California Independent System Operator Corporation

California ISO

Q2 2012 Report on Market Issues and Performance

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Executive summary

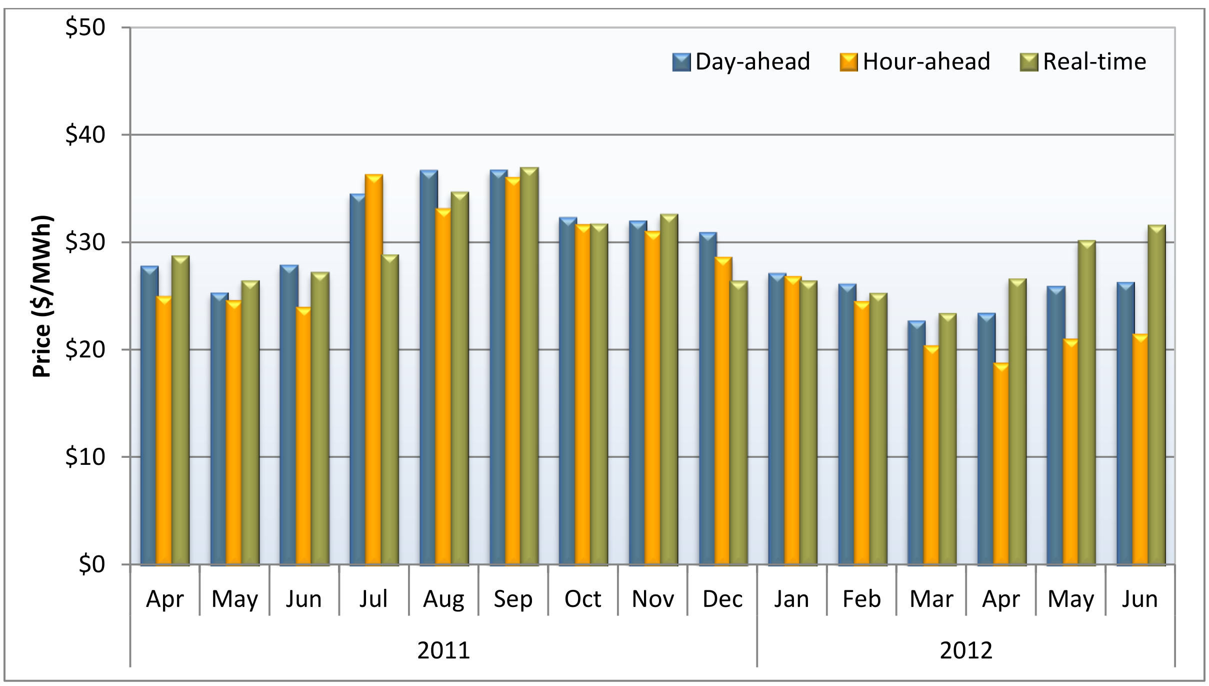
This report provides an overview of general market performance during the second quarter of 2012 (April – June) by the Department of Market Monitoring (DMM).

Energy market performance

- The day-ahead integrated forward market was stable and competitive. Average day-ahead energy prices continued to be approximately equal to benchmark prices that DMM estimates would occur under highly competitive conditions. Although real-time prices exceeded day-ahead prices in the second quarter, the real-time market continues to account for a very small portion of the wholesale market, so that overall market wholesale costs continue to be highly competitive.

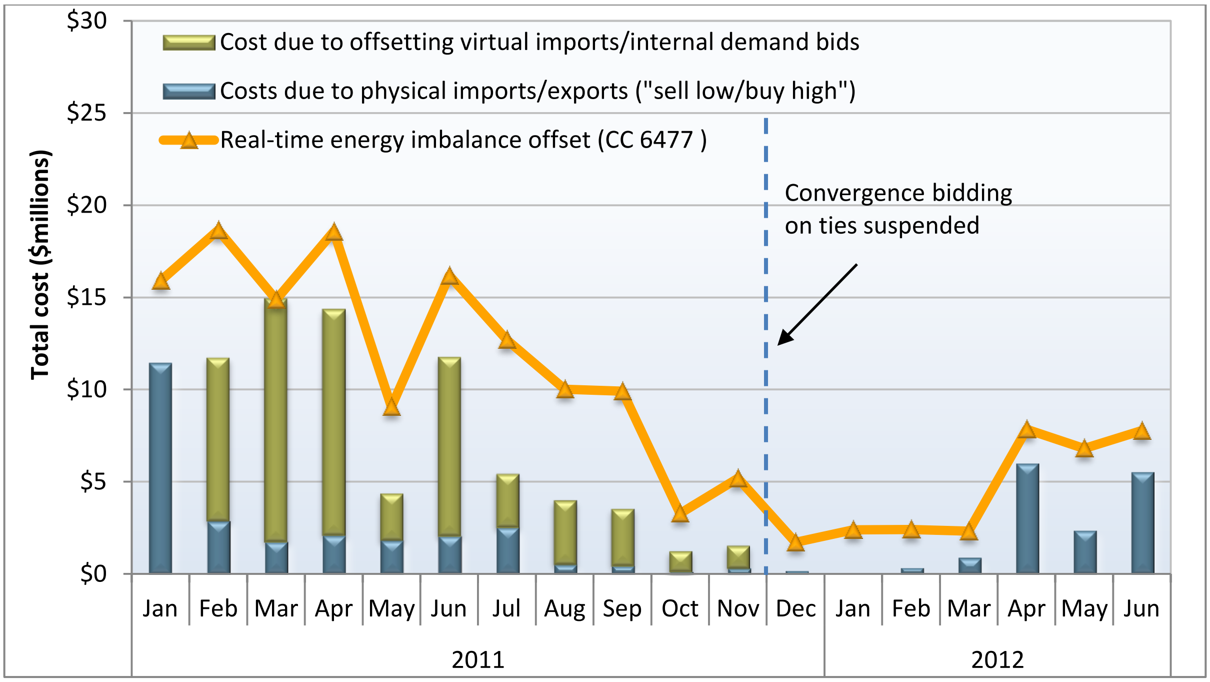
- Average real-time prices exceeded day-ahead and hour-ahead prices during the quarter, reversing a trend of improved price convergence that occurred in recent quarters (see Figure E.1). This price divergence was driven largely by an increase in the frequency of real-time price spikes. Many of these price spikes continue to be caused by brief limitations in upward ramping capacity. In the second quarter, congestion within the ISO system also caused additional price spikes in the real-time market.

Figure E.1 Average monthly system marginal energy prices (all hours)



- Real-time energy imbalance offset costs totaled $22 million in the second quarter (See Figure E.2). This is the highest quarterly value since the third quarter of 2011 when convergence bidding at the inter-ties was still allowed and contributed to these imbalance costs.[1] DMM estimates that about $14 million of these costs were driven by price divergence between the hour-ahead and real-time markets. In the hour-ahead market, exports were increased and imports were reduced at relatively low prices, while additional energy was dispatched at higher costs in the 5-minute real-time market.

Figure E.2 Estimated energy imbalance costs attributable to decreased net hour-ahead imports requiring dispatch of additional energy in 5-minute market at a higher price



- Congestion within the ISO system had an increased effect on overall prices in the second quarter in both the day-ahead and real-time markets. The impact of day-ahead and real-time congestion was relatively high in the SCE area, representing roughly 5 percent of the total prices in both markets. SDG&E congestion costs were about 5 percent of total costs in the day-ahead market and about 2 percent in the real-time market. While import limitations into San Diego increased congestion costs into the SDG&E area, import limitations into the SCE area lowered the congestion costs into the SDG&E area, most notably in the real-time market. Congestion primarily occurred as a result of the market addressing reliability concerns related to the outages of San Onofre Nuclear Generating Station (SONGS) units 2 and 3.

[1] When convergence bidding was allowed at inter-ties, real-time imbalance offset costs increased due to virtual import bids that offset virtual demand bids within the ISO system that did not increase the efficiency of unit commitment decisions. For further details see the *2011 Annual Report on Market Issues and Performance*, Chapter 4, http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.

Convergence bidding

The ISO implemented convergence (or virtual) bidding in the day-ahead market on February 1, 2011. Virtual bidding on inter-ties was suspended on November 28, 2011.[2] Thus, the second quarter of 2012 represents the second full quarter with virtual bidding within the ISO system but not at the inter-ties. Convergence bids within the ISO system that are profitable may increase market efficiency by increasing the efficiency of day-ahead unit commitment and scheduling. Convergence bidding within the ISO also provides a mechanism for participants to hedge against price differences due to congestion at different locations and between price differences between the day-ahead and real-time markets.

Convergence bidding activity was marked by several key trends in the second quarter:

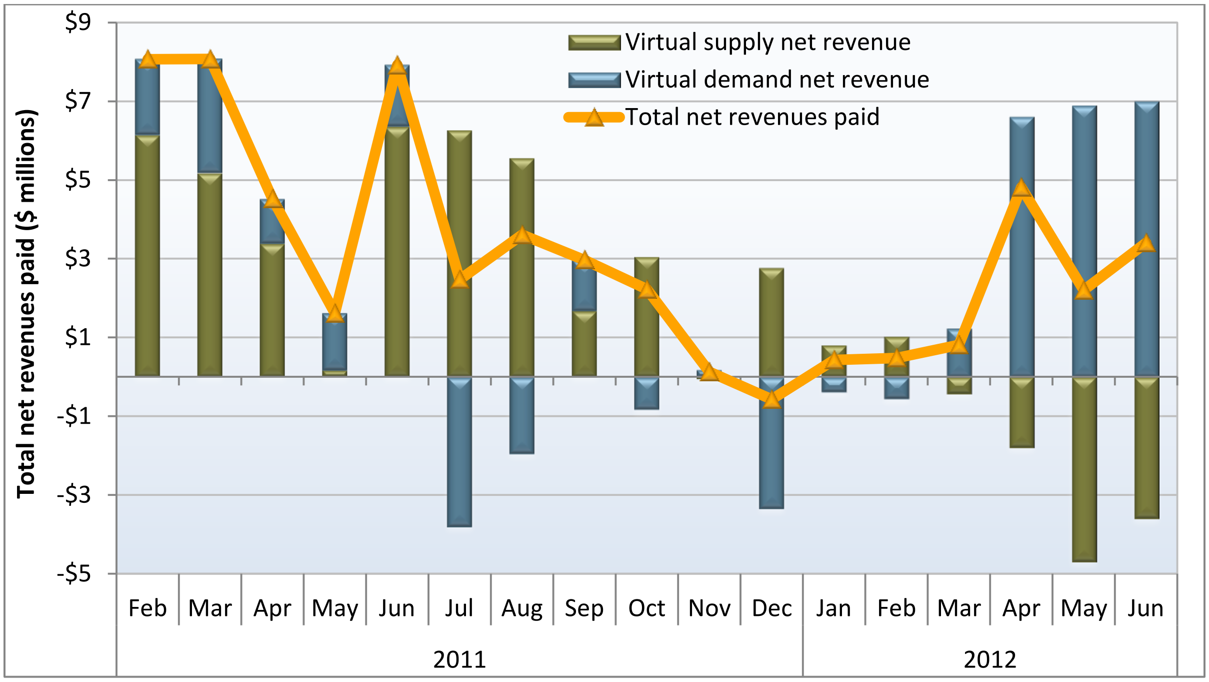
- Virtual demand at internal scheduling points within the ISO system exceeded virtual supply by an average of about 430 MW in the second quarter. For the quarter, internal virtual supply averaged around 1,040 MW while virtual demand averaged around 1,470 MW each hour. This trend of net virtual demand represents a reversal of a trend of net virtual supply that began in mid-December and continued through the first quarter.

- Market participants can hedge congestion costs or earn revenues associated with differences in congestion between different points within the ISO system by placing an equal amount of virtual demand and supply bids at different internal locations during the same hour. This type of offsetting virtual position at internal locations accounted for an average of about 650 MW of demand offset by 650 MW of virtual supply at other locations per hour in the second quarter. These offsetting bids represent about 70 percent of all cleared internal virtual bids. This suggests that since suspension of virtual bidding on inter-ties virtual bidding has been heavily used to hedge or profit from internal congestion.

- In the second quarter, net revenues paid out to participants placing virtual bids totaled over $10 million (see Figure E.3). This is significantly above the level paid to convergence bidding entities in the first quarter ($2 million) and the highest quarterly level since the second quarter of 2011. The higher net revenues paid out for convergence bids reflect increasing price divergence because of the higher incidence of real-time price spikes and congestion. The net revenues primarily resulted from virtual demand positions. These virtual demand positions have the potential to increase market efficiency by increasing the efficiency of day-ahead unit commitment and scheduling.

[2] See 137 FERC ¶ 61,157 (2011) accepting and temporarily suspending convergence bidding at the inter-ties subject to the outcome of a technical conference and a further commission order. More information can also be found under FERC docket number ER11-4580-000.

Figure E.3 Total monthly net revenues paid to convergence bidders



Convergence bidding on inter-ties

DMM has recommended that the ISO not re-implement convergence bidding on inter-ties.[3] DMM's analysis of convergence bidding at inter-ties and review of alternatives shows that the potential costs of re-introducing convergence bidding at inter-ties outweigh the potential benefits. Recent market performance reinforces DMM's position. Specifically, the recent increase in price divergence and real-time imbalance offset costs would likely have been exacerbated had convergence bidding been allowed at the inter-ties. Thus, DMM believes that continued suspension of convergence bidding at the inter-ties remains important until the ISO addresses structural differences between how the hour-ahead and real-time markets are dispatched and settled.

Special issues

- **Flexible ramping constraint performance.** The flexible ramping constraint, implemented in December 2011, addresses non-contingency based deviations in load and supply between the real-time commitment and dispatch models (e.g., because of load and wind forecast variations). The constraint procures ramping capacity in the 15-minute real-time pre-dispatch process that is subsequently made available for use in the 5-minute real-time dispatch. The flexible ramping constraint was less effective in addressing real-time price volatility in the second quarter than in the first quarter. This may partly be a result of internal congestion in the real-time market. The flexible ramping constraint procures on a system-wide basis and was not designed to address zonal or local

[3] See DMM's *Comments on ISO's Third Revised Straw Proposal for Settlement of Interties in Real-time*, July 26, 2012: http://www.caiso.com/Documents/DMM-Comments-IntertiePricingSettlementThirdRevisedStrawProposal.pdf.

ramping issues. Furthermore, a lower requirement for the flexible ramping constraint was used than in the first quarter that may also have reduced its effectiveness. Total payments made for flexible ramping capacity during the first half of the year were around $14.8 million. For sake of comparison, payments for spinning reserve totaled about $12 million for the same period. DMM has recommended that the ISO review how the flexible ramping constraint has affected the unit commitment decisions made in real-time. DMM believes this is an important measure of the overall effectiveness of the constraint. Furthermore, DMM recommends that the ISO continue to fine tune the flexible ramping constraint to increase its effectiveness. Finally, given the high level of price divergence in recent months, DMM recommends that the ISO seek to identify and pursue other steps that might be taken to reduce extreme real-time price spikes and price divergence.

- **Performance of new local market power mitigation procedures.** The ISO implemented new local market power mitigation procedures in mid-April to enhance the competitive path assessment mechanism and mitigation trigger in the day-ahead market. In addition, the ISO incorporated virtual bids into the day-ahead mitigation run and began clearing that market run against bid-in demand instead of forecast load. These enhancements have improved the accuracy of local market power mitigation considerably by better aligning the model inputs between the mitigation and actual market runs. The dynamic competitive path assessment has also improved the accuracy of identifying where local market power exists by assessing competitiveness based on actual system and market conditions observed by the market software. Finally, the new mitigation trigger has improved the accuracy of local market power mitigation by applying bid mitigation only to resources where the locational margin8al price is increased by congestion on an uncompetitive constraint.

- **Compensating injections.** As DMM had highlighted in its 2011 annual report, the effectiveness of compensating injections, which are designed to help the real-time software better match actual and modeled flows on inter-ties, is significantly affected by limiting parameters.[4] These parameters not only limit the effectiveness of the compensating injections, they also add variability into the real-time model that can create operational challenges. This trend continued into the second quarter and created noticeable effects on certain constraints. As a result, the ISO has begun to regularly track the effectiveness of compensating injections and intends to reduce the variability by adjusting the limiting parameters.

[4] See DMM's *2011 Annual Report on Market Issues and Performance*, April 2012, Section 8.4, http://www.caiso.com/market/Pages/MarketMonitoring/MarketIssuesPerfomanceReports/Default.aspx.

1 Energy market performance

The day-ahead integrated forward market was stable and competitive. Average day-ahead energy prices continued to be approximately equal to benchmark prices that DMM estimates would occur under highly competitive conditions. Although real-time prices exceeded day-ahead prices in the second quarter, the real-time market continues to account for a very small portion of the wholesale market, so that overall market wholesale costs continue to highly competitive.

1.1 Energy market performance

Average real-time prices exceeded day-ahead and hour-ahead prices during the quarter, reversing a trend of improved price convergence that occurred in recent quarters. Figure 1.1 and Figure 1.2 show monthly system marginal energy prices for peak and off-peak periods, respectively.[5]

- In peak and off-peak periods in the second quarter, hour-ahead prices remained lower than day-ahead prices. With the exception of peak hours in July and off-peak hours in September, this pattern has held for over the last year.
- Prices in the 5-minute real-time market were higher than day-ahead prices in all months for peak hours and in May and June for off-peak periods in the second quarter.
- Prices in the 5-minute real-time market also exceeded hour-ahead prices in both peak and off-peak hours in all months during the second quarter. The largest average difference was over $13/MWh in June off-peak hours and about $11/MWh in April for peak hours.

Figure 1.1 and Figure 1.2 show that average hour-ahead and real-time market prices diverged during the second quarter relative to previous periods. Figure 1.3 and Figure 1.4 further highlight the systematic differences between hour-ahead and real-time prices in the second quarter.

- Figure 1.3 shows average hourly prices for the second quarter. In previous quarters, real-time prices were higher relative to day-ahead and hour-ahead prices in some hours and lower in other hours. In the second quarter, average real-time prices were above day-ahead and hour-ahead prices in all hours. Meanwhile, hour-ahead prices were consistently lower than both day-ahead and real-time prices for most of the day. This trend was also different from previous periods, when hour-ahead prices were higher than day-ahead and real-time prices in some hours and lower in others.
- Figure 1.4 highlights the magnitude of price differences in the hour-ahead and real-time markets based on this simple average of price differences in these markets, price divergence began in April and increased through June to an average of about $10/MWh for all hours of the month (see green line in Figure 1.4). This was the largest average price divergence since January 2011 and further emphasizes the trend in Figure 1.3 showing that real-time prices were consistently above hour-ahead prices in most hours.

[5] In previous reports, DMM has used the PG&E area price to illustrate price levels and price convergence. When congestion levels were low, the PG&E area price was a good approximation of the system price. However, congestion has begun to play an increasing role in recent quarters. As a result, DMM has switched its price analysis to the system marginal energy price, which is not affected by congestion or losses.

Figure 1.1 Average monthly on-peak prices – system marginal energy price

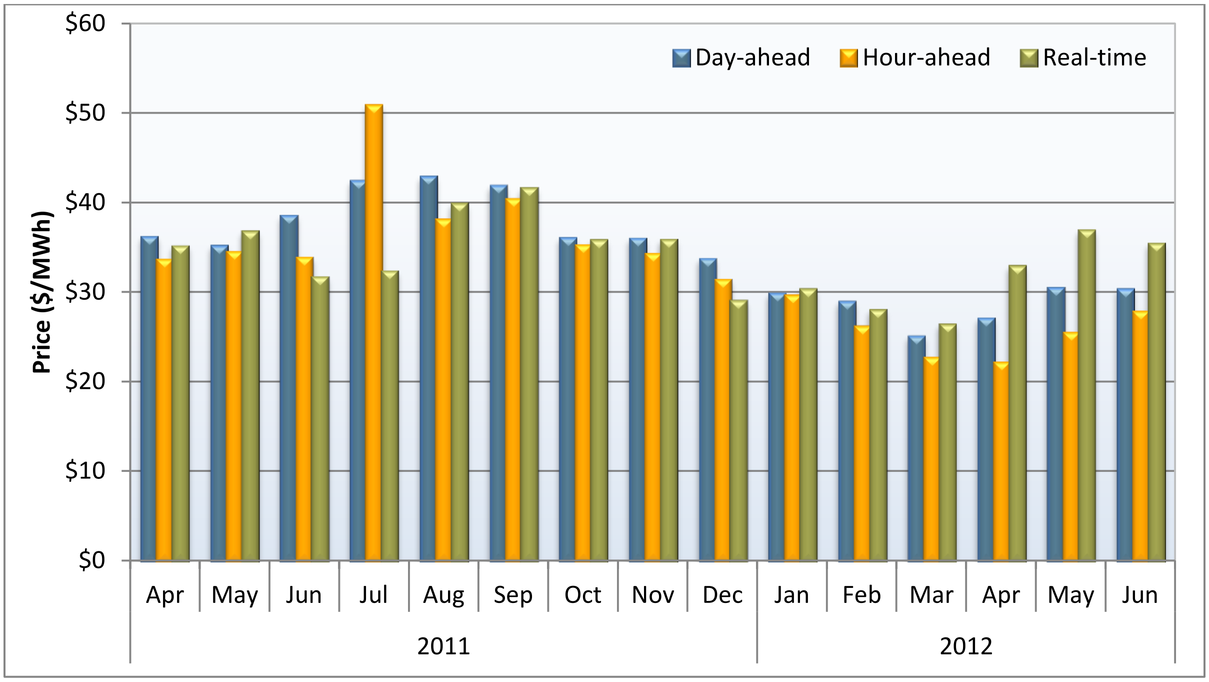


Figure 1.2 Average monthly off-peak – system marginal energy price

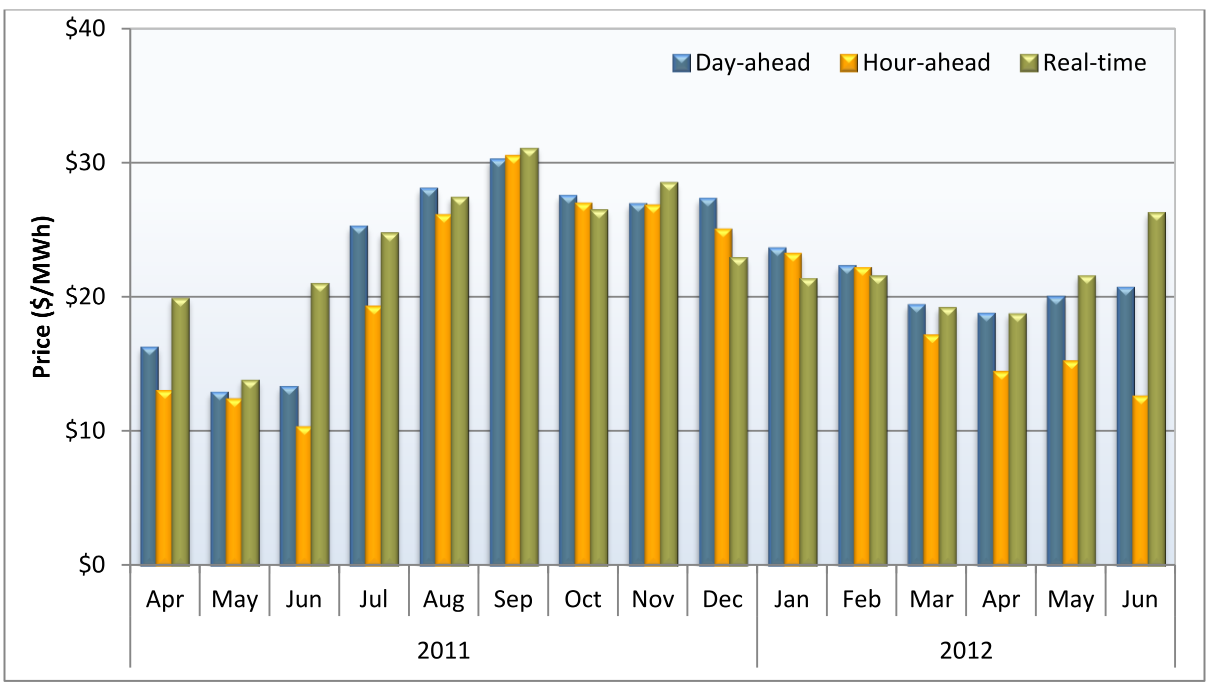


Figure 1.3 Hourly comparison of system marginal energy prices (April - June)

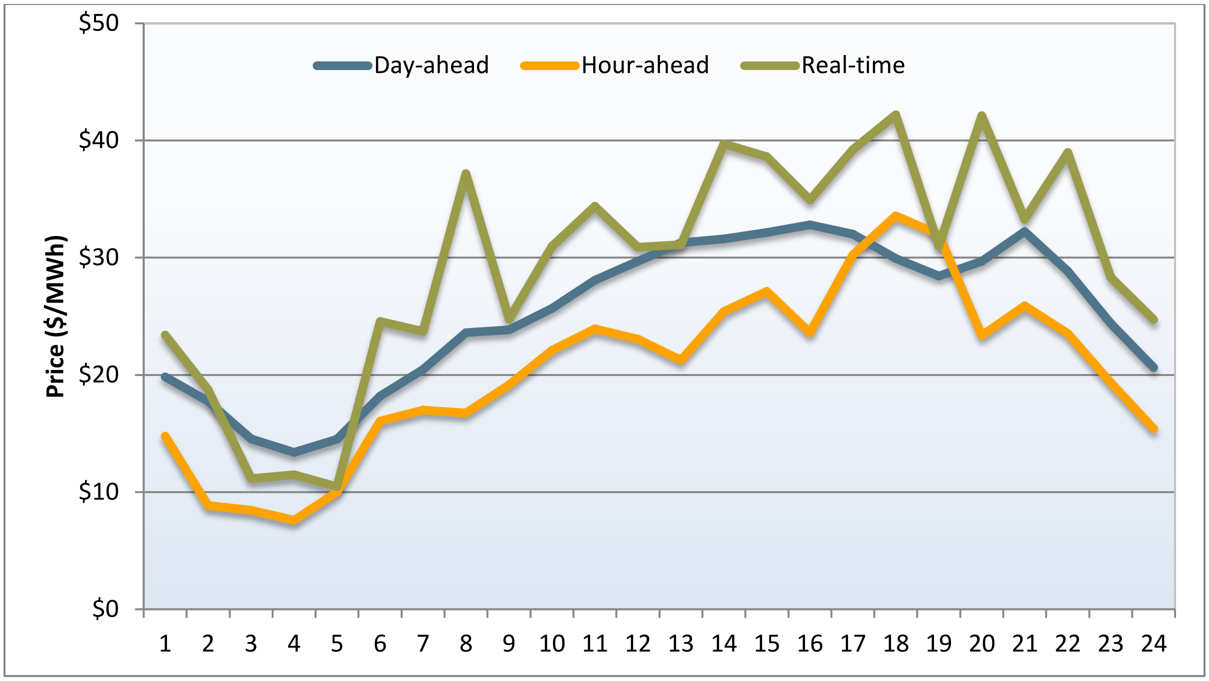
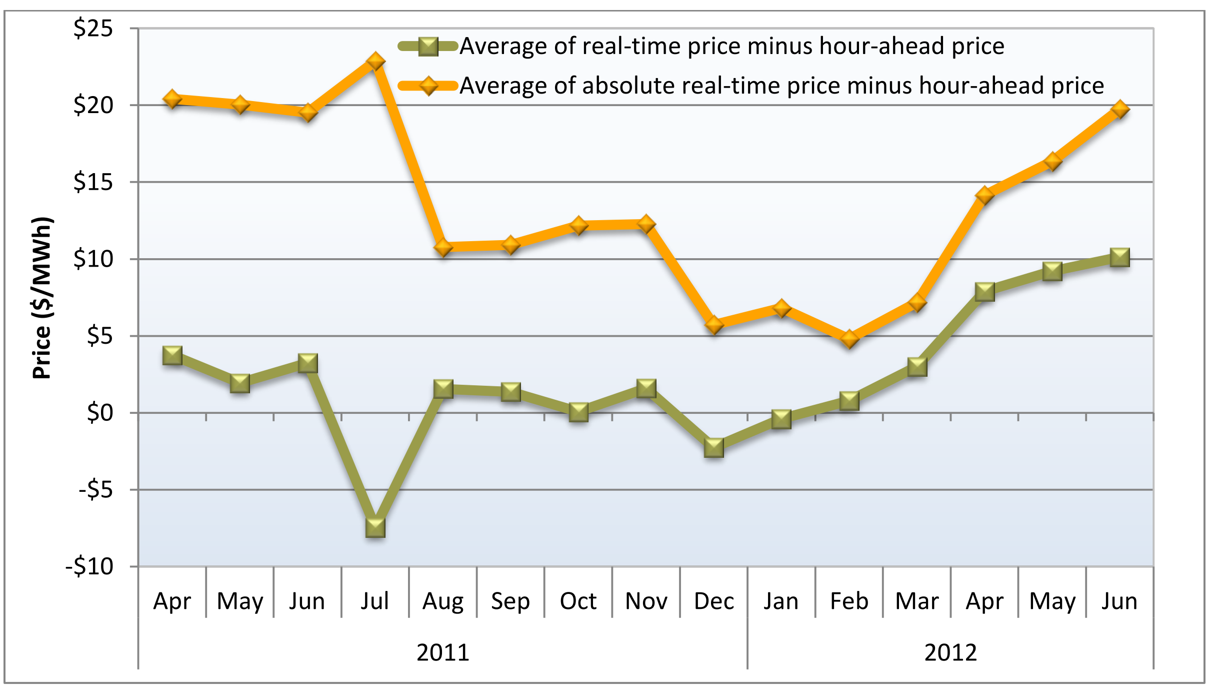


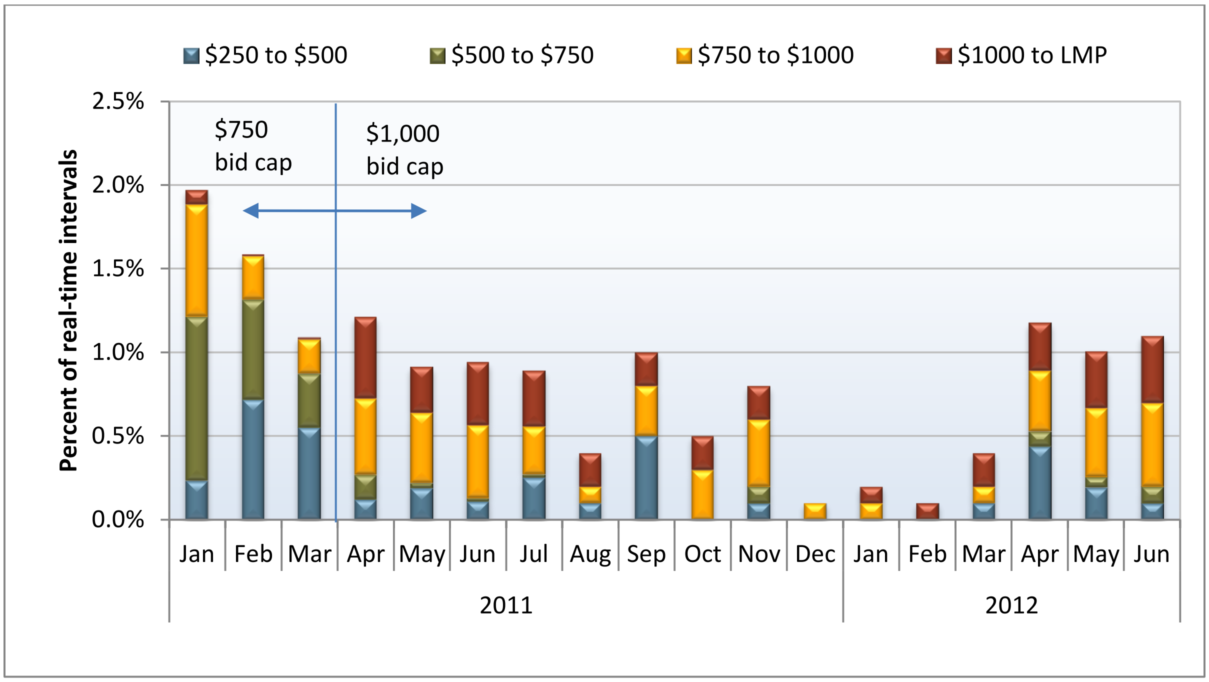
Figure 1.4 Difference in monthly hour-ahead and real-time prices based on simple average and absolute average of price differences (system marginal energy, all hours)



- Also shown in Figure 1.4, the average absolute price difference in the hour-ahead and real-time markets shows that price divergence increased during the second quarter to almost $20/MWh in June (yellow line in Figure 1.4). This difference was about as large as the difference in average absolute prices during the second quarter of 2011.[6]

Figure 1.5 shows an increase in the frequency of price spikes that occur in each investor-owned utility area in the real-time market in the second quarter, from an average of 0.2 percent in the first quarter to about 1.1 percent in the second quarter. The second quarter had the highest percentage occurrence of price spikes since the first quarter of 2011. While the price spikes at or above $1,000/MWh in the second quarter of 2012 (0.3 percent) were slightly lower than in the second quarter of 2011 (0.4 percent), price spikes below $1,000/MWh increased in the second quarter of 2012 as a result of congestion related price spikes.

Figure 1.5 Frequency of price spikes (all LAP areas)



1.2 Power balance constraint

The system-wide real-time power balance constraint continues to contribute to extreme positive and negative real-time prices. Overall, power balance constraint relaxations show an increasing trend compared to previous quarters. Figure 1.6 and Figure 1.7 show the frequency the power balance constraint was relaxed in the 5-minute real-time market software since the second quarter of 2011.

[6] By taking the absolute value, the direction of the difference is eliminated and only the magnitude of the difference remains. Mathematically, this measure will always exceed the simple average of price differences shown in Figure 1.4 if both negative as well as positive price differences occur. If the magnitude decreases, price convergence would be improving. If the magnitude increases, price convergence would be getting worse. DMM does not anticipate that the average absolute price convergence should be zero. This metric is considered secondary to the simple average metrics and helps to further interpret price convergence.

Figure 1.6 Relaxation of power balance constraint because of insufficient upward ramping capacity

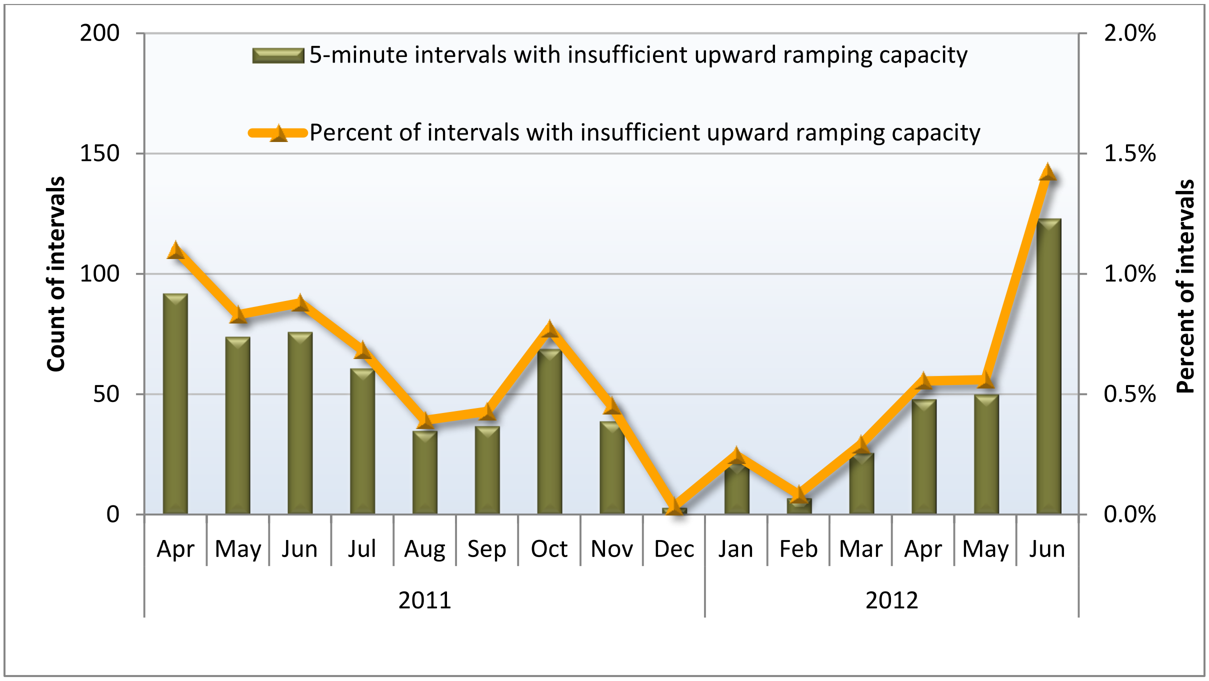
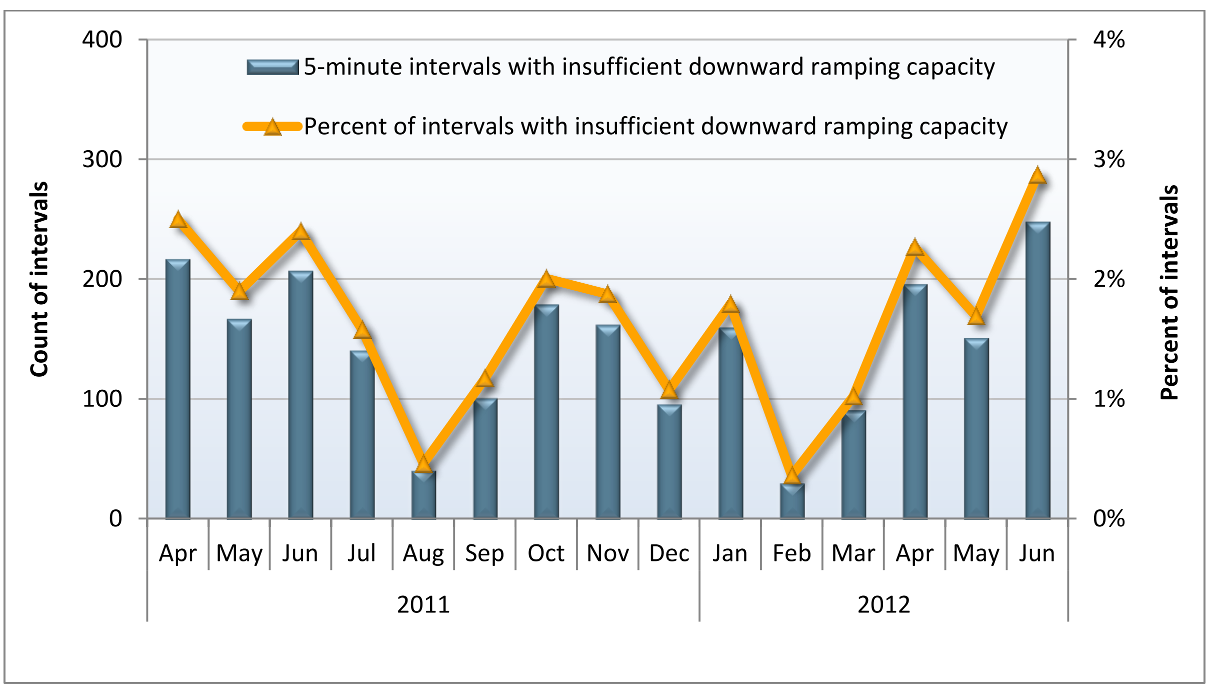


Figure 1.7 Relaxation of power balance constraint because of insufficient downward ramping capacity



- Figure 1.6 shows that relaxations because of insufficient upward ramping capacity began an upward trend in the second quarter, peaking in June. The constraint relaxations were dispersed over different hours of the day but were slightly more common between 3:00 p.m. and 8:00 p.m., during the evening load ramp and peak. Decreased capacity availability from planned generator outages, the continued outage of SONGS nuclear units, limited ramping capacity, increased load because of hot weather in June and congestion all appear to have contributed to increasing the number of upward ramping limitations. When these upward ramping limitations occur, the real-time system energy price is set by a penalty parameter equal to the bid cap of $1,000/MWh.

- Figure 1.7 shows an increase in the number of real-time power balance constraint relaxations from insufficiencies of dispatchable decremental energy in the second quarter relative to the first quarter. Almost 80 percent of downward ramping limitations occurred in hours ending 1 through 8. In these hours, power balance constraint relaxations occurred in around 4 percent of the intervals. In hour ending 7, one of the key ramping hours, almost 8 percent of the intervals had a downward power balance constraint relaxation. One of the causes of these decremental dispatch insufficiencies includes unanticipated changes in variable unit output in the early morning hours. The flexible ramping constraint cannot resolve relaxations from insufficiencies of dispatchable decremental energy as it has only been applied to address upward, not downward, ramping limitations. When these downward ramping limitations occur, the real-time system energy price is set by a penalty parameter equal to the bid floor of -$30/MWh.

Most shortages of upward and downward ramp limitations lasted for only short periods of time. For instance, about 83 percent of shortages of upward ramping capacity persisted for only one to three 5-minute intervals (or 5 to 15 minutes). Even so, these upward ramping shortages can cause real-time prices to increase dramatically and greatly outweigh the effects of the negative prices associated with the more frequent downward ramping shortages. Figure 1.8 and Figure 1.9 control for the effects of these ramping limitations by removing the prices in all markets in hours with real-time ramping limitations and highlight the change in prices when these hours are removed.

- Figure 1.8 highlights the degree to which monthly average price differences were caused by extreme prices during the small percentage of intervals when power balance constraint relaxations occurred. The main bars represent the price results in the day-ahead, hour-ahead and real-time markets after the adjustments were made. The smaller bars (designated as Diff), indicate how the price differs between the original prices and the adjusted prices. As Figure 1.8 shows, when these intervals were excluded, real-time prices were very close to day-ahead prices in April and May, and were slightly lower than day-ahead prices in June.

- Figure 1.9 highlights the difference between average hour-ahead and real-time prices when comparing hours where power balance constraint relaxations are excluded with prices that include them. As seen in this figure, average real-time prices in the second quarter remained higher than average hour-ahead prices even when the ramping limitations were accounted for. This was the result of multiple factors including modeling differences between the hour-ahead and real-time markets as well as differences in load and generation.

Figure 1.8 Change in monthly prices excluding hours when power balance constraint relaxed

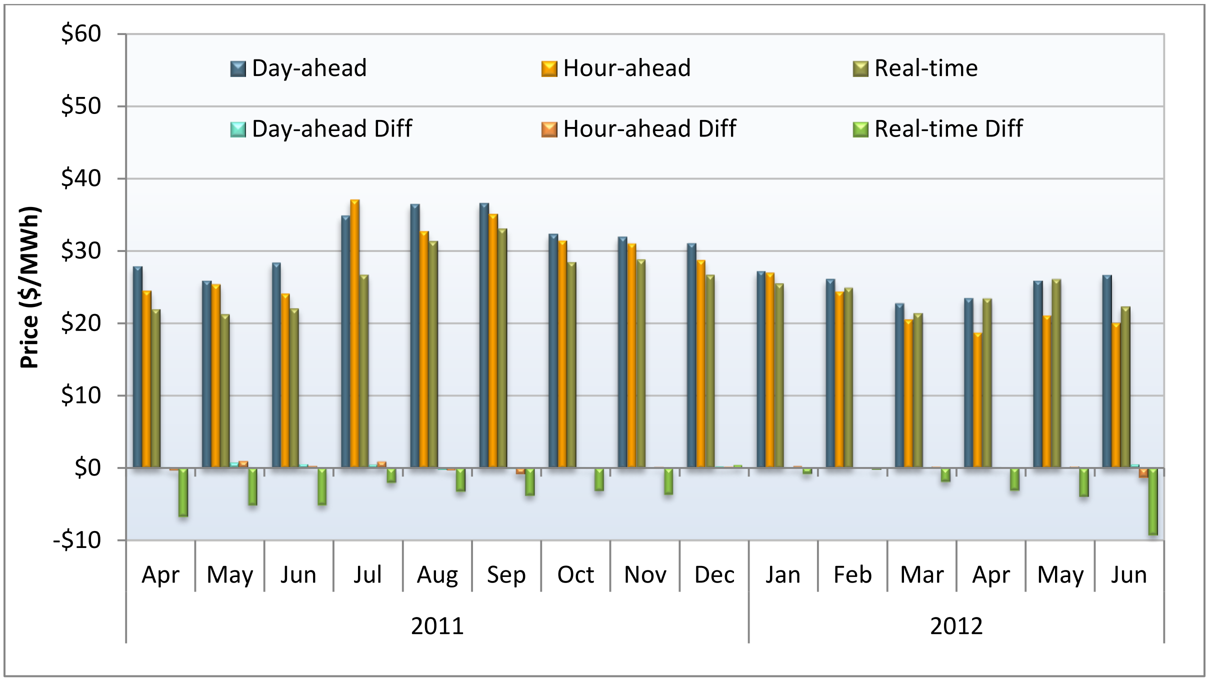
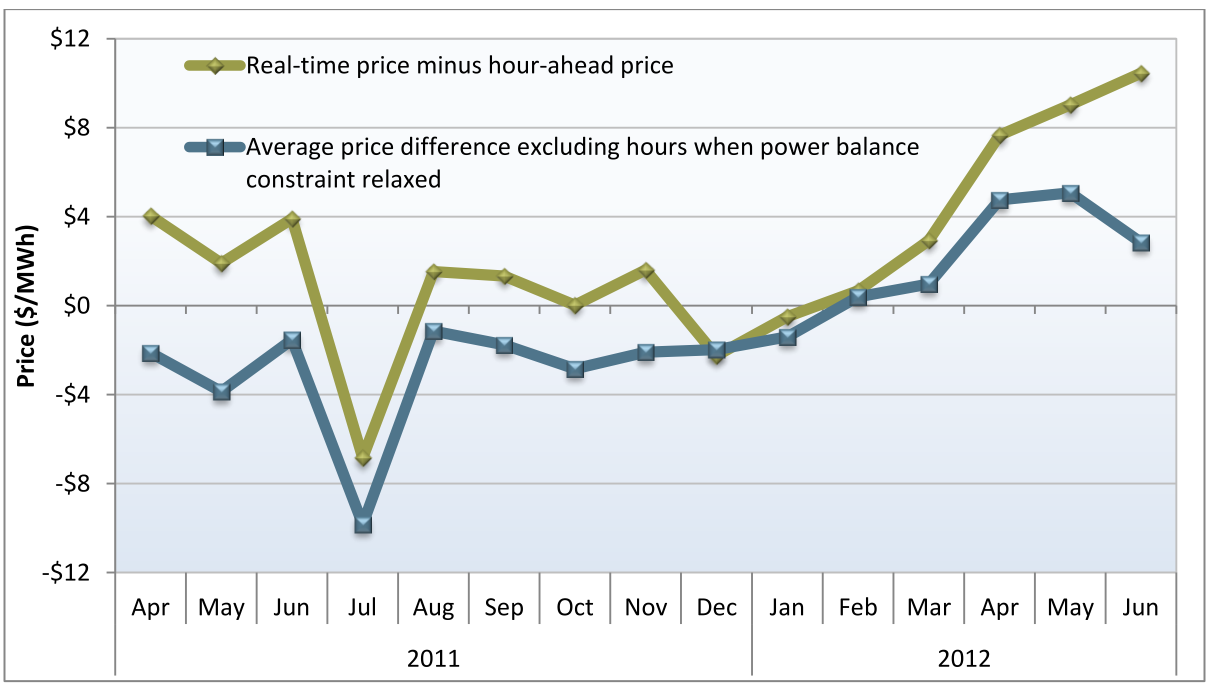


Figure 1.9 Difference in monthly hour-ahead and real-time prices excluding hours when power balance constraint relaxed

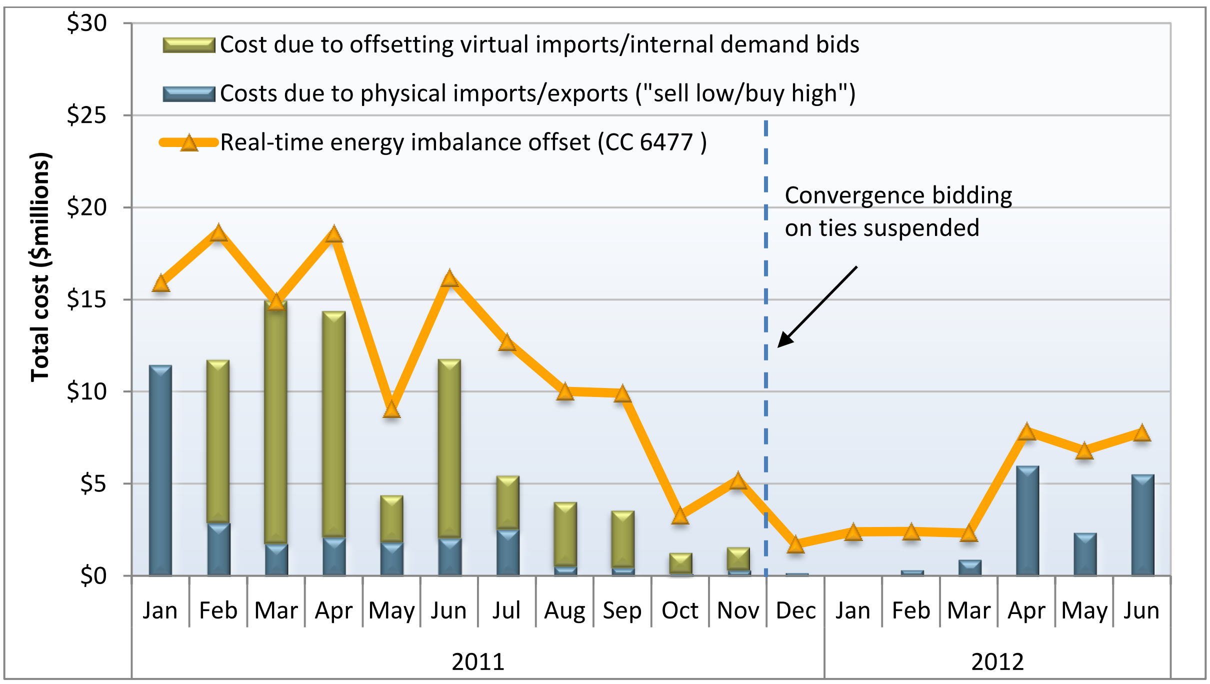


1.3 Real-time imbalance offset costs

Real-time energy imbalance offset costs totaled $22 million in the second quarter. This increase was primarily driven by price divergence between the hour-ahead and real-time markets. In the hour-ahead market, exports were increased and imports were reduced at relatively low prices, while additional energy was dispatched at higher costs in the 5-minute real-time market. These conditions were very similar to conditions that occurred in the market in 2009 and 2010.[7]

Figure 1.10 compares the total real-time energy imbalance costs (yellow line) with the portion of these costs DMM estimates are attributable to (1) additional imbalance energy because of changes in net imports in the hour-ahead that are offset by imbalance energy in real-time at a different price (blue bar)[8] and (2) offsetting convergence bids at inter-ties and internal locations (green bar). The estimated imbalance costs due to physical schedules during the second quarter of 2012 increased to about $14 million from about $6 million during the second quarter of 2011.

Figure 1.10 Estimated energy imbalance costs because of decreased net hour-ahead imports requiring dispatch of additional energy in 5-minute market at a higher price



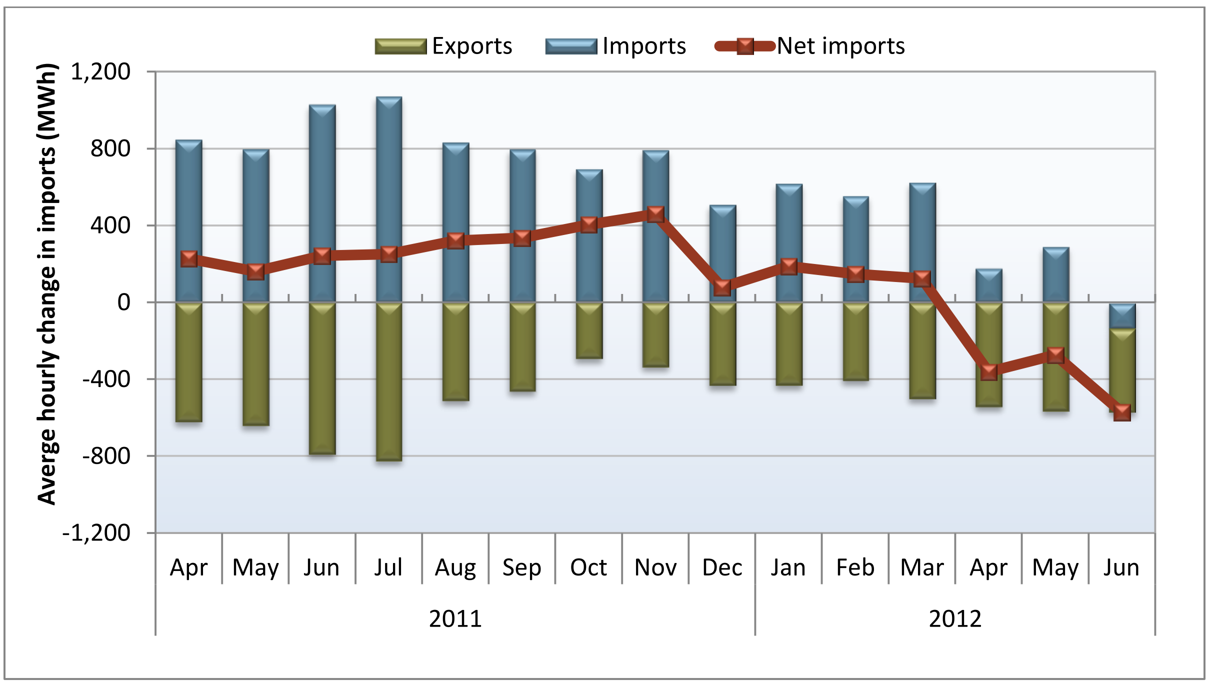
[7] See DMM's *2009 Annual Report on Market Issues and Performance,* p. 7, http://www.caiso.com/Documents/2009AnnualReportonMarketIssuesandPerformance.pdf and *2010 Annual Report on Market Issues and Performance*, p. 5, http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf.

[8] DMM estimates these costs based on the following: 1) the decrease in hour-ahead net imports that were subsequently re-procured in real-time from dispatchable generation; 2) the increase in hour-ahead imports that were subsequently sold in real-time; and 3) the difference in hour-ahead versus real-time prices during the corresponding hour. This cost estimate is only one element of the real-time imbalance energy offset charge and, therefore, will differ from the total value of the charge for various reasons. Further detail on the different elements contained within the charge can be found in the following report: http://www.caiso.com/2416/2416e7a84a9b0.pdf.

The increase in estimated physical net import costs was a result of increased price divergence between the hour-head and real-time market prices along with decreases in net imports in the hour-ahead market.[9] From the second quarter of 2011 through the first quarter of 2012, the net import schedules clearing the hour-ahead market were systematically higher than the net import schedules clearing the day-ahead market. This pattern shifted in the second quarter of 2012. As shown in Figure 1.11:

- During each month from the second quarter of 2011 through the first quarter of 2012, net imports clearing the hour-ahead market averaged 500 MW to 1,000 MW more than net day-ahead import schedules. Most of the increase in net imports was because of an increase in new imports in the hour-ahead market, which averaged over 400 MW per hour from the second quarter of 2011 through the first quarter of 2012.
- The trend of positive net imports flipped during the second quarter of 2012 when new exports in the hour-ahead market outweighed new imports by an average of 400 MW during the quarter.

Figure 1.11 Change in net imports in hour-ahead relative to the final day-ahead schedules



Decreasing physical net imports in the hour-ahead market likely increases the need to re-dispatch imbalance energy in real-time.[10] This scenario occurred in almost 90 percent of the hours in the second

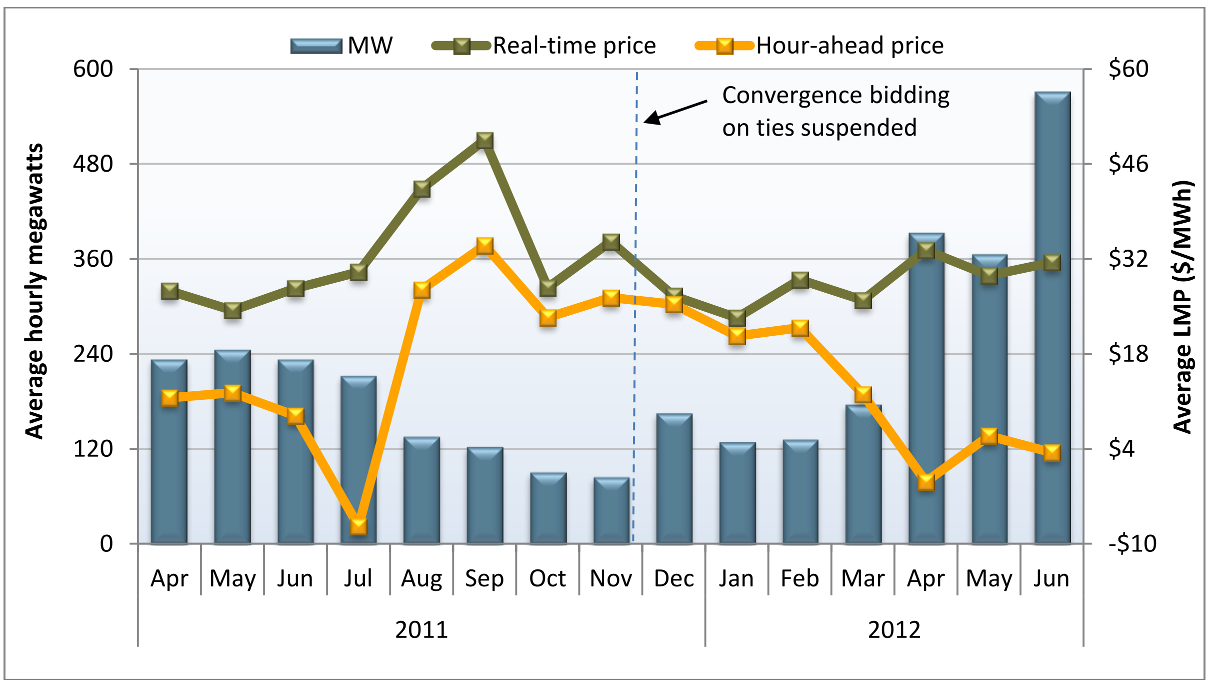
[9] The hour-ahead market allows day-ahead inter-tie schedules to be modified through a re-optimization of the entire market. Market participants with accepted day-ahead imports or export bids can either self-schedule their energy in the hour-ahead market, or re-bid day-ahead scheduled quantities at the same or different prices. If an import scheduled in the day-ahead market does not clear in the hour-ahead market, the market participant buys back the import at the hour-ahead price. Exports scheduled in the day-ahead market that do not clear in the hour-ahead market are sold back at the hour-ahead price.

[10] In some cases, reductions in net imports may occur in the hour-ahead market to manage congestion or reduce supply because of energy not scheduled in the day-ahead market, such as renewable generation or unscheduled start-up or minimum load energy from thermal units. The hour-ahead software takes this energy into account while optimizing imports and exports.

quarter. The blue bars in Figure 1.12 show DMM's estimate of the average hourly decrease in hour-ahead net imports that were subsequently re-procured by the real-time dispatch by month. The lines in Figure 1.12 compare the corresponding weighted average prices at which this decrease in net imports was settled in the hour-ahead market and the weighted average prices for additional energy procured in the real-time market during each month.[11] Together, the hourly decrease in hour-ahead net imports and the difference in hour-ahead and real-time prices produce the estimated imbalance energy costs. The total costs are determined by the quantity that is reduced in the hour-ahead market and then re-procured in the 5-minute real-time market, combined with the difference in prices in these two markets.

As shown in Figure 1.12, there has been a substantial increase in the price divergence between hour-ahead and 5-minute real-time market prices in the second quarter of 2012 compared to the second quarter of 2011 as well as an increase in quantity of megawatts bought back. The average price difference in the second quarter of 2012 was around $29/MWh with an increased average quantity of about 445 MW compared to a price difference of about $16/MWh and a quantity of 240 MW in the second quarter of 2011.

Figure 1.12 Monthly average quantity and prices of net import reductions in hour-ahead market and resulting increase in real-time energy dispatched



[11] DMM estimates the hourly decrease in hour-ahead net imports that were subsequently re-procured by the real-time dispatch by month based on the difference between the decrease in net imports each hour with the amount of energy dispatched in the 5-minute market during that hour. For instance, if the net imports were decreased by 500 MW in the hour-ahead, and 700 MW of net incremental energy was dispatched in the 5-minute market that hour, the entire 500 MW decrease of net imports in hour-ahead was re-procured in the 5-minute market. If net imports were decreased by 500 MW in the hour-ahead market, but only 200 MW of net incremental energy was dispatched in the 5-minute market that hour, then only 200 MW of the decrease of net imports in hour-ahead was counted as being re-procured in the 5-minute market.

1.4 Congestion

Compared to the first quarter, congestion within the ISO system in the second quarter had an increased effect on overall prices in the day-ahead and real-time markets. Much of the congestion was related to the outages of the San Onofre Nuclear Generating Station units 2 and 3, in conjunction with other generation and transmission outages.

The impact of congestion on any constraint on each pricing node in the ISO system can be calculated by summing the product of the shadow price of that constraint and the shift factor for that node relative to the congested constraint. This calculation can be done for individual nodes, as well as groups of nodes that represent different load aggregation points or local capacity areas.

Often, congestion on constraints within Southern California increases prices within the Southern California Edison and San Diego Gas and Electric areas, but decreases prices in the Pacific Gas and Electric area. This is the inverse of congestion in Northern California. The price impacts on individual constraints can differ between the day-ahead and real-time markets as seen in the following sections.

1.4.1 Congestion impacts of individual constraints

Day-ahead congestion

Congestion in the day-ahead market generally occurs more frequently than in real-time, but with smaller price impacts. Table 1.1 provides a more detailed analysis for the second quarter and shows:

- At almost 36 percent of the hours, the SCE_PCT_IMP_BG was congested more often than any other individual constraint in the quarter. This constraint alone increased the prices in the SCE area by $3.40/MWh in congested hours. The prices in the PG&E and SDG&E areas decreased by $2.87/MWh. This constraint has been directly affected by the outages of SONGS units 2 and 3.

- The SLIC 18830001_SDGE_OC_NG constraint had the second highest percent of hours binding during the second quarter at just under 32 percent. This constraint increased the prices in the SDG&E area by $6.46/MWh in congested hours and SCE by $0.28/MWh while decreasing prices on PG&E by $0.71/MWh. This constraint is directly related to the outage of SONGS and ended with the addition of the Sunrise Power Link in mid-June.

- Congestion on the 6110_TM_BNK_TMS_DLO_NG increased prices in the PG&E area by $0.80/MWh in congested hours and decreased prices in the SCE and SDG&E areas by about $0.85/MWh. This congestion was related to scheduled maintenance.

As shown in Table 1.1, congestion on other constraints significantly affected prices during hours when congestion occurred. However, since this internal congestion occurred infrequently, it had a minimal impact on overall day-ahead energy prices.

Table 1.1 Impact of congestion on day-ahead prices by load aggregation point in congested hours

		Frequency		Q1			Q2		
Area	**Constraint**	**Q1**	**Q2**	**PG&E**	**SCE**	**SDG&E**	**PG&E**	**SCE**	**SDG&E**
PG&E	6110_TM_BNK_FLO_TMS_DLO_NG		6.3%				$0.80	-$0.85	-$0.85
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	8.6%		$1.24	-$0.97	-$0.97			
SCE	SCE_PCT_IMP_BG	4.6%	35.6%	-$1.31	$1.62	-$1.31	-$2.87	$3.40	-$2.87
	PATH26_BG	4.8%	3.6%	-$1.63	$1.39	$1.39	-$1.41	$1.16	$1.16
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _2		0.7%				-$3.22	$2.39	$2.44
	SLIC1852244PATH26LIOSN2S	4.7%		-$1.98	$1.66	$1.66			
	SLIC1883001 MIGUEL BKS	1.4%		-$0.14		$5.01			
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	1.0%		-$1.15	$1.65	-$1.93			
	SLIC 1848345_23021_Outage	0.5%		-$1.17		$7.79			
SDG&E	SLIC 1883001_SDGE_OC_NG	14.2%	31.7%	-$0.65	-$0.06	$6.27	-$0.71	$0.28	$6.46
	SDGE_CFEIMP_BG	9.0%	2.4%	-$0.45	-$0.45	$4.19	-$0.56	-$0.56	$5.64
	SDGE_PCT_UF_IMP_BG		1.1%				-$0.40	-$0.40	$4.27
	SLIC 1883001 Miguel_BKS_NG_2	2.4%	0.9%	-$0.07		$3.08	-$0.45		$6.79
	SLIC 1977036 Barre-Ellis NG		0.5%				-$0.75		$6.90
	22832_SYCAMORE_230_22828_SYCAMORE_69.0_XF_2	0.1%				$24.09			

Real-time congestion

Congestion in the real-time market differs slightly from the day-ahead market in that real-time congestion occurs less frequently overall, but often on more constraints and with a larger price effect in the intervals when it occurs. Table 1.2 provides a detailed analysis for the second quarter and shows:

- Congestion on SLIC 1902749 ELDORADO_LUGO-1 occurred nearly 2 percent of the time. At those times, congestion increased prices in the PG&E area by $12.43/MWh and decreased prices in the SCE and SDG&E areas by $8.32/MWh and $14.48/MWh, respectively. This congestion was due to scheduled maintenance.

- SCE_PCT_IMP_BG was congested slightly more than 2 percent of the hours and was congested as a result of the outages of SONGS units 2 and 3. This congestion decreased the prices in the PG&E and SDG&E areas by about $70/MWh and increased prices for the SCE area by over $86/MWh during congested hours. Path26_N-S and Path15_N-S were also congested about 2 percent of the time, increasing prices in SCE and SDG&E by nearly $49/MWh and $29/MWh, respectively. Prices decreased in PG&E by nearly $60/MWh and $38/MWh, respectively.

- In nearly 3 percent of the hours, congestion on SLIC 1883001_SDGE_OC_NG increased the price in the SDG&E area about $69/MWh when it was binding. PG&E prices decreased by about $8/MWh while the impact on the SCE area price was negligible. This constraint is directly related to the outage of SONGS.

Comparing Table 1.1 and Table 1.2 indicates that congestion is more frequent in the day-ahead market compared to the real-time market. However, the price impact of congestion is lower in the day-ahead market than the real-time market. Differences in congestion in the day-ahead and real-time markets occur as system conditions change, as convergence bids liquidate, and as constraints are sometimes adjusted in real-time to make market flows consistent with actual flows and to provide reliability margin.

For example, while the SCE_PCT_IMP_BG was binding in nearly 36 percent of the hours in the day-ahead market, it was binding in about 2 percent of the time in the real-time market. The constraint increased day-ahead prices in the SCE area by $3.40/MWh, but by over $86/MWh in the real-time market. Other examples include nomograms, such as PATH26_N-S and PATH15_S-N, which may be adjusted to mitigate the difference in market and actual flows and to provide a reliability margin. Even though the nomograms are binding less frequently (in about 2 percent of the hours for each constraint), the shadow prices are significantly larger, indicating a greater impact on prices when the constraint is binding.

Table 1.2 Impact of congestion on real-time prices by load aggregation point in congested intervals

		Frequency		Q1			Q2		
Area	Constraint	Q1	Q2	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
PG&E	SLIC 1902749 ELDORADO_LUGO-1	1.1%	1.7%	$3.30	-$2.36	-$3.96	$12.43	-$8.32	-$14.48
	6110_TM_BNK_FLO_TMS_DLO_NG		1.7%				$20.04	-$25.77	-$25.77
	LBN_S-N	0.02%	0.5%	$1.59	-$1.29	-$1.29	$228.26	-$199.05	-$199.05
	LOSBANOSNORTH_BG	0.01%	0.1%	$3.22	-$2.74	-$2.74	$179.78	-$142.40	-$142.40
	PATH15_S-N		0.1%				$59.14	-$50.27	-$50.27
	SLIC 1977990 SYL_PAR_NG		0.03%				$26.58	-$20.03	-$98.65
	PATH26_S-N	0.3%	0.02%	$30.46	-$25.84	-$25.84	$1.63	-$1.41	-$1.41
	SLIC 1902748 ELDORADO_LUGO-1	1.1%		$4.29	-$2.98	-$6.43			
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	3.2%		$4.76	-$3.65	-$3.65			
SCE	SCE_PCT_IMP_BG	0.2%	2.2%	-$63.37	$79.72	-$63.37	-$69.78	$86.32	-$69.66
	PATH26_N-S	2.8%	2.1%	-$17.37	$14.65	$14.65	-$59.99	$48.95	$48.95
	PATH15_N-S		1.7%				-$38.79	$29.03	$29.03
	SLIC-1832324-SOL7		0.7%				-$26.50	$17.82	$17.82
	SLIC 1832324_SOL7_REV1		0.4%				-$8.11	$5.52	$5.52
	7680 Sylmar_1_NG	0.1%	0.1%			-$60.31	-$11.98	$6.19	-$29.41
	PATH26_BG		0.1%				-$66.41	$50.25	$50.25
	24114_PARDEE _230_24147_SYLMAR S_230_BR_2 _1	0.02%	0.1%	-$18.58	$22.52	-$70.75	-$10.86	$9.51	-$45.44
SDG&E	SLIC 1883001_SDGE_OC_NG	5.3%	2.7%	-$2.64	-$0.08	$24.17	-$8.17		$68.55
	7820_TL 230S_OVERLOAD_NG	0.2%	1.1%			$3.64			$50.51
	SLIC 1884984 Gould-Sylmar		0.5%						-$57.35
	230S overload for loss of PV		0.5%						-$51.27
	SDGEIMP_BG		0.1%				-$17.03	-$17.03	$172.81
	HASYAMPA-NGILA-NG1		0.1%				-$20.22		$141.43
	SDGE_CFEIMP_BG	0.7%	0.1%	-$3.91	-$3.91	$36.83	-$5.16	-$5.16	$54.25
	SOUTHLUGO_RV_BG	0.1%	0.05%	-$74.07	$59.77	$80.34	-$5.40	$3.82	$6.26
	SLIC 1883001 Miguel_BKS_NG_2	1.2%	0.02%			$14.54			$3.77
	SLIC1852244PATH26LIOSN2S	2.8%		-$7.22	$6.02	$6.02			
	SLIC1883001 MIGUEL BKS	1.4%				$20.10			
	SLIC 1883001 Miguel_BKS_NG	1.0%				$14.23			
	SOUTHEAST_IMPORTS	1.0%				$8.73			
	SLIC 1846936_23021_Outage	0.4%		-$1.78		$12.45			
	SLIC 1908221_22_23028-9_NG	0.2%				-$33.54			

1.4.2 Congestion impact on average prices

This section provides an assessment of differences on overall average prices in the day-ahead and real-time markets caused by congestion between different areas of the ISO system. Unlike the analysis provided in the previous section, this assessment is made based on the average congestion component of the price as a percent of the total price during all congested and non-congested hours. This approach shows the impact of congestion taking into account the frequency that congestion occurs as well as the magnitude of the impact that congestion has when it occurs.[12]

Day-ahead price impacts

Table 1.3 shows the overall impact of day-ahead congestion on average prices in each load aggregation area in the second quarter of 2012 by constraint. These results show the following:

- Limitations on imports increased day-ahead prices in the SCE area above system average prices by \$1.21/MWh or around 4.7 percent. This constraint is designed to ensure that enough generation is being supplied from units within the SCE area in the event of a contingency that significantly limits imports into SCE or decreases generation within the SCE area.
- Day-ahead prices in the San Diego area were impacted the most by internal congestion associated with the outage of SONGS units 2 and 3. Congestion increased average day-ahead prices in the San Diego area above the system average by over \$2/MWh or about 7.7 percent, mainly because of import limitations into the SDG&E area. Congestion costs were decreased into SDG&E, however, as a result of import limitations into the Southern California Edison system (SCE_PCT_IMP_BG). This congestion caused SDG&E area prices to fall by over \$1/MWh, or just under 4 percent of the price.
- The overall impact of congestion on day-ahead prices in the PG&E area decreased prices by about \$1.29/MWh or about 5.4 percent from the system average. This occurs because prices in the PG&E area are lower when congestion occurs on the constraints that limit flows in the north-to-south direction and on constraints limiting flows into the SCE and SDG&E areas.

Table 1.3 Impact of congestion on overall day-ahead prices

	PG&E		SCE		SDG&E	
Constraint	\$/MWh	Percent	\$/MWh	Percent	\$/MWh	Percent
SCE_PCT_IMP_BG	-\$1.02	-4.19%	\$1.21	4.67%	-\$1.02	-3.81%
SLIC 1883001_SDGE_OC_NG	-\$0.22	-0.92%		0.01%	\$2.05	7.66%
SDGE_CFEIMP_BG	-\$0.01	-0.05%	-\$0.01	-0.05%	\$0.13	0.50%
PATH26_BG	-\$0.05	-0.21%	\$0.04	0.16%	\$0.04	0.16%
6110_TM_BNK_FLO_TMS_DLO_NG	\$0.05	0.21%	-\$0.03	-0.10%	-\$0.03	-0.10%
SLIC 1883001 Miguel_BKS_NG_2		-0.01%			\$0.06	0.23%
SDGE_PCT_UF_IMP_BG		-0.02%		-0.02%	\$0.05	0.18%
30060_MIDWAY _500_24156_VINCENT _500_BR_1 _2	-\$0.02	-0.09%	\$0.02	0.06%	\$0.02	0.06%
SLIC 1977036 Barre-Ellis NG		-0.01%			\$0.03	0.12%
SOUTHLUGO_RV_BG	-\$0.01	-0.03%	\$0.01	0.02%	\$0.01	0.03%
Other		-0.02%		-0.01%	\$0.05	0.17%
Total	-\$1.30	-5.4%	\$1.23	4.8%	\$1.39	5.2%

Real-time price impacts

Table 1.4 shows the overall impact of real-time congestion on average prices in each load area in the second quarter of 2012 by constraint. These results show the following:

[12] In addition, this approach identifies price differences caused by congestion without including price differences that result from variations in transmission losses at different locations.

- Congestion drove prices in the SCE area above system average prices by about $1.96/MWh or just over 6 percent. Most of this increase was due to limits on the percentage of load in the SCE area that can be met by total flows on all transmission paths into the SCE area (SCE_PCT_IMP_BG). Another major driver was congestion in the north-to-south direction on Path 26 and Path 15. SCE congestion fell by about $1/MWh (3 percent) when LBN_S-N was constrained.

- Prices in the San Diego area were impacted the most by internal congestion associated with the outage of SONGS, sometimes driving prices up and other times down. As with the day-ahead, congestion in the SCE area drove SDG&E prices down (e.g., SCE_PCT_IMP_BG) while SDG&E import constraints drove prices up (e.g., SLIC_1883001_SDGE_OC_NG). This situation caused average real-time prices in the San Diego area to increase only by about $0.53/MWh or about 2 percent above the system average.

- The overall impact of congestion on prices in the PG&E area was to change prices from the system average by about -$2.12/MWh or about -7.3 percent. This happens because prices in the PG&E area are lowered when congestion occurs on the constraints that limit flows in the north-to-south direction (e.g., Path 26) and on constraints limiting flows into the SCE and SDG&E areas. Congestion related to the Los Banos constraint increased prices over $1.12/MWh (almost 4 percent) during the second quarter.

Table 1.4 Impact of congestion on overall real-time prices

	PG&E		SCE		SDG&E	
Constraint	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
SCE_PCT_IMP_BG	-$1.55	-5.38%	$1.92	6.20%	-$1.55	-5.21%
PATH26_N-S	-$1.24	-4.31%	$1.01	3.27%	$1.01	3.41%
LBN_S-N	$1.12	3.87%	-$0.97	-3.14%	-$0.97	-3.27%
SLIC 1883001_SDGE_OC_NG	-$0.22	-0.78%			$1.88	6.33%
PATH15_N-S	-$0.65	-2.25%	$0.49	1.57%	$0.49	1.64%
6110_TM_BNK_FLO_TMS_DLO_NG	$0.33	1.15%	-$0.35	-1.12%	-$0.35	-1.17%
SLIC 1902749 ELDORADO_LUGO-1	$0.21	0.73%	-$0.14	-0.45%	-$0.25	-0.82%
7820_TL 230S_OVERLOAD_NG					$0.54	1.82%
LOSBANOSNORTH_BG	$0.18	0.62%	-$0.14	-0.46%	-$0.14	-0.48%
SLIC-1832324-SOL7	-$0.18	-0.64%	$0.12	0.40%	$0.12	0.42%
SLIC 1884984 Gould-Sylmar					-$0.30	-1.02%
230S overload for loss of PV					-$0.27	-0.91%
SDGEIMP_BG	-$0.02	-0.06%	-$0.02	-0.06%	$0.19	0.62%
HASYAMPA-NGILA-NG1	-$0.02	-0.08%			$0.16	0.54%
PATH26_BG	-$0.07	-0.23%	$0.05	0.16%	$0.05	0.17%
PATH15_S-N	$0.05	0.19%	-$0.05	-0.15%	-$0.05	-0.15%
SLIC 1832324_SOL7_REV1	-$0.04	-0.12%	$0.02	0.08%	$0.02	0.08%
24114_PARDEE _230_24147_SYLMAR S_230_BR_2 _1	-$0.01	-0.03%	$0.01	0.03%	-$0.04	-0.15%
SDGE_CFEIMP_BG		-0.01%		-0.01%	$0.04	0.13%
7680 Sylmar_1_NG		-0.01%		0.01%	-$0.04	-0.13%
SLIC 1977990 SYL_PAR_NG	$0.01	0.02%	-$0.01	-0.01%	-$0.03	-0.10%
Other		-0.01%	$0.01	0.02%	$0.01	0.02%
Total	-$2.12	-7.3%	$1.96	6.3%	$0.53	1.8%

While real-time congestion occurred less frequently than day-ahead congestion, its overall price impact was larger than what occurred in the day-ahead market. As mentioned earlier, the differences in congestion can be attributed to differences in market conditions as well as changes associated with conforming line limits to make market flows reflect actual flows as well as to provide a reliability margin.

2 Convergence bidding

The ISO implemented convergence (or virtual) bidding in the day-ahead market on February 1, 2011. Virtual bidding is a part of FERC's standard market design and is in place at all other ISO's with day-ahead energy markets. Virtual bidding on inter-ties was suspended on November 28, 2011.[13] Thus, the second quarter of 2012 represents the second full quarter with virtual bidding within the ISO system but not at the inter-ties.

Convergence bids at points within the ISO that are profitable may increase market efficiency by increasing the efficiency of day-ahead unit commitment and scheduling. Convergence bidding also provides a mechanism for participants to hedge against price differences due to congestion at different locations and between price differences between the day-ahead and real-time markets.

Participants in virtual bidding were paid net revenues of about $10 million in the second quarter. Most of these net revenues resulted from virtual demand bids at internal locations, reflecting the systematic trend of higher average real-time prices compared to day-ahead prices or the quarter. Internal virtual supply averaged around 1,040 MW while virtual demand averaged around 1,470 MW each hour during the quarter. The average hourly net virtual position in the second quarter was 430 MW of virtual demand. Net virtual demand within the ISO may help to increase market efficiency by increasing the efficiency of day-ahead unit commitment and scheduling, and reducing real-time prices.

Background

Convergence bidding allows participants to place purely financial bids for supply or demand in the day-ahead energy market. These virtual supply and demand bids are treated similar to physical supply and demand in the day-ahead market. However, all virtual bids clearing the day-ahead market are removed from the hour-ahead and real-time markets, which are dispatched based on physical supply and demand only. Virtual bids accepted in the day-ahead market are liquidated financially in the real-time markets as follows:

- Participants with virtual demand bids accepted in the day-ahead market pay the day-ahead price for this virtual demand. Virtual demand at points within the ISO is then paid the real-time price for these bids.
- Participants with accepted virtual supply bids are paid the day-ahead price for this virtual supply. Virtual supply at points within the ISO is then charged the real-time price.

Thus, virtual bidding allows participants to profit by arbitraging the difference between day-ahead and real-time prices. In theory, as participants take advantage of opportunities to profit through convergence bids, this activity should tend to make prices in these different markets closer. For instance:

[13] See 137 FERC ¶ 61,157 (2011) accepting and temporarily suspending convergence bidding at the inter-ties subject to the outcome of a technical conference and a further commission order. More information can also be found under FERC docket number ER11-4580-000.

- If prices in the real-time market tend to be higher than day-ahead market prices, convergence bidders will seek to arbitrage this price difference by placing virtual demand bids. Virtual demand will raise load in the day-ahead market and thereby increase prices. This increase in load and prices could also lead to commitment of additional physical generating units in the day-ahead market, which in turn could tend to reduce average real-time prices. In this scenario, virtual demand could help improve price convergence by increasing day-ahead prices and reducing real-time prices.

- If real-time market prices tend to be lower than day-ahead market prices, convergence bidders will seek to profit by placing virtual supply bids. Virtual supply will tend to lower day-ahead prices by increasing supply in the day-ahead market. This increase in virtual supply and decrease in day-ahead prices could also reduce the amount of physical supply committed and scheduled in the day-ahead market.[14] This would tend to increase average real-time prices. In this scenario, virtual supply could help improve price convergence by reducing day-ahead prices and increasing real-time prices.

2.1 Convergence bidding trends

Total hourly trading volumes increased to 2,500 MW in the second quarter from 2,300 MW in the first quarter. Also, the net virtual positions shifted from primarily net virtual supply in previous periods, to net virtual demand in the second quarter.

Figure 2.1 shows the monthly quantities of both virtual demand and supply offered and cleared in the market. Figure 2.2 illustrates an hourly distribution of the offered and cleared volumes over the second quarter. As shown in these figures:

- On average, 49 percent of virtual supply and demand bids offered into the market cleared in the second quarter.

- Cleared volumes of virtual demand outweighed cleared virtual supply in the second quarter by around 430 MW on average, whereas virtual supply outweighed virtual demand by around 300 MW on average in the first quarter.

- Virtual demand exceeded virtual supply during peak hours by about 760 MW, while during the off-peak hours virtual supply was greater than virtual demand by 230 MW. In the first quarter, peak hours had fairly balanced quantities of virtual demand and supply.

[14] This will not create a reliability issue as the residual unit commitment process occurs after the integrated forward market run. The residual unit commitment process removes convergence bids and re-solves the market to the ISO forecasted load. If additional units are needed, the residual unit commitment process will commit more resources.

Figure 2.1 Monthly average virtual bids offered and cleared

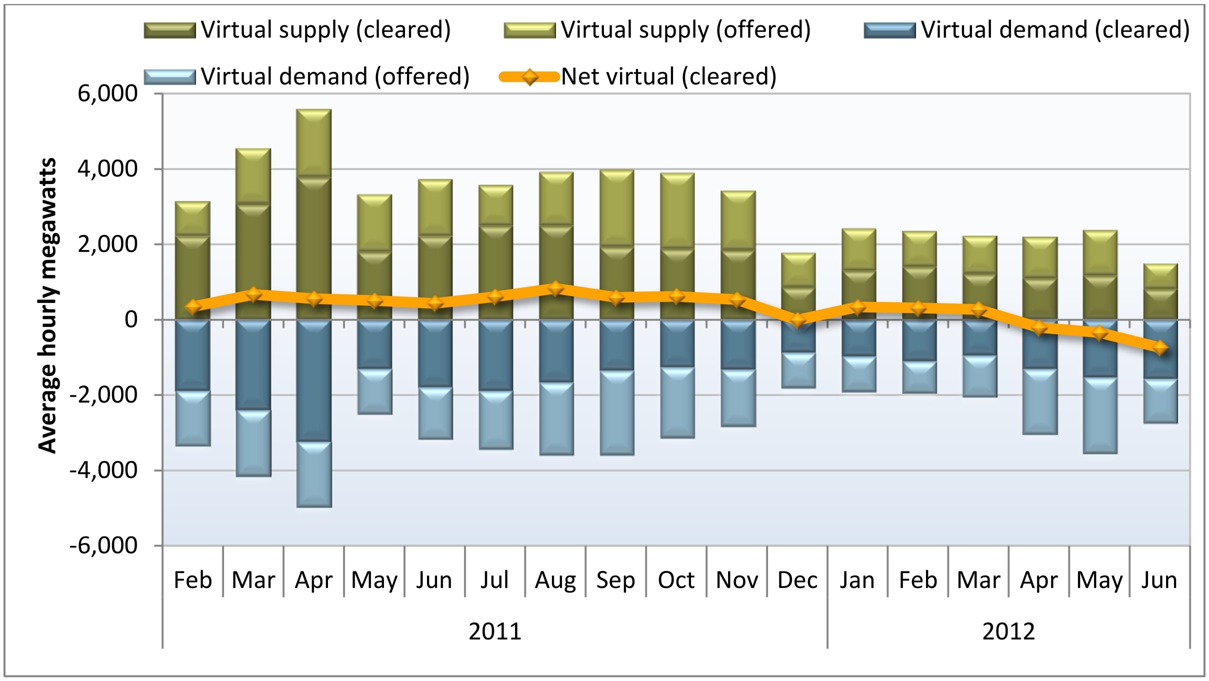


Figure 2.2 Hourly offered and cleared virtual activity (April – June)

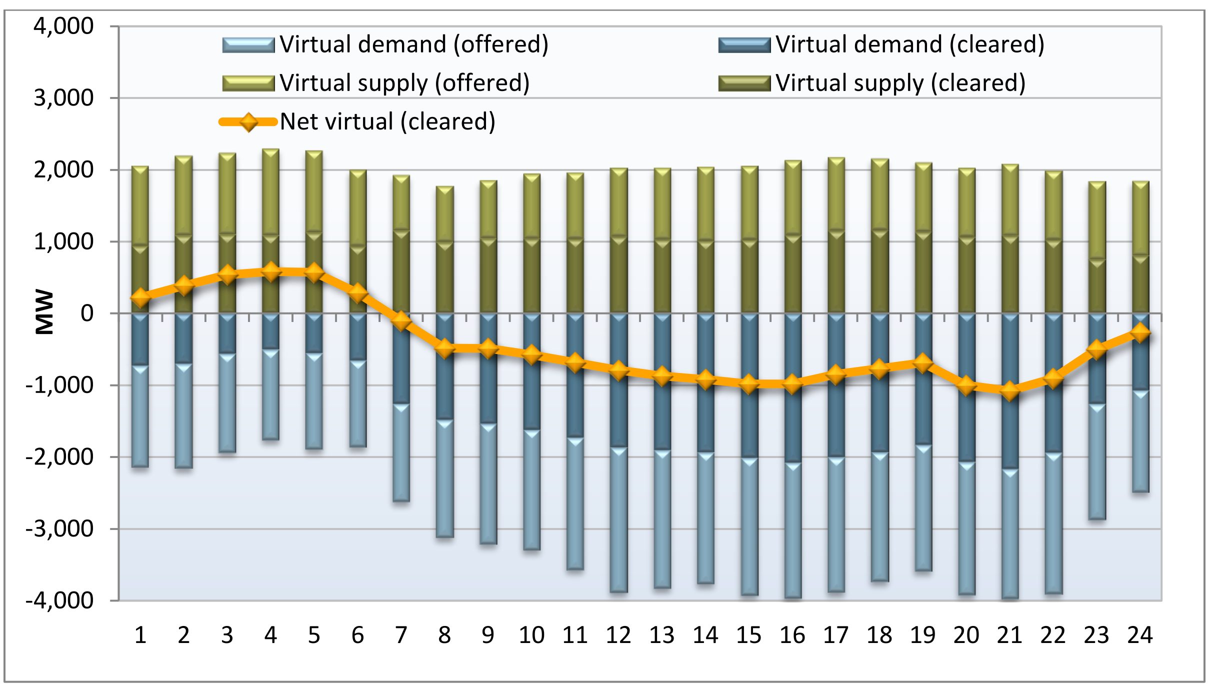
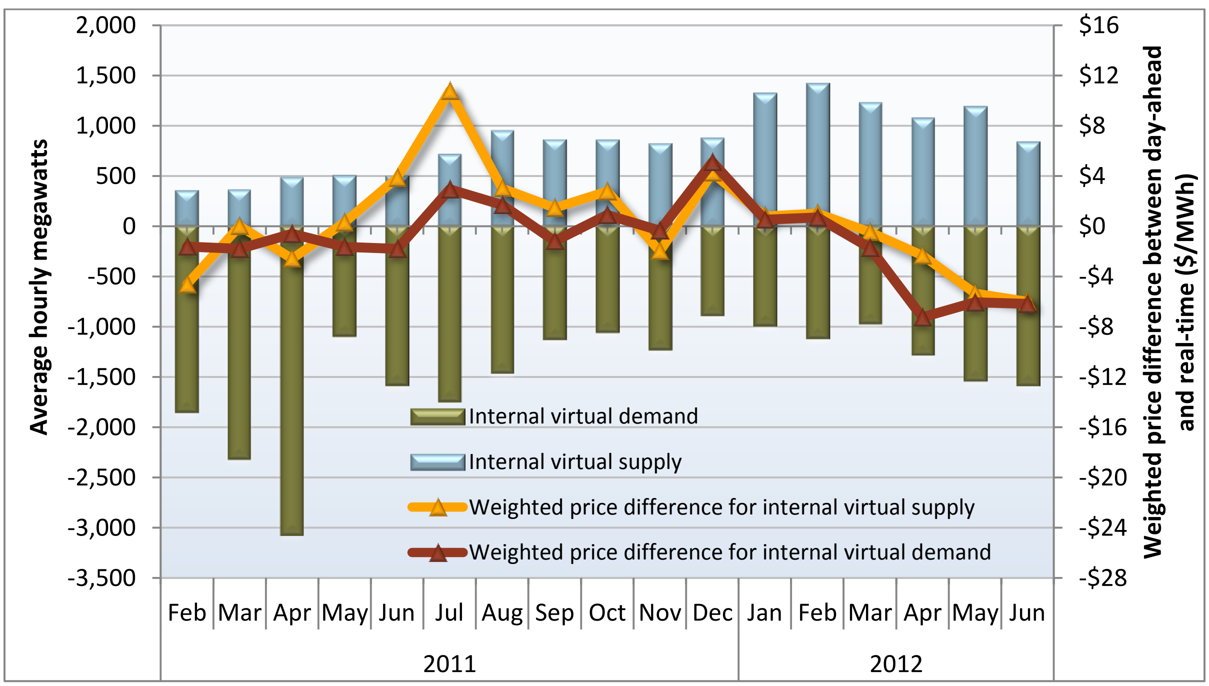


Figure 2.3 compares cleared convergence bidding volumes with the volume weighted average price differences at which these virtual bids were settled. The difference between day-ahead and real-time prices shown in Figure 2.3 represents the average price difference weighted by the amount of virtual bids clearing at different internal locations. As shown in Figure 2.3:

- Months in which the red line in Figure 2.3 is negative indicates that the weighted average price charged for internal virtual demand in the day-ahead market was lower than the weighted average real-time price paid for this virtual demand. Internal virtual demand volumes were consistent with weighted average price differences since March 2012. This indicates that virtual demand was profitable in the second quarter.
- Months in which the yellow line in Figure 2.3 is positive indicates that the weighted average price paid for internal virtual supply in the day-ahead market was higher than the weighted average real-time price charged when this virtual supply was liquidated in the real-time market. Beginning in March and continuing through the second quarter of 2012, virtual supply at internal locations were not profitable as the line was negative.
- As noted later in this section, a large portion of the internal virtual supply clearing the market was paired with internal demand bids at different internal locations by the same market participant. Such offsetting virtual supply and demand bids are likely used as a way of hedging or profiting from internal congestion within the ISO. When virtual supply and demand bids are paired in this way, one of these bids may be unprofitable independently, but the combined bids may break even or be profitable because of congestion.

Figure 2.3 Convergence bidding volumes and weighted price differences at internal locations



In many hours, particularly during the peak periods in May and June, the net cleared virtual position was consistent with the day-ahead and real-time price differences. Thus, average hourly convergence bidding volumes and prices indicate that net convergence bidding volumes at internal nodes were directionally consistent with converging prices between the day-ahead and real-time markets in many hours and may have helped to converge day-ahead with real-time prices.

Figure 2.4, Figure 2.5 and Figure 2.6 show average hourly net cleared convergence bidding volumes compared to the difference in the day-ahead and real-time system marginal energy prices in April, May and June, respectively. The blue bars represent the net cleared internal virtual position, whereas the green line represents the difference between the day-ahead and real-time system marginal energy prices.

- As shown in Figure 2.4, convergence bidding volumes in a majority of hours in April were consistent, on average, with price convergence at internal locations. The net convergence bidding volume direction and the price difference were most consistent between hours ending 7 through 15.
- In May, as seen in Figure 2.5, convergence bidding volumes in 21 hours were consistent, on average, with price convergence at internal locations. Consistency was best in the peak hours. As a result, the net virtual demand position grew even further over the course of the month, which was consistent with average price differences.
- Figure 2.6 shows that in the month of June, convergence bidding volumes again were directionally consistent with differences between day-ahead and real-time prices. The consistency of net cleared convergence bidding volumes with off-peak hourly prices improved while the consistency of volumes with peak prices decreased slightly compared to previous months.

Figure 2.4 Hourly convergence bidding volumes and prices – April

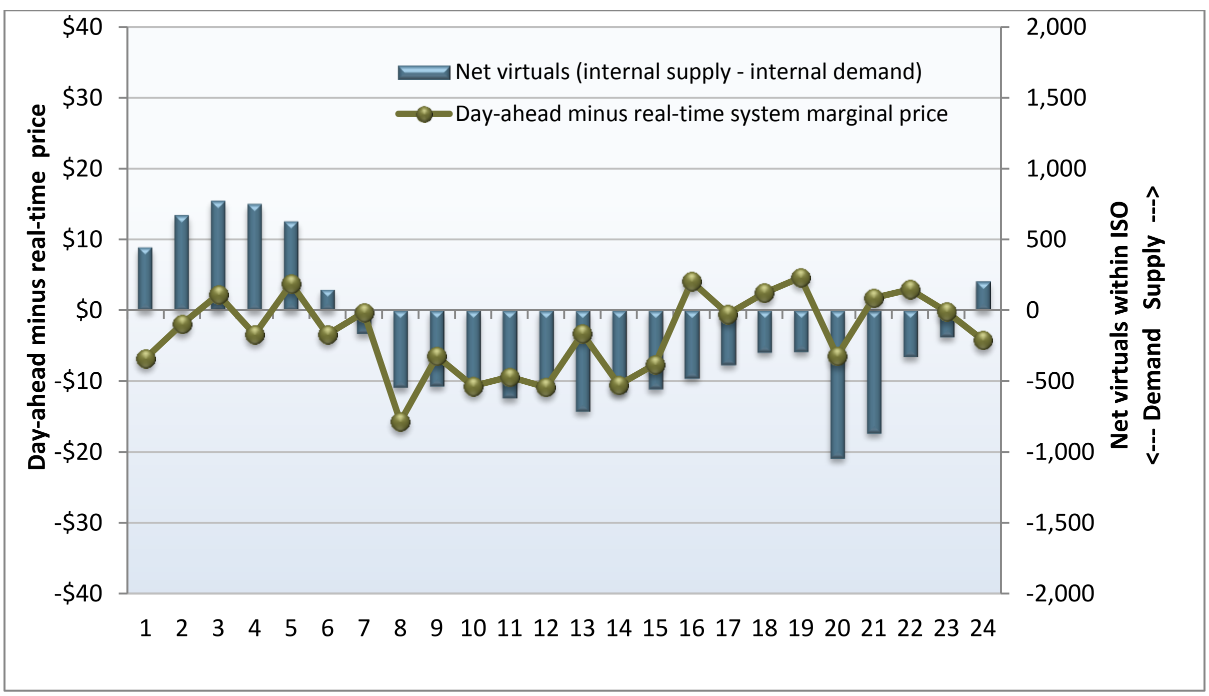


Figure 2.5 Hourly convergence bidding volumes and prices – May

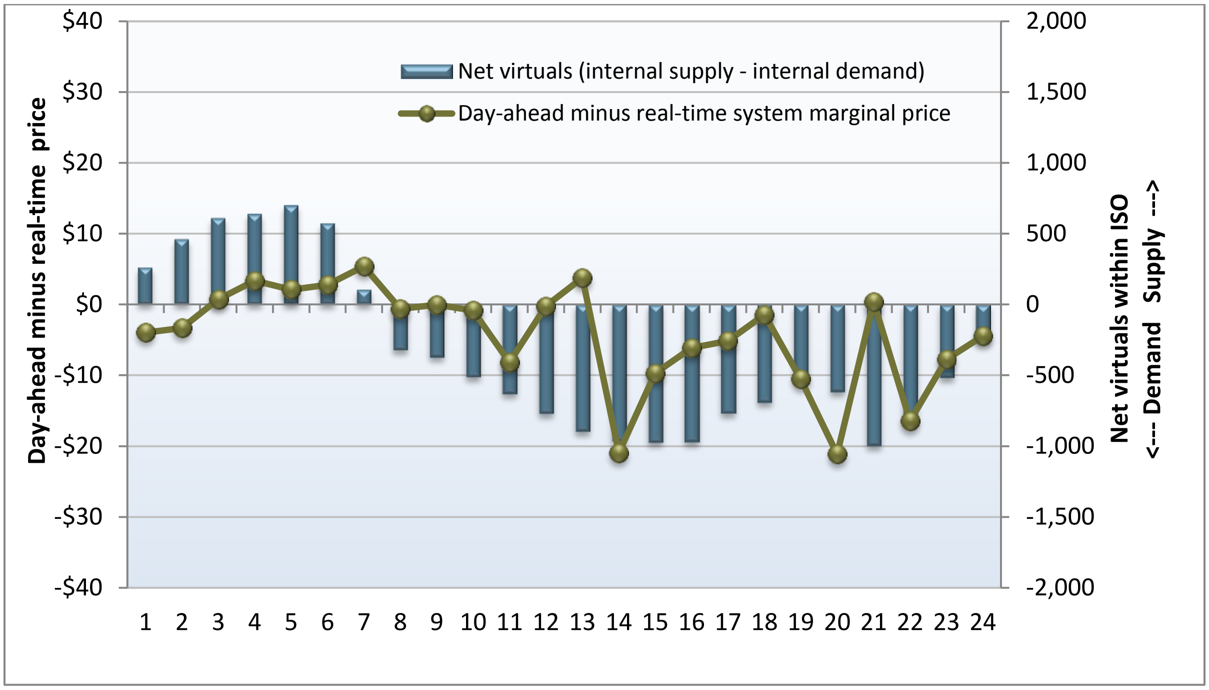
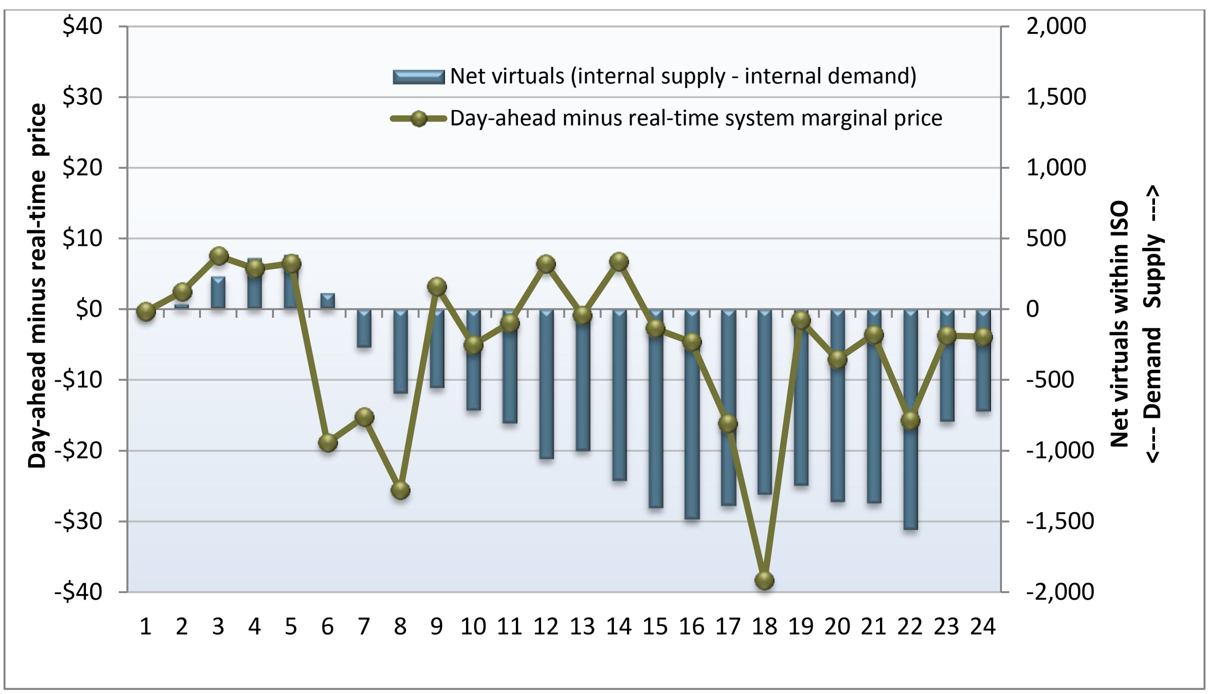


Figure 2.6 Hourly convergence bidding volumes and prices – June



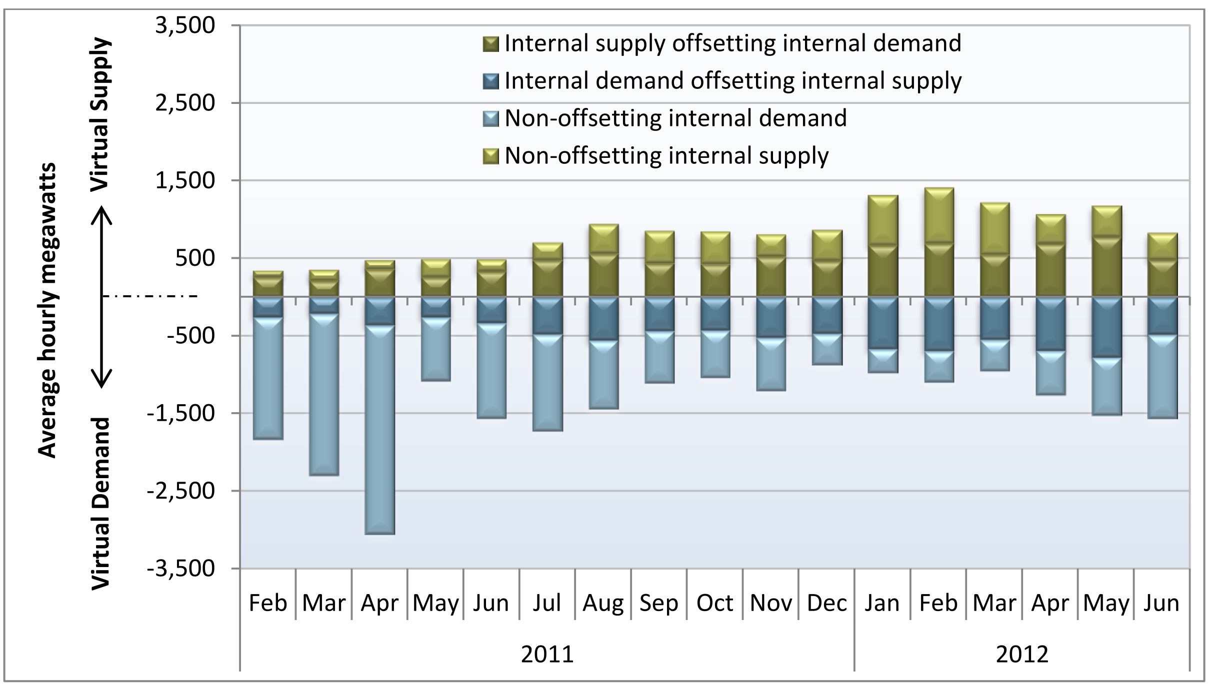
Offsetting virtual supply and demand bids at internal points

Market participants can also hedge congestion costs or earn revenues associated with differences in congestion between different points within the ISO by placing virtual demand and supply bids at different internal locations during the same hour.

Figure 2.7 shows the average hourly volume of offsetting virtual supply and demand positions at internal locations. The dark blue and dark green bars represent the average hourly offset between internal demand and internal supply by the same participants.[15] The light blue bars represent the remaining portion of internal virtual supply that was not offset by internal virtual demand by the same participants. The light green bars represent the remaining portion of internal virtual demand that was not offset by internal virtual supply by the same participants.

As shown in Figure 2.7, this type of offsetting virtual position at internal locations accounted for an average of about 650 MW of demand offset by 650 MW of virtual supply at other locations per hour in the second quarter. These offsetting bids represent about 70 percent of all cleared internal virtual bids. This suggests that since suspension of virtual bidding on inter-ties virtual bidding has been heavily used to hedge or profit from internal congestion.

Figure 2.7 Average hourly offsetting virtual supply and demand positions by same participants



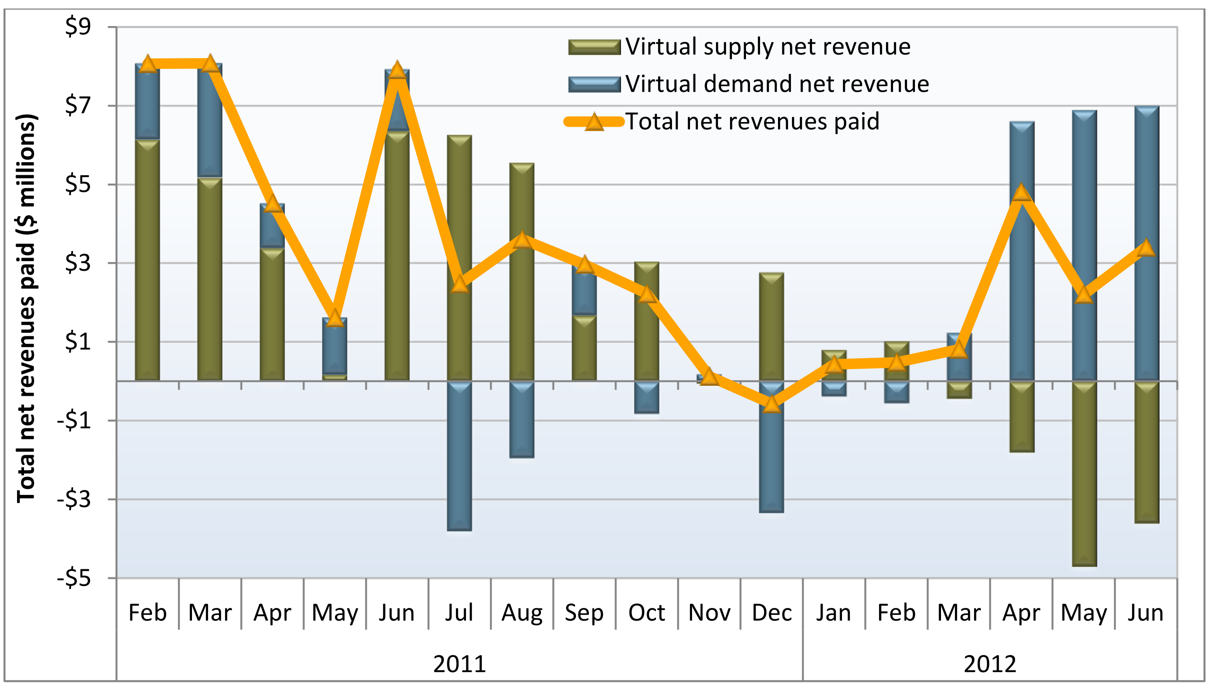
[15] When calculating the offset between each participant's accepted virtual supply and demand bids at internal points each hour, we did not include the portion (if any) of the participant's internal virtual demand bids that were offset by accepted virtual import bids by that participant in the months before virtual bidding at the inter-ties were suspended. This was done to avoid any potential double counting of internal virtual demand as offsetting virtual imports and virtual supply within the ISO during the same hour.

2.2 Convergence bidding payments

Figure 2.8 shows total monthly net payments for accepted virtual supply and demand bids. This figure shows the following:

- Virtual demand positions were consistently profitable in the second quarter. Between March and June, the higher frequency of real-time price spikes increased virtual demand revenues (see Section 1.1 for details).
- Since March, virtual supply bids were no longer profitable. This trend reflects that real-time prices (or congestion) were higher than day-ahead prices beginning in March 2012.
- Total net revenues paid to virtual bidders increased from the first to the second quarter of 2012. Total net revenues paid were higher in the second quarter because of the increased frequency of real-time price spikes (see Section 1.1 for further detail).
- In the second quarter of 2012, net revenues paid to convergence bidding entities totaled around $10 million. These payments were driven primarily by virtual demand revenues of $20 million, which was offset by revenue losses on virtual supply bids of about $10 million. As noted above, the virtual supply bids may be related to an attempt to arbitrage congestion, with one side of the congestion making money and the other side losing money.

Figure 2.8 Total monthly net revenues paid from convergence bidding



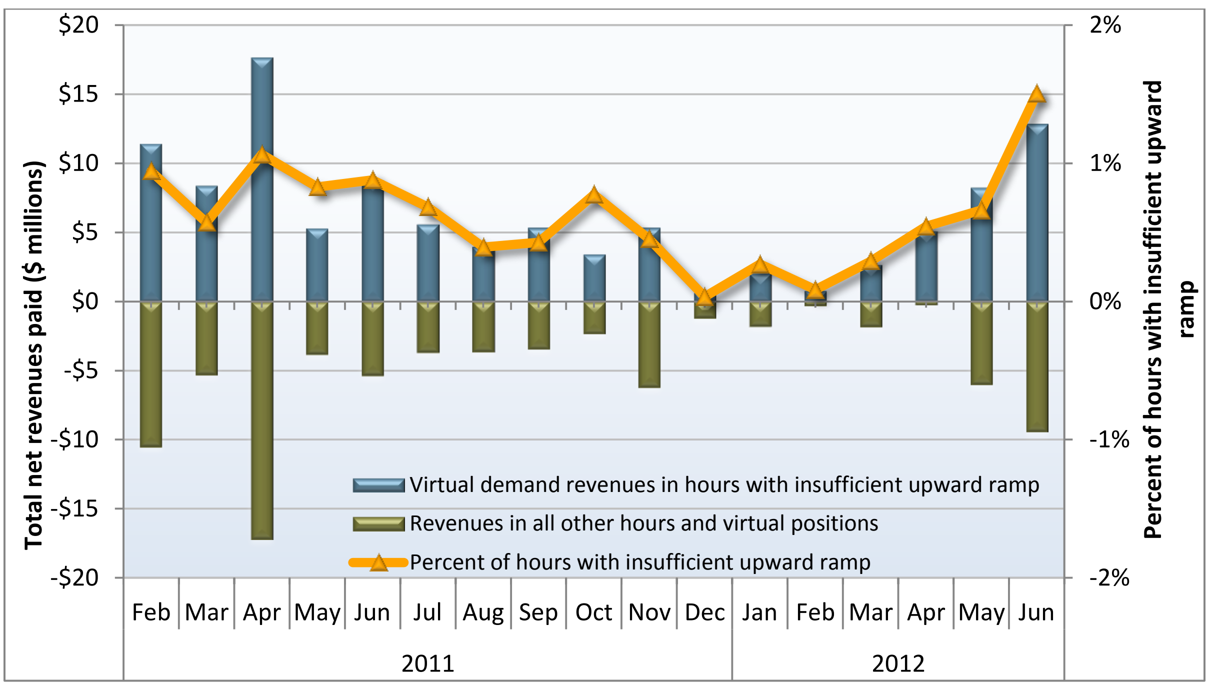
Net revenues at internal scheduling points

In the first quarter, virtual demand accounted for about 44 percent of cleared bids at internal locations; in the second quarter it increased to 59 percent. Virtual demand bids at internal nodes are profitable when real-time prices spike in the 5-minute real-time market. Historically, almost all net revenues paid for these internal virtual demand positions have resulted from a relatively small portion of intervals when the system power balance constraint becomes binding because of insufficient upward ramping capacity or with congestion.

Figure 2.9 compares total net revenues paid out for internal virtual bids during hours when the power balance constraint was relaxed because of short-term shortages of upward ramping capacity with the overall net revenues of internal virtual bids during all other hours. As shown in Figure 2.9:

- Although upward ramping capacity was insufficient in about 1 percent of the hours in the quarter, these hours accounted for all net revenues paid for internal virtual demand. Revenues paid for virtual demand during these brief but extreme price spikes can be high enough to outweigh losses when the day-ahead price exceeds the real-time market price. In fact, having a single 5-minute interval price spike can yield enough aggregate revenue to compensate for losses in the remaining hours of the day.
- During the other 99 percent of intervals when sufficient ramping capacity was available, virtual demand bids were highly unprofitable. Since February 2012, the frequency of real-time price spikes has increased. As a result, the revenues of internal virtual demand bids exceeded $12 million in June. As noted earlier (Section 1.1), the frequency of real-time price spikes increased mostly because of congestion and upward ramping shortages.

Figure 2.9 Net revenues paid for convergence bids at internal scheduling points



These price spikes are typically associated with brief shortages of ramping capacity and congestion. In theory, virtual demand at internal scheduling points can potentially result in additional capacity being committed and available in the real-time market. In practice, however, the impact of internal virtual demand on real-time price spikes appears to have been limited by the fact that any additional capacity available to convergence bidding may not be enough to resolve congestion or the short-term ramping limitations. This is further exacerbated by the hour-ahead market, which does not reflect the same system conditions and reduces net imports, decreasing the benefits of additional capacity added in the day-ahead market.

Also, in the event of over-generation, real-time prices can be negative, but rarely fall below the bid floor of -$30/MWh. This diminishes the risk of market participants losing substantial money by bidding virtual demand as well as reduces the potential benefits to virtual supply bids at internal nodes.

2.3 Changes in unit commitment

If physical generation resources clearing the day-ahead energy market are less than the ISO forecasted demand, the residual unit commitment ensures that enough additional capacity is available to meet the forecasted demand. Total direct residual unit commitment costs, which are the residual unit commitment clearing price times the non-resource adequacy capacity cleared in each hour, were around $21,000 in the second quarter of 2012, down from $350,000 in the first quarter of 2012. Bid cost recovery payments for capacity committed in the residual unit commitment process, which account for start-up and minimum load costs for units and real-time revenues, were around $330,000 in the second quarter of 2012, down from $1.1 million in the previous quarter.

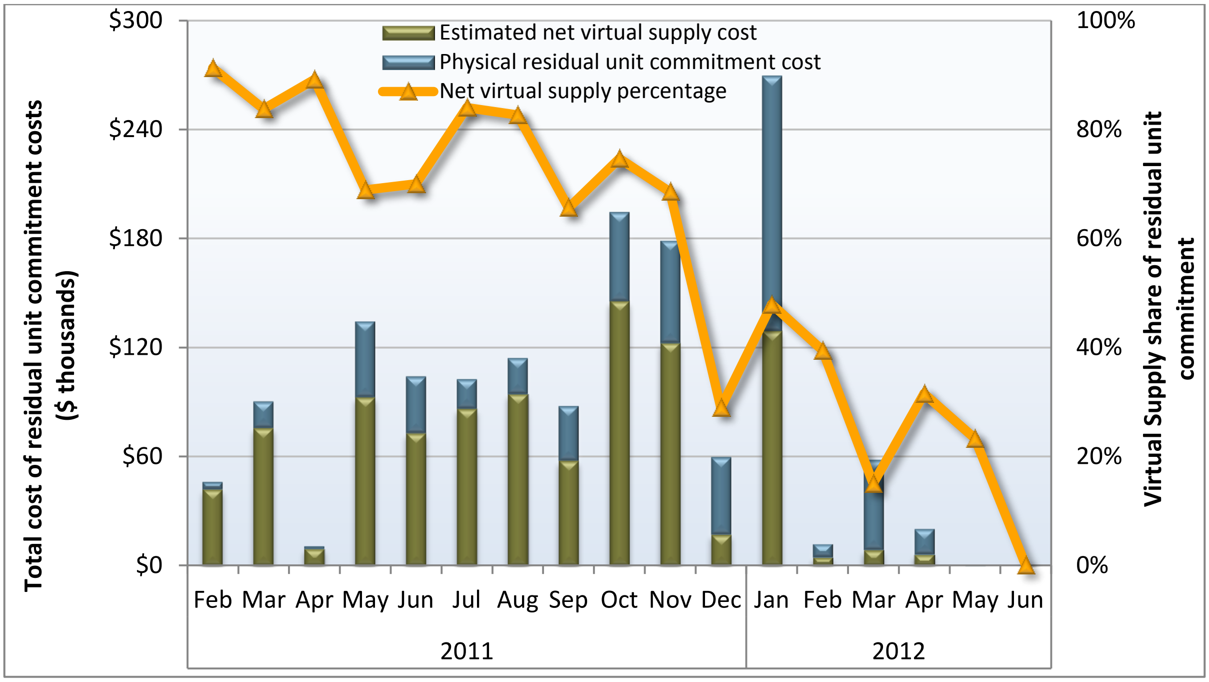
As noted above, the amount of cleared virtual demand increased significantly in the second quarter relative to previous quarters. The increase in virtual demand caused a higher amount of generation to clear in the day-ahead market. Because of the higher amount of capacity scheduled in the day-ahead market, less capacity was added by the residual unit commitment process. Therefore, the amount of direct residual unit commitment costs and bid cost recovery payments declined.

The residual unit commitment adds more capacity to meet differences between forecasted and bid-in demand, to offset the loss of virtual supply and to meet additional local reliability needs. DMM has estimated the share of the total residual unit commitment cost that is attributable to virtual supply by reviewing the factors that led to residual unit commitment and comparing the virtual supply as a percentage of the total.

Figure 2.10 compares the relationship between the cost of the residual unit commitment and the share of net virtual supply. The blue bars represent the estimated physical portion of the residual unit commitment cost, whereas the green bars represent the estimated cost attributed to the net virtual supply. The yellow line illustrates the share of net virtual supply. Figure 2.10 shows the following:

- In 2011, approximately 73 percent of the residual unit commitment costs were attributed to the virtual supply. At that time, the overall net virtual position was virtual supply from the inter-ties.
- In 2012, the residual unit commitment costs were high in January, but dropped afterwards. This change was consistent with the shift from net virtual supply to net virtual demand. As a result, the share of net virtual supply decreased to 26 percent in the first half of 2012.

Figure 2.10 Virtual supply share of total residual unit commitment cost



3 Special Issues

3.1 Real-time flexible ramp constraint performance

In December 2011, the ISO began enforcing the flexible ramping constraint in the upward ramping direction in the 15-minute real-time pre-dispatch and the 5-minute real-time dispatch markets. The constraint is only applied to internal generation and proxy demand response resources and not to external resources.[16] The total payments for flexible ramping resources during the first six months of the year were around $14.8 million.[17] For sake of comparison, costs for spinning reserves totaled about $12 million during the same period.

Application of the constraint in the 15-minute real-time pre-dispatch market ensures that enough capacity is procured to meet the flexible ramping requirement. The requirement is currently set to around 300 MW, down from a default level of 450 MW in the first quarter based on the observed utilization of the flexible ramping capacity in the real-time market. The flexible ramping constraint was implemented to account for the non-contingency based variations in supply and demand between the 15-minute real-time pre-dispatch and the 5-minute real-time dispatch. The additional flexible ramping capacity is designed to supplement the existing non-contingent spinning reserves in the system in managing these variations.

The ISO procures the available 15-minute dispatchable capacity from the available set of resources in the 15-minute real-time pre-dispatch run. If there is sufficient capacity already online, the ISO does not commit additional resources in the system, which often leads to a low (or often zero) shadow price for the procured flexible ramping capacity. During intervals when there is not enough 15-minute dispatchable capacity available among the committed units, the ISO can commit additional resources (mostly short-start units) for energy to free up capacity from the existing set of resources. The short-start units can be eligible for bid cost recovery payments in real-time.[18] A procurement shortfall of flexible ramping capacity will occur where there is a shortage of available supply bids to meet the flexible ramping requirement or when there is energy scarcity in the 15-minute real-time pre-dispatch.[19] As shown below, payments at such times accounted for more than half of flexible ramping costs.

Analysis of the flexible ramping constraint

Since implementation, DMM has monitored the daily flexible-ramping constraint activity and cost. As part of this analysis, DMM has provided a monthly summary of the overall flexible ramping constraint

[16] See the December 12, 2011 FERC order for ER12-50-000 at: http://www.caiso.com/Documents/2011-12-12_ER12-50_FlexiRamporder.pdf.

[17] On July 27, 2012, the ISO filed an offer of settlement for the flexible ramping constraint. See the following for further information: http://www.caiso.com/Documents/July272012Offer-SettlementRegarding-ISOFlexibleRampingConstraintAmendment-DocketNoER12-50-000.pdf.

[18] Further detailed information on the flexible ramping constraint implementation and related activities can be found here: http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/FlexibleRampingConstraint.aspx.

[19] The penalty price associated with procurement shortfalls is set to just under $250.

activity and a summary of the hourly compensation profile to generators for providing flexible-ramping capacity.

Table 3.1 provides a review of the monthly flexible ramping constraint activity in the 15-minute real-time market since the beginning of 2012. The table highlights the following:

- The flexible ramping constraint binding frequency has varied since implementation. The number of binding intervals spiked to about a quarter of the total 15-minute intervals during the months of April and May. This increase was due to the lack of available ramping capacity in the system. The lower online capacity was a result of a combination of low seasonal load during the second quarter and the high level of generation from hydro and other renewable resources in the footprint.
- The frequency of procurement shortfalls peaked in May at over 6 percent of all 15-minute intervals, about one quarter of the intervals in which the flexible ramping constraint was binding.
- The total payments to generators for the flexible-ramping constraint increased from previous months, peaking at over $4 million during the month of May and falling to about $1.5 million in June.

Table 3.1 Flexible ramping constraint monthly summary

Month	Total payments to generators ($ millions)	15-minute intervals constraint was binding (%)	15-minute intervals with procurement shortfall (%)	Average shadow price when binding ($/MWh)
Jan	$2.45	17%	1.0%	$38.44
Feb	$1.46	8%	1.3%	$77.37
Mar	$1.90	12%	1.0%	$42.75
Apr	$3.37	22%	1.5%	$39.86
May	$4.11	23%	6.0%	$79.48
Jun	$1.49	13%	2.3%	$52.18

Figure 3.1 shows the monthly flexible ramping payments to generators, which is the total procured volume times the shadow price of the constraint. The green bar shows the payments made during intervals with procurement shortfalls and the blue bar shows the payments in all other periods.

Figure 3.2 shows the hourly flexible ramping payment distribution during the first quarter of the year. As seen in the figure, most payments have been for ramping capacity during the peak hours. Natural gas-fired capacity accounted for about 70 percent of these payments with hydro-electric capacity accounting for most of the remaining 30 percent.

Figure 3.1 Monthly flexible ramping constraint payments to generators

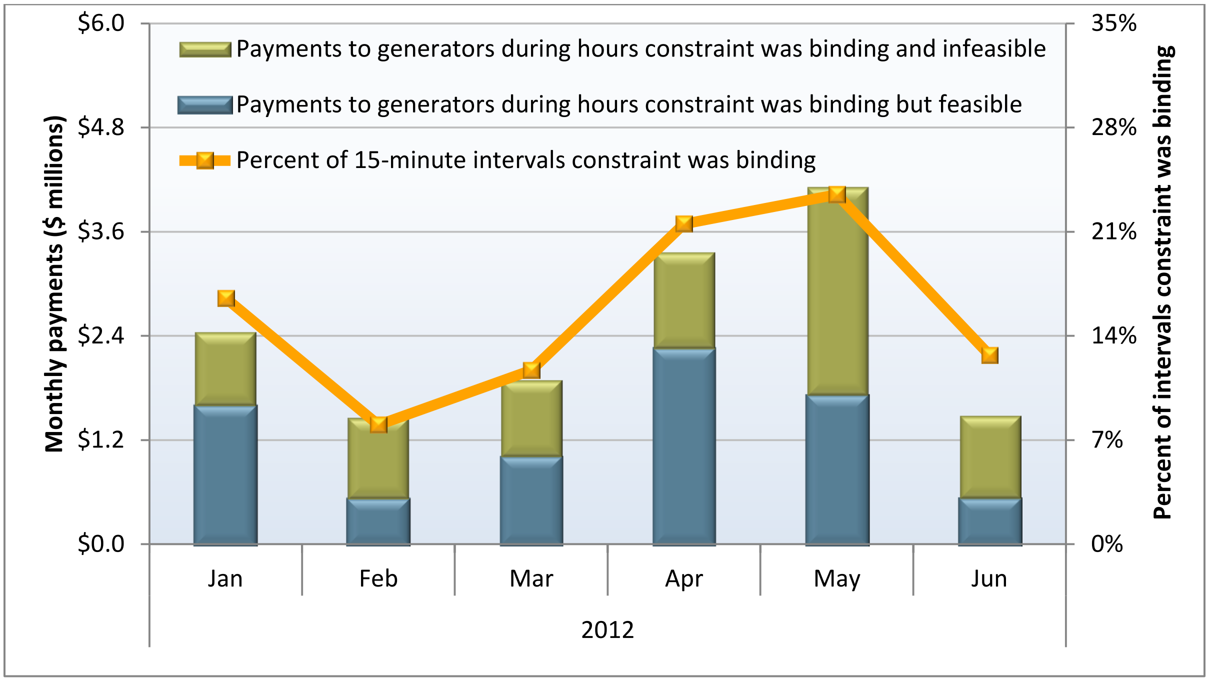


Figure 3.2 Hourly flexible ramping constraint payments to generators (April – June)

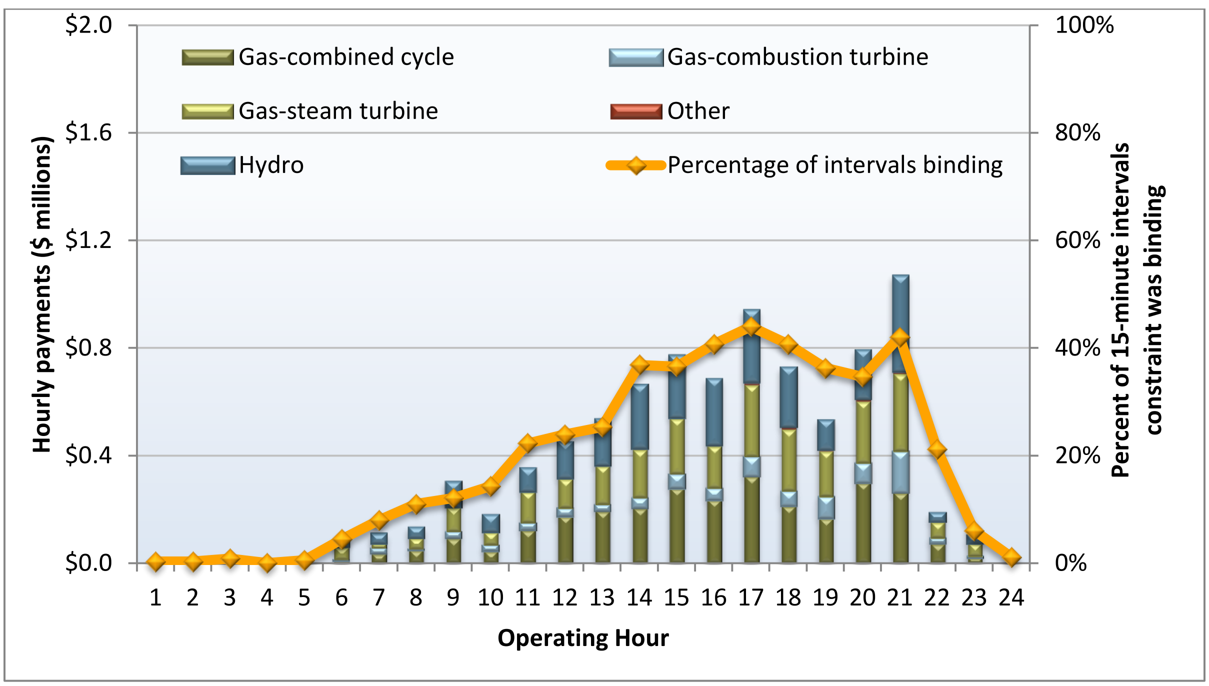
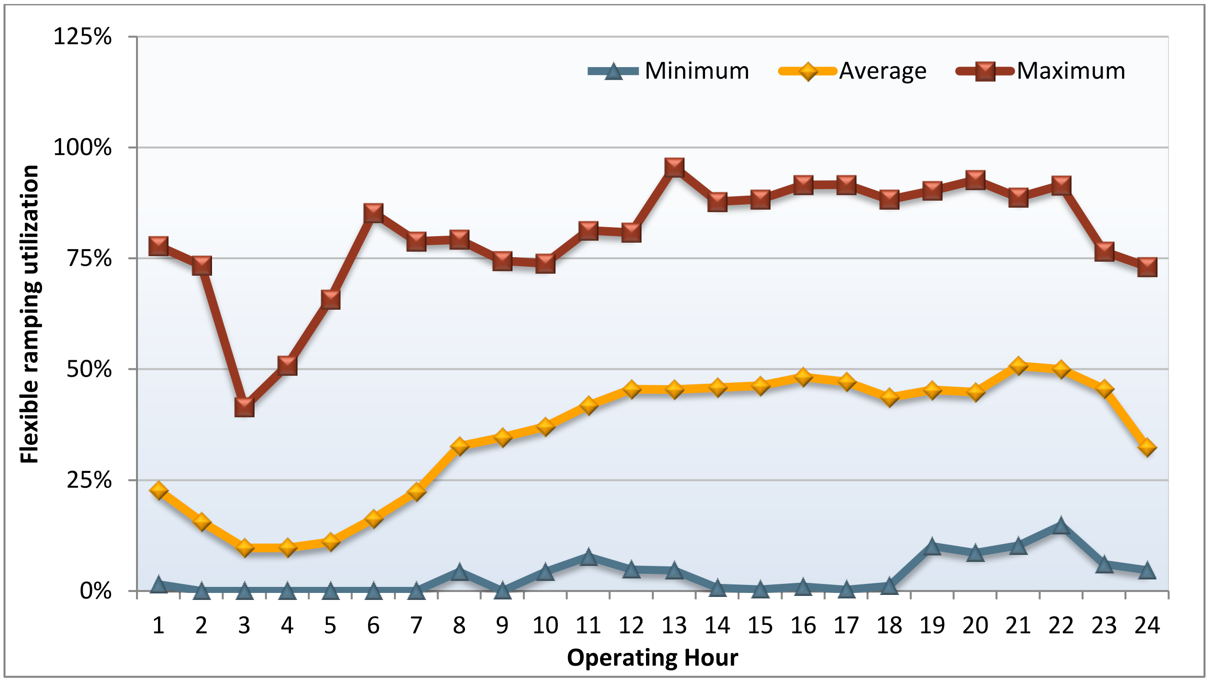


Figure 3.3 Flexible ramping utilization by hour (April – June)



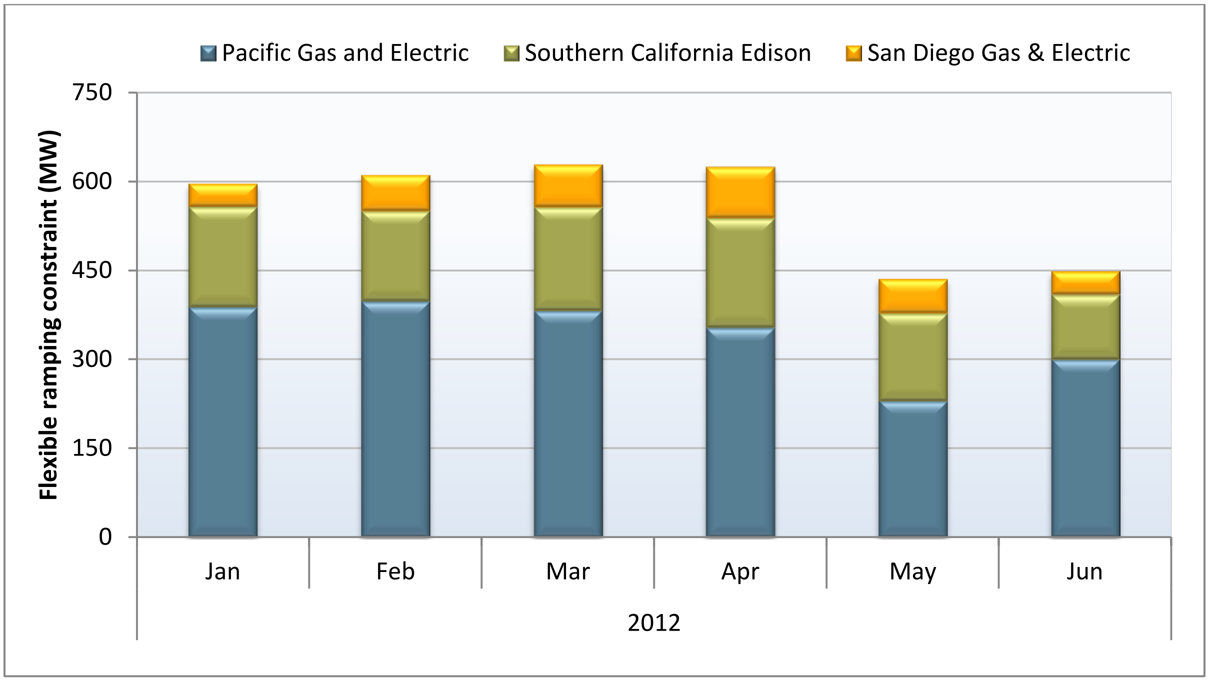
DMM uses the ISO's methodology along with settlement data to calculate the flexible ramping capacity utilization during the second quarter. The metric determines how much of the procured flexible ramping capacity in the 15-minute real-time pre-dispatch is utilized in the 5-minute real-time dispatch. Figure 3.3 shows the minimum, average and maximum hourly utilization of procured flexible ramping capacity in the 5-minute real-time dispatch. The average utilization of procured flexible ramping varies from about 10 percent in hour ending 3, to a high of about 51 percent in hour ending 21. The utilization is a function of prevailing system conditions, including load and generation levels. The range of hourly average utilization varied from a low of 0 percent to a high of about 95 percent during the quarter. The utilization was at 100 percent at individual 5-minute intervals during load ramping hours and during peak periods. The utilization during the intervals when the flexible ramping constraint was binding was only marginally higher than during non-binding intervals.

Flexible ramping regional procurement

Figure 3.4 shows the procurement of flexible ramping capacity by investor-owned utility area. During the year, over 60 percent of the capacity procured for flexible ramping constraint was in the Pacific Gas and Electric area. This real-time flexible capacity can be deployed during instances of tight system-wide conditions. However, the majority of this capacity cannot be utilized when there is congestion in the southern part of the state.

For example, in the month of June only 39 MW of flexible ramping capacity was procured in the San Diego region, on average. Thus, only a small amount of dispatchable flexible ramping capacity was available to resolve ramping conditions in 5-minute real-time intervals with San Diego congestion. Similarly, during real-time intervals with congestion into the SCE area, only about 110 MW of generation in the month of June was available to ramp when 5-minute real-time congestion occurred.

Figure 3.4 Flexible ramping constraint by investor-owned utility area



DMM continues to recommend that the ISO review how the flexible ramping constraint has affected the unit commitment decisions made in the 15-minute real-time pre-dispatch. DMM believes that evaluating commitment decisions is an important measure of the overall effectiveness of the constraint. In addition, identifying commitment changes caused by the flexible ramping constraint will help in calculating secondary costs related to the flexible ramping constraint. These secondary costs include additional ancillary services payments and additional real-time bid cost recovery payments paid to short-term units committed to deliver energy and displace capacity on other units to provide flexible ramping capacity. Furthermore, DMM recommends that the ISO continue to fine tune the flexible ramping constraint to increase its effectiveness, particularly during periods of congestion.

3.2 Performance of new local market power mitigation procedures

On April 11, 2012, the ISO implemented the first phase of the new competitiveness assessment and mitigation mechanism to address local market power. This included enhancing the competitive path assessment mechanism and mitigation trigger in the day-ahead market. The ISO also incorporated virtual bids into the day-ahead mitigation run and began clearing that market run to bid-in demand instead of forecast load. This section presents analysis of the impact of these changes on the accuracy of local market power mitigation in the day-ahead market.[20]

[20] Further detailed information on the local market power mitigation implementation and related activities can be found here: http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalMarketPowerMitigationEnhancements.aspx.

These enhancements have improved the accuracy of local market power mitigation considerably. One of the factors that creates local market power is congestion. Including convergence bids in the mitigation run and clearing that run to bid-in demand (not forecast demand) has improved accuracy of the mitigation run prediction of where congestion will occur in the actual market run from 45 percent to 93 percent. This increased accuracy is due to more closely aligned model inputs between the mitigation run and the market run.

The move to a dynamic competitive path assessment has also improved the accuracy of identifying where local market power exists. Because the prior approach to determining path competitiveness was performed off-line and well in advance of market operation (up to 4 months), the methodology took a conservative approach accounting for more extreme possibilities. The new approach assesses competitiveness based on actual system and market conditions observed by the market software. The accuracy of the competitive path designations increased from 32 percent to 85 percent. Most of this improvement is attributed to more accurate designations of competitive constraints as the default designation of "non-competitive" is eliminated and the new approach positively tests all binding constraints.

Finally, the new mitigation trigger, which breaks down the price, has improved the accuracy of local market power mitigation by eliminating the unintended mitigation inherent with the prior approach. The new price decomposition method will apply bid mitigation only to resources where the locational marginal price is increased by congestion on an uncompetitive constraint. The prior approach inferred which resources had local market power based on a comparison of dispatch with and without uncompetitive constraints applied in the market model. This indirect approach resulted in a high degree of unintended bid mitigation where the inference of local market power was incorrect.[21] The price decomposition eliminates this unintended mitigation by identifying the opportunity to exercise local market power through direct measurement of the price impact of local market power at each resource.

The impact of mitigation at the resource level can be observed by measuring the change in bid price at the point where the resource is dispatched in the market. In 94 percent of the mitigation instances, the resource's bid price is not impacted. In these cases, the submitted bid was priced at or below the default energy bid at the point of market dispatch. In the remaining 6 percent of instances, the majority of resources have their bid price decreased by $10/MWh or less as a result of mitigation.

Improved accuracy of identification of local market power

Local market power is created by two factors: 1) congestion that limits the supply of imported electricity into the congested area; and 2) insufficient or concentrated control of supply within the congested area. Identification of where local market power will exist based on these two causes was enhanced with this first phase of implementation, which ultimately improved the accuracy of the local market power mitigation.

The first enhancement is in the mitigation run's ability to predict congestion in the subsequent market run where local market power may be exercised. Bid mitigation is applied after the mitigation run is completed, and the set of resulting mitigated bids is then used in the market run. The ability of the mitigation run to accurately predict congestion that occurs in the market run, and therefore identify

[21] See DMM report to the ISO Board of Governors at http://www.caiso.com/Documents/Impact%20assessment%20of%20proposed%20local%20market%20power%20mitigation%20enhancements for more detail.

where local market power may exist, directly impacts the accuracy and effectiveness of the mitigation process.

The first phase implementation also included adding convergence bids to the mitigation run as well as clearing supply against bid-in demand. Previously, no convergence bids were included in the mitigation run and the mitigation run was cleared against forecast load. These two enhancements brought the mitigation run more in line with the actual market run. This resulted in improved congestion prediction and consequently improved identification of where local market power may exist.

The consistency of the occurrence of congestion between the mitigation run and the market run is shown in Table 3.2 for the day-ahead market. Prior to the enhancements, the mitigation run accurately predicted congestion on a constraint only 45 percent of the time and under-predicted congestion nearly as often – 37 percent of the time. Under-prediction reflects under-identification of potential local market power and precludes the mitigation process from further evaluation and application of bid mitigation. These are instances where local market power may exist and be exercised but would not be mitigated.

Table 3.2 Congestion parity between mitigation run and market run (Q2 of 2011 and 2012)[22]

Mitigation Run vs Market Run	2011 Q2	2012 Q2
Consistent	45%	93%
Over-identified	18%	3%
Under-identified	37%	4%

The accuracy of the congestion prediction increased to 93 percent as a result of the mitigation enhancements implemented in April. Moreover, the frequency of under-identification of congestion and potential local market power decreased markedly to 4 percent. While there were other areas of improvement in accuracy that are discussed below, this improvement in congestion prediction represented a considerable increase in the accuracy of local market power mitigation.

Another area where the mitigation enhancements improved accuracy is in evaluating the competitiveness of supply to relieve congestion on binding constraints. While congestion can create the potential for market power to exist, the amount and concentration of control of supply available to meet demand in the congested area determine whether local market power exists as a result of the congestion.

Historically, DMM has performed quarterly competitiveness assessments that have been used in the market model as part of the local market power mitigation process.[23] These studies used historical data and considered a range of possible system conditions that may occur during the period where the path determinations will be used in the mitigation process. Because the study and application of results was

[22] These figures represent instances where internal paths were congested in the mitigation run, the market run, or both. Instances where a line was not congested in either are not included. This is due to the large number of transmission constraints and the relative infrequency of congestion. The mitigation run consistently predicts no congestion in the market run in a very large number of instances.

[23] DMM uses a residual supplier test for the competitiveness assessments. For more detailed description of the residual supplier test applied, see http://www.caiso.com/Documents/WhitePaper-CompetitivePathAssessment.pdf.

forward looking, a more conservative approach to determining competitiveness was taken. A wide range of load and hydro-electric conditions were considered. A failure in any one of the many simulated hours forced a non-competitive designation and any constraint congested less than 500 hours in the past year was automatically deemed non-competitive.

The mitigation enhancements moved the evaluation of competitiveness into the market software so that it is now run in-line with the market. A congested path is deemed competitive unless the residual supplier index, with the three largest effective suppliers removed, is less than one. This dynamic competitive path assessment leverages up-to-date information regarding system and market conditions, and provides a more targeted and accurate assessment of the supply conditions in areas where congestion may have created local market power.

There were about 5,300 binding constraint hours in the mitigation run between April 11 and June 30. The dynamic competitive path assessment deemed 79 percent of these instances competitive and the remaining 21 percent non-competitive. A comparison of path designations between the static and dynamic approaches is presented in Table 3.3.[24] These are compared to the competitiveness as measured in the market run using the same methodology as the dynamic competitive path assessment. These results indicate that the dynamic competitive path assessment is more accurate in assessing competitive paths. For instance, the accuracy rate for competitive designations for the dynamic competitive path assessment was 98 percent (51 percent binding were deemed competitive whereas 52 percent binding measured competitive).

Also, the dynamic competitive path assessment performs comparably to the static approach in assessing non-competitive paths, and is 85 percent accurate overall, where the static approach was only 32 percent accurate.

The figures in Table 3.3 are color coded to indicate accuracy or the nature of the inaccuracy. Green indicates an accurate path designation in the mitigation run compared to our measurement of competitiveness in the actual market run. Blue indicates the mitigation run deemed the constraint non-competitive when it was measured as competitive in the actual market run. These instances reflect the potential for unnecessary mitigation since the constraint was measured competitive in the actual market run. Orange indicates the mitigation run deemed the constraint competitive when it was measured in the actual market run to be non-competitive. These instances reflect the potential for under-identification of local market power and potential under-mitigation.

As indicated in the table, the dynamic competitive path assessment results in considerably more accurate path designations, and consequently more accurate application of local market power mitigation, than does the static approach. Most of the improvement in accuracy arises from fewer instances where the assessment falsely designated a path non-competitive.

[24] This comparison is intended to provide an indication of the accuracy of the competitiveness designation that stems from the mitigation compared to the competitiveness observed in the actual market run. We note two important aspects that may affect the parity of path designations. First, the mitigation run uses unmitigated bids and the actual market run uses bids that were mitigated. This may change the relative economics of individual resources between the two runs. This, in turn, may result in a different dispatch which can change the amount of available capacity that is used in the residual supply index calculation and ultimately result in a different path designation. Second, DMM calculates the residual supply index for the market run where the calculation for the mitigation run is performed by the market software. The DMM calculation is designed to mirror the calculation performed in the market software and perform when benchmarked, however slight differences may exist. If the residual supply index is different between the two runs but both figures have the same relationship to the threshold of one then both path designations will be the same.

Table 3.3 Static and dynamic path designations compared to measured competitiveness in the market run (April 11 – June 30, 2012)[25]

			As measured in the market run	
			Competitve	**Non-competitive**
As measured in the mitigation run	Static CPA	Competitive	1%	17%
		Non-competitive	51%	31%
			52%	48%
	Dynamic	Competitive	51%	14%
		Non-competitive	1%	34%
			52%	48%

Improvement in the application of bid mitigation

Another mitigation enhancement feature was the improvement of the mitigation trigger. This trigger, which breaks down the price, has improved the accuracy of local market power mitigation by eliminating the unintended mitigation inherent with the prior approach. The price decomposition method will apply bid mitigation only to resources where the locational marginal price is increased by congestion on an uncompetitive constraint. The prior approach inferred which resources had local market power based on a comparison of dispatch with and without uncompetitive constraints applied in the market model. This indirect approach resulted in a high degree of unintended bid mitigation where the inference of local market power was incorrect. The price decomposition eliminates this unintended mitigation by identifying the opportunity to exercise local market power through direct measurement of the impact of local market power on prices at each resource. The result is that all bid mitigation is applied to resources that have been positively identified as having local market power.

Impact of mitigation on resource bids

Although a resource may be subject to bid mitigation, the mitigation may not have a meaningful impact on the resource's bid price. Further, even if the bid price is affected, this may not have an effect on market prices. This section presents information about the impact of bid mitigation on an individual resource's bid curves. Mitigation will lower the bid price to the higher of the resource's default energy bid or the calculated competitive price.[26] Mitigation may have no impact on a resource's bid price in

[25] Data reflected in this table include instances where a constraint was binding in both the mitigation run and the market run.

[26] The calculated competitive price is a price calculated by the mitigation process that removes the impact that local market power may have had on the locational price. The methodology considers both direct and indirect impacts of local market power and is described in more detail at http://www.caiso.com/Documents/DraftFinalProposal-LocalMarketPowerMitigationEnhancements.pdf.

instances where the bid price is below the mitigation floor. In fact, bid mitigation has no material impact on the resource's bid price in nearly all instances where bid mitigation is applied. Generally, this has been the result of predominantly competitive bidding where resources are submitting offers at or below their competitive bid curves known as default energy bid curves.[27]

During the study period, there were 29,576 unit hours where bid mitigation was applied. In 94 percent of these instances, there was no meaningful change in the bid price.[28] Table 3.4 shows the distribution of decrease in bid price for the remaining 1,779 unit-hours where bid mitigation did result in a change in bid price.

Table 3.4 Decrease in bid price resulting from mitigation (includes only non-zero impacts)

Input bid change	Unit-hours	# of units
($0-$5]	815	30
($5-$10]	224	22
($10-$25]	68	12
($25-$100]	199	12
$100+	473	11

In the majority of instances, the decrease in bid price resulting from mitigation was $10/MWh or less, and about 80 percent of those were $5/MWh or less. There were instances where higher priced bids were lowered by mitigation, which resulted in bid price decreases of over $25/MWh. These intervals represent about 38 percent of the total intervals where mitigation had a measurable effect on bid price. The impact of mitigation on market price is a companion measure useful in evaluating the effectiveness of any mitigation methodology. More detailed analysis including effect on market price and evaluation of the real-time market will be included in a subsequent report.

3.3 Compensating injections

In July 2010, the ISO re-implemented an automated feature in the hour-ahead and real-time software to account for unscheduled flows along the inter-ties. This feature accounts for observed unscheduled flows by incorporating compensating injections into the market model. These are additional megawatt injections and withdrawals that are added to the market model at various locations external to the ISO system. The quantity and location of these compensating injections are calculated to minimize the difference between actual observed flows on inter-ties and the scheduled flows calculated by the market software. The software re-calculates the level and location of these injections in the real-time pre-dispatch run performed every 15 minutes. The injections are then included in both the hour-ahead and 5-minute real-time market runs.

[27] The default energy bid is used as a reference bid for internal resources. It may be determined under any of three different methodologies, all of which are designed to reflect a competitive bid.

[28] We define a meaningful bid price change as one measured at the point of market dispatch. It is unlikely that a bid price change at an output level further away from the market dispatch would have had an impact on the dispatch, locational price, or the revenue for that resource.

Before implementing this feature, the ISO identified that if the net quantity of compensating injections – or the difference of the injections and withdrawals added to the market model – is significantly positive or negative, this can create operational challenges if the net compensating injections were assumed to persist because of the impact this has on the area control error (ACE). The ACE is a measure of the instantaneous difference in matching supply and demand on a system-wide basis. It is a critical tool for managing system reliability.

To avoid creating problems managing the ACE, a constraint was added to the software that limits the net impact of compensating injections to an absolute difference of no more than 100 MW. This limitation is imposed by applying a discount factor to the compensating injections calculated by the software as this absolute difference increases beyond this 100 MW threshold. This reduces the compensating injections at each location if the overall net system-level compensating injections exceed this 100 MW threshold. This discount factor is set to 0.3 for absolute net compensating injections between 100 MW and 335 MW. Compensating injections are cancelled when absolute net injections increase above 335 MW.

As a result of this constraint, there can be three distinct modes or statuses of compensating injections.

- **Full compensating injections** — This is when compensating injections are fully enabled and are not limited by the discount factor.
- **Partial compensating injections —** This is when the compensating injections are limited by the discount factor.
- **Compensating injections turned off —** This is when the compensating injections are turned off because the net compensating injections value would have been too high relative to the area control error to resolve the solution.

Prior analysis by DMM indicated the accuracy of the modeled transmission flows relative to the actual flows is only improved when this software is consistently operating with full compensating injections in effect. Moreover, DMM has expressed concern that if compensating injections are frequently switched from these different modes, this may create sudden and frequent changes in modeled flows that could in some cases decrease the efficiency of the congestion management and potentially create operational challenges.[29]

Figure 3.5 displays the 15-minute status of compensating injections for a representative day during the second quarter to highlight how the status of compensating injections changed over the course of a day. Recently, the ISO has determined that the frequent variability of compensating injections, as depicted in Figure 3.5, has resulted in operational challenges around certain constraints. As a result, the ISO has begun to regularly track the performance of compensating injections and is gradually modifying the controlling parameters to reduce the variability and improve the performance of this feature. The changes include increasing the absolute difference limitation threshold from 100 MW to 150 MW, increasing the level of where absolute net injections are cancelled from 335 MW to 400 MW, and increasing the discount parameter from 0.3 to 0.5 for absolute net compensating injections between 150 MW and 400 MW.

[29] For an in-depth analysis of compensating injections see DMM's *2011 Annual Report on Market Issues and Performance*, April 2012, Section 8.4, http://www.caiso.com/market/Pages/MarketMonitoring/MarketIssuesPerfomanceReports/Default.aspx.

Figure 3.5 Compensating injection levels (May 31, 2012)