California ISO
Shaping a Renewed Future

California Independent System Operator Corporation

California ISO

Q3 2012 Report on Market Issues and Performance

November 13, 2012

Prepared by: Department of Market Monitoring

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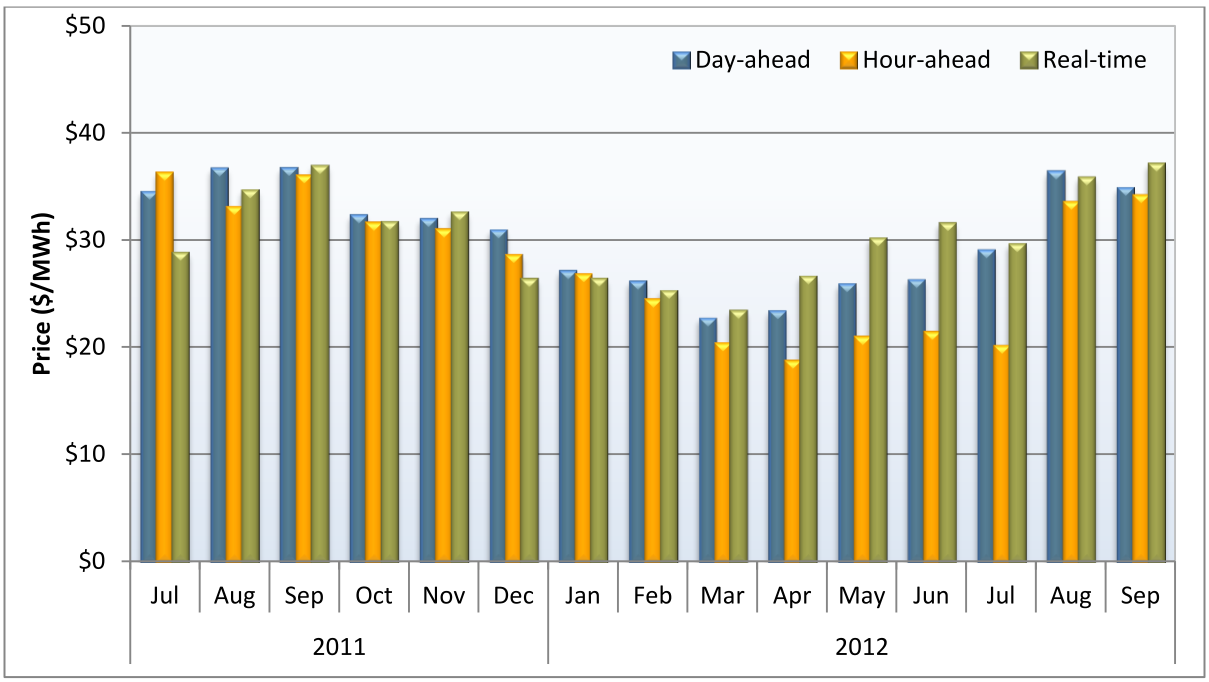
Executive summary

This report provides an overview of general market performance during the third quarter of 2012 (July – September) by the Department of Market Monitoring (DMM).

Energy market performance

- Average prices in the real-time market continued to be significantly higher than hour-ahead prices in the summer months (see Figure E.1). This price divergence was driven largely by a continuation of frequent real-time price spikes in the third quarter. Many of these price spikes were caused by brief limitations in upward ramping capacity and congestion.
- While average real-time prices were closer to day-ahead prices, real-time price spikes drove average real-time prices above day-ahead prices during the highest load hours (hours ending 15 to 18) while remaining lower in other hours.

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



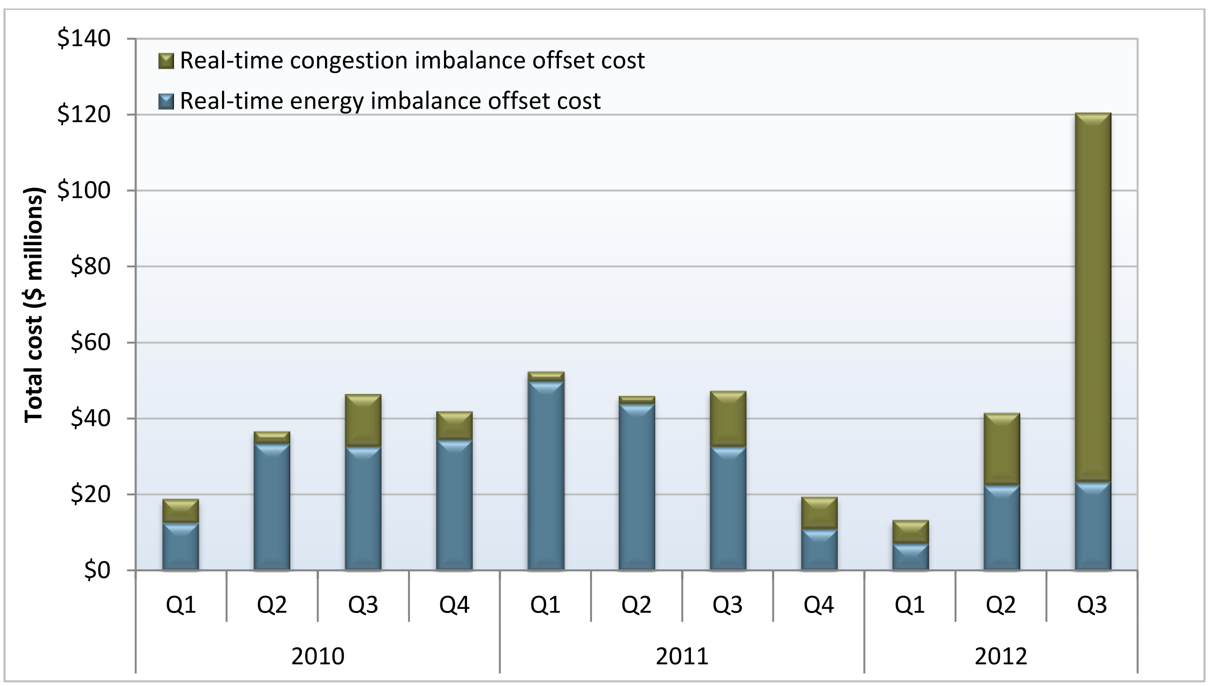
- Congestion within the ISO system had an increased effect on overall prices in the third quarter in the day-ahead and real-time markets. The impact of day-ahead and real-time congestion was relatively high in the San Diego area, accounting for roughly 10 percent of the total prices in the day-ahead market and over 20 percent in the real-time market. Congestion increased SCE area prices by adding about 3 percent to the day-ahead price and 5 percent to the real-time price. Import limitations primarily caused San Diego and SCE area congestion.

- Congestion typically reduced prices in the Pacific Gas and Electric area relative to the system energy price. This congestion reduced prices in the Pacific Gas and Electric area by about 4 percent in the day-ahead market and 11 percent in the real-time market. Congestion primarily occurred as a result of the market addressing reliability concerns related to model constraints added for reliability purposes, unscheduled flows, fires and outages.

- Real-time imbalance offset costs totaled over $120 million in the third quarter (see Figure E.2). This is the highest quarterly value since the nodal market began in April 2009. Roughly $100 million came from real-time congestion imbalance offset costs. This amount is more than the congestion uplifts in the last two and a half years combined. Real-time energy offset costs – which are primarily caused by differences in hour-ahead and real-time prices – remained about the same as in the second quarter but were lower than summer periods in previous years.

- These uplifts were created as a result of changing transmission conditions in real-time, which were not reflected in the day-ahead market. Operators often reduced real-time constraint limits to manage reliability, which impacted the real-time market congestion. The ISO is taking steps to reduce these charges by making constraints and congestion more consistent between the day-ahead and real-time markets. The ISO is also improving the modeling of unscheduled flows in real-time through the use of the *compensating injections*, which is an automated software feature that adjusts modeled flows on inter-ties with other balancing areas based on actual flows each 15 minutes.

Figure E.2 Real-time imbalance offset costs



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.[1] Thus, the third quarter of 2012 represents the first third quarter with virtual bidding within the ISO system but not at the inter-ties. Convergence bids within the ISO system that are often 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 because of 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 third quarter:

- Virtual demand at internal scheduling points within the ISO system exceeded virtual supply by an average of about 900 MW. Internal virtual supply averaged around 1,120 MW for the quarter while virtual demand averaged around 2,020 MW each hour. This trend of net virtual demand continues a trend that began in the second quarter.

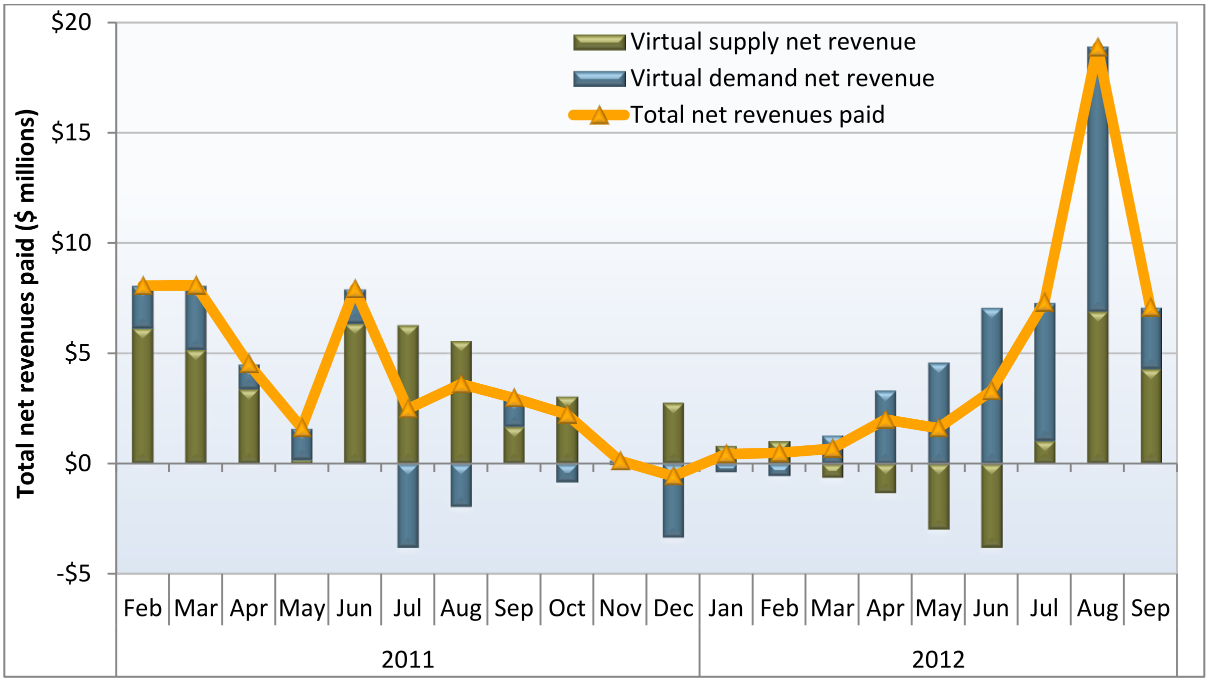
- Market participants can hedge congestion costs or earn revenues associated with differences in congestion between different points within the ISO system by placing an equal amount of virtual demand and supply bids at different internal locations during the same hour. This type of offsetting virtual position at internal locations accounted for an average of about 780 MW of demand offset by 780 MW of virtual supply at other locations per hour in the third quarter. These offsetting bids represent about 66 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.

- Net revenues paid out to participants placing virtual bids in the third quarter totaled over $33 million (see Figure E.3). This is roughly the same as the net convergence bidding revenues earned in the previous 15 months combined and the highest quarterly level since convergence bidding was implemented in the second quarter of 2011. Unlike the second quarter, third quarter net revenues came from both virtual supply and demand positions.

- The higher net revenues paid out for convergence bids reflect a combination of several factors. These payments can be partly attributed to the fact that hourly average day-ahead prices tended to be higher than real-time prices in off-peak hours and lower in peak hours. High net revenues paid to convergence bidders can also be attributed in part to real-time congestion that occurred when transmission constraints limits were reduced in the real-time market relative to limits used in the day-ahead market.

[1] 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



Other issues and recommendations

- **Ancillary services requirements.** In late August, the ISO implemented an automated feature, known as the *ancillary service requirement setter*, to more accurately calculate the ancillary services requirement. Instead of setting the reserve requirement as a percentage of the day-ahead load forecast, the requirement setter also takes into account the generation resource mix and contingencies. To date, this feature has been utilized to assess the requirement for spinning and non-spinning reserves in the 15-minute real-time pre-dispatch market only. This has resulted in systematic reductions in the operating reserve requirement by an average of 125 MW each hour in the real-time market relative to the day-ahead requirement. Given this systematic difference, DMM has recommended that the ISO implement this new feature in the day-ahead market as soon as possible to address the over-procurement of operating reserves day-ahead.

- **Ancillary service testing.** The ISO announced that it will begin ancillary service compliance testing in mid-October.[2] Earlier in the year, DMM identified concerns with participant performance during real-time ancillary service contingency events. Specifically, some resources did not perform up to their rated ancillary service level. DMM worked with the ISO to ensure that a compliance testing process was in place to test market participant ancillary service compliance and performance. DMM has highlighted a list of resources for the ISO to test and awaits the results.

- **Flexible ramping constraint performance.** The flexible ramping constraint implemented in December 2011 addresses non-contingency based deviations in load and supply between the real-

[2] See the following market notice for more information: http://www.caiso.com/Documents/CaliforniaISOConductUnannouncedComplianceTesting.htm.

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. As occurred in the second quarter, the flexible ramping constraint was less effective in addressing real-time price volatility in the third quarter during periods of congestion and under tight capacity conditions. The flexible ramping constraint procures on a system-wide basis and was not designed to address zonal or local ramping issues. Furthermore, the flexible ramping constraint continued to be static and did not vary as loads changed, which may also have reduced its overall effectiveness. Total payments made for flexible ramping capacity during the third quarter were almost $3 million. By comparison, payments for spinning reserve totaled about $13 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.

- **Enhancements to compensating injections.** This is an automated software feature designed to adjust modeled flows on inter-ties each 15 minutes based on observed real-time flows. As highlighted in DMM's 2011 annual report, the effectiveness of compensating injections is significantly affected by limiting parameters.[3] 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 third quarter and created noticeable effects on certain constraints. Throughout the third quarter and into the beginning of the fourth quarter the ISO adjusted the compensating injections parameters. As a result, the aggregate compensating injections have been more stable. Going forward, the ISO will continue to review and enhance the compensating injections, focusing on performance at or near the inter-ties.

- **Market performance during heat waves.** The ISO experienced two periods of extreme heat and high loads in the summer of 2012. The first was from about August 7 through August 17 and the second was on October 1 and 2. Overall, the ISO systems worked well during these periods of stress. On August 13, the ISO experienced peak conditions that were about 500 MW higher than the 1 in 2 year forecast. With the help of demand response, the ISO was able to successfully meet demand. On October 1 and 2, the ISO was able to meet the operational challenges and the real-time market performed well. However, the day-ahead market experienced issues as the market software could not determine an optimal solution within the allotted solution time. As a result, the software was forced to stop while still searching for a solution. The software failure was discovered after the day-ahead market results were published. Thus, corrections could only be made through the price correction process. As a result of this problem, the ISO has enhanced the day-ahead market process to include additional monitoring of the market solution prior to publishing the market results. Furthermore, the ISO will add more solution run time to produce accurate and quality day-ahead results when necessary.

- **Enhancements to address price convergence.** DMM continues to stress the importance of improving price convergence. Systematic differences in hour-ahead and real-time prices have been significant factors in increasing uplifts paid by load-serving entities. Moreover, congestion differences have also played an increasing role in increasing uplifts. DMM is supportive of the steps that the ISO has undertaken to address these differences. These steps include:

[3] 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.

- ***Derating transmission limits in the day-ahead and hour-ahead markets to better align resources to deal with anticipated transmission conditions in real-time.*** DMM is supportive of this change as it allows the day-ahead to better reflect expected conditions in real-time, which allows for better unit commitment and inter-tie scheduling to resolve the real-time situation. DMM recommends the ISO develop detailed procedures to outline under what circumstances and conditions the day-ahead limits will be adjusted to better reflect real-time conditions. Ideally, these procedures would provide for adjustments made based on statistical analysis of actual unscheduled flows in real-time.

- ***Implementing the transmission reliability margin (TRM).***[4] This allows the ISO to create a transmission margin on inter-ties in the hour-ahead market to better allow for management of unscheduled flows before real-time. The ISO implemented this in the third quarter on selected paths.

- ***Enhancing compensating injections to reduce variability.*** As noted in prior reports, DMM found that the compensating injections used to model unscheduled flows on inter-ties where highly variable from one 15-minute interval to another. This variability appeared to reduce the effectiveness of compensating injections and even create additional difficulties in managing flows in real-time. The ISO has implemented enhancements to this software feature that have removed the variability at the aggregate level and should improve the ability to manage flows.

- ***Taking steps to modify transmission constraint relaxation parameters.*** The ISO is initiating a stakeholder process to examine and revise the transmission constraint relaxation parameter to address the uneconomic effect of diminishing returns when high shadow prices are produced with insignificant amount of flow reductions.[5]

[4] For further detail on transmission reliability margin, see the following: http://www.caiso.com/informed/Pages/StakeholderProcesses/TransmissionReliabilityMargin.aspx.

[5] For more information, see the following link: http://www.caiso.com/informed/Pages/StakeholderProcesses/TransmissionConstraintRelaxationParameterChange.aspx .

1 Market performance

1.1 Energy market performance

Figure 1.1 and Figure 1.2 show monthly system marginal energy prices for peak and off-peak periods, respectively.[6]

- In peak and off-peak periods in the third quarter, hour-ahead prices remained lower than day-ahead prices in all months and periods except during off-peak hours in September. Hour-ahead prices in the third quarter averaged almost $5/MWh lower than day-ahead prices in peak hours and about $3.50/MWh in off-peak hours. The quarterly difference between hour-ahead and day-ahead prices was largest for peak hours since the first quarter of 2011. The difference was primarily driven by day-ahead and hour-ahead price differences in July.
- Average system prices in the 5-minute real-time market were close to day-ahead prices in all months for peak hours and July for off-peak periods in the third quarter.
- Average system prices in the 5-minute real-time market exceeded hour-ahead prices in both peak and off-peak hours in all months during the third quarter. The largest average difference was over $9/MWh in July peak and off-peak hours.

Figure 1.1 and Figure 1.2 show continued price divergence between average hour-ahead and real-time market prices during the third quarter. Figure 1.3 and Figure 1.4 further highlight that systematic difference between hour-ahead and real-time system prices continued into the third quarter.

- As shown in Figure 1.3, real-time prices were close to hour-ahead prices during hours ending 4 through 9 and hours ending 16 and 17, but over $16/MWh higher in hours ending 15 and 18. Real-time prices were higher than day-ahead prices in hours ending 15 through 18. In the second quarter, average real-time prices were above day-ahead and hour-ahead prices in all hours. Meanwhile, hour-ahead prices were lower than both day-ahead and real-time prices for most of the day in the third quarter, except for hours ending 16, 17 and 22.
- Figure 1.4 highlights the magnitude of price differences for all hours 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). The trend in price divergence continued into July before falling off in August and September.

[6] 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

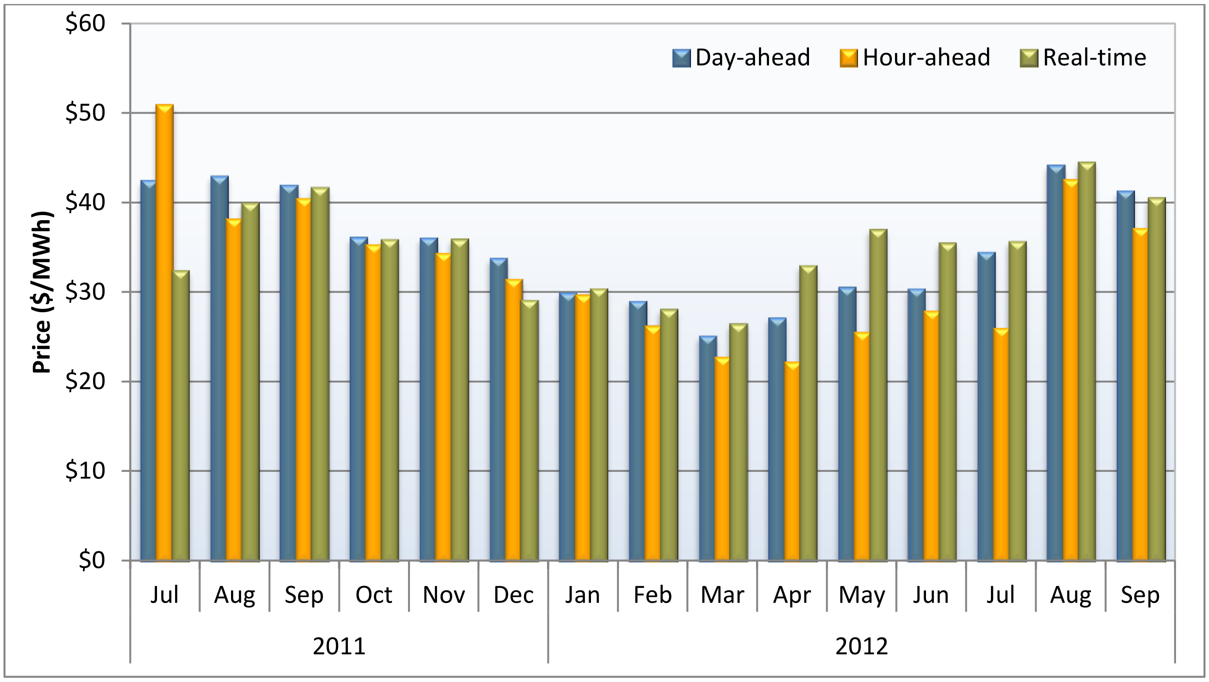


Figure 1.2 Average monthly off-peak prices — system marginal energy price

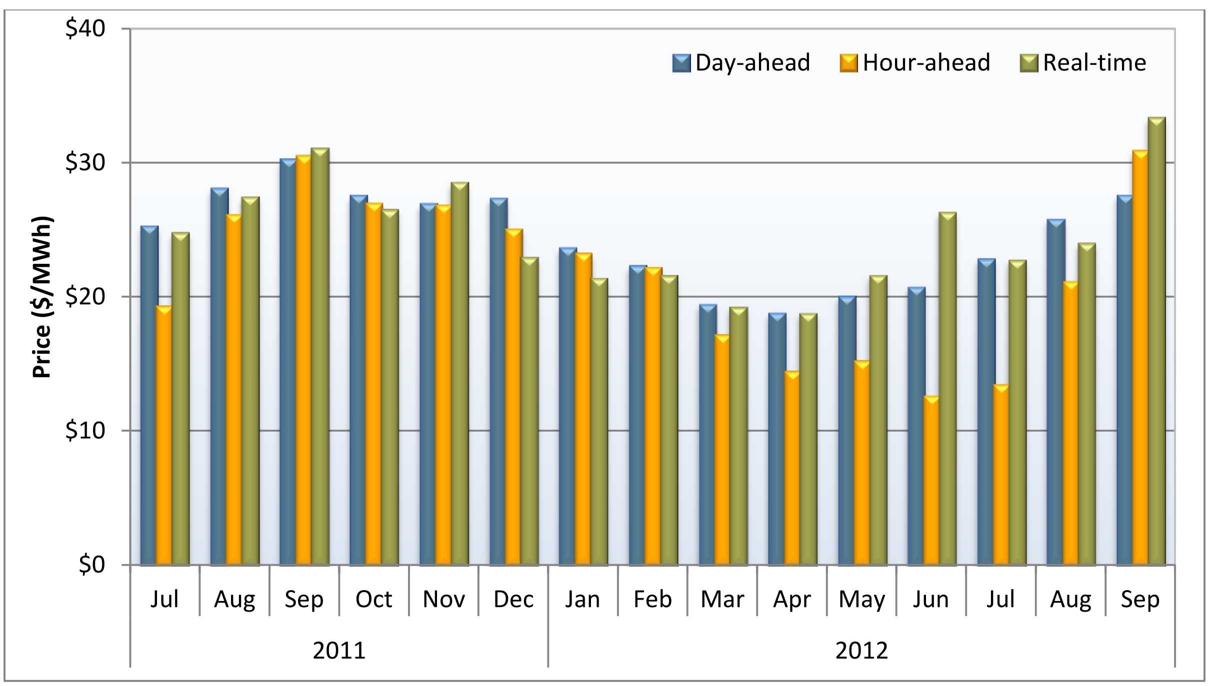


Figure 1.3 Hourly comparison of system marginal energy prices (July – September)

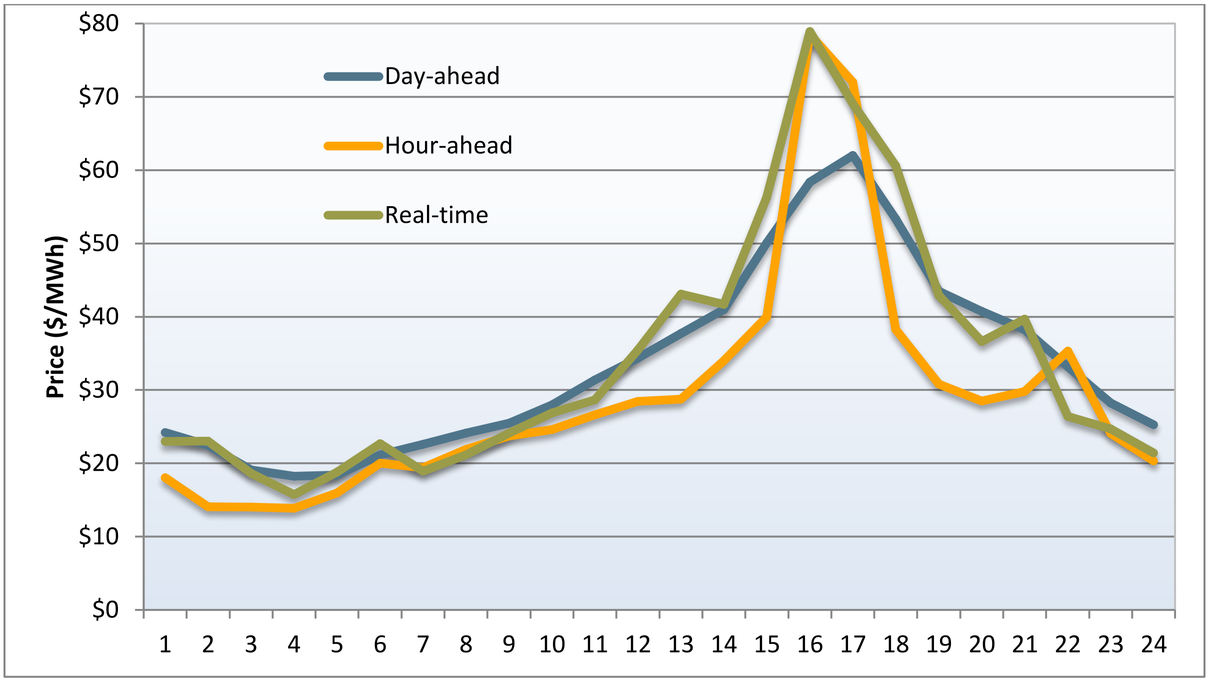
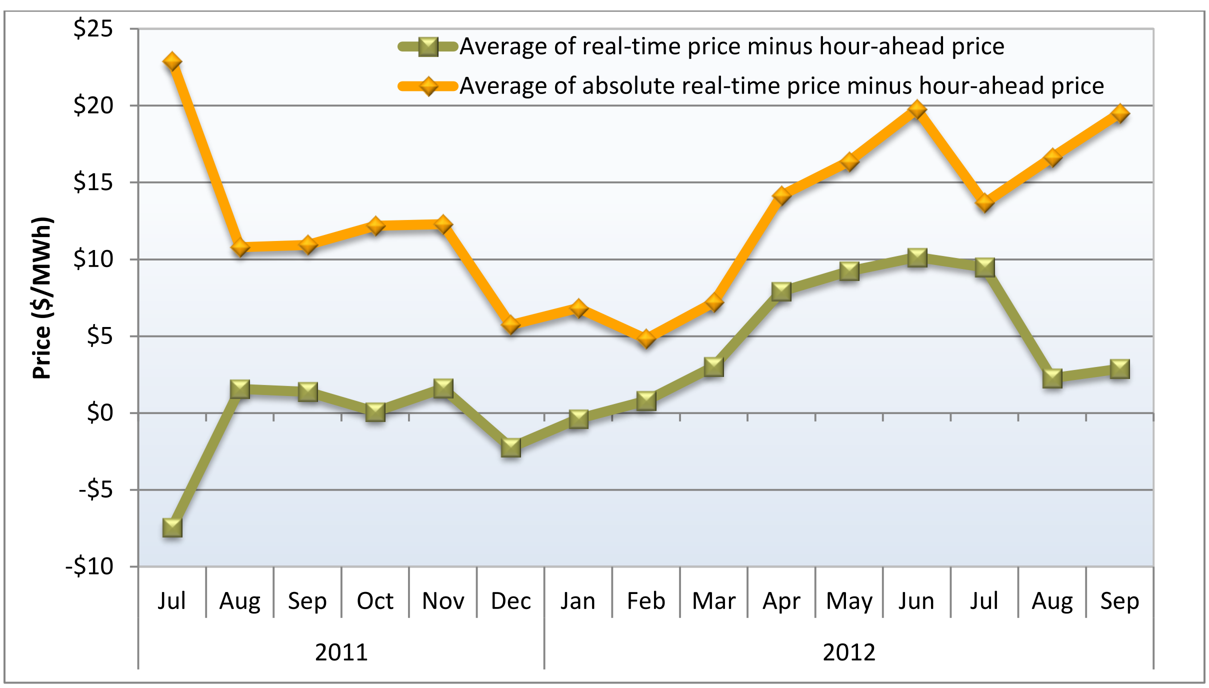


Figure 1.4 Difference in monthly hour-ahead and real-time prices based on simple average and absolute average of price differences (system marginal energy, all hours)



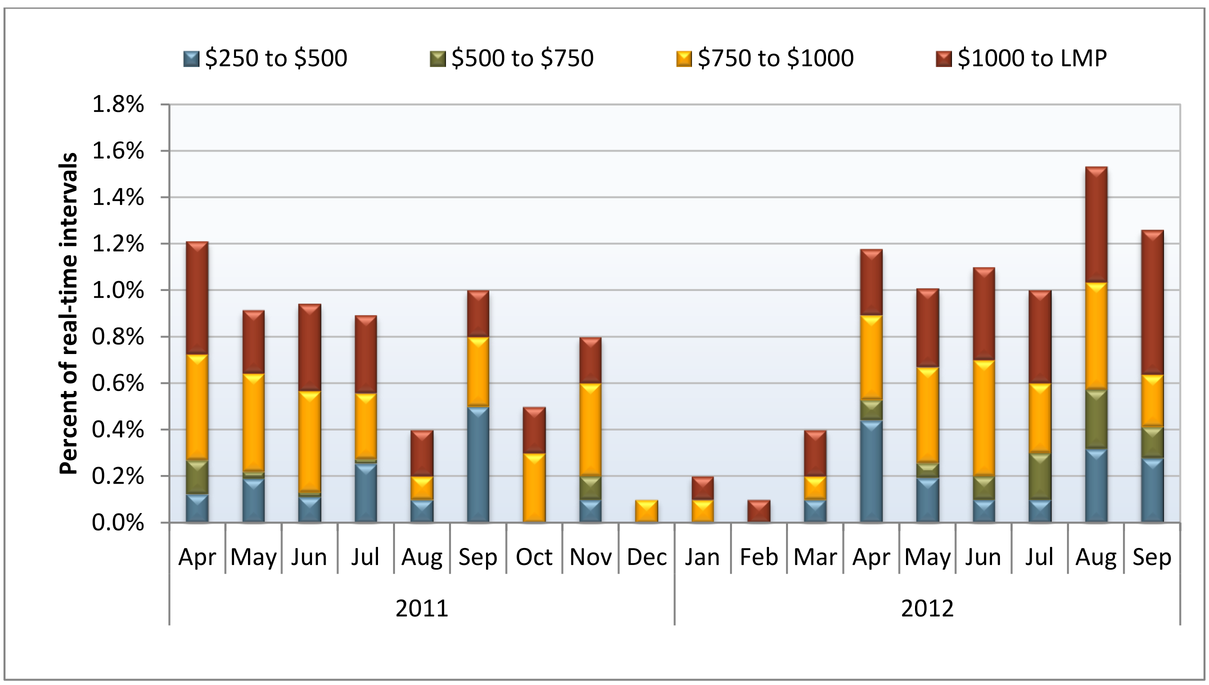
- Also shown in Figure 1.4, the average absolute price difference in the hour-ahead and real-time markets shows that price divergence remained at about the same level in the third quarter as in the second quarter, averaging over $16.50/MWh in both quarters and peaking at about $20/MWh in September (yellow line in Figure 1.4). This difference was about as large as the difference in average absolute prices during the second quarter of 2011.[7]

1.2 Real-time price variability

Figure 1.5 shows a slight increase in the frequency of price spikes that occur in each investor-owned utility area in the real-time market in the third quarter, from an average of 1.1 percent in the second quarter to about 1.3 percent in the third quarter. The third quarter had the highest percentage occurrence of price spikes since the first quarter of 2011. Price spikes at or above $1,000/MWh in the third quarter of 2012 (0.5 percent) had the highest frequency since the nodal market began in April 2009. Increases in the incidence of congestion boosted the frequency and level of these price spikes.

Some of these high prices were caused by system power balance constraint relaxations, which occur when the ISO has limited short-term ramping capacity. Overall, power balance constraint relaxations are lower 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 third quarter of 2011. Figure 1.8 shows factors that contributed to high real-time prices.

Figure 1.5 Frequency of price spikes (all LAP areas)



[7] 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 shows that relaxations because of insufficient upward ramping capacity were generally lower than the previous quarter except for September. The constraint relaxations were dispersed over different hours of the day but were slightly more common between 1:00 p.m. and 5:00 p.m. during the summer peak load period. Most shortages of upward ramp limitations lasted for only short periods of time. For instance, about 90 percent of upward ramping capacity shortages persisted for only one to three 5-minute intervals (or 5 to 15 minutes). When these upward ramping limitations occur on a system-wide level, the real-time system energy price is set by a penalty parameter equal to the bid cap of $1,000/MWh.

- Limited ramping capacity and congestion, particularly as a result of unscheduled flow, appear to have contributed to increasing the number of upward ramping limitations. Extreme congestion, especially in Southern California, played a key role in numerous instances of power balance constraint relaxations. Power balance relaxations can occur in the presence of congestion. In these cases, the system-wide power balance is not affected. Rather, the penalty parameter is incorporated into the shadow price of the related constraint instead of the system energy price.

- Figure 1.7 shows a notable decrease in the number of real-time power balance constraint relaxations from insufficiencies of dispatchable decremental energy in the third quarter relative to the second quarter. Seasonal decreases in hydro-electric and wind generation along with increases in overall load lowered the number of instances where over-generation occurred in the market.[8] Furthermore, the continued outage of the base load generation associated with the San Onofre Nuclear Generating Station has also been a contributing factor. As a result, the number of real-time power balance constraint relaxations declined. 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.

- Figure 1.8 illustrates different factors affecting high real-time prices at the investor-owned utility aggregate price locations. The prices on the figure include all intervals in which the real-time price for an investor-owned utility aggregate price location was approaching the bid cap.[9] Around 50 percent of the extremely high prices in the third quarter were caused by power balance constraint relaxations or a combination of power balance constraint relaxations and congestion. About 75 percent of the high prices resulted from power balance constraint relations and congestion in September, which included several days of persistent congestion on certain nomograms and branch groups. The flexible ramping constraint had a limited role in decreasing the power balance constraint relaxations as the units committed by the flexible ramping constraint were typically located in Northern California where congestion was relatively limited, while the congestion was often in Southern California.

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[8] The market has a more diverse supply of generators in the summer when loads increase and therefore can more effectively react to the situations that cause unanticipated changes in load and generation. 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.

[9] The analysis behind this figure reviews price spikes above $700/MWh.

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

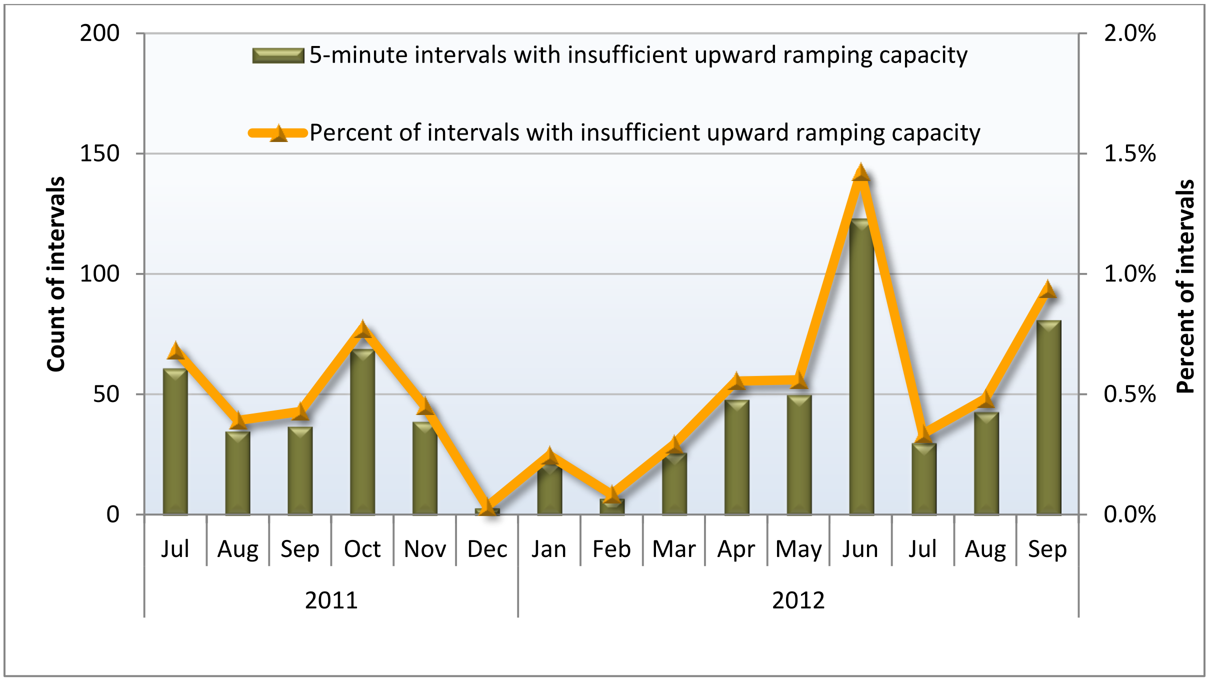


Figure 1.7 Relaxation of power balance constraint because of insufficient downward ramping capacity

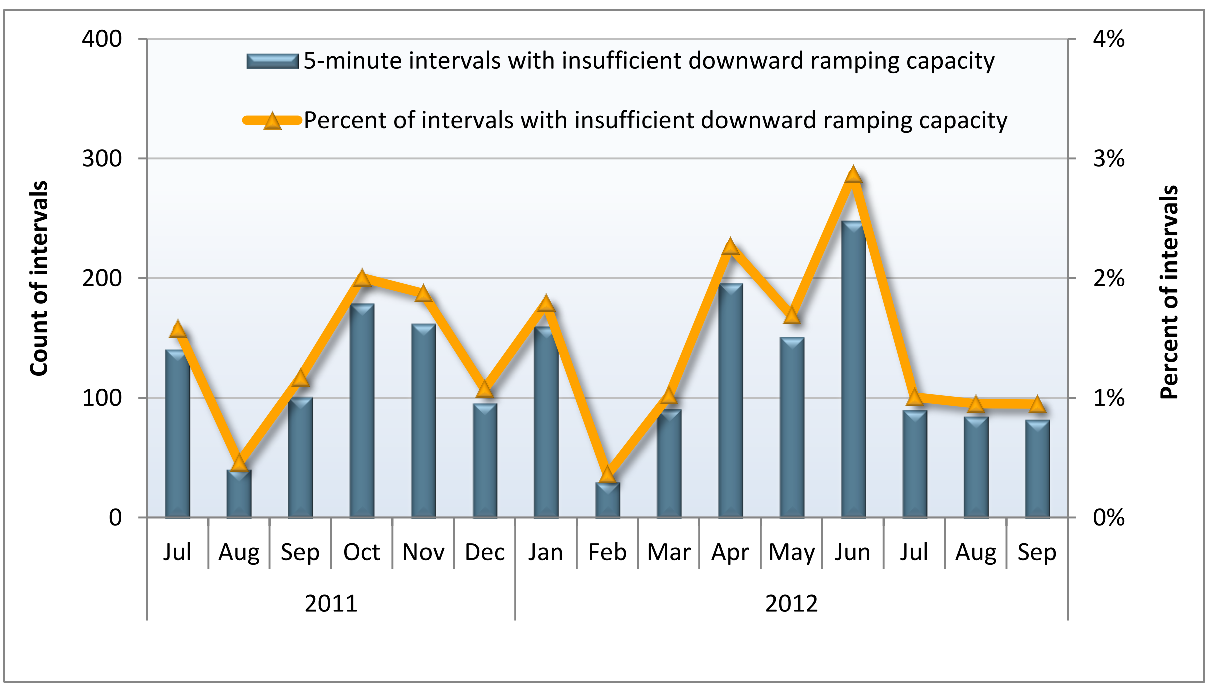
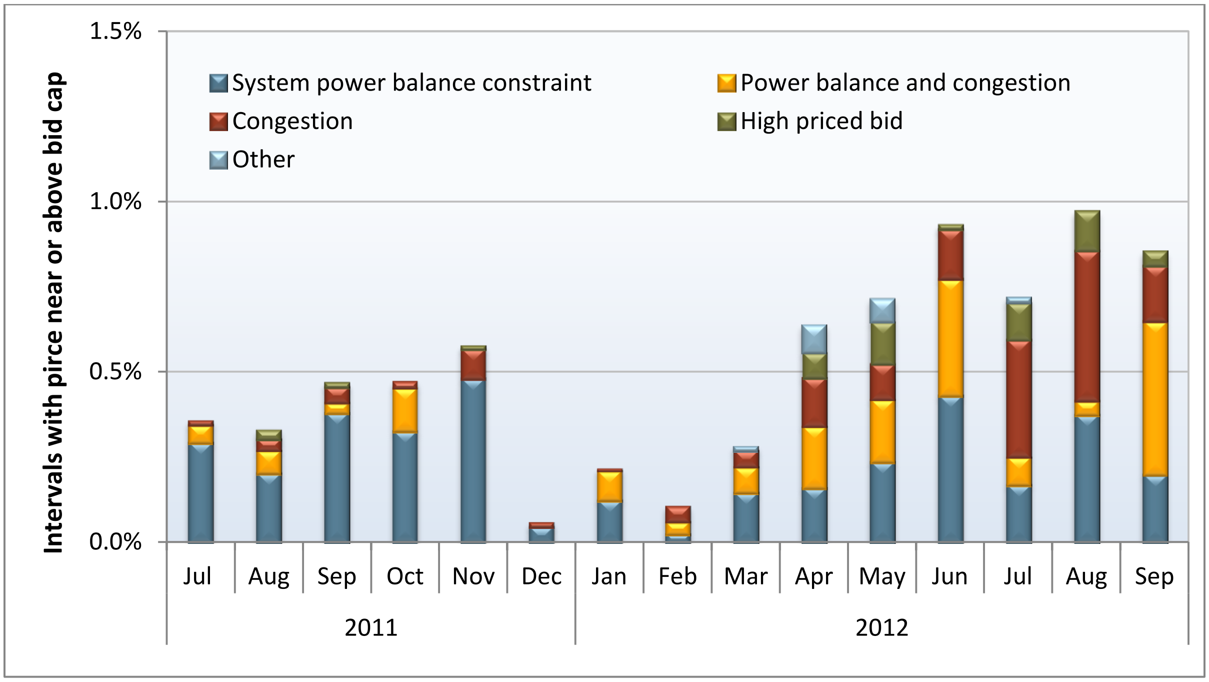


Figure 1.8 Factors causing high real-time prices



1.3 Congestion

Congestion within the ISO system in the third quarter, compared to the first two quarters, had an increased effect on overall prices in the day-ahead and real-time markets. Much of the congestion was related to unscheduled flows along the California-Oregon Inter-tie (COI).[10] Other factors contributing to congestion included changes to system topography, improved modeling which identified additional constraints, fires, transmission outages and generation outages, which included the outages of the San Onofre Nuclear Generating Station (SONGS) units 2 and 3.

1.3.1 Congestion impacts of individual constraints

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.

[10] The delay in the implementation of the transmission reliability margin feature until later in the third quarter exacerbated the issue. For further detail on transmission reliability margin, see the following: http://www.caiso.com/informed/Pages/StakeholderProcesses/TransmissionReliabilityMargin.aspx.

Day-ahead congestion

Congestion in the day-ahead market generally occurs more frequently than in real-time, but usually with smaller price impacts.[11] Table 1.1 provides a more detailed analysis for the third quarter and shows:

- The SCE_PCT_IMP_BG was congested more often than any other individual constraint in the quarter, with congestion occurring in roughly 24 percent of the hours. This constraint increased the prices in the SCE area by $2.43/MWh in congested hours. The prices in the PG&E and SDG&E areas decreased by about $2.14/MWh. This constraint has been directly affected by the SONGS outages.

- Congestion on 6110_TM_BNK_TMS_DLO_NG, which occurred in 23 percent of hours, increased prices in the PG&E area by $1.80/MWh in congested hours and decreased prices in the SCE and SDG&E areas by about $1.51/MWh. This congestion was mainly due to unscheduled flows on COI and the Caribou (Chips) Fire. Further detail is provided below.

- The 7830_SXCYN_CHILLS_NG and the 223242_HDWSH_500_22536_N.GILA_500_BR_1_1 were the dominant binding constraints in the SDG&E area, affecting roughly 23 and 16 percent of the hours respectively. 7830_SXCYN_CHILLS_NG increased SDG&E area prices in congested hours by $7.43/MWh with no impact on PG&E and SCE. There was a $9.20/MWh increase in SDG&E prices from 223242_HDWSH_500_22536_N.GILA_500_BR_1_1 while impacting PG&E prices by -$1.47/MWh and SCE by -$0.34/MWh. These constraints are described in further detail below.

As shown in Table 1.1, congestion on other constraints significantly affected prices during hours when congestion occurred. However, since these other constraints were congested infrequently, they 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			Q3		
Area	Constraint	Q1	Q2	Q3	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
PG&E	6110_TM_BNK_FLO_TMS_DLO_NG		6.3%	23.4%				$0.80	-$0.85	-$0.85	$1.80	-$1.51	-$1.51
	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%	24.3%	-$1.31	$1.62	-$1.31	-$2.87	$3.40	-$2.87	-$2.15	$2.43	-$2.13
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _2		0.7%	11.3%				-$3.22	$2.39	$2.44	-$5.24	$3.47	$3.57
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2			0.7%							-$4.00	$2.37	$2.28
	BARRE-LEWIS_NG			5.7%							-$0.54	$0.61	$0.37
	PATH26_BG	4.8%	3.6%	0.4%	-$1.63	$1.39	$1.39	-$1.41	$1.16	$1.16	-$3.05	$1.80	$1.80
	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	7830_SXCYN_CHILLS_NG			23.3%									$7.43
	22342_HDWSH _500_22536_N.GILA _500_BR_1 _1			15.9%							-$1.47	-$0.34	$9.20
	SDGEIMP_BG			4.4%							-$0.71	-$0.71	$7.19
	SOUTHLUGO_RV_BG			3.6%							-$9.02	$5.25	$8.15
	14013_HDWSH _500_22536_N.GILA _500_BR_1 _1			1.4%							-$0.40		$2.91
	22831_SYCAMORE_138_22116_CARLTHTP_138_BR_1 _1			0.4%									$9.93
	SLIC 2034755 TL23040_NG			0.6%									$7.36
	SDGE_PCT_UF_IMP_BG		1.1%	0.4%				-$0.40	-$0.40	$4.27	-$0.47	-$0.47	$4.70
	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			
	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						

[11] Volumetric effects tend to be larger in the day-ahead market as more load and generation are transacted in the day-ahead market than in the real-time market.

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 third quarter and shows:

- Congestion on 6110_TM_BNK_FLO_TMS_DLO_NG occurred nearly 5 percent of the time. At those times, however, congestion increased prices in the PG&E area by $28.95/MWh and decreased prices in the SCE and SDG&E areas by -$27.11/MWh. This congestion was mainly due to unscheduled flows on COI and the Caribou (Chips) Fire.

- SCE_PCT_IMP_BG continued to be congested in the third quarter at 4.4 percent of the hours and was congested as a result of the outages of SONGS units 2 and 3.[12] This congestion decreased the prices in the PG&E and SDG&E areas by about $24/MWh and increased prices for the SCE area by over $27/MWh during congested intervals.

- The BARRE-LEWIS_NG was congested 1.7 percent of the intervals with prices in SDG&E just over $190/MWh. This constraint increased SCE area prices by about $5/MWh and decreased PG&E's by nearly $8/MWh. In nearly 2.4 percent of the hours, congestion on 7830_SXCYN_CHILLS_NG increased the price in the SDG&E area by over $37/MWh when it was binding. The two Hoodoo Wash – North Gila nomograms[13] were each congested about 1.3 percent of the hours resulting in price increases for the SDG&E area of $231/MWh and $311/MWh respectively. Additionally, the SCIT_BG was congested in nearly 1 percent of the hours for the period and increased the prices in SDG&E by over $55/MWh and $50/MWh in the SCE area while PG&E decreased by nearly $78/MWh.

A comparison of Table 1.1 and Table 1.2 shows 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 roughly 24 percent of the hours in the day-ahead market, it was binding in about 4 percent of the time in the real-time market. The constraint increased day-ahead prices in the SCE area by $2.43/MWh, but increased real-time prices by over $27/MWh. Other examples of constraints, such as 22342_HDWSH_500_22536_N.GILA_500_BR_1_1, and 6110_TM_BNK_FLO_TMS_DLO_NG, were adjusted to mitigate the difference in market and actual flows and to provide a reliability margin. Even though the constraints were binding less frequently overall (in less than 5 percent of the hours for each constraint), the shadow prices were significantly larger, indicating a greater impact on prices when the constraint was binding.

[12] The ISO is attempting to improve the real-time limit by using a dynamic limit rather than an hourly limit. This will allow the constraint limit to follow the load better. Since the constraint is calculated as a percentage of load, this will help reduce the need for the operator to make manual adjustments.

[13] This includes both the 22342_HDWSH_500_22536_N.GILA_500_BR_1_1 and the 14013_HDWSH_500_22536_N.GILA_500_BR_1_1 nomograms.

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

		Frequency			Q1			Q2			Q3		
Area	Constraint	Q1	Q2	Q3	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
PG&E	6110_TM_BNK_FLO_TMS_DLO_NG		1.7%	4.9%				$20.04	-$25.77	-$25.77	$28.95	-$27.11	-$27.11
	T-135 VICTVLUGO_EDLG_NG			1.8%							$13.62	-$8.51	-$18.09
	30055_GATES1 _500_30900_GATES _230_XF_11_P			0.3%							$3.63	-$3.04	-$3.04
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _2			1.3%							-$69.86	$46.78	$48.06
	TRACY230_BG			0.1%							$33.26	-$21.89	-$21.89
	SLIC 1902749 ELDORADO_LUGO-1	1.1%	1.7%		$3.30	-$2.36	-$3.96	$12.43	-$8.32	-$14.48			
	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%	4.4%	-$63.37	$79.72	-$63.37	-$69.78	$86.32	-$69.66	-$24.70	$27.25	-$23.63
	PATH26_N-S	2.8%	2.1%	0.2%	-$17.37	$14.65	$14.65	-$59.99	$48.95	$48.95	-$51.51	$33.76	$33.76
	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	0.0%	0.1%		-$18.58	$22.52	-$70.75	-$10.86	$9.51	-$45.44			
SDG&E	7830_SXCYN_CHILLS_NG			2.4%									$37.61
	BARRE-LEWIS_NG			1.7%							-$7.84	$5.16	$190.44
	22342_HDWSH _500_22536_N.GILA _500_BR_1 _1			1.3%							-$47.85		$311.05
	14013_HDWSH _500_22536_N.GILA _500_BR_1 _1			1.3%							-$32.03		$231.77
	SCIT_BG			0.8%							-$77.70	$50.96	$55.22
	SOUTHLUGO_RV_BG	0.1%	0.0%	0.5%	-$74.07	$59.77	$80.34	-$5.40	$3.82	$6.26	-$192.73	$125.29	$177.63
	SLIC 2034755 TL23040_NG			0.4%									$38.15
	SLIC 1953261 ELD-LUGO PVDV			0.3%							$34.59	-$20.15	-$67.32
	SDGE IMPORTS			0.2%							-$68.23	-$68.23	$646.45
	7820_TL 230S_OVERLOAD_NG			0.2%									$146.81
	HASYAMPA-NGILA-NG1		0.1%	0.2%				-$20.22		$141.43	-$27.71		$227.22
	22844_TALEGA _230_22840_TALEGA _138_XF_1			0.1%									$78.25
	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			
	SDGE_CFEIMP_BG	0.7%	0.1%		-$3.91	-$3.91	$36.83	-$5.16	-$5.16	$54.25			
	SLIC 1883001 Miguel_BKS_NG_2	1.2%	0.0%				$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						

1.3.2 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.[14]

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

Day-ahead price impacts

Table 1.3 shows the overall impact of day-ahead congestion on average prices in each investor-owned utility area in the third quarter of 2012 by constraint. These results show the following:

- Day-ahead prices in the San Diego area were impacted the most by internal congestion associated with 7830_SXCYN_CHILLS_NG. This constraint increased day-ahead prices in SDG&E by $1.73/MWh or around 4.5 percent with negligible impact on PG&E and SCE. This constraint protects the system for the potential loss of the Imperial Valley – Miguel 500 kV line. Additionally, the day-ahead prices in the San Diego area were impacted by the 223242_HDWSH_500_22536_N.GILA_500_BR_1_1 constraint. This constraint increased the prices by $1.47/MWh or around 3.8 percent.
- The SCE_PCT_IMP_BG increased day-ahead prices in the SCE area above system average prices by $0.59/MWh or around 1.7 percent, down from $1.21/MWh (4.7 percent) in the second quarter. Prices decreased by about $0.52/MWh or about 1.5 percent in PG&E and SDG&E when this constraint was binding. 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. Additionally, the 30060_MIDWAY_500_24156_VINCENT_500_BR_1_2 constraint increased SCE and SDG&E prices $0.39/MWh (1.1 percent) and $0.41 (1 percent) respectively, while decreasing prices in PG&E by $0.59 (1.85 percent). This constraint was impacted by planned work and forced outages.
- The overall impact of congestion on day-ahead prices in the PG&E area decreased prices by about $1.36/MWh or about 4.3 percent from the system average. This occurred because prices in the PG&E area were 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**
7830_SXCYN_CHILLS_NG					$1.73	4.54%
22342_HDWSH _500_22536_N.GILA _500_BR_1 _1	-$0.23	-0.73%			$1.47	3.85%
SCE_PCT_IMP_BG	-$0.52	-1.63%	$0.59	1.72%	-$0.52	-1.36%
30060_MIDWAY _500_24156_VINCENT _500_BR_1 _2	-$0.59	-1.85%	$0.39	1.14%	$0.41	1.06%
6110_TM_BNK_FLO_TMS_DLO_NG	$0.42	1.31%	-$0.25	-0.72%	-$0.25	-0.65%
SOUTHLUGO_RV_BG	-$0.32	-1.01%	$0.19	0.55%	$0.29	0.77%
SDGEIMP_BG	-$0.03	-0.10%	-$0.03	-0.09%	$0.32	0.83%
BARRE-LEWIS_NG	-$0.03	-0.09%	$0.04	0.10%		
30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _	-$0.03	-0.09%	$0.02	0.05%	$0.02	0.04%
SLIC 2034755 TL23040_NG					$0.05	0.12%
14013_HDWSH _500_22536_N.GILA _500_BR_1 _1	-$0.01	-0.02%			$0.04	0.10%
22831_SYCAMORE_138_22116_CARLTHTP_138_BR_1 _1					$0.04	0.11%
PATH26_BG	-$0.01	-0.03%	$0.01	0.02%	$0.01	0.02%
SDGE_PCT_UF_IMP_BG		-0.01%		-0.01%	$0.02	0.05%
Other		-0.01%			$0.03	0.08%
Total	-$1.36	-4.3%	$0.95	2.8%	$3.64	9.6%

Real-time price impacts

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

- Prices in the San Diego area were impacted the most by internal congestion associated with the Hoodoo Wash to North Gila constraints. Combined, these constraints drove prices above the system average in SDG&E by nearly 16 percent or about $7.15/MWh. Also, congestion in the SCE area sometimes drove SDG&E prices down (e.g., SCE_PCT_IMP_BG) while congestion in the PG&E area also drove prices down (e.g., 6110_TM_BNK_FLO_TMS_DLO_NG). Together, the positive and negative congestion caused average real-time prices in the San Diego area to increase by about $9.84/MWh or about 22 percent above the system average.
- Congestion drove prices in the SCE area above system average prices by about $1.66/MWh or 4.7 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 of congestion was north-to-south congestion on Midway-Vincent and the South of Lugo branch group. SCE congestion fell by about $1/MWh (3 percent) when the 6110_TM_BNK_FLO_TMS_DLO_NG was constrained.
- The overall impact of congestion on prices in the PG&E area was to change prices from the system average by about -$3.37/MWh or about -11 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., Midway-Vincent and Path 26) and on constraints limiting flows into the SCE and SDG&E areas. Congestion related to the Table Mountain – Tesla and Table Mountain – Vaca constraint (6110_TM_BNK_FLO_TMS_DLO_NG) increased prices over $1.41/MWh (4.6 percent) during the third quarter.

Real-time congestion occurred with less frequency than day-ahead congestion, yet 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.

The constraints with the largest effects were related to Hoodoo Wash to North Gila, Sycamore Canyon to Carlton Hills, and Table Mountain to Tesla and Table Mountain to Vaca. The next section will discuss the nature and reason why these constraints were binding.

Table 1.4 Impact of congestion on overall real-time prices

	PG&E		SCE		SDG&E	
Constraint	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
22342_HDWSH _500_22536_N.GILA _500_BR_1 _1	-$0.62	-2.04%			$4.05	9.01%
14013_HDWSH _500_22536_N.GILA _500_BR_1 _1	-$0.43	-1.40%			$3.10	6.89%
6110_TM_BNK_FLO_TMS_DLO_NG	$1.41	4.61%	-$1.05	-2.96%	-$1.05	-2.34%
SCE_PCT_IMP_BG	-$1.10	-3.59%	$1.21	3.41%	-$1.05	-2.34%
SOUTHLUGO_RV_BG	-$1.03	-3.37%	$0.67	1.89%	$0.95	2.12%
30060_MIDWAY _500_24156_VINCENT _500_BR_1 _2	-$0.88	-2.88%	$0.59	1.66%	$0.61	1.35%
SCIT_BG	-$0.65	-2.11%	$0.42	1.19%	$0.46	1.02%
SDGE IMPORTS	-$0.13	-0.42%	-$0.13	-0.36%	$1.22	2.71%
7830_SXCYN_CHILLS_NG					$0.92	2.04%
T-135 VICTVLUGO_EDLG_NG	$0.24	0.80%	-$0.14	-0.39%	-$0.32	-0.72%
HASYAMPA-NGILA-NG1	-$0.06	-0.19%			$0.47	1.05%
SLIC 1953261 ELD-LUGO PVDV	$0.11	0.36%	-$0.06	-0.18%	-$0.21	-0.47%
7820_TL 230S_OVERLOAD_NG					$0.31	0.69%
PATH26_N-S	-$0.13	-0.42%	$0.08	0.24%	$0.08	0.19%
BARRE-LEWIS_NG	-$0.13	-0.43%	$0.09	0.24%	$0.03	0.06%
SLIC 2034755 TL23040_NG					$0.14	0.32%
SDGE_PCT_UF_IMP_BG	-$0.01	-0.02%	-$0.01	-0.02%	$0.07	0.16%
22844_TALEGA _230_22840_TALEGA _138_XF_1					$0.07	0.16%
TRACY230_BG	$0.02	0.06%	-$0.01	-0.03%	-$0.01	-0.03%
30055_GATES1 _500_30900_GATES _230_XF_11_P	$0.01	0.03%	-$0.01	-0.02%	-$0.01	-0.02%
T-165 SOL-6_NG_SUM	-$0.01	-0.02%	$0.01	0.01%	$0.01	0.03%
Other	$0.00	0.01%			$0.01	0.01%
Total	-$3.37	-11.0%	$1.66	4.7%	$9.84	21.9%

Constraints with large impacts on day-ahead and real-time prices

This section provides a brief description of selected constraints with large price impacts in the third quarter.

- ***Hoodoo Wash – North Gila 500 kV Line nomograms.*** These nomograms are for the Hoodoo Wash to North Gila 500 kV line, which is a segment of the Southwest Powerlink (SWPL), a major transmission corridor that brings power primarily in the east-to-west direction from generation resources in Arizona to the Imperial Irrigation District (IID) service territory and into the San Diego area of California. Improved analysis and detailed modeling was performed in 2012 around this area. This analysis resulted in the development of new nomograms to better represent actual system flow and protect for the low voltage loss of Hassayampa to North Gila.

- ***Sycamore Canyon – Carlton Hills nomogram.*** This nomogram was implemented when the new Sunrise Powerlink 500 kV line came into service, which increased transfer capability and voltage stability, and improved San Diego import capability. This nomogram is for the Sycamore Canyon to Carlton hills 138 kV line in San Diego, California. With the addition of the new Sunrise line, there is a possible potential for overload on the Sycamore Canyon to Carlton Hills 138 kV line due to the loss of the Imperial Valley to Miguel 500 kV line. This nomogram protects the Sycamore Canyon to Carlton Hills 138 kV line by limiting the flows on other transmission lines.

- ***Table Mountain – Tesla nomogram.*** This nomogram is to protect lines connecting Table Mountain with Tesla, Vaca and Rio Oso. Specifically, this nomogram is for the Table Mountain 500/230 kV transformer for the double loss of the 500 kV lines Table Mountain to Tesla and Table Mountain to Vaca. One of the key reasons for congestion was related to Northern California dispatch (which includes Northern California Hydro, Hatchet Ridge wind farm North of Round Mountain and redispatched generation in the Feather River area) and the Caribou (Chips) fire. Other reasons for recent congestion include unscheduled north-to-south flows from the Pacific Northwest on the California-Oregon Inter-tie (COI), which caused adjustments to line limits and generation redispatch, as well as local area load.

Frequently, the actual real-time transmission conditions would differ from modeled conditions on these transmission elements,[15] particularly with respect to unscheduled flows. When modeled conditions do not match actual conditions in real-time, ISO operators often conform (i.e., adjust) the modeled transmission limits to better align market flows with actual flows. When these limits were changed, this often resulted in high shadow prices and market prices in real-time. These high prices were mostly the result of a limited set of resources available to resolve the transmission situation in the real-time dispatch.[16]

To better anticipate expected real-time conditions and to better align resources to resolve the transmission constraints, the ISO made adjustments to its process in mid-August to allow for the adjustment of day-ahead and hour-ahead limits to better reflect anticipated conditions in real-time. DMM is supportive of this change as it allows the day-ahead to better reflect expected conditions in real-time, which allows for better unit commitment and inter-tie scheduling to resolve the real-time situation. DMM recommends the ISO develop detailed procedures to outline under what circumstances and conditions the day-ahead limits will be adjusted to better reflect real-time conditions. Ideally, these procedures would provide for adjustments made based on statistical analysis of actual unscheduled flows in real-time.

However, before the ISO was able to take action to address the modeling inconsistencies between the day-ahead and real-time markets, large uplifts resulted. This is addressed in the next section.

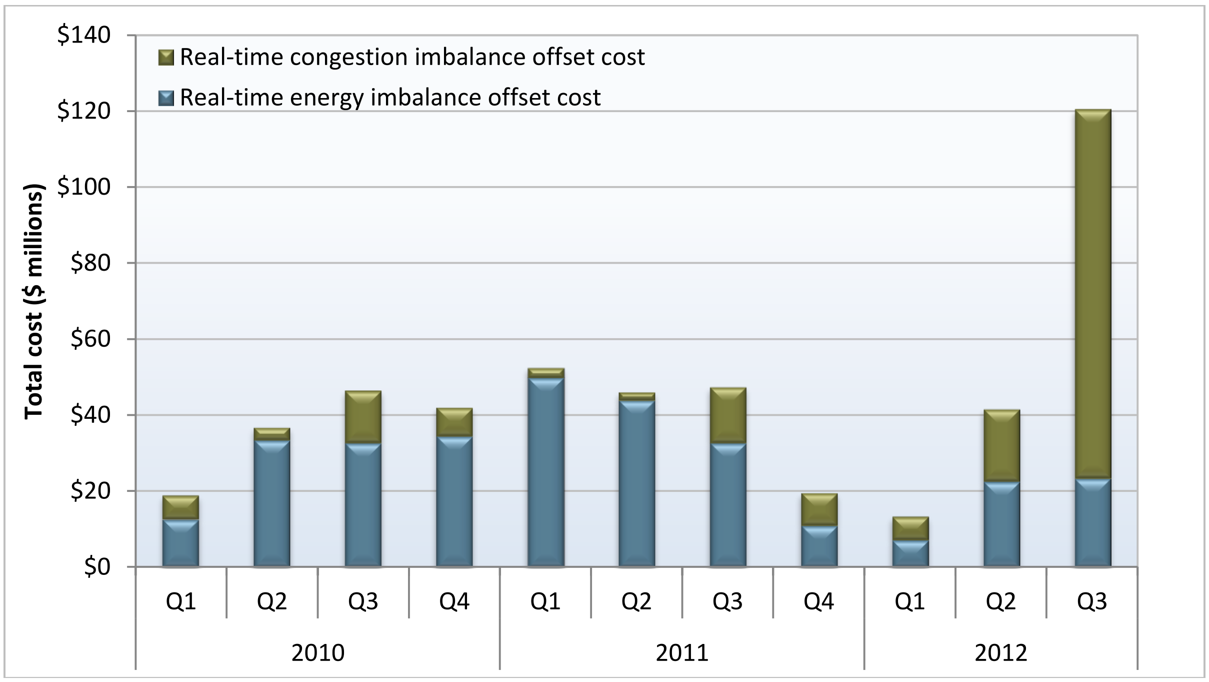
[15] In particular, unscheduled flows greatly affected the Hoodoo Wash to North Gila and the Table Mountain to Tesla nomograms.

[16] The ability to resolve constraints in the real-time market is more limited than in the day-ahead and hour-ahead markets. For example, unit commitment and inter-tie schedule adjustments are not available in the 5-minute real-time market to relieve congestion, only re-dispatch.

1.4 Real-time imbalance offset costs

Real-time congestion uplifts increased significantly in the third quarter as the result of reductions in transmission limits in real-time, high congestion and prices, and large volumes of affected market transactions. These uplifts totaled almost $50 million in the month of August and just under $100 million in the third quarter (see Figure 1.9). Congestion uplifts in the third quarter were more than occurred in the previous two and a half years combined. For the sake of comparison, energy imbalance uplifts totaled about $23 million in the third quarter and never totaled more than $22 million in any month or $50 million in any quarter.

Figure 1.9 Real-time imbalance offset costs



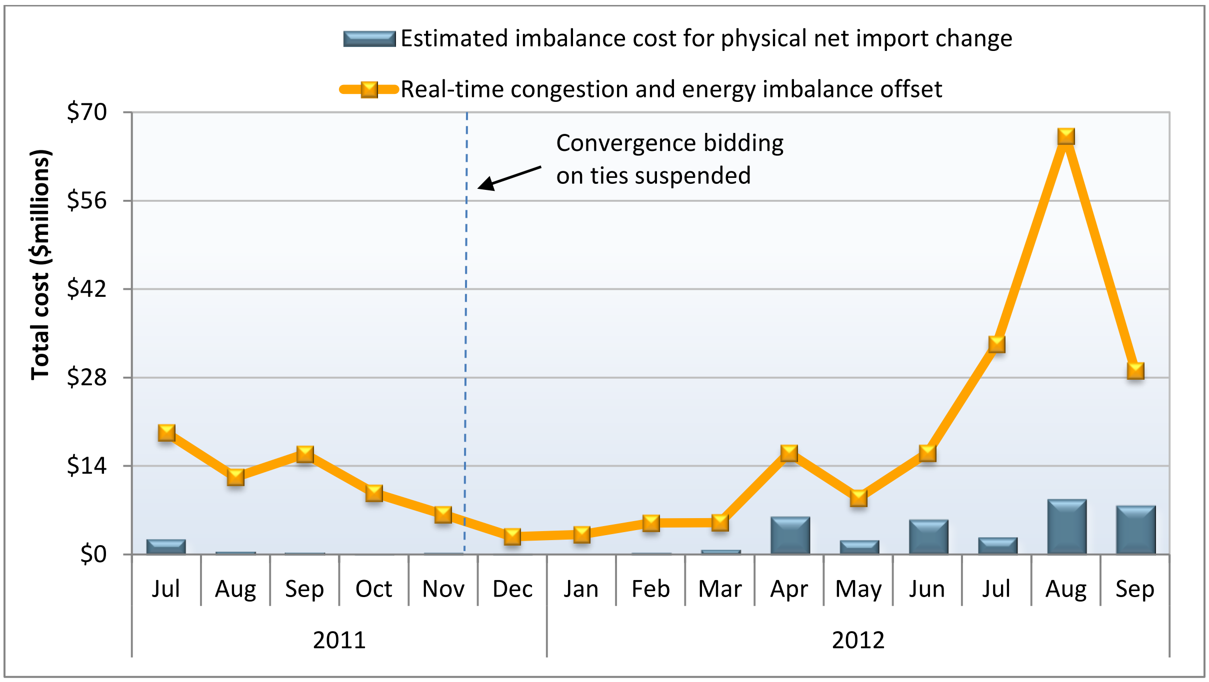
Real-time energy offset costs totaled over $20 million in the third quarter, which contributed to real-time energy and congestion offset charges totaling over $120 million (see Figure 1.9). This was the highest quarterly value since the nodal market began in April 2009. These costs were primarily driven by two factors:

- First, as discussed in previous quarterly reports, offset costs result when net imports in the hour-ahead market are reduced at relatively low prices and additional energy must then be procured in the 5-minute real-time market at higher prices. This primarily affects the real-time energy imbalance costs, but also contributed to the congestion imbalance offset to the extent there were congestion differences between the hour-ahead and real-time markets.
- The second factor, which was very prominent in the third quarter, occurs when transmission limits are reduced in real-time and congestion occurs. This reduces the flow volumes on transmission paths in the real-time market from higher flows in the day-ahead market at higher prices. These revenue imbalances are reflected in the real-time congestion imbalance offset costs.

Costs from selling imports at low prices and buying back internally at high prices

Figure 1.10 compares the real-time energy and congestion imbalance costs (yellow line) with the estimated costs of 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).[17] The physical imbalance cost during the third quarter of 2012 increased to about $19 million from about $4 million during the third quarter of 2011 and $14 million in the second quarter of 2012. The third quarter physical imbalance cost estimates are almost equal to the combined costs from June 2011 through June 2012.

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



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.[18] From the third 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

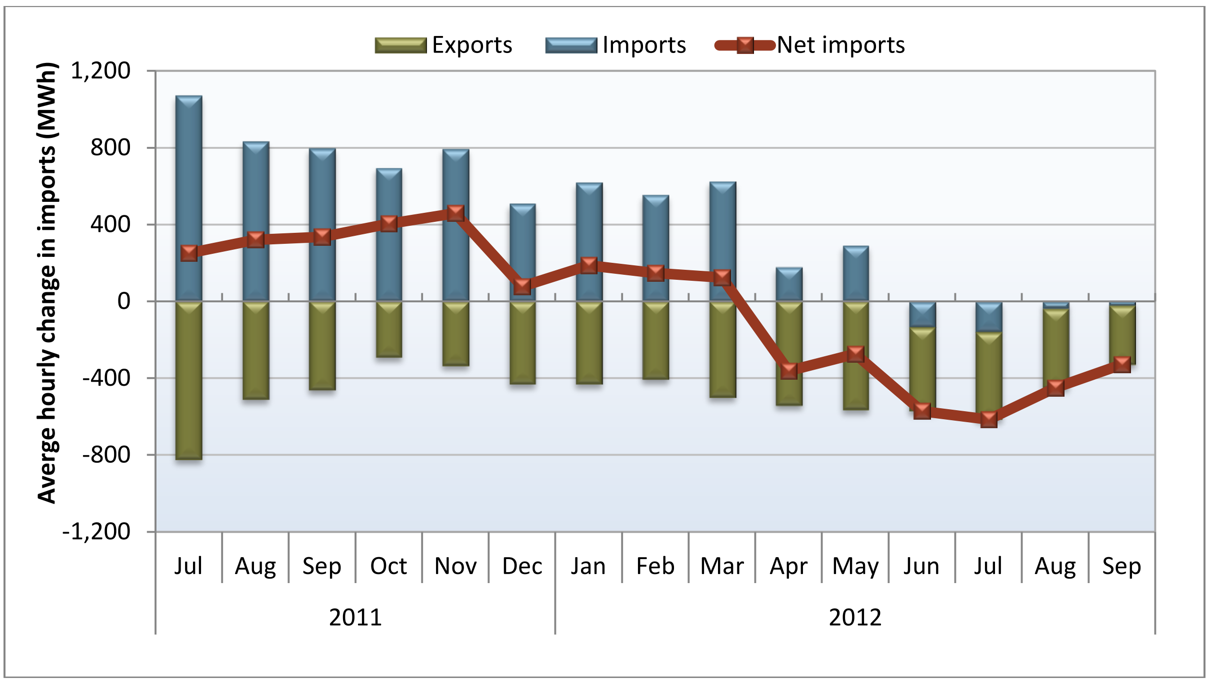
[17] DMM estimates these costs based on the following: 1) the decrease in hour-ahead net imports that were subsequently re-procured in real-time; 2) the increase in hour-ahead imports that were subsequently sold in real-time; and 3) the difference in hour-ahead versus real-time prices during the corresponding 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.

[18] 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. In order to profit from the buyback of day-ahead inter-tie schedules, participants must have a feasible day-ahead e-tag.

day-ahead market. This pattern shifted in the second quarter of 2012 and continued into the third quarter. The following key points are 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 250 MW more than net day-ahead import schedules.
- Most of the increase in net imports was due to an increase in new imports in the hour-ahead market, which averaged over 750 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. This trend continued into the third quarter where new exports (400 MW) in the hour-ahead market combined with reductions in imports (70 MW) from scheduled day-ahead levels reduced overall net imports.

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

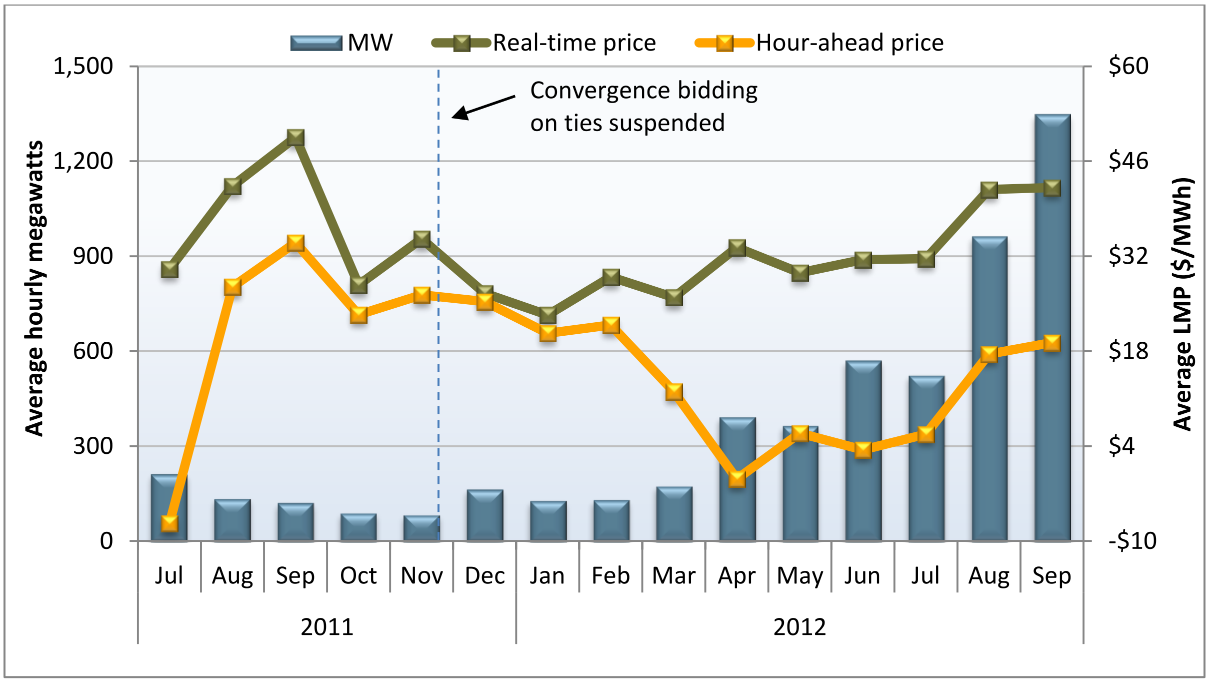


When physical net imports decrease in the hour-ahead market, the decreased net imports in the hour-ahead are likely to increase the need to re-dispatch imbalance energy in real-time.[19] This scenario occurred in almost 96 percent of the hours in the third quarter. The blue bars in Figure 1.12 show DMM's 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

[19] 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.

the weighted average prices for additional energy procured in the real-time market during each month.[20] 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 average prices in these two markets.

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



As shown in Figure 1.12, the substantial increase in the price divergence between hour-ahead and 5-minute real-time market prices continued during the third quarter of 2012 compared to the third quarter of 2011. The average price difference in the third quarter of 2012 was around $24/MWh with an increased average quantity of about 945 MW compared to a price difference of about $22/MWh and a quantity of 157 MW in the third quarter of 2011.

[20] 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. The price locations used in the calculation are the same between the hour-ahead and real-time.

Costs from transmission limit reductions in real-time

DMM's preliminary analysis reveals that the main cause of excessive congestion imbalance charges in the third quarter was a result of the ISO setting the real-time limit of a handful of constraints to substantially lower limits than in the day-ahead market. When these constraints were bound at these lower real-time limits with high shadow prices, large real-time imbalance charges were created when payments to relieve the congestion were larger than payments received because of price differences. Large real-time revenue inadequacy can occur even if the day-ahead, hour-ahead and real-time markets have the same system energy prices and constraint congestion prices.[21] A constraint binding at its real-time limit in the hour-ahead or real-time market will cause real-time revenue shortfalls if the day-ahead flow over the constraint was greater than the real-time constraint limit. A more detailed description of how these uplifts occur is outlined below.

When the flow over a real-time binding constraint is less in real-time than it was in the day-ahead, real-time injections and withdrawals must reduce the flow on the constraint by the amount the day-ahead flow exceeded the real-time limit. For instance, if the day-ahead flows on a line were 1,500 MW and the real-time limit was 900 MW, then real-time injections and withdrawals must reduce the flow by 600 MW. The injections and withdrawals can be virtual, which liquidates from the day-ahead in real-time, or physical, which must be re-dispatched in real-time. In addition to reducing the flow over the constraint, system-wide supply must continue to equal demand. Thus, real-time injections must equal real-time withdrawals. However, because of the different line limits, injections must be at locations that impact the constraint differently than the withdrawal locations. Specifically, injections must be at locations where they reduce flow on the constraint, or have a small impact on increasing flow on the constraint. At the same time, withdrawals must be at locations where they reduce flow on the constraint, or have a small impact on increasing flow on the constraint.

The constraint's impact on the real-time injection or withdrawal price is directly proportional to the effectiveness of the injection or withdrawal in impacting flow on the constraint. A constraint's congestion price will have a positive impact on the price at locations where an injection would reduce flow on the constraint. Conversely, a constraint's congestion price will have a negative impact on the price at nodes where a withdrawal would reduce flow on the constraint. Therefore, in order to reduce the day-ahead flow on the constraint to the lower real-time limit, the real-time injections must be at locations with higher prices than the equal quantity of withdrawals.[22] As a result, a constraint binding in real-time at a lower limit than the day-ahead flow across the constraint directly causes the market to pay injections that reduce flow a higher price than an equal quantity of withdrawals pays to (or in extreme cases is paid by) the market. This creates payment imbalances that are recovered by load-serving entities through the real-time congestion imbalance offset.

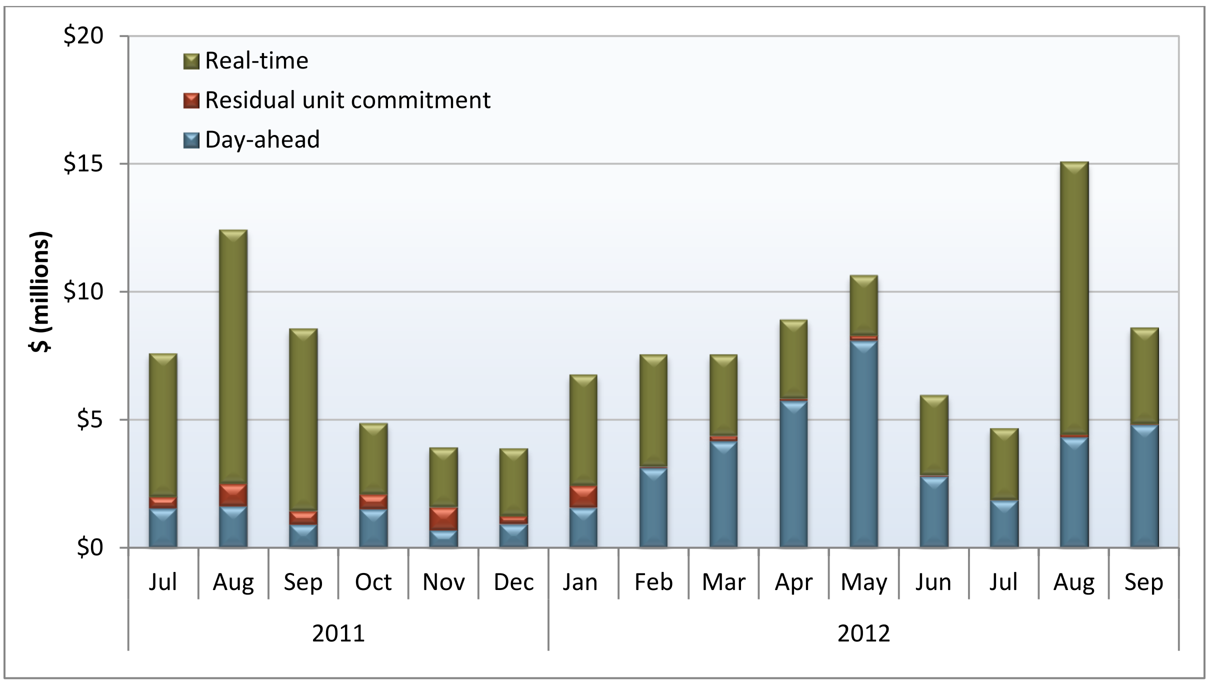
[21] Empirically, as shown in Section 1.3, real-time congestion often occurred at higher prices than the day-ahead.

[22] This is further complicated in the 5-minute real-time market because it is limited to dispatching internal resources only and cannot commit or decommit resources to change flow.

1.5 Bid cost recovery payments

Bid cost recovery payments are designed to ensure that generators receive enough market revenues to cover the cost of all their bids when dispatched by the ISO.[23] Figure 1.13 shows that bid cost recovery payments were around $28 million in the third quarter, compared to $26 million in the second quarter. The real-time portion of the bid cost recovery payments increased notably in the third quarter, reaching around $17 million, with $11 million in August. A sustained heat wave and the resulting increases in August load required the ISO to commit extra units by exceptional dispatch after the day-ahead market to protect the system from potential system or local contingencies. Unit commitment costs, mainly start-up and minimum load costs, from the exceptional dispatches played a significant role in the real-time commitment cost increases. DMM estimates that approximately $13 million in real-time bid cost recovery payments in the third quarter stemmed from these exceptional dispatch unit commitment costs.

Figure 1.13 Monthly bid cost recovery payments



The ISO also incorporates minimum online constraints in the day-ahead market model. These constraints are based on existing operating procedures that require a minimum quantity of online capacity from a specific group of resources in a defined area.[24] These constraints make sure that the system has enough longer start capacity online to meet locational voltage requirements and respond to

[23] Bid cost recovery covers the bids for start-up, minimum load, ancillary services, residual unit commitment availability, and day-ahead and real-time energy.

[24] See *Technical Bulletin 2010-01-02: Minimum Online Commitment Constraint*, January 11, 2010: http://www.caiso.com/271d/271dedc860760.pdf.

contingencies that cannot be directly modeled.[25] After February 2012, the ISO created new minimum online constraints to be able to respond to potential contingencies from the outages of the two SONGS units. As a result, the ISO frequently committed some units at their minimum capacity in the day-ahead market. When market revenues are insufficient to meet the bid costs for the units added to meet the minimum online constraint, bid cost recovery payments make the units whole. DMM estimates that the bid cost recovery payments resulting from the minimum online constraints were around $2.5 million in the third quarter compared to payments of around $7 million in the second quarter.[26]

Bid cost recovery payments from the residual commitment process remained low in the third quarter. This was mainly because minimum online constraints committed additional units in the day-ahead market run and the virtual market primarily cleared net virtual demand in the majority of the hours (see Section 2.1). When the market clears net virtual demand, the need for and amount of residual unit commitments are reduced as additional physical resources are made available to meet the virtual demand.

1.6 Ancillary services

1.6.1 Ancillary services requirement setter

The ISO implemented on August 21 an automated feature in the day-ahead market and 15-minute real-time pre-dispatch (RTPD) process to more accurately calculate the ancillary services requirement. At this time, this feature has only been used to assess the requirement for spinning and non-spinning reserves in the 15-minute real-time pre-dispatch market. This feature, known as the *ancillary services requirement setter,* first calculates the ancillary services requirement (for spinning and non-spinning reserves) based on the following three different ways:

- the resource mix (e.g., hydro versus thermal);
- the single largest contingency in the system; and
- a percentage of load forecast (between 5 and 5.7 percent in real-time depending on system conditions).

The final requirement is the largest of these three values. The operator has the ability to override the requirement setter if necessary by setting the ancillary service requirement as a fixed percentage of the load forecast.

The day-ahead requirement remains fixed as a percentage of the day-ahead load forecast, which is currently set at 6.75 percent. This is consistent with the way the day-ahead and real-time requirement was set prior to the implementation of the ancillary services requirement setter.

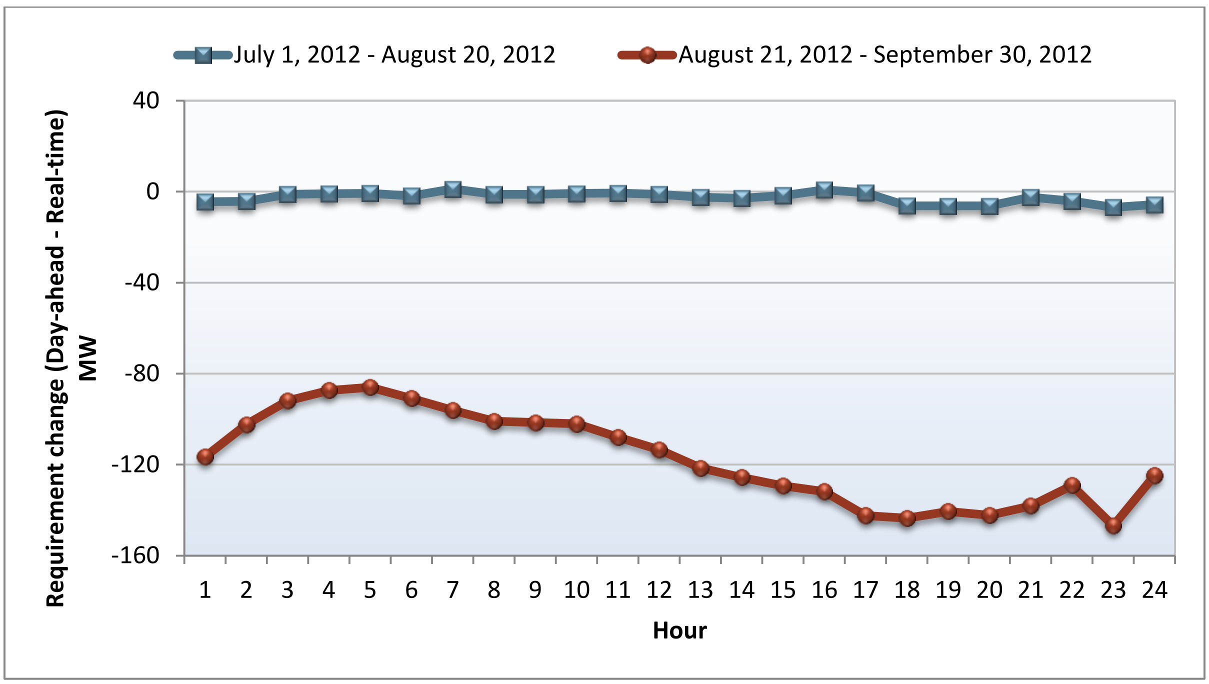
[25] There are two factors determining the minimum online constraints. First, there are regional procedures, such as SDG&E or SCE procedures, which are determined by the day-ahead load forecast for the region. These procedures are usually active throughout the year and the level of the constraint is mainly calculated for each hour based on the day-ahead load forecasts. Second, planned outages or prolonged forced outages, which can be based on generator outages or transmission outages, may create needs for new minimum online requirements. Accordingly, the ISO may create new minimum online capacity requirements for potential contingencies and locational voltage requirements.

[26] Bid cost recovery payments associated with minimum online constraints were lower in the third quarter as a minimum online constraint for the San Diego area was removed after the Sunrise Powerlink became operational in mid-June.

The different requirement methodology between the two markets has resulted in an over-procurement of ancillary services in the day-ahead market. Since implementation in late-August, the ISO has over-procured on average about 125 MW of spinning and non-spinning reserves in each hour. However, since the requirement change, not all 125 MW are reduced in real-time as the ISO does not automatically reduce the spinning or non-spinning reserve levels. In the event that a unit is no longer capable of providing spinning or non-spinning reserves or is backed down by the ISO from providing reserves, the ISO only re-procures up to the new requirement level.

DMM has recommended and the ISO plans to fine tune the requirement settings between the two markets by enhancing and using this new feature in the day-ahead market to reduce the systematic ancillary services over-procurement in the day-ahead market.[27] Figure 1.14 displays the hourly change in spinning reserve requirement before and after launching the new ancillary services requirement setter. As the figure shows, since implementing the new procedure, the ISO has consistently over-procured the associated reserves in the day-ahead market by an average of 125 MW over the day.

Figure 1.14 Spinning and non-spinning reserves requirement change



[27] The ISO provided just a brief note on this modification at the November Market Performance and Planning Forum: http://www.caiso.com/Documents/Market%20performance%20and%20planning%20forum. Unfortunately, the ISO did not provide further technical detail.

1.6.2 Ancillary services compliance testing

The ISO announced in mid-October that it will begin ancillary service compliance testing.[28] Earlier in the year, DMM identified concerns with participant performance during real-time ancillary service contingency events. Specifically, some resources did not perform up to their rated ancillary service level. DMM worked with the ISO to ensure that a compliance testing process was in place to test market participant ancillary service compliance. DMM has provided a list of resources to the ISO to include as part of their unannounced compliance testing process and awaits the results.

[28] See the following market notice for more information: http://www.caiso.com/Documents/CaliforniaISOConductUnannouncedComplianceTesting.htm.

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 ISOs with day-ahead energy markets. Virtual bidding on inter-ties was suspended on November 28, 2011.[29] Thus, the third quarter of 2012 represents the third full quarter with virtual bidding within the ISO system but not at the inter-ties.

When convergence bids are profitable, they may increase market efficiency by improving day-ahead unit commitment and scheduling. Convergence bidding also provides a mechanism for participants to hedge against price differences in the two following circumstances:

- price differences between the day-ahead and real-time markets; and
- congestion at different locations.

Participants in virtual bidding were paid net revenues of over $33 million in the third quarter. Most of these net revenues resulted from virtual demand bids at internal locations during on-peak hours and virtual supply bids during off-peak hours. This reflects the systematic relationship between average real-time and day-ahead prices. In the peak hours real-time prices are higher, while in the off-peak hours day-ahead prices are higher (see Figure 1.3 for further detail).

Internal virtual supply averaged around 1,120 MW while virtual demand averaged around 2,020 MW each hour during the quarter. Thus, the average hourly net virtual position in the third quarter was 900 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 only on physical supply and demand. Virtual bids accepted in the day-ahead market are liquidated financially in the real-time market 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.

[29] 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.

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 as illustrated in the following:

- 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 the 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.[30] 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 3,100 MW in the third quarter from 2,500 MW in the second quarter. Also, the share of cleared virtual demand reached 64 percent in the third quarter up from 59 percent in the previous quarter.

Figure 2.1 shows the monthly quantities of 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 third quarter. As shown in these figures:

- On average, 55 percent of virtual supply and demand bids offered into the market cleared in the third quarter.
- Cleared volumes of virtual demand outweighed cleared virtual supply in the third quarter by around 900 MW on average, up from around 430 MW in the previous quarter.
- Virtual demand exceeded virtual supply during peak hours by about 1,400 MW, while during the off-peak hours virtual supply was greater than virtual demand by 155 MW. In the second quarter, the same trend existed, but the volumes were lower in peak periods and slightly higher in off-peak periods.

[30] 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

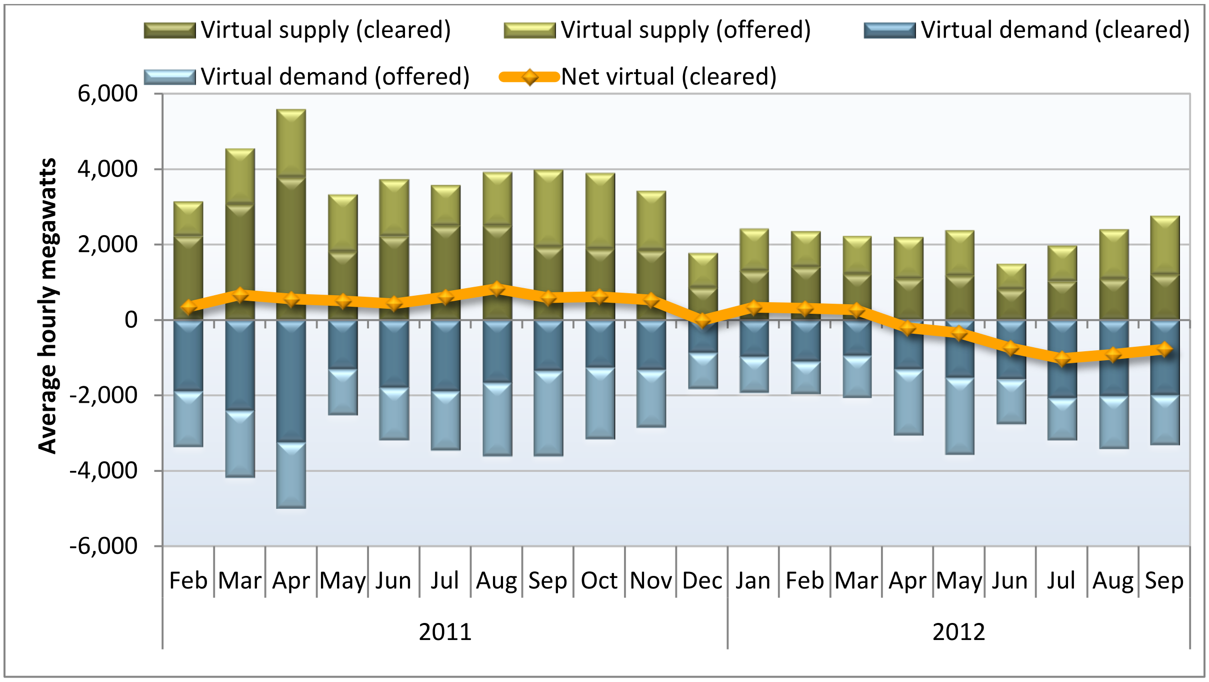


Figure 2.2 Hourly offered and cleared virtual activity (July – September)

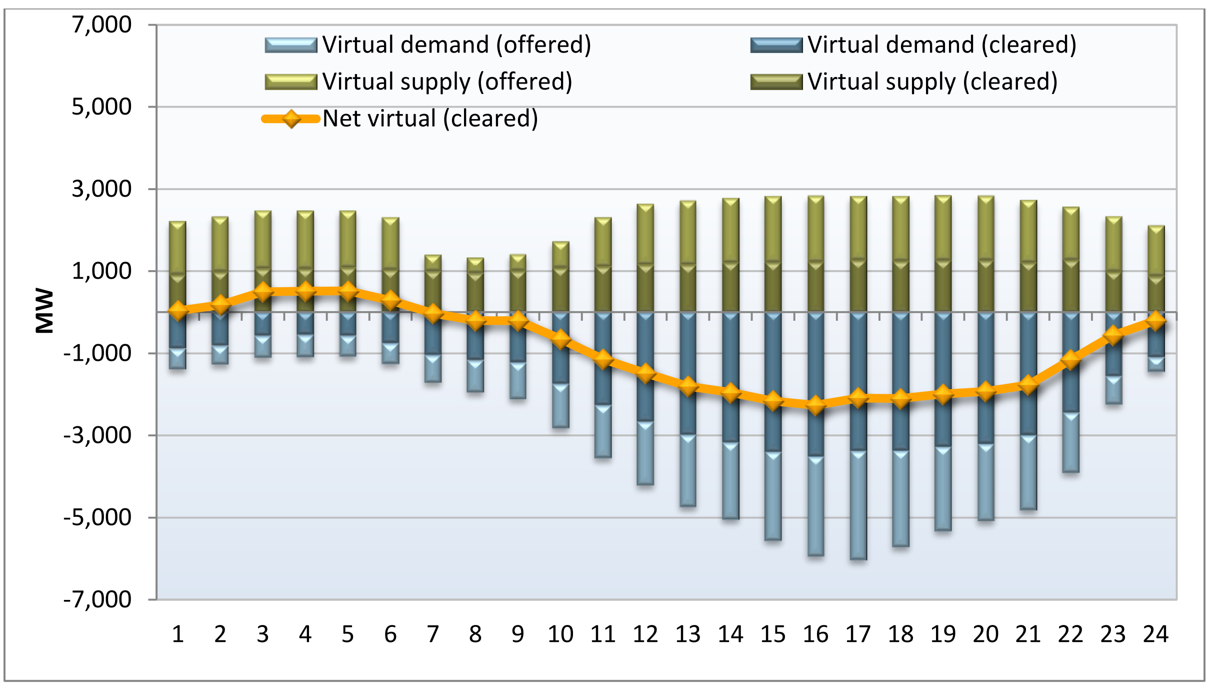
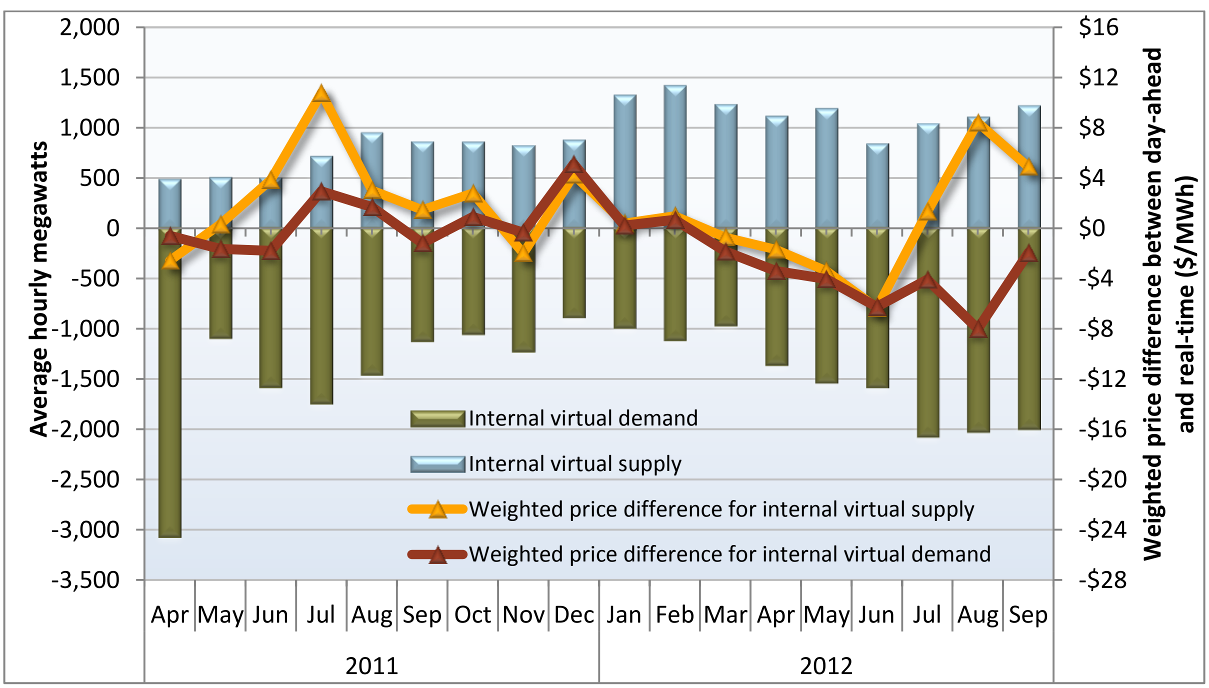


Figure 2.3 compares cleared convergence bidding volumes with the volume weighted average price differences at which these virtual bids were settled. The difference between day-ahead and real-time prices shown in Figure 2.3 represents the average price difference weighted by the amount of virtual bids 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 third 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. Virtual supply at internal locations was profitable and consistent with weighted average price differences in the third quarter.
- 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



Convergence bidding helps to bring together day-ahead and real-time prices when the net market virtual position is directionally consistent (and profitable) with the price difference between two markets. Convergence bidding was consistent with improving prices in many hours in the second quarter. In the beginning of the third quarter, net convergence bidding was not consistent with price differences between the day-ahead and real-time markets in many hours. The directional consistency improved in August and September.

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 July, August and September, 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. In anticipation of real-time price spikes, market participants bid virtual demand in the on-peak hours. Even though these spikes do not occur frequently, the revenues received outweigh losses that happened otherwise in every month of the third quarter (see Section 2.2 for further detail).

- As shown in Figure 2.4, convergence bidding volumes in a majority of hours in July were not consistent with price convergence at internal locations. The net convergence bidding volume direction and the price difference were most consistent in hour ending 13 and between hours ending 16 through 18.
- In August, as seen in Figure 2.5, convergence bidding volumes were consistent in the majority of hours, on average, with price convergence at internal locations. Consistency was best in the peak hours and in the early morning hours.
- Figure 2.6 shows that in September, convergence bidding volumes again were directionally consistent with differences between day-ahead and real-time prices in many hours. 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 – July

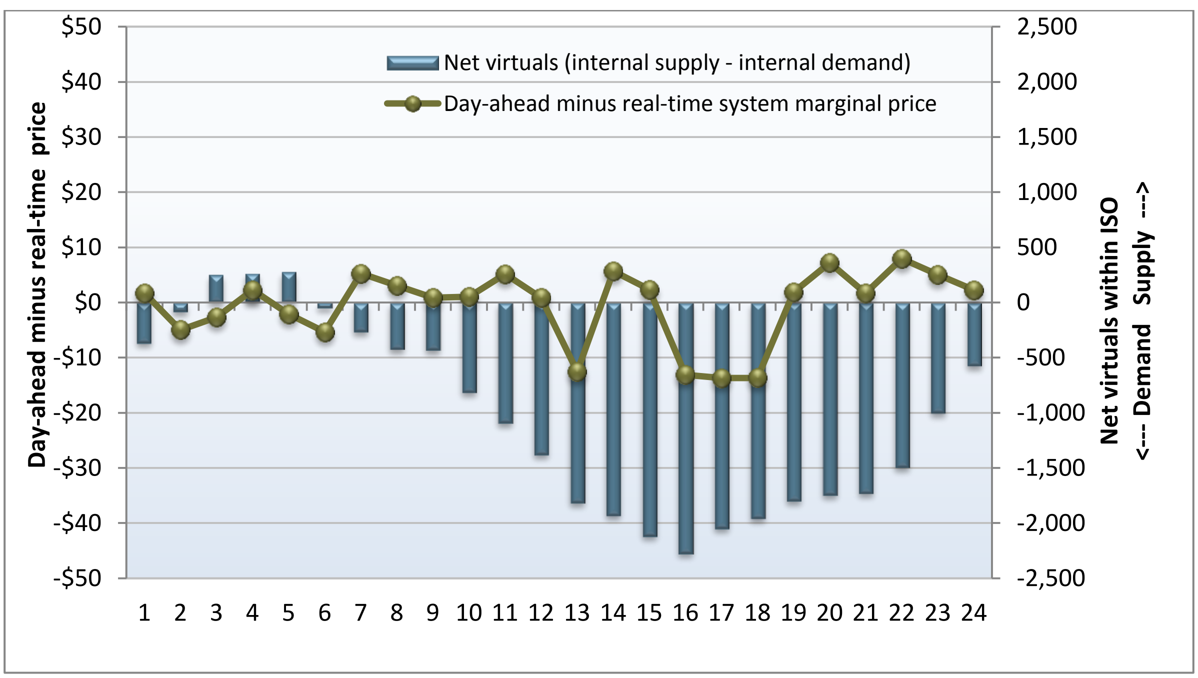


Figure 2.5 Hourly convergence bidding volumes and prices – August

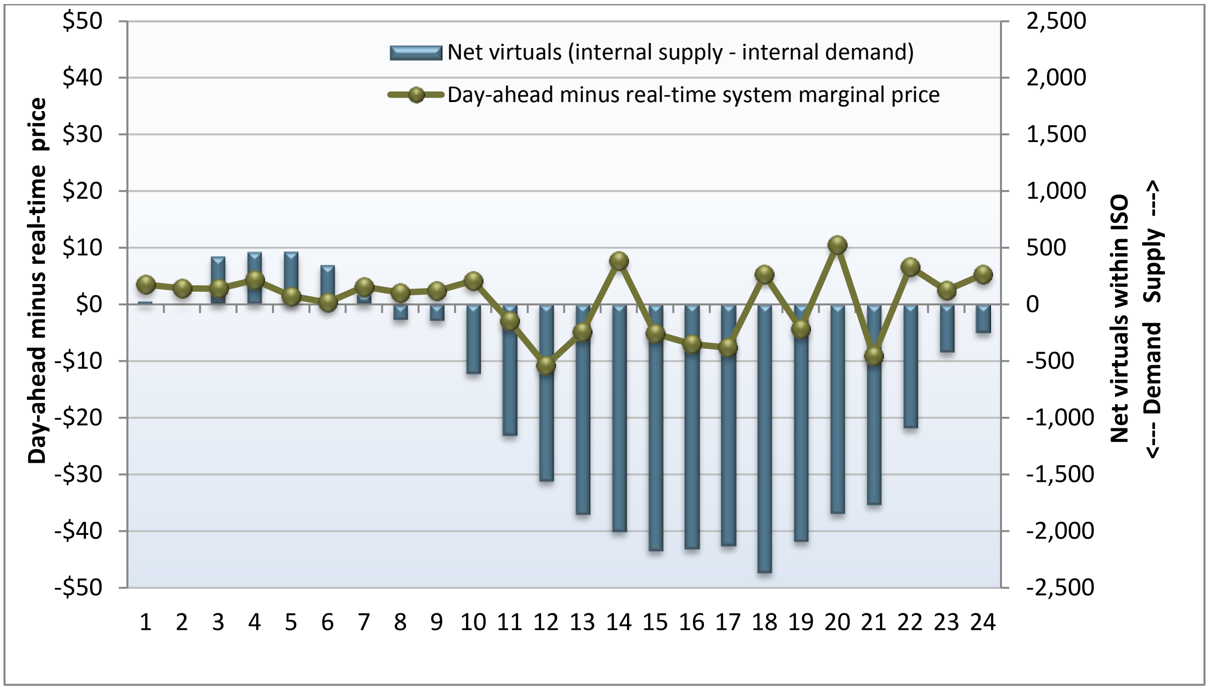
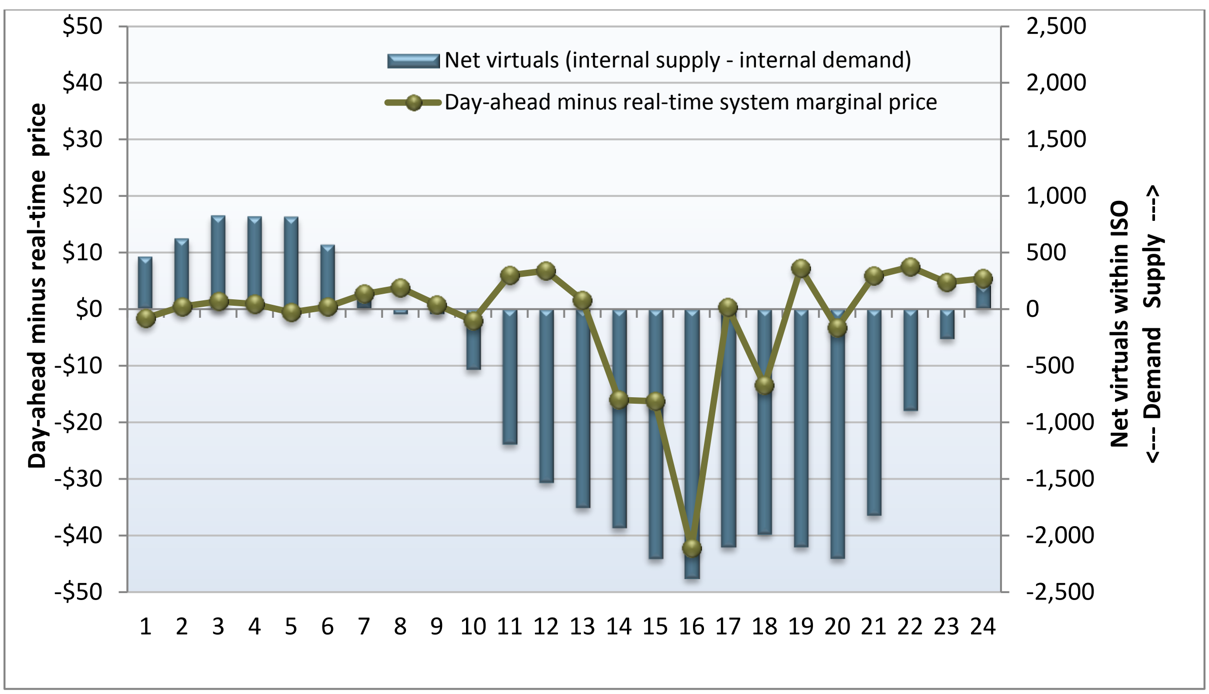


Figure 2.6 Hourly convergence bidding volumes and prices – September



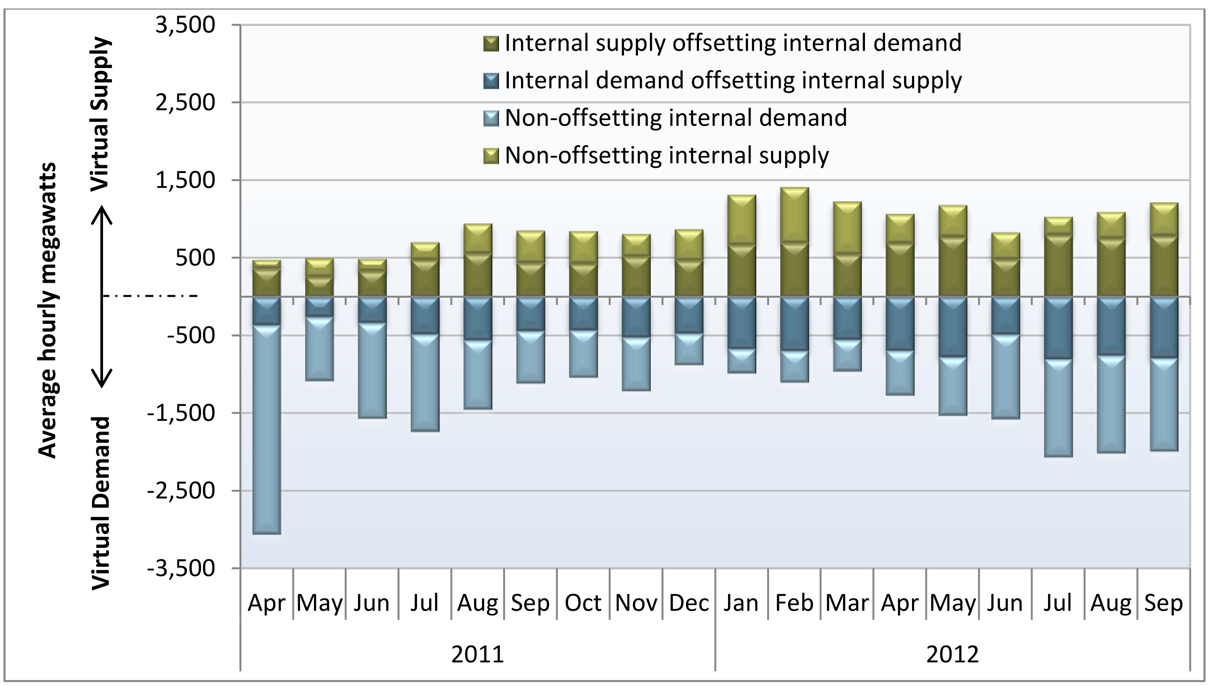
Offsetting virtual supply and demand bids at internal points

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.[31] 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 780 MW of demand offset by 780 MW of virtual supply at other locations per hour in the third quarter. These offsetting bids represent about 66 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



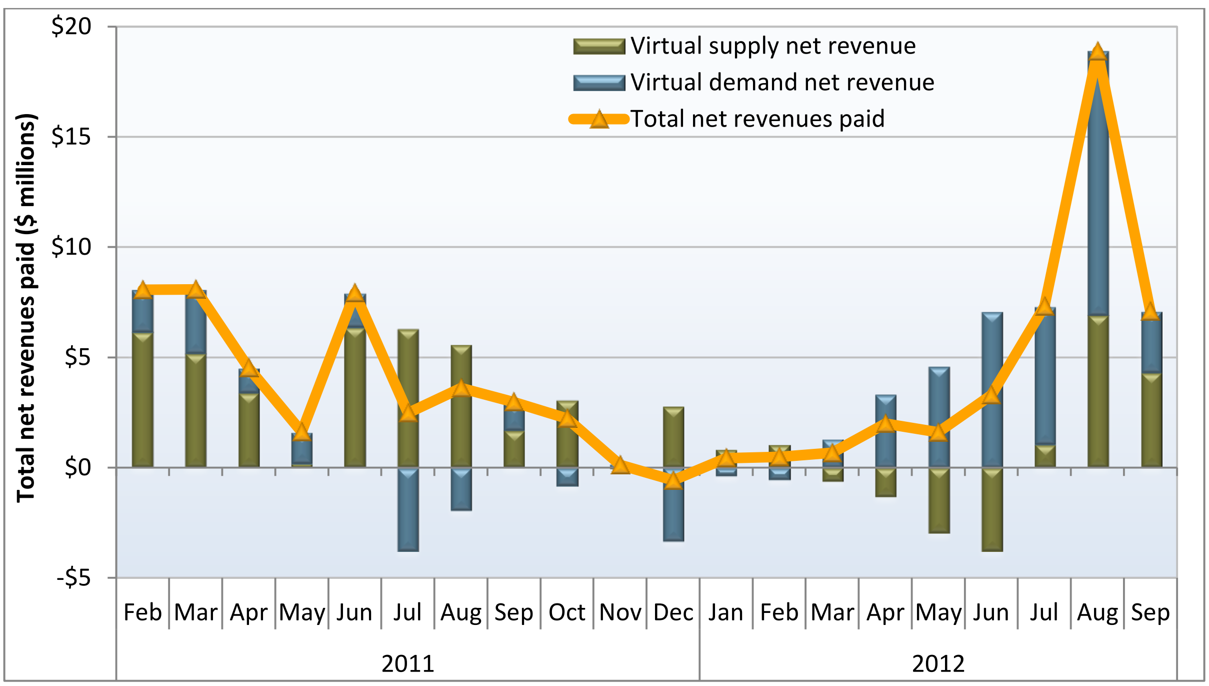
[31] When calculating the offset between each participant's accepted virtual supply and demand bids at internal points each hour, we did not include the portion (if any) of the participant's internal virtual demand bids that were offset by accepted virtual import bids by that participant in the months 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 cleared virtual supply and demand. This figure shows the following:

- Virtual demand revenues increased substantially in the third quarter. In July and August, the higher frequency of real-time price spikes accompanied by congestion contributed to these revenues (see Section 1.2 for details).
- Virtual supply positions were increasingly profitable in the third quarter. In these cases, real-time prices (or congestion) were lower than day-ahead prices.
- Total net revenues paid to virtual bidders increased significantly from the second to the third quarter of 2012. It was driven by increased revenues on virtual demand positions and positive revenues on virtual supply.
- In the third quarter of 2012, net revenues paid to convergence bidding entities totaled over $33 million. Virtual demand accounted for $21 million, and virtual supply was about $12 million. As noted above, the virtual supply bids were typically profitable during off-peak hours, while virtual demand was profitable in the peak hours.

Figure 2.8 Total monthly net revenues paid from convergence bidding[32]



[32] The revenues in Figure 2.8 and Figure 2.9 for the second quarter 2012 changed from what was published in the previous quarterly report as DMM fixed issues related to an upstream data problem that affected prices.

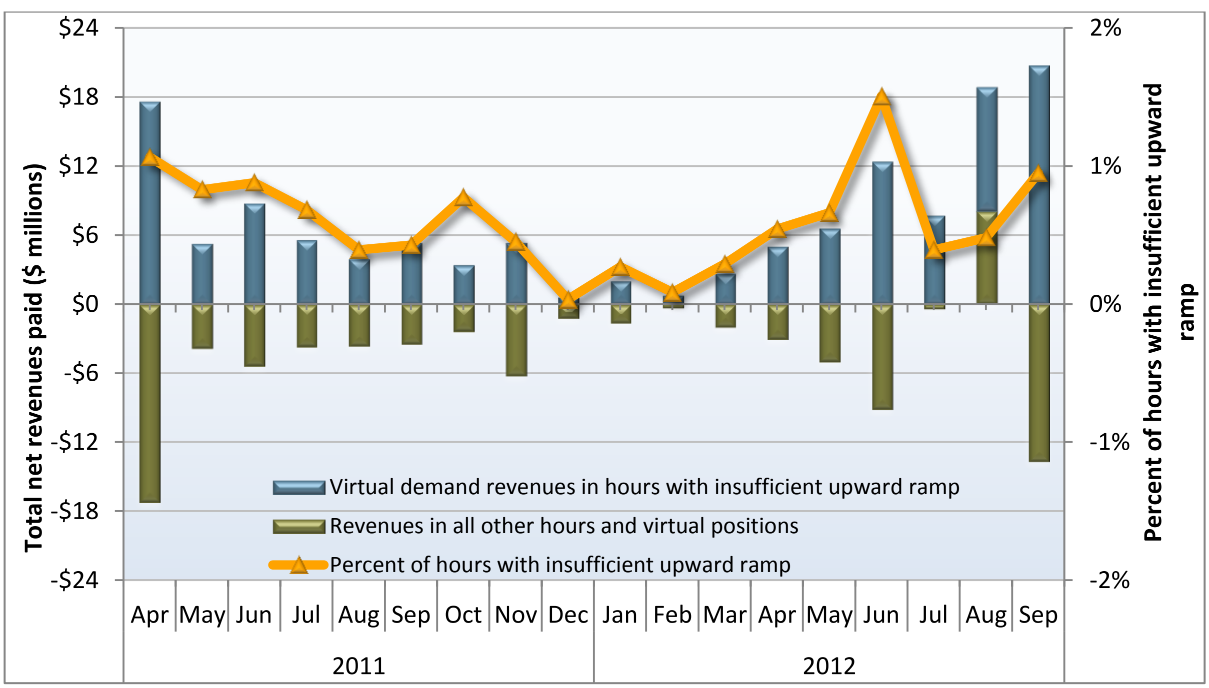
Net revenues at internal scheduling points

In the second quarter, virtual demand accounted for about 59 percent of cleared bids at internal locations; in the third quarter it increased to 64 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. Virtual supply bids are profitable when real-time prices drop below day-ahead prices. Usually, it happens during off-peak hours when over-generation drives the prices down.

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.
- Except in July and August, for 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 $20 million in September during these periods. As noted earlier (see Section 1.2), 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, 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 often does not reflect the same system conditions and frequently reduced 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 $1,600 in the third quarter of 2012, down from $21,000 in the second quarter. 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 $130,000 in the third quarter of 2012, down from $330,000 in the previous quarter.

As noted above, the amount of cleared virtual demand increased significantly in the third quarter relative to previous quarters. This 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.

- 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 17 percent in the first three quarters of 2012.
- Beginning with June 2012, residual unit commitment costs became insignificant, totaling just $1,600. This is attributed to increasing volumes of net virtual demand.

3 Special Issues

3.1 Flexible ramping 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.[33] The total payments for flexible ramping resources during the first nine months of the year were around $17.6 million, with almost $3 million in the third quarter.[34] For the sake of comparison, costs for spinning reserves have totaled about $25.3 million in 2012, with over $13 million occurring in the third quarter.

Applying 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.[35] 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.[36] As shown below, payments at such times accounted for more than half of flexible ramping costs.

Analysis of the flexible ramping constraint

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:

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

[34] 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.

[35] 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.

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

- The frequency of the flexible ramping constraint 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 situation changed in August when additional ramping capacity in the system pushed the percentage of binding intervals to an all-time low of about 7 percent.
- The frequency of procurement shortfalls (i.e., instances when the requirement is not met) 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 frequency of procurement shortfalls fell to less than 1 percent of all 15-minute intervals in September and was much lower overall compared to the second quarter.
- The total payments to generators for the flexible ramping constraint decreased from previous months, falling to less than $1 million in August and less than $3 million for the quarter.

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
Jul	$1.01	8%	1.4%	$47.94
Aug	$0.77	7%	1.2%	$34.81
Sep	$1.03	13%	0.8%	$32.54

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 third 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 72 percent of these payments with hydro-electric capacity accounting for most of the remaining 28 percent.

Figure 3.1 Monthly flexible ramping constraint payments to generators

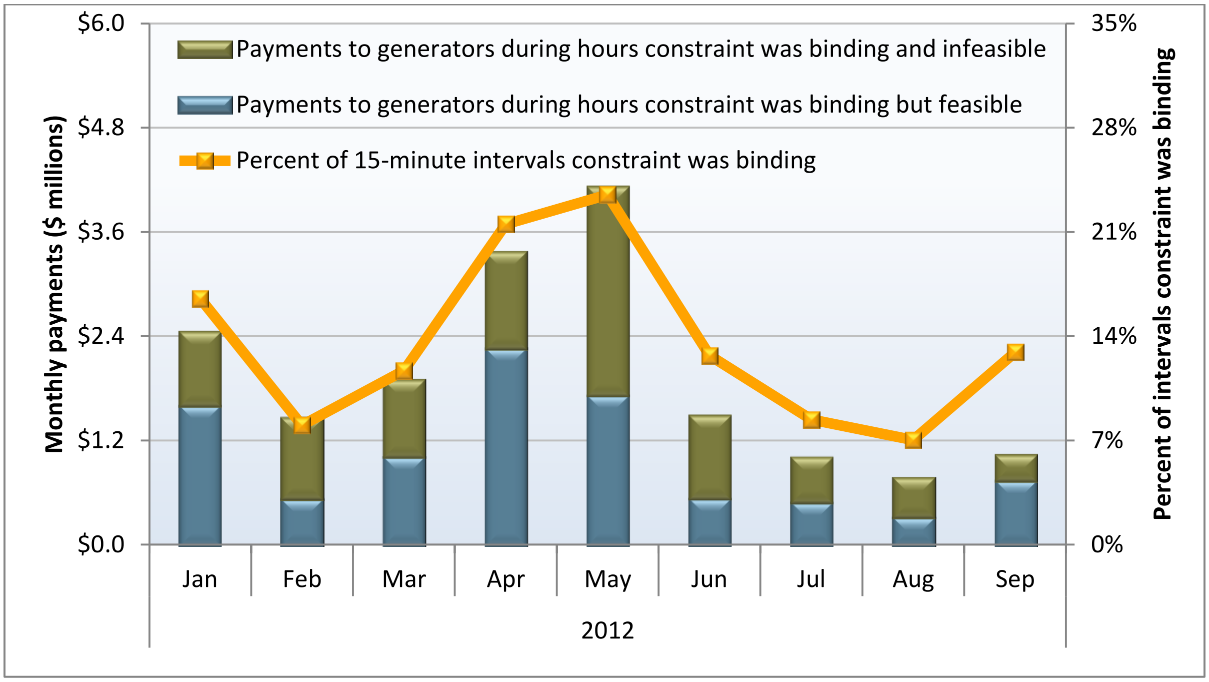
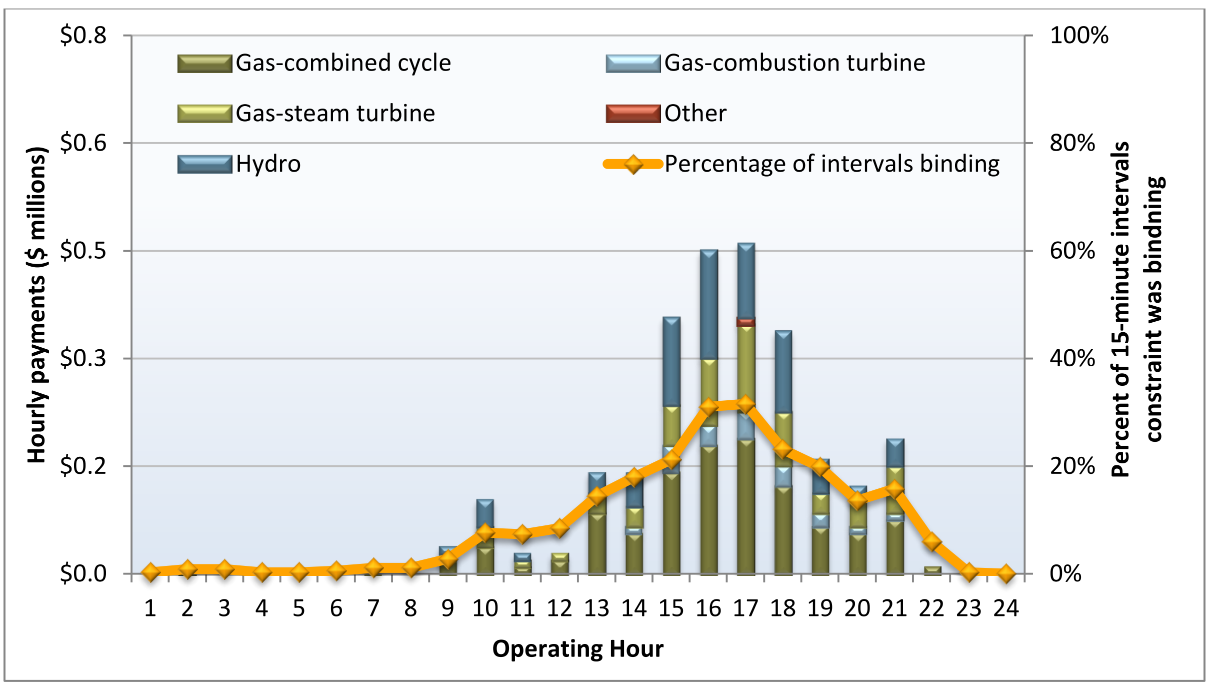


Figure 3.2 Hourly flexible ramping constraint payments to generators (July – September)



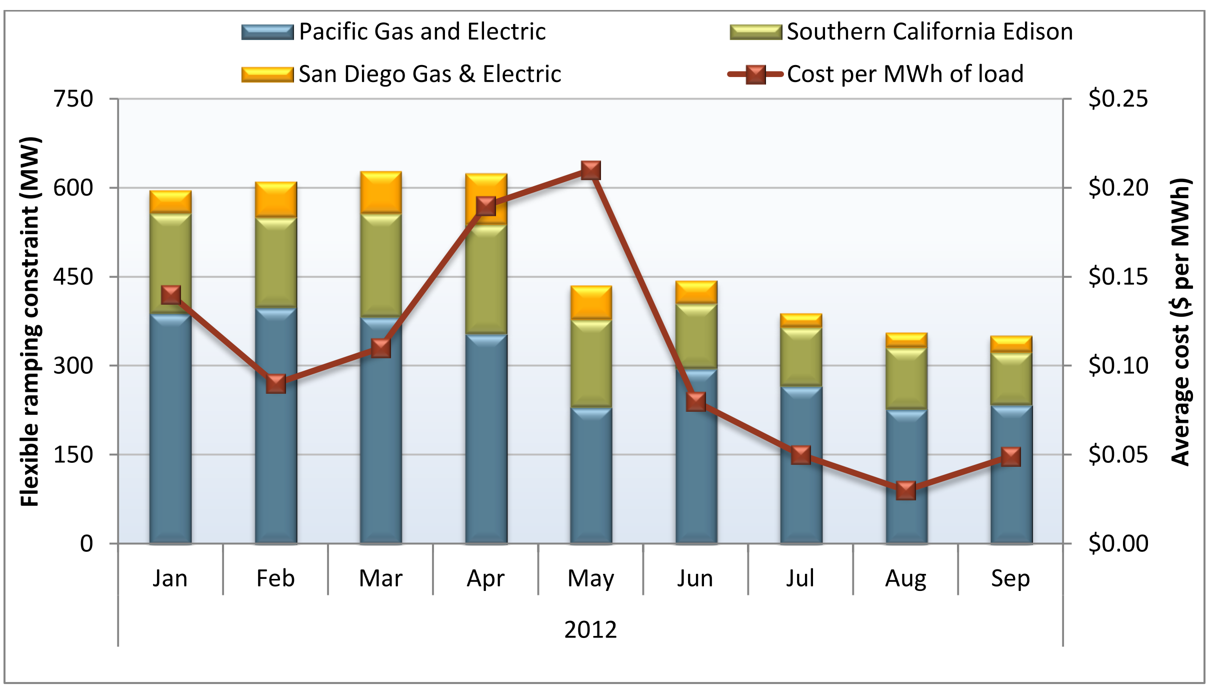
DMM uses the ISO's methodology along with settlement data to calculate the flexible ramping capacity utilization. The metric determines how much of the procured flexible ramping capacity in the 15-minute real-time pre-dispatch was used in the 5-minute real-time dispatch. The utilization is a function of prevailing system conditions, including load and generation levels. The average utilization of procured flexible ramping was comparable in the third quarter to the second quarter. The range of hourly average utilization varied from a low of 0 percent to a high of about 100 percent during the quarter. Average utilization ranged from 9 percent in the early morning to 54 percent in the late evening. The percentage of intervals when the utilization is over 95 percent has increased steadily during the third quarter. The utilization was at 100 percent at almost 0.5 percent of individual 5-minute intervals during evening load ramping hours in August and September. Utilization during intervals when the flexible ramping constraint was binding was only slightly higher than during non-binding intervals.

Flexible ramping regional procurement

Figure 3.3 shows the procurement of flexible ramping capacity by investor-owned utility area. The red line provides an estimated cost of the flexible ramping cost per megawatt-hour of load served in the ISO footprint. During the year, over 63 percent of the capacity procured for the flexible ramping constraint was in the Pacific Gas and Electric area. Because flexible capacity is deployed during tight system-wide conditions, the majority of this capacity cannot be used when there is congestion in the southern part of the state.

For example, in August only 25 MW of flexible ramping capacity was procured on average in the San Diego region. 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 90 MW of generation in September was available to ramp when 5-minute real-time congestion occurred.

Figure 3.3 Flexible ramping constraint procurement by investor-owned utility area



DMM recommends that the ISO continue to fine tune the flexible ramping constraint to increase its effectiveness, particularly during periods of congestion. Furthermore, 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.

3.2 Enhancements to 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 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 market runs.[37]

During the third quarter, the ISO performed various enhancements to the operational characteristics of the compensating injections.[38] The enhancements were focused on the following aspects of compensating injections:

- As the net compensating injections approach a threshold level (40 MW), they are gradually reduced to zero using a reduction factor.[39] Previously, when the compensating injections approached the threshold (100 MW), the software would immediately take the net compensating injections down to zero in the next interval.

- As the net compensating injections increase above a threshold level (40 MW) and remain below a higher threshold (2,000 MW), their system effect is gradually reduced using a reduction factor that reduces imports and increases exports or vice versa to have a more gradual impact on market

[37] For a more detailed discussion of the operational characteristics of compensating injections see DMM's *2012 Second Quarter Report on Market Issues and Performance,* August 14, 2012, pp. 44-46: http://www.caiso.com/Documents/2012SecondQuarterReport-MarketIssues-Performance-August2012.pdf.

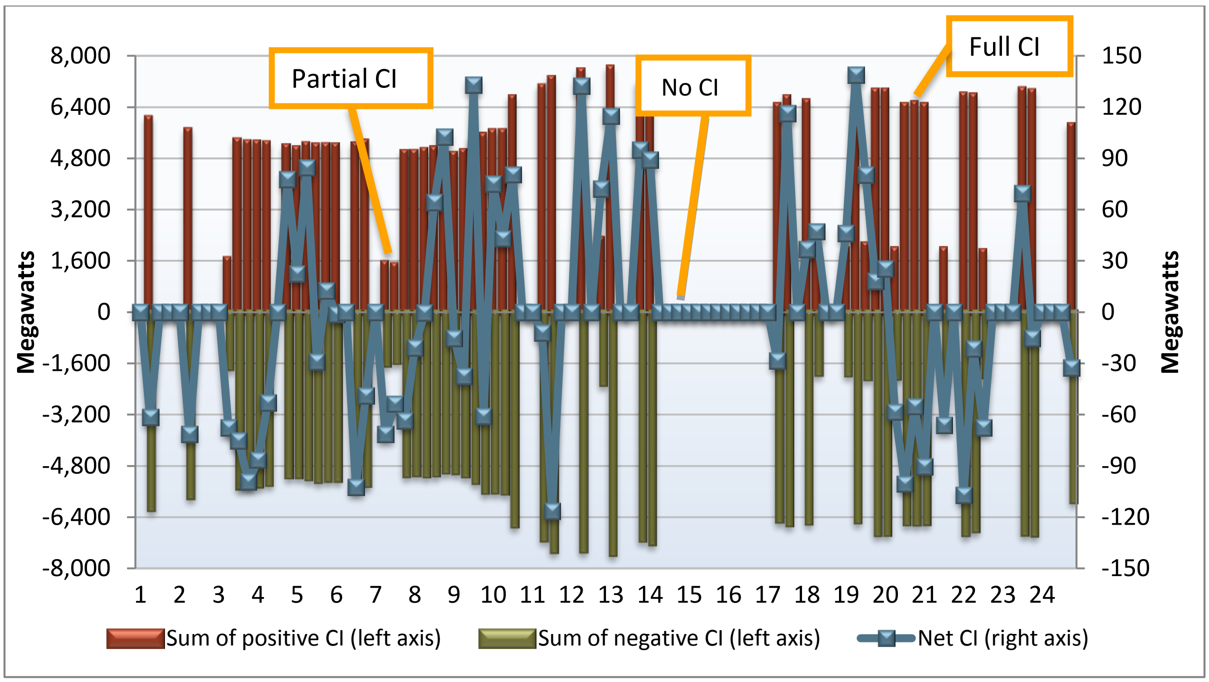
[38] The ISO provided just a brief note on these modifications at the November Market Performance and Planning Forum: http://www.caiso.com/Documents/Market%20performance%20and%20planning%20forum. Unfortunately, the ISO did not provide further technical detail.

[39] In the previous mechanism, the compensating injection algorithm shut down the entire algorithm when the net compensating injection hit a pre-defined value (100 MW in most cases). The enhancement to the algorithm reduces the net compensating injection gradually by using a pre-defined reduction factor (less than 1). The value tends to approach zero over multiple market intervals. Imports are increased and exports are decreased proportionately over these intervals to reflect the decreasing value of net compensating injection.

flows.[40] Previously, both exports and imports were reduced by a single fixed parameter value in the next interval.

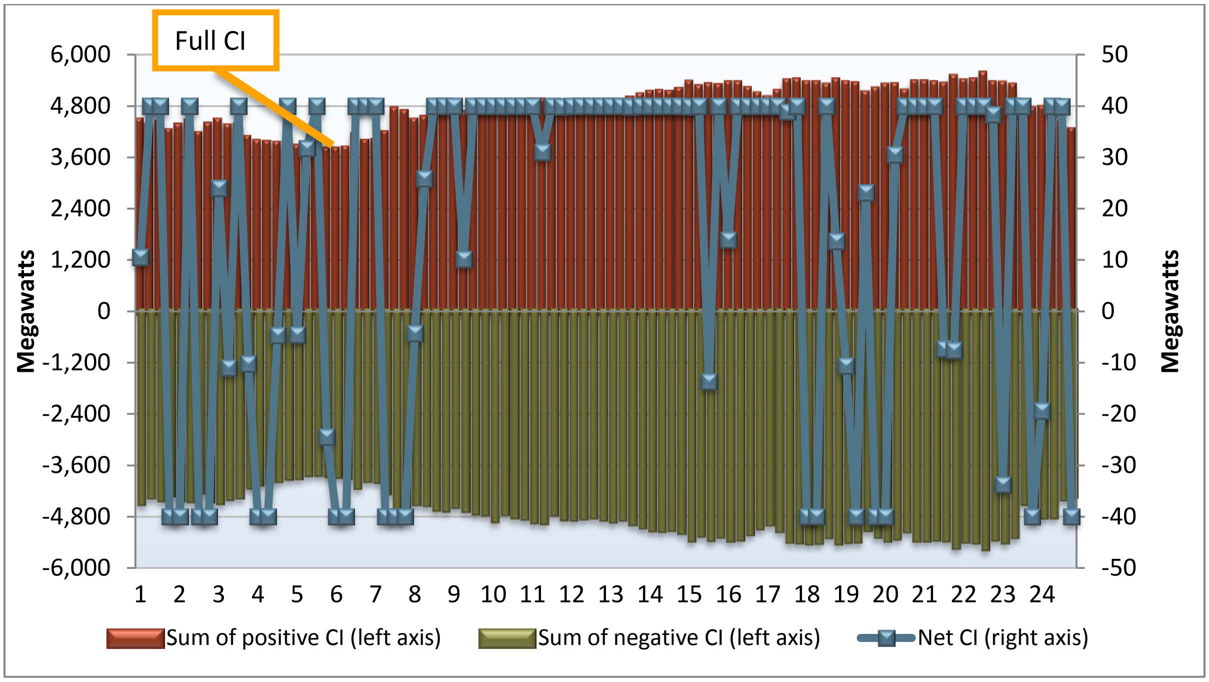
As a result of the updates, the total effect of compensating injections has become more consistent over the day and less variable. Figure 3.4 shows the daily profile of the compensating injections prior to the recent enhancements performed by the ISO. The chart shows that the compensating injection status varied consistently during the day. Figure 3.5 shows the daily profile of compensating injections after the ISO performed the enhancements. The status remains more consistent and less variable than before the enhancements. There have been only a handful of intervals when the compensating injection status was limited or off after the enhancements.

Figure 3.4 Compensating injection status prior to enhancements (July 24, 2012)



[40] In the previous mechanism, the imports and exports were both decreased simultaneously to bring the net compensating injection within the defined range. The resultant power balance was applied to all the subsequent market intervals. The enhancement to the algorithm reduces the power balance gradually by utilizing a pre-defined reduction factor (less than 1). The value tends to approach zero over multiple market intervals. Imports are increased and exports are decreased proportionately over these intervals to reflect the decreasing value of power balance. This provides a more even compensating injection value over multiple market intervals.

Figure 3.5 Compensating injection status after the enhancements (October 4, 2012)



3.3 Market performance during heat waves

The ISO market experienced two system-wide heat waves and subsequent high loads in 2012. The first wave was from August 7 to August 17 and the second heat wave was on October 1 and 2. For the most part, the ISO systems and markets performed fairly well under stressed conditions. The following sections highlight key items during these periods.

Summer heat wave: August 7 through 17

Peak loads from August 7 through 17 were above 40,000 MW, reaching the annual peak for 2012 at 46,847 megawatts on August 13.[41] As a preliminary precaution, the ISO issued Flex Alerts on August 10 and August 14. A Flex Alert is an urgent call to consumers to immediately conserve electricity in the peak hours and shift demand to the hours typically after 6:00 p.m. Flex Alerts are based on the ISO's load forecast and its assessment of potential contingencies, and ideally they are issued a day in advance to give consumers an early notice to take action. The ISO estimated that Flex Alerts reduce the system peak load up to 1,000 MW. The ISO also implemented its Restricted Maintenance Operations procedure, where market participants are cautioned to avoid actions that may jeopardize generator or transmission availability.[42] On most days during the heat wave, day-ahead market prices averaged

[41] This was about 500 MW above the 1 in 2 year forecast of 46,352 MW.

[42] The Restricted Maintenance Operations procedure is a part of operating procedure 4420 - System Emergency. The procedure requires participating transmission owners, scheduling coordinators and generators obtain permission from the ISO to go ahead with pre-scheduled or planned work, regardless of whether prior approvals were obtained from the ISO. Details of operating procedure 4420 can be found at http://www.caiso.com/Documents/4420.pdf.

around $45/MWh and real-time prices averaged around $50/MWh. However, the real-time market experienced a few price spikes around $1,000/MWh at the 5-minute interval level.

Supply conditions were tight on August 13, particularly during the afternoon hours. As a result, the real-time market experienced price spikes around $1,000/MWh in several intervals from hour ending 15 to 18 (see Section 1.2 for further details on real-time prices spikes) including the majority of intervals in hour ending 16. Average day-ahead and real-time peak prices were over $100/MWh on this day.

Load-serving entities activated several demand response programs on August 13, which are estimated to have decreased load by around 1,250 MW on average for each hour from hour ending 15 through 18. The ISO did not issue a Flex Alert on this day, but used other tools to maintain reliability during the tight supply conditions. For instance, the ISO committed 800 MW of capacity in the San Diego area in the peak hours using minimum online constraints in the day-ahead market.[43] Additionally, the ISO exceptionally dispatched around 2,200 MW of real-time energy in the peak hours to meet various reliability needs.

Fall heat wave: October 1 and 2

A second system-wide heat wave occurred on October 1 and 2, with peak loads reaching around 42,000 MW on each day. While the ISO did not issue a Flex Alert on these days, the ISO did call on its Restricted Maintenance Operations procedure for October 1. The heat wave was highlighted by relatively high loads in Southern California, several binding transmission constraints between Northern and Southern California, and high congestion costs.

For both the October 1 and 2 day-ahead market runs, the ISO determined that a price correction was necessary for all hours of the day because the market software failed to find a solution within the expected optimal threshold.[44] In both days, the market software did not come close to the optimal solution for the day-ahead market run and was forced to stop by a timeout parameter while still searching for the optimal solution. The software failure was discovered after the day-ahead market results were published.

Because the ISO did not determine that there was an issue until after the market results had published, the ISO was not able to rerun the market software to obtain a new day-ahead solution. On both days, the mixed integer programming (MIP) percentage solution gap was large and the market schedules did not appear to provide an economic solution in multiple cases. Later in the week, as part of the price validation and correction process, the ISO reran the day-ahead market for trading days October 1 and 2 to correct the prices to reflect an optimal solution. Prices were republished within the price correction window.

The ISO has enhanced the day-ahead market process to include additional monitoring of the market solution. In addition to the existing day-ahead monitoring and correction process, these enhancements include explicit monitoring of the mixed-integer programming gap and congestion. The enhancements

[43] See Section 1.5 for further discussion of minimum online constraints.

[44] The ISO market software is designed to find a solution with an expected level of optimality. The optimality is defined by the mixed-integer programming (MIP) gap. The ISO has analyzed data related to the day-ahead market solutions over the past three years. During this period, the vast majority of the day-ahead market runs reached an optimum solution significantly below the 30 percent gap that occurred on October 1 and 2. In addition to the MIP gap percentage, the ISO also considers the dollar value of the MIP gap when it analyzes the results and looks for additional evidence of poor solution quality including evidence of uneconomic commitment decisions. On October 1 and 2, all of these factors indicated a poor quality solution.

also include additional support for the day-ahead market run, including monitoring of the solution by the market validation unit, a dedicated day-ahead operations engineer, and leverage of the two day-ahead process[45] to identify potential issues earlier. Furthermore, the ISO will add more solution run time to produce accurate and quality day-ahead results when necessary.

[45] The two day-ahead process (sometimes referred to as the D+2 run) performs a run of the day-ahead market two days out. While the two day-ahead process does not contain all the same variables that are ultimately used in the day-ahead market, including all bids and outages, it does allow the ISO to find potential issues the day before the day-ahead market is run with the existing bids and anticipated system configuration.