 Base Case (Gas units bid at cost + 20%)	Dec 10 Load Underscheduling	Dec 11 Local Market Power	Dec 12 High Load/ Forecast Error (+5%)
Bay Area			HE 3-4	HE 16-17 and 23
Big Creek/Ventura		HE 8	HE 8-9	
LA Basin				
San Diego	HE 11-23	HE 13-22	HE 10-23	HE 7-22

Appendix A provides a detailed hourly summary of the number of units subject to mitigation in the IFM within each LCA on these four days, along with the total capacity of these units and other statistics relating to LMPM. Figure 83 lists the specific data included in the hourly summaries.

The following sections include examples of these hourly summaries – along with graphical examples of bid mitigation for specific hours in which LMPM bid mitigation was triggered in the San Diego LCA.

Figure 83. Description of Data in Table 15

Total Bids (MW). Total capacity bid into IFM in each hour by all resources within an LCA. Includes self-scheduled energy and non-gas units.

Dispatched MW - CC Run. Total capacity (MW) within an LCA dispatched in the Competitive Constraints (CC) run of the pre-market local market power mitigation procedures. CC run based on load forecast (instead of load bids in IFM) and unmitigated market bids of supply resources.

Dispatched MW - AC Run. Total capacity (MW) within an LCA dispatched in the All Constraints (AC) run of the pre-market local market power mitigation procedures. AC run is based on load forecast (instead of load bids in IFM) and unmitigated market bids of supply resources.

Dispatched MW – IFM. Total capacity (MW) within an LCA dispatched in the IFM, after any bid mitigation occurring from the CC and AC runs.

Mitigation – Units. Number of units within LCA subject to potential bid mitigation. A unit is subject to bid mitigation if dispatched in AC run at a higher level than in CC run.

Mitigation – MW. Total capacity of the units within an LCA subject to bid mitigation, i.e., the capacity greater than the unit's dispatch in the CC run up to the unit's maximum bid level (typically PMax). It should be noted that whether these units' market bids for this portion of their capacity was actually mitigated (i.e., lowered) depends on two factors. First, the units highest accepted bid in the CC run is a floor below which bid prices for additional capacity above this level cannot be lower. Second, the market bids are only lowered if they are greater than the unit's DEB for that portion of their capacity.

AC Run – Max Bid. Maximum bid within an LCA cleared in AC run (based on market bids prior to any mitigation), which can provide an indication of the potential impact of mitigation when compared to maximum bid dispatched in the IFM (after mitigation). However, maximum bid in AC run reflects fact that AC run is based on total forecasted demand, which is often less than demand clearing IFM. Negative bid prices representing negative bids placed on self-schedules and energy clearing AC run are omitted.

AC Run – Max LMP. Maximum LMP within an LCA cleared in AC run (based on market bids prior to any mitigation), which can provide an indication of the potential impact of mitigation when compared to maximum LMP in the (after mitigation). However, maximum LMP in AC run reflects fact that AC run is based on total forecasted demand, which is often less than demand clearing IFM. Negative LMPs typically reflect negative bids placed on self-schedules and capacity clearing AC run.

IFM – Max Bid. Maximum bid within an LCA cleared in IFM (after any mitigation). Can provide indication of whether high LMPs within LCA are set by resources within an LCA or system conditions.

IFM – Max LMP. Maximum LMP within an LCA in IFM.

Table 15. Summary of IFM and LMPM Results: San Diego LCA December 11, 2008 Market Simulation (With High MIP Gap of 12%)

Hour	Total Bids (MW)	Dispatched MW			Mitigation		AC Run		IFM	
		CCR	ACR	IFM	Units	MW	Max. Bid	Max. LMP	Max. Bid	Max. LMP
1	2,920	506	506	498				-$29	$31	$49
2	2,919	497	497	497				-$29	$31	$43
3	2,919	497	497	497				$39	$31	$36
4	2,919	497	497	497				$39	$31	$35
5	2,919	497	497	497				-$29	$31	$36
6	2,954	532	532	512				$44	$31	$43
7	2,969	547	547	527				$35	$31	$35
8	2,969	555	555	527				$49	$31	$49
9	2,969	593	593	535				$60	$57	$60
10	2,969	664	727	633	3	171	$92	$71	$68	$64
11	2,971	766	885	717	4	186	$92	$78	$70	$70
12	2,971	803	972	797	6	174	$92	$94	$73	$82
13	**2,971**	**848**	**1,055**	**871**	**5**	**326**	**$92**	**$93**	**$73**	**$84**
14	2,971	865	1,108	912	3	309	$92	$96	$92	$120
15	2,970	998	1,243	918	2	297	$89	$90	$119	$317
16	2,970	1,089	1,372	1,031	2	297	$94	$95	$400	$513
17	**2,970**	**1,096**	**1,427**	**1,110**	**6**	**407**	**$400**	**$457**	**$400**	**$554**
18	2,970	1,043	1,285	1,041	2	297	$89	$90	$400	$513
19	2,970	983	1,230	918	2	297	$89	$90	$119	$313
20	2,970	864	1,103	911	3	309	$92	$93	$92	$108
21	2,970	847	1,063	891	5	326	$92	$93	$85	$90
22	2,970	802	981	870	5	371	$92	$86	$73	$86
23	2,970	745	804	760	3	171	$92	$73	$68	$69
24	2,955	589	589	626				-$29	$57	$60

San Diego – December 11, Hour Ending 13

As shown in Table 15, during Hour Ending 13 of the December 11 local market power scenario:

- A total of 848 MW was dispatched from resources within the San Diego LCA during the initial CC run of the pre-IFM LMPM procedure.
- During the AC run of the pre-IFM LMPM procedure, a total of 1,055 MW was dispatched, triggering LMPM bid mitigation procedures.
- During the AC run, five units were dispatched above the amount of these units' dispatch level in the CC run. As a result, all remaining capacity from these units above the CC dispatch level (326 MW) was subject to bid mitigation prior to the actual IFM market run.[22]
- During the AC run, the highest market bid dispatched (prior to mitigation) equaled $92, with the highest LMP within the LCA equaling $93.
- In the IFM, a total of 871 MW from capacity within the San Diego LCA was dispatched. The highest market bid dispatched (after mitigation) equaled $73, with the highest LMP within the LCA equaling $84.[23]

Figure 84 provides a graphical illustration of LMPM bid mitigation and IFM results for this hour. As indicated in the legend of this figure:

- The yellow line represents the combined bid curves of all bids submitted in the IFM by all resources in the San Diego LCA during this hour (prior to any bid mitigation). This bid curve includes all the ~2,900 MW of resources in the LCA, including longer start units that may not be committed in the IFM. The zero-price (flat, leftmost) portion of this bid curve represents capacity of any self-scheduled units, as well as the minimum load energy of any non-self scheduled resources.
- The light blue line represents the combined bid curves of all resources dispatched in the AC run of the pre-IFM LMPM procedures (<u>prior</u> to any bid mitigation). This bid curve represents less capacity than the yellow line since it excludes any resources not committed in the AC run. Under the LMPM market design, only bids from resources clearing the AC run are included in the IFM market run.
- The red line represents the combined bid curves of all resources dispatched in the AC run of the pre-IFM LMPM procedures <u>after</u> any bid mitigation. As noted above, during this hour five units (with combined bid quantity above their CC dispatch level of 326 MW) were subject to bid mitigation. Thus the difference in the light blue and red lines represents the effect of bid mitigation on the overall bid curves used in the IFM.

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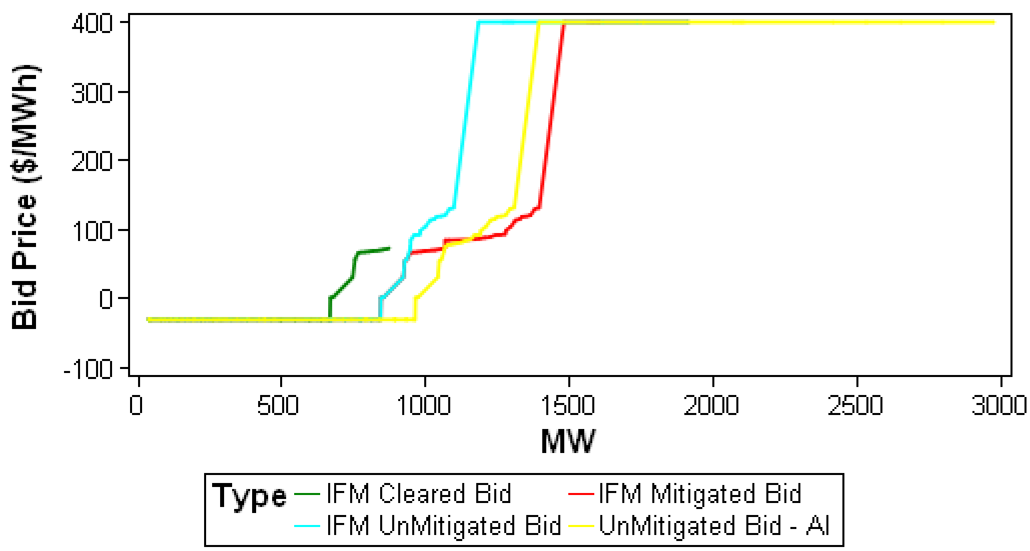
[22] For units with a dispatch in the CC run, their highest accepted bid is used as a floor below which their final IFM bid for any remaining capacity is not mitigated. Bid mitigation is then performed by taking the lower of a unit's market bid and their DEB for any remaining capacity (subject to this bid floor). In the base case market simulation, however, IFM market bids for gas-fired units always exceeded their DEBs, since initial IFM bids in the base scenario were set at marginal cost + 20 percent, while DEBs were set at marginal cost +10 percent.

[23] However, during this hour, since the quantity clearing the IFM in this hour (871 MW) was significantly less than the quantity dispatched in the AC run (1,055 MW), the highest prices of bids dispatched and LMPs in the AC cannot be directly compared to IFM bids and LMPs to assess LMPM effectiveness.

- Finally, the green (leftmost) line represents bids actually clearing the IFM market. As shown in Table 15, the quantity of capacity within the LCA clearing the IFM this hour (871 MW) was significantly lower than the quantity dispatched in the AC run (1,055 MW).

Figure 84. IFM Bid Mitigation – San Diego LCA

December 11, HE 13



San Diego – December 11, Hour Ending 17

Table 15 also provides a summary LMPM and IFM results for Hour Ending 17 of the December 11 local market power scenario for the San Diego LCA. Figure 85 provides a graphical summary of LMPM and IFM bids and dispatches for this hour.

As shown in Table 15 and Figure 85, during these hours, a $400 bid was dispatched in the IFM and the highest LMP in the San Diego LCA reached $554. However, a review of market results for this day indicates that these high LMPs on this day are not attributable to any failure of LMPM provisions. Instead, the high LMPs on this day within the San Diego LCA are attributable to the fact that the IFM software did not reach its target quality of solution threshold. As explained in a December 23 review of MRTU results with stakeholders:[24]

- On this day, the IFM solution reached within the initial solution time provided had an extremely high MIP Gap (12 percent), compared to a target level of less than 1 percent.[25]

[24] See *Quality of Solution – Pricing Review*, Mark Rothleder, MRTU Structured Simulation – Follow-up, December 23, 2008, slide 5-7, presentation Dec 23, 2008 http://www.caiso.com/20a6/20a67f452b390.pdf

[25] The MIP ("Mixed Integer Programming") Gap is the measure of the optimality of a solution (relative to a theoretical minimum that could be reached ignoring mixed integer constraints). The smaller the MIP Gap, the closer the solution is to this theoretical optimal level.

However, in order to complete the IFM market on a timeline that would allow participants to proceed with the real-time simulation tests being run during this period, the CAISO did not re-run the software allowing for additional solution time to reach a more optimal solution.

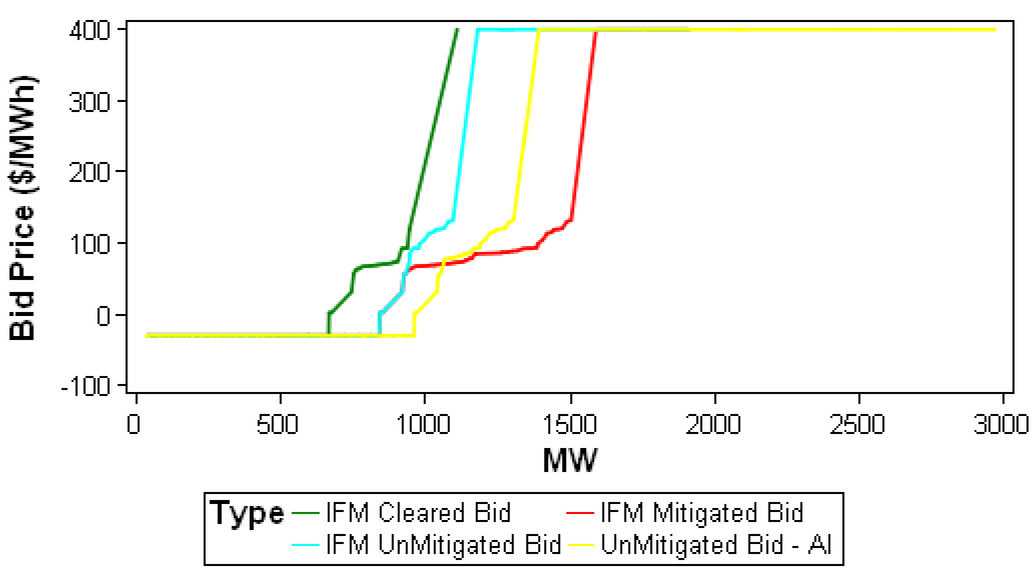
- Under this less optimal solution, a transmission constraint into the San Diego area (Miguel) was violated slightly during some hours, and had extremely high shadow prices ($660-$1,200) during Hours Ending 15-19.
- In addition, under this less optimal IFM solution, at least one Reliability Must Run (RMR) resource that was committed in the AC run was not committed in the IFM.
- Thus, under this less optimal solution, the IFM software had – in effect – violated the Miguel constraint (and incurred the resulting penalty price in the objective function), rather than committing an extra RMR unit within the San Diego area.
- After re-running the same IFM scenario off-line with additional solution time, the MIP Gap was reduced to expected levels (.13 percent).
- Under this more optimal solution, an additional RMR unit that was dispatched in the AC run was also dispatched in the IFM, with shadow prices for congestion on the Miguel constraint being lowered to approximately $73.

In order to avoid such situations after MRTU implementation, the CAISO has indicated it will continue to tune penalty prices used in the MRTU software and allow for sufficient solution time to meet target MIP Gap levels.

In addition, in light of the very significant market impacts that could result from high MIP Gap levels, DMM is specifically recommending that in the event a similar situation should occur under actual market operations, the CAISO should be prepared to extend the solution time of the market software and re-run the software prior to closing the IFM.

Figure 85. IFM Bid Mitigation – San Diego LCA

December 11, HE 17 (with High MIP Gap)



Market Simulation Results for HASP/RTM

LMPM was not triggered during any hour within any LCA during the structured market simulation tests. At least two factors contributed to these results:

- As previously noted, a significantly greater amount of capacity within these LCAs was self-scheduled in the RTM in the December 11 market simulation than in the IFM for that operating day, while less capacity was bid at the $400/MW level (see Figure 82).
- In addition, as discussed in Section III of this report, the relatively high prices observed in the HASP and RTM during the December 9-12 market simulation tests during some hours can be primarily attributed to *system-level* conditions, reflecting limitations of the amount of energy available to meet *overall system energy requirements*. Such conditions can tend to prevent LMPM provisions from being triggered by raising overall system energy prices and reducing the amount of additional energy dispatched from units within transmission constrained areas in the AC run (relative to the CC run) of the LMPM procedures performed prior to the hourly HASP/RTM run.

DMM will continue to test the LMPM procedures incorporated in the HASP/RTM model using bidding scenarios specifically designed to test these procedures in different transmission constrained areas.

Appendix A. Summary of IFM Local Market Power Mitigation Results for Major Local Capacity Areas

Market Simulation Trade Days December 9-12, 2008

Description of Data in Tables A-1 through A-16

Total Bids (MW). Total capacity bid into IFM during hour by all resources within LCA. Includes self-scheduled energy and non-gas units. *Note: Data for December 10 excludes some bids missing from database available for use in this analysis. Actual bid quantities are approximately equal to other days.*

Dispatched MW - CC Run. Total capacity (MW) within LCA dispatched in the Competitive Constraints (CC) run of the pre-market local market power mitigation procedures. CC run based on load forecast (instead of load bids in IFM) and unmitigated market bids of supply resources.

Dispatched MW - AC Run. Total capacity (MW) within LCA dispatched in the All Constraints (AC) run of the pre-market local market power mitigation procedures. AC run based on load forecast (instead of load bids in IFM) and unmitigated market bids of supply resources.

Dispatched MW – IFM. Total capacity (MW) within LCA dispatched in the IFM, after any bid mitigation occurring based on results of CC and AC runs.

Mitigation – Units. Number of units within LCA subject to potential bid mitigation. Unit is subject to bid mitigation if dispatched in AC run at a higher level than in CC run. *Note: In some hours, due to rounding of CC and AC dispatch totals, mitigation may occur when AC dispatch level is < 1 MW higher than AC dispatch level.*

Mitigation – MW. Total capacity of the units within LCA subject to bid mitigation, i.e., the capacity greater than the units dispatch in the CC run up to the units maximum bid level (typically PMax). It should be noted that whether these units' market bids for this portion of their capacity was actually mitigated (i.e., lowered) depends on two factors. First, the units highest accepted bid in the CC run is a floor below which bid prices for additional capacity above this level cannot be lower. Second, the market bids are only lowered if they are greater than the unit's DEB for that portion of their capacity.

AC Run – Max Bid. Maximum bid within LCA cleared in AC run (based on market bids prior to any mitigation). Can provide an indication of the potential impact of mitigation when compared to maximum bid dispatched in IFM (after mitigation). However, maximum bid in AC run reflects fact that AC run is based on total forecasted demand, which is often less than demand clearing IFM. Negative bid prices representing negative bids placed on self-schedules and capacity clearing AC run excluded.

AC Run – Max LMP. Maximum LMP within LCA cleared in AC run (based on market bids prior to any mitigation). Can provide an indication of the potential impact of mitigation when compared to maximum LMP in the (after mitigation). However, maximum LMP in AC run reflects fact that AC run is based on total forecasted demand, which is often less than demand clearing IFM. Negative LMPs reflect represent negative bids placed on self-schedules, and capacity clearing AC run.

IFM – Max Bid. Maximum bid within LCA cleared in IFM (after any mitigation). Can provide indication of whether high LMPs within LCA are set by resources within LCA or system conditions.

IFM – Max LMP. Maximum LMP within LCA in IFM.

Table A-1. Summary of IFM and LMPM Results: Bay Area LCA

December 9, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	AC Run	IFM	Mitigation Units	MW	AC Run Max. Bid	Max. LMP	IFM Max. Bid	Max. LMP
1	5,921	1,804	1,804	1,781	0			-$31	$77	$56
2	5,882	1,352	1,352	1,112	0			$48	$2	$49
3	5,862	1,152	1,152	962	0			$32	$2	$42
4	5,851	1,139	1,139	949	0			-$32	$2	$38
5	5,830	1,112	1,112	922	0			-$32	$2	$38
6	5,835	1,138	1,138	922	0			-$32	$2	$49
7	5,737	1,027	1,027	837	0			-$26	$2	$36
8	5,739	1,066	1,066	1,066	0			$52	$53	$50
9	5,745	1,847	1,847	1,655	0		$60	$63	$60	$61
10	5,753	2,436	2,436	2,305	0		$63	$69	$63	$66
11	5,769	2,764	2,764	2,663	0			-$56	$74	$71
12	5,785	3,368	3,368	2,992	0			-$23	$72	$73
13	5,852	4,020	4,020	3,149	0			-$64	$73	$73
14	5,889	4,562	4,562	3,409	0			-$180	$75	$77
15	5,896	4,828	4,795	4,149	0			-$43	$75	$81
16	5,887	5,097	5,066	4,395	0			-$41	$83	$86
17	5,905	5,083	5,054	4,406	0			-$42	$83	$89
18	5,922	5,045	5,014	4,386	0			-$234	$80	$86
19	5,893	4,913	4,913	4,276	0			-$65	$75	$81
20	5,903	4,579	4,579	3,961	0			-$63	$75	$80
21	5,886	4,351	4,351	3,254	0			-$69	$74	$80
22	5,863	4,218	4,218	3,147	0			-$89	$74	$77
23	5,956	3,489	3,489	3,022	0			$14	$74	$74
24	5,923	2,859	2,859	2,800	0			-$32	$72	$69

Table A-2. Summary of IFM and LMPM Results: Bay Area LCA
December 10, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	5,237	1,902	1,902	2,026	0			$59	$72	$54
2	5,200	1,372	1,372	1,879	0			-$26	$72	$50
3	5,180	1,287	1,287	1,667	0			-$32	$60	$38
4	5,169	1,274	1,274	1,524	0			$42	$2	$38
5	5,151	1,265	1,265	1,250	0			-$26	$2	$38
6	5,156	1,295	1,295	1,295	0			-$32	$72	$48
7	5,068	1,180	1,180	1,165	0			-$31	$2	$37
8	5,060	1,466	1,466	1,201	0			$53	$53	$51
9	5,062	2,266	2,266	1,246	0			-$27	$77	$56
10	5,070	2,675	2,675	1,232	0			-$26	$77	$53
11	5,078	3,195	3,195	1,742	0			-$27	$77	$59
12	5,093	4,177	4,177	2,429	0		$73	-$28	$77	$63
13	5,161	4,144	4,144	2,771	0			-$44	$77	$65
14	5,196	4,564	4,564	2,997	0			-$43	$77	$67
15	5,202	4,959	4,926	2,960	0		$83	-$62	$63	$72
16	5,199	5,049	5,018	3,091	0		$85	-$53	$74	$75
17	5,222	5,075	5,046	3,117	0		$72	-$48	$74	$76
18	5,239	5,078	5,047	3,126	0		$75	-$55	$74	$75
19	5,207	4,938	4,904	3,081	0		$72	-$63	$74	$73
20	5,216	4,662	4,662	2,992	0		$74	-$43	$63	$70
21	5,197	4,320	4,320	2,571	0		$76	$40	$63	$69
22	5,180	4,173	4,173	2,554	0		$74	$14	$63	$70
23	5,273	3,603	3,603	2,529	0		$74	-$27	$63	$67
24	5,240	2,623	2,623	2,123	0			$63	$60	$59

Table A-3. Summary of IFM and LMPM Results: Bay Area LCA
December 11, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	5,919	1,944	1,944	2,151	0			-$31	$400	$53
2	5,882	1,222	1,222	1,651	0			-$31	$400	$48
3	5,862	1,152	1,152	1,212	1	371	$49	$43	$2	$48
4	5,851	1,139	1,139	949	1	371	$49	$43	$2	$48
5	5,833	1,115	1,115	925	0			-$32	$2	$45
6	5,838	1,140	1,140	925	0			$48	$2	$54
7	5,751	1,030	1,030	840	0			$37	$2	$37
8	5,742	1,130	1,130	826	0			$52	$2	$53
9	5,744	1,876	1,876	1,063	0		$60	$63	$53	$65
10	5,752	2,515	2,515	1,712	0			-$103	$63	$66
11	5,760	2,835	2,835	2,119	0			-$96	$63	$70
12	5,775	3,334	3,334	2,591	0			$47	$71	$73
13	5,843	3,560	3,560	2,842	0			-$64	$74	$73
14	5,878	3,819	3,819	3,046	0			-$77	$74	$78
15	5,884	4,089	4,089	3,293	0			$27	$88	$96
16	5,881	4,167	4,167	3,292	0			$54	$88	$116
17	5,904	4,193	4,193	3,335	0			$89	$88	$124
18	5,921	4,216	4,216	3,358	0			$29	$88	$115
19	5,889	4,112	4,112	3,329	0			$29	$88	$98
20	5,898	3,910	3,910	3,157	0			-$25	$75	$79
21	5,879	3,529	3,529	2,696	0			-$68	$75	$82
22	5,862	3,467	3,467	2,646	0			-$87	$74	$78
23	5,955	3,037	3,037	2,660	0			-$102	$74	$73
24	5,922	2,783	2,783	2,593	0			-$31	$73	$65

Table A-4. Summary of IFM and LMPM Results: Bay Area LCA

December 12, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	5,920	1,589	1,589	1,875	0			$59	$63	$52
2	5,882	982	982	1,580	0			$53	$60	$42
3	5,860	961	961	1,401	0			$6	$2	$39
4	5,850	947	947	1,137	0			-$27	$2	$44
5	5,828	921	921	1,111	0			-$27	$2	$44
6	5,836	923	923	1,113	0			-$32	$2	$46
7	5,753	837	837	1,027	0			-$28	$2	$36
8	5,743	821	821	1,011	0			-$28	$2	$48
9	5,745	1,317	1,312	1,247	0			-$28	$53	$60
10	5,750	2,158	2,158	1,758	0			-$28	$63	$67
11	5,764	2,756	2,756	2,308	0			-$101	$74	$70
12	5,784	3,102	3,102	2,673	0			-$90	$74	$69
13	5,847	3,521	3,521	2,958	0			-$69	$74	$71
14	5,881	3,979	3,979	3,155	0			-$64	$75	$74
15	5,887	4,170	4,137	3,394	0			-$267	$75	$78
16	5,878	4,160	4,141	3,694	1	96	$88	$108	$75	$83
17	5,896	4,181	4,162	3,718	1	96	$88	$105	$80	$85
18	5,914	4,203	4,172	3,734	0			-$126	$75	$82
19	5,886	4,116	4,082	3,505	0			-$303	$75	$79
20	5,896	3,737	3,737	3,111	0			-$64	$75	$76
21	5,878	3,373	3,373	2,676	0			-$68	$71	$75
22	5,865	3,241	3,241	2,705	0			-$59	$74	$75
23	5,953	2,969	2,985	2,688	2	178	$74	$77	$74	$71
24	5,923	2,569	2,569	2,535	0			-$31	$73	$66

Table A-5. Summary of IFM and LMPM Results: Ventura/Big Creek LCA
December 9, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	4,580	1,575	1,575	1,575	0			-$26	$46	$53
2	4,592	1,434	1,434	1,434	0			$46	$21	$45
3	4,596	1,438	1,438	1,438	0			$23	$21	$37
4	4,599	1,441	1,441	1,441	0			-$25	$21	$36
5	4,602	1,444	1,444	1,444	0			-$25	$21	$36
6	4,602	1,444	1,444	1,444	0			-$25	$21	$44
7	4,657	1,499	1,499	1,499	0			-$21	$21	$34
8	4,667	1,508	1,508	1,508	0			$49	$21	$46
9	4,702	1,950	1,950	1,757	0			$59	$56	$58
10	4,638	2,417	2,417	1,883	0		$59	$64	$59	$61
11	4,716	2,870	2,870	2,515	0			-$46	$64	$66
12	4,709	3,357	3,357	2,703	0			-$18	$68	$68
13	4,694	3,362	3,362	2,707	0			-$54	$69	$69
14	4,672	3,642	3,642	2,785	0			-$155	$71	$72
15	4,644	3,805	3,805	2,910	0			-$35	$73	$76
16	4,621	4,069	4,069	3,217	0			-$34	$76	$80
17	4,600	4,093	4,093	3,281	0			-$35	$78	$81
18	4,560	3,992	3,992	3,201	0			-$203	$76	$79
19	4,539	3,849	3,849	2,962	0			-$55	$73	$75
20	4,539	3,501	3,501	2,652	0			-$53	$71	$73
21	4,549	3,460	3,460	2,693	0			-$58	$72	$72
22	4,571	3,138	3,138	2,487	0			-$77	$67	$70
23	4,541	2,898	2,898	2,358	0			$14	$66	$67
24	4,528	2,509	2,509	2,263	0			-$27	$59	$64

Table A-6. Summary of IFM and LMPM Results: Ventura/Big Creek LCA

December 10, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	4,138	1,702	1,702	1,762	0			$56	$59	$49
2	4,150	1,434	1,434	1,574	0			-$21	$59	$48
3	4,154	1,438	1,438	1,438	0			-$26	$21	$36
4	4,157	1,441	1,441	1,441	0			$40	$21	$36
5	4,160	1,444	1,444	1,444	0			-$21	$21	$36
6	4,160	1,444	1,444	1,444	0			-$26	$21	$45
7	4,215	1,499	1,499	1,499	0			-$25	$21	$35
8	4,225	1,528	1,529	1,662	1	222	$46	$50	$21	$47
9	4,260	1,987	1,987	1,544	0			-$22	$21	$50
10	4,196	2,431	2,431	1,480	0			-$21	$21	$50
11	4,274	2,806	2,806	1,693	0			-$22	$46	$56
12	4,267	3,052	3,052	2,097	0			-$23	$59	$61
13	4,252	3,205	3,205	2,174	0			-$37	$59	$63
14	4,230	3,673	3,673	2,360	0			-$36	$59	$65
15	4,202	4,016	4,016	2,603	0		$75	-$53	$69	$70
16	4,179	4,092	4,092	2,657	0		$82	-$44	$71	$73
17	4,158	4,071	4,071	2,696	0		$82	-$40	$73	$75
18	4,118	3,992	3,992	2,596	0		$76	-$47	$71	$73
19	4,097	3,841	3,841	2,515	0		$76	-$54	$69	$71
20	4,097	3,362	3,362	2,395	0		$46	-$36	$66	$67
21	4,107	3,261	3,261	2,345	0		$46	$38	$64	$65
22	4,129	2,953	2,953	2,056	0		$46	$15	$64	$65
23	4,099	2,767	2,767	2,020	0		$46	-$24	$64	$63
24	4,086	2,453	2,449	1,707	0		$46	$59	$59	$55

Table A-7. Summary of IFM and LMPM Results: Ventura/Big Creek LCA December 11, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	4,580	1,675	1,675	1,522	0			-$26	$56	$51
2	4,592	1,434	1,434	1,434	0			-$25	$21	$45
3	4,596	1,438	1,438	1,438	0			$42	$21	$38
4	4,599	1,441	1,441	1,441	0			$42	$21	$36
5	4,602	1,444	1,444	1,444	0			-$25	$56	$37
6	4,602	1,444	1,444	1,444	0			$47	$56	$44
7	4,657	1,499	1,499	1,499	0			$36	$21	$35
8	4,667	1,508	1,509	1,662	1	222	$46	$50	$21	$50
9	4,702	1,960	1,960	1,817	1	450	$59	$61	$56	$61
10	4,638	2,138	2,138	2,078	0			-$85	$64	$62
11	4,716	2,634	2,634	2,195	0			-$79	$67	$66
12	4,709	2,988	2,988	2,420	0			$46	$69	$71
13	4,694	2,972	2,972	2,572	0			-$54	$70	$70
14	4,672	3,051	3,051	2,780	0			-$66	$70	$76
15	4,644	3,023	3,023	2,888	0			$26	$70	$99
16	4,621	3,000	3,000	2,922	0			$46	$70	$121
17	4,600	2,980	2,980	2,901	0			$85	$70	$129
18	4,560	2,939	2,939	2,861	0			$28	$70	$121
19	4,539	2,918	2,918	2,840	0			$28	$70	$99
20	4,539	2,896	2,896	2,764	0			-$20	$70	$74
21	4,549	2,929	2,929	2,774	0			-$58	$70	$74
22	4,571	2,928	2,928	2,796	0			-$76	$70	$72
23	4,541	2,766	2,766	2,371	0			-$88	$67	$67
24	4,528	2,233	2,233	2,043	0			-$27	$63	$61

Table A-8. Summary of IFM and LMPM Results: Ventura/Big Creek LCA December 12, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	4,580	1,645	1,645	1,492	0			$56	$63	$49
2	4,592	1,484	1,484	1,484	0			$49	$21	$39
3	4,596	1,488	1,488	1,488	0			-$9	$21	$36
4	4,599	1,491	1,491	1,491	0			-$28	$21	$36
5	4,602	1,494	1,494	1,494	0			-$28	$21	$36
6	4,602	1,494	1,494	1,494	0			-$25	$21	$42
7	4,657	1,549	1,549	1,549	0			-$23	$21	$33
8	4,667	1,558	1,558	1,558	0			-$22	$21	$44
9	4,702	1,830	1,830	1,663	0			-$23	$46	$56
10	4,638	2,324	2,324	1,803	0			-$23	$63	$62
11	4,716	2,976	2,976	2,442	0			-$83	$63	$65
12	4,709	3,376	3,376	2,665	0			-$74	$68	$66
13	4,694	3,497	3,497	2,816	0			-$58	$68	$68
14	4,672	3,748	3,748	2,838	0			-$54	$67	$70
15	4,644	4,206	4,206	3,284	0			-$229	$74	$75
16	4,621	4,304	4,304	3,415	0			$59	$74	$79
17	4,600	4,288	4,288	3,514	0			$76	$76	$81
18	4,560	4,182	4,182	3,354	0			-$107	$74	$78
19	4,539	4,019	4,019	3,207	0			-$262	$72	$75
20	4,539	3,623	3,623	2,845	0			-$54	$69	$71
21	4,549	3,672	3,672	2,625	0			-$57	$69	$71
22	4,571	3,292	3,292	2,547	0			-$50	$69	$70
23	4,541	2,657	2,657	2,337	0			$66	$64	$66
24	4,528	2,263	2,263	2,010	0			-$27	$59	$61

Table A-9. Summary of IFM and LMPM Results: LA Basin

December 9, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	9,825	3,898	3,898	3,888	0			-$30	$58	$53
2	9,798	3,716	3,716	3,716	0			$45	$58	$45
3	9,850	3,755	3,755	3,735	0			$23	$47	$37
4	9,853	3,649	3,649	3,652	0			-$30	$34	$36
5	9,852	3,690	3,690	3,650	0			-$30	$34	$36
6	9,851	3,690	3,690	3,762	0			-$30	$58	$44
7	9,845	3,640	3,640	3,756	0			-$26	$58	$34
8	9,856	3,830	3,830	3,800	0		$47	$50	$58	$47
9	9,861	3,975	3,975	3,991	0		$65	$60	$67	$59
10	9,854	4,295	4,295	4,247	0		$47	$65	$68	$62
11	9,847	4,667	4,667	4,534	0		$58	$14	$69	$67
12	9,839	5,391	5,391	4,842	0		$58	$34	$71	$71
13	9,862	5,754	5,754	5,071	0			$16	$71	$71
14	9,876	5,924	5,924	5,630	0			-$36	$73	$75
15	9,872	6,475	6,475	5,925	0			$37	$81	$79
16	9,867	6,509	6,509	6,004	0			$39	$81	$84
17	9,866	6,541	6,541	6,023	0			$37	$81	$86
18	9,855	6,412	6,412	5,980	0			-$55	$81	$84
19	9,866	6,408	6,408	5,934	0			$16	$81	$78
20	9,865	6,302	6,302	5,564	0			$17	$73	$76
21	9,816	6,137	6,137	5,276	0			$12	$79	$75
22	9,774	5,503	5,503	5,215	0			-$9	$79	$73
23	9,772	5,144	5,144	4,655	0			$40	$69	$69
24	9,749	4,547	4,547	4,413	0			-$30	$68	$65

Table A-10. Summary of IFM and LMPM Results: LA Basin LCA

December 10, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	AC Run	IFM	Mitigation Units	MW	AC Run Max. Bid	Max. LMP	IFM Max. Bid	Max. LMP
1	7,150	4,039	4,039	3,930	0		$58	$56	$58	$50
2	7,123	3,844	3,844	3,524	0		$58	-$25	$58	$48
3	7,175	3,804	3,804	3,544	0			-$30	$58	$36
4	7,178	3,712	3,712	3,452	0			$39	$34	$36
5	7,177	3,751	3,751	3,451	0			-$25	$34	$36
6	7,176	3,750	3,750	3,490	0			-$30	$41	$45
7	7,170	3,704	3,704	3,444	0			-$30	$34	$36
8	7,181	3,938	3,938	3,496	0			$51	$41	$48
9	7,186	4,099	4,099	3,625	0			-$26	$54	$51
10	7,179	4,509	4,509	3,693	0			-$25	$58	$51
11	7,172	4,911	4,911	3,789	0			-$26	$67	$57
12	7,164	5,495	5,495	4,028	0		$85	-$27	$67	$62
13	7,187	5,859	5,859	4,178	0			-$22	$67	$65
14	7,201	6,316	6,316	4,304	0		$71	-$20	$67	$66
15	7,197	6,352	6,352	4,435	0		$71	-$34	$79	$72
16	7,192	6,461	6,461	4,553	0		$71	-$24	$81	$76
17	7,191	6,460	6,460	4,580	0		$71	-$20	$81	$78
18	7,180	6,384	6,384	4,573	0			-$28	$81	$76
19	7,191	6,384	6,384	4,467	0			-$35	$81	$73
20	7,190	6,281	6,281	4,307	0			-$21	$79	$69
21	7,141	6,213	6,213	4,226	0		$71	$44	$79	$67
22	7,099	5,710	5,710	4,176	0		$71	$18	$67	$67
23	7,097	5,049	5,049	4,003	0			-$27	$67	$64
24	7,074	4,577	4,577	3,561	0			$59	$58	$56

Table A-11. Summary of IFM and LMPM Results: LA Basin LCA

December 11, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	AC Run	IFM	Mitigation Units	MW	AC Run Max. Bid	Max. LMP	IFM Max. Bid	Max. LMP
1	9,987	3,778	3,778	3,831	0		$73	-$30	$112	$51
2	9,960	3,554	3,554	3,516	0			-$30	$72	$45
3	10,012	3,511	3,511	3,557	0			$41	$47	$38
4	10,015	3,514	3,514	3,554	0			$41	$47	$37
5	10,014	3,512	3,512	3,547	0			-$30	$47	$37
6	10,013	3,512	3,512	3,512	0			$46	$41	$45
7	10,007	3,463	3,463	3,543	0			$36	$47	$36
8	10,018	3,638	3,638	3,662	0		$47	$51	$58	$50
9	10,023	3,433	3,433	3,675	0			$62	$67	$62
10	10,016	4,106	4,106	3,991	0			-$22	$81	$63
11	10,009	4,680	4,680	4,454	0			-$15	$72	$67
12	10,001	5,720	5,720	4,831	0			$67	$81	$75
13	10,024	6,431	6,431	5,024	0			$9	$81	$76
14	10,038	6,906	6,906	5,451	0			$3	$81	$95
15	10,034	7,731	7,731	6,272	0			$55	$87	$197
16	10,028	7,997	7,997	6,923	0			$69	$112	$296
17	10,028	8,032	8,032	6,924	0			$256	$112	$319
18	10,017	7,940	7,940	6,903	0			$56	$112	$296
19	10,028	7,549	7,549	6,693	0			$56	$90	$195
20	10,027	7,120	7,120	5,871	0			$30	$81	$89
21	9,977	7,074	7,074	5,443	0			$7	$81	$80
22	9,936	6,256	6,256	5,001	0			-$7	$81	$78
23	9,934	5,399	5,399	4,656	0			-$21	$81	$69
24	9,911	4,392	4,392	4,358	0			-$30	$70	$62

Table A-12. Summary of IFM and LMPM Results: LA Basin LCA
December 12, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	9,825	3,866	3,866	3,866	0			$55	$69	$49
2	9,798	3,732	3,732	3,653	0			$49	$58	$39
3	9,850	3,711	3,711	3,724	0			-$9	$58	$36
4	9,853	3,611	3,611	3,703	0			-$33	$58	$36
5	9,852	3,650	3,650	3,610	0			-$33	$34	$36
6	9,851	3,649	3,649	3,639	0			-$30	$41	$42
7	9,845	3,600	3,600	3,600	0			-$27	$2	$33
8	9,856	3,775	3,775	3,724	0			-$27	$47	$45
9	9,861	3,826	3,826	3,815	0			-$28	$67	$56
10	9,854	3,742	3,742	3,941	0			-$27	$69	$63
11	9,847	4,135	4,135	4,334	0			-$20	$81	$66
12	9,839	4,790	4,790	4,580	0			-$9	$79	$68
13	9,862	5,275	5,275	4,708	0			$12	$81	$70
14	9,876	5,736	5,736	5,236	0			$16	$73	$72
15	9,872	5,902	5,902	5,504	0			-$70	$79	$77
16	9,867	6,203	6,203	5,725	0			$95	$81	$82
17	9,866	6,327	6,327	5,756	0			$98	$81	$84
18	9,855	6,253	6,253	5,713	0			-$2	$81	$81
19	9,866	6,138	6,138	5,617	0			-$87	$79	$77
20	9,865	6,092	6,092	5,314	0			$16	$73	$73
21	9,816	5,930	5,930	5,013	0			$13	$71	$73
22	9,774	5,555	5,555	4,863	0			$16	$81	$72
23	9,772	4,803	4,803	4,532	0			$69	$79	$68
24	9,749	4,248	4,248	4,187	0			-$30	$79	$62

Table A-13. Summary of IFM and LMPM Results: San Diego LCA
December 9, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	2,920	566	566	598	0			-$29	$70	$51
2	2,919	517	517	517	0			$44	$31	$43
3	2,919	517	517	517	0			$22	$31	$36
4	2,919	517	517	517	0			-$29	$31	$34
5	2,919	497	497	517	0			-$29	$31	$34
6	2,954	532	532	552	0			-$29	$31	$42
7	2,969	547	547	567	0			-$25	$31	$33
8	2,969	547	547	567	0			$48	$31	$45
9	2,969	622	622	575	0			$59	$57	$57
10	2,969	809	809	788	0			$64	$70	$60
11	2,971	885	970	868	5	85	$92	$93	$70	$65
12	2,971	1,178	1,234	1,041	6	56	$92	$98	$70	$70
13	2,971	1,220	1,316	1,185	8	134	$111	$109	$70	$72
14	2,971	1,340	1,471	1,264	7	132	$111	$135	$75	$78
15	2,970	1,493	1,653	1,581	7	188	$113	$129	$82	$84
16	2,970	1,588	1,792	1,744	8	218	$113	$130	$87	$92
17	2,970	1,608	1,832	1,800	9	254	$113	$129	$88	$95
18	2,970	1,563	1,731	1,784	7	188	$113	$161	$87	$91
19	2,970	1,411	1,554	1,657	7	188	$111	$111	$82	$83
20	2,970	1,251	1,383	1,472	9	150	$111	$110	$77	$79
21	2,970	1,241	1,333	1,491	9	98	$99	$105	$77	$77
22	2,970	1,160	1,220	1,149	3	67	$85	$86	$70	$74
23	2,970	884	895	847	2	18	$70	$70	$70	$67
24	2,955	729	729	729	0			-$29	$57	$63

Table A-14. Summary of IFM and LMPM Results: San Diego LCA December 10, 2008 IFM Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	2,174	526	526	518	0		$57	$54	$31	$48
2	2,173	517	517	517	0			-$24	$31	$46
3	2,173	517	517	517	0			-$29	$31	$34
4	2,173	517	517	517	0			$38	$31	$34
5	2,173	517	517	517	0			-$24	$31	$34
6	2,208	552	552	552	0			-$30	$31	$43
7	2,223	547	547	547	0			-$30	$31	$35
8	2,223	600	600	527	0			$49	$31	$46
9	2,223	600	600	527	0			-$26	$31	$49
10	2,223	825	825	557	0			-$24	$31	$50
11	2,225	1,021	1,021	631	0			-$26	$54	$55
12	2,225	1,222	1,222	687	0			-$26	$57	$60
13	2,225	1,181	1,214	725	5	41	$76	$93	$57	$62
14	2,225	1,269	1,322	829	6	63	$76	$93	$70	$64
15	2,224	1,573	1,627	1,131	5	60	$70	$110	$70	$72
16	2,224	1,678	1,737	1,202	5	62	$70	$119	$76	$80
17	2,224	1,712	1,789	1,199	5	114	$70	$123	$76	$81
18	2,224	1,658	1,712	1,212	5	62	$70	$111	$76	$79
19	2,224	1,461	1,533	1,112	6	77	$70	$109	$70	$75
20	2,224	1,241	1,292	914	6	56	$76	$93	$70	$67
21	2,224	1,241	1,256	828	2	18	$69	$71	$70	$64
22	2,224	1,160	1,161	828	1	10	$69	$69	$70	$64
23	2,224	904	904	800	0			-$26	$70	$61
24	2,209	833	833	531	0			$42	$70	$54

Table A-15. Summary of IFM and LMPM Results: San Diego LCA

December 11, 2008 IFM Market Simulation (with High MIP Gap Solution)

Hour	Total Bids (MW)	Dispatched MW CC Run	AC Run	IFM	Mitigation Units	MW	AC Run Max. Bid	Max. LMP	IFM Max. Bid	Max. LMP
1	2,920	506	506	498	0			-$29	$31	$49
2	2,919	497	497	497	0			-$29	$31	$43
3	2,919	497	497	497	0			$39	$31	$36
4	2,919	497	497	497	0			$39	$31	$35
5	2,919	497	497	497	0			-$29	$31	$36
6	2,954	532	532	512	0			$44	$31	$43
7	2,969	547	547	527	0			$35	$31	$35
8	2,969	555	555	527	0			$49	$31	$49
9	2,969	593	593	535	0			$60	$57	$60
10	2,969	664	727	633	3	171	$92	$71	$68	$64
11	2,971	766	885	717	4	186	$92	$78	$70	$70
12	2,971	803	972	797	6	174	$92	$94	$73	$82
13	2,971	848	1,055	871	5	326	$92	$93	$73	$84
14	2,971	865	1,108	912	3	309	$92	$96	$92	$120
15	2,970	998	1,243	918	2	297	$89	$90	$119	$317
16	2,970	1,089	1,372	1,031	2	297	$94	$95	$400	$513
17	2,970	1,096	1,427	1,110	6	407	$400	$457	$400	$554
18	2,970	1,043	1,285	1,041	2	297	$89	$90	$400	$513
19	2,970	983	1,230	918	2	297	$89	$90	$119	$313
20	2,970	864	1,103	911	3	309	$92	$93	$92	$108
21	2,970	847	1,063	891	5	326	$92	$93	$85	$90
22	2,970	802	981	870	5	371	$92	$86	$73	$86
23	2,970	745	804	760	3	171	$92	$73	$68	$69
24	2,955	589	589	626	0			-$29	$57	$60

Table A-16. Summary of IFM and LMPM Results: San Diego LCA December 12, 2008 Market Simulation

Hour	Total Bids (MW)	Dispatched MW CC Run	Dispatched MW AC Run	Dispatched MW IFM	Mitigation Units	Mitigation MW	AC Run Max. Bid	AC Run Max. LMP	IFM Max. Bid	IFM Max. LMP
1	2,920	506	506	498	0			$54	$31	$47
2	2,919	505	505	497	0			$47	$31	$38
3	2,919	497	497	497	0			-$9	$31	$34
4	2,919	497	497	497	0			-$32	$31	$34
5	2,919	505	505	497	0			-$32	$31	$34
6	2,954	532	532	532	0			-$29	$31	$41
7	2,969	527	547	527	1	300		-$27	$31	$32
8	2,969	580	600	527	1	300		-$26	$31	$43
9	2,969	580	600	545	1	300		-$27	$70	$55
10	2,969	834	854	732	1	300		-$27	$70	$60
11	2,971	947	1,028	832	7	525	$92	$75	$70	$64
12	2,971	1,220	1,281	851	5	345	$92	$86	$70	$66
13	2,971	1,260	1,360	970	9	381	$99	$105	$70	$71
14	2,971	1,310	1,454	1,164	8	432	$111	$109	$70	$73
15	2,970	1,623	1,876	1,313	9	497	$113	$166	$79	$79
16	2,970	1,712	2,145	1,527	13	585	$113	$114	$85	$87
17	2,970	1,712	2,193	1,559	13	585	$113	$115	$85	$90
18	2,970	1,678	1,961	1,553	12	608	$113	$145	$84	$86
19	2,970	1,563	1,736	1,372	7	188	$113	$172	$79	$81
20	2,970	1,280	1,423	1,298	9	150	$111	$109	$74	$74
21	2,970	1,290	1,384	1,292	8	141	$99	$106	$74	$73
22	2,970	1,220	1,276	1,206	6	56	$92	$102	$70	$72
23	2,970	1,117	1,117	886	0			$62	$70	$66
24	2,955	845	845	729	0			-$29	$57	$60