California Independent System Operator Corporation

California ISO

Q1 Report on Market Issues and Performance

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Executive summary

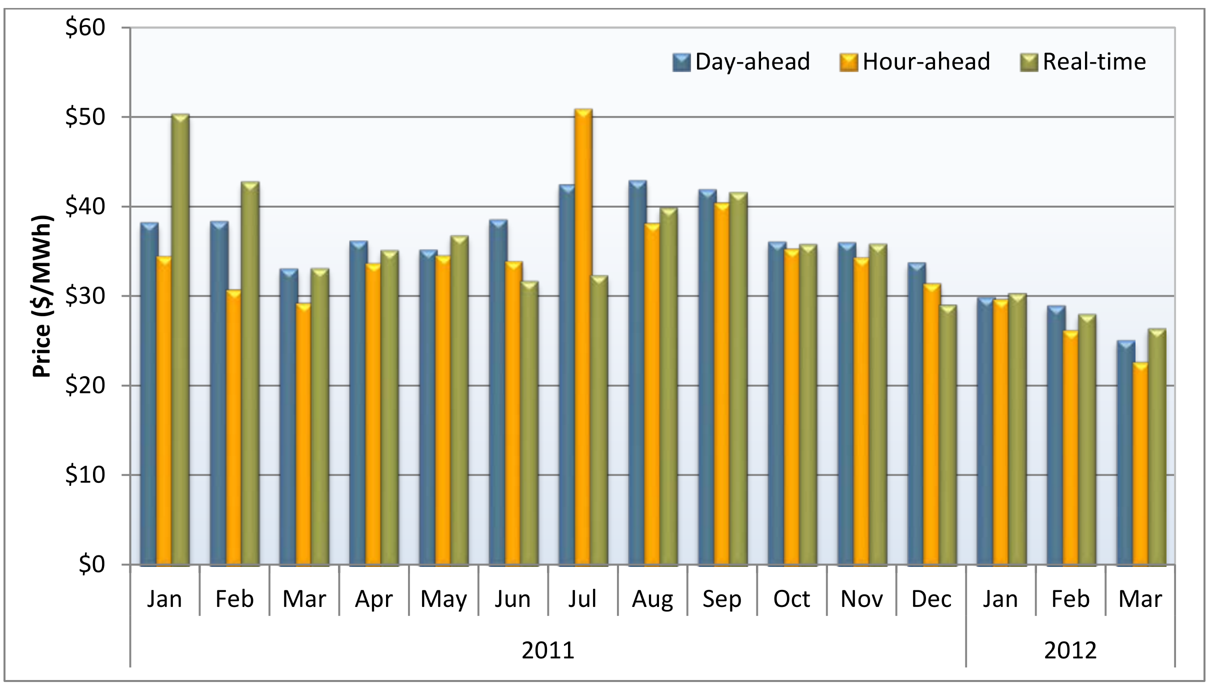
This report provides an overview of general market performance during the first quarter of 2012 (January – March) by the Department of Market Monitoring (DMM).

Energy market performance

- The day-ahead integrated forward market was stable and competitive. The level of load and supply scheduled in the day-ahead market continued to be within a few percentage points of actual loads in most hours. Average day-ahead energy prices continued to be approximately equal to benchmark prices that DMM estimates would occur under highly competitive conditions.

- Average prices in the energy markets continued a trend toward improved price convergence that began in August (see Figure E.1). Average peak and off-peak real-time prices were very close to day-ahead prices during the quarter, but were slightly higher than the hour-ahead peak prices for the same period, particularly March. Price divergence between hour-ahead and real-time prices continued to improve in the first quarter during peak and off-peak periods. However, differences between hour-ahead and real-time prices increased slightly in March as incidences of short-term upward ramping limitations increased.

Figure E.1 Average monthly on-peak prices (system marginal energy price)



- While overall outage levels in the first quarter of 2012 remained consistent with outage levels in the first quarters of 2011 and 2010, forced outages increased in 2012 compared to 2011. This was primarily the result of the forced outage of San Onofre Nuclear Generating Station (SONGS) Unit 3.

This outage, in conjunction with other generation and transmission outages, including the extended planned outage of SONGS Unit 2, increased the incidence of congestion in the markets.

- Congestion within the ISO system had an increased effect on overall prices in the first quarter in both the day-ahead and real-time markets. The impact of day-ahead and real-time congestion was relatively high in San Diego, representing over 5 percent and about 9 percent of the total price respectively. This congestion occurred as a result of nomograms designed primarily to address reliability concerns related to the SONGS outage.

Convergence bidding

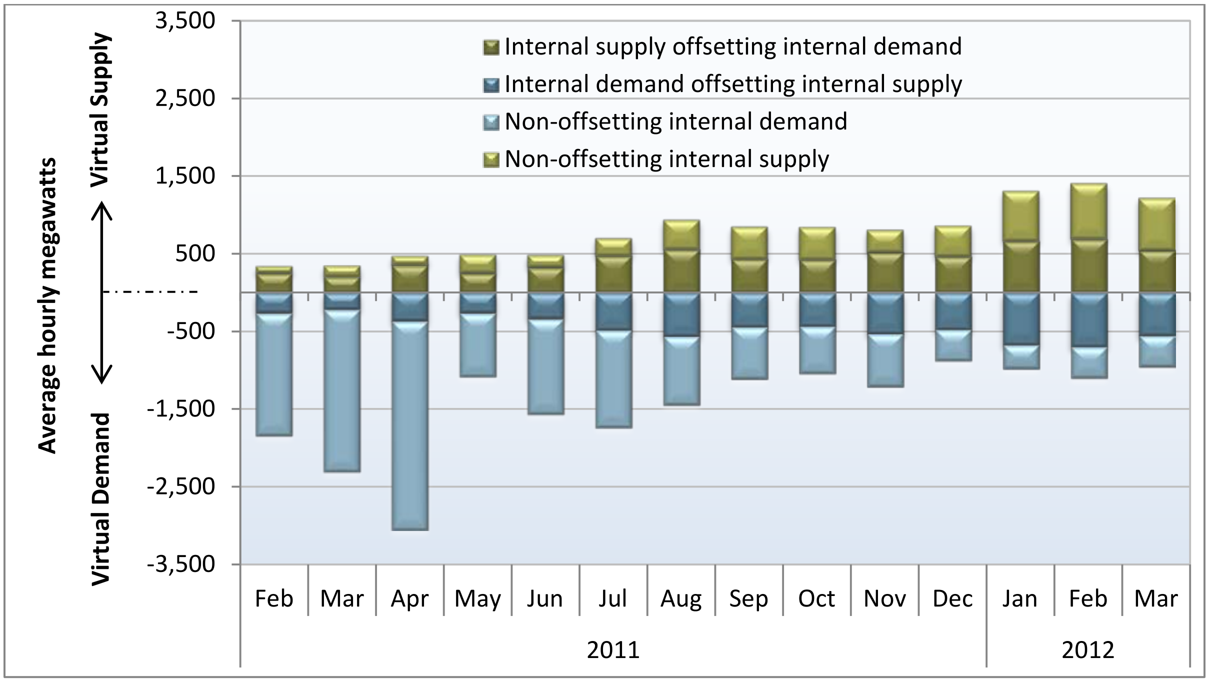
The ISO implemented convergence (or virtual) bidding in the day-ahead market on February 1, 2011. Virtual bidding on inter-ties was suspended on November 28, 2011.[1] Thus, the first quarter of 2012 represents the first full quarter with virtual bidding within the ISO system but not at the inter-ties. Convergence bidding activity was marked by several key trends in the first quarter:

- Historically, most virtual bids accepted at scheduling points within the ISO system have consisted of virtual demand since the start of convergence bidding in February through most of the fourth quarter. However, in the second half of December and continuing into 2012, internal virtual positions have consisted primarily of virtual supply. Virtual supply outweighed virtual demand by an average of about 300 MW in the first quarter.
- Market participants can hedge congestion costs or earn revenues associated with differences in congestion between different points within the ISO system by placing virtual demand and supply bids at different internal locations during the same hour (see Figure E.2). This type of offsetting virtual position at internal locations accounted for about 75 percent of the positions in the first quarter of 2012, up from 43 percent in 2011 for all cleared internal virtual bids. After suspension of convergence bidding at the inter-ties, the amount of these offsetting internal virtual bidding positions taken by participants grew in volume and as a share of total internal virtual bids. This suggests that virtual bidding was increasingly used to hedge or profit from internal congestion.
- In the first quarter, net profits for convergence bidding entities totaled almost $2 million – about the same level paid to convergence bidding entities in the fourth quarter, and well below the levels from previous quarters. The lower net profits paid out for convergence bids reflect lower volumes of accepted virtual bids, and improved price convergence.

DMM's overall assessment of convergence bidding from its implementation in February 2011 until the suspension of virtual bidding at the inter-ties in late November is that convergence bidding had little or no overall benefit in terms of helping to improve price convergence or the efficiency of day-ahead unit commitment decisions. However, after the suspension of inter-tie convergence bids, DMM has found that the aggregate system-wide impact of convergence bidding positions began to be more consistent with positions that would promote convergence of average prices in the day-ahead and 5-minute real-time markets.

[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.2 Average hourly offsetting virtual supply and demand positions at internal points



In many hours in the first quarter, particularly during the off-peak periods, the net cleared virtual position was consistent with the day-ahead and real-time price differences. In previous periods, internal virtual bidding positions were almost exclusively net virtual demand, which were often inconsistent with improving price convergence. DMM believes that continued suspension of convergence bidding at the inter-ties remains important until the ISO addresses structural differences between how the hour-ahead and real-time markets are dispatched and settled.

Special Issues

- **Flexible ramping constraint performance.** The ISO implemented a new flexible ramping constraint in the real-time market in mid-December. The constraint addresses non-contingency based deviations in load and supply between the real-time commitment and dispatch models (e.g., due to 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. Since the implementation of the constraint, the upward volatility of 5-minute real-time prices has dropped as fewer upward ramping infeasibilities have occurred. Total payments made to flexible ramping capacity during the first quarter were around $5.8 million. This compares with a payment of about $3 million for spinning reserve units for the same period. DMM has recommended that the ISO also review how the flexible ramping constraint has affected the unit commitment decisions made in real-time. DMM believes that evaluating commitment decisions is an important measure of the overall effectiveness of the constraint.

- **San Onofre Nuclear Generating Station (SONGS) outage.** SONGS Units 2 and 3 were offline for most of the first quarter due to a combination of both planned and forced outages as well as for testing of critical systems. In order to deal with the initial reliability conditions, the ISO created new minimum online capacity requirements, utilized exceptional dispatches, and used the capacity procurement mechanism to account for potential contingencies and locational voltage requirements. Accordingly, bid cost recovery payments increased, reaching $22 million in the first quarter, up from $13 million in the fourth quarter. There remains significant uncertainty in the return timetable of these units and if they will be available to meet summer peak loads. Currently the ISO assumes that both of the units will stay offline in the summer months. If both units remain offline, the ISO expects that San Diego and parts of the Los Angeles Basin may face local reliability issues. The ISO is working on a contingency plan that includes calling Huntington Beach Units 3 and 4 back into service, full utilization of available demand response programs, and acceleration of completion of the Barre-Ellis transmission upgrade project and Sunrise Powerlink transmission project.

1 Market performance

Day-ahead market

During the first quarter, the day-ahead integrated forward market continued to be stable and competitive. The level of load and supply scheduled in the day-ahead market continued to be within a few percentages of actual loads in most hours. Average day-ahead energy prices continued to be approximately equal to benchmark prices that DMM estimates would occur under highly competitive conditions.

Real-time market

Average peak and off-peak real-time prices were very close to day-ahead prices during the quarter, but were higher than the hour-ahead peak prices in the first quarter, particularly in March. Price divergence between hour-ahead and real-time prices continued to improve in much of the first quarter as price differences in January and February remained small. However, differences in hour-ahead and real-time prices increased slightly in March as incidences of short-term upward ramping limitations increased.

Outages

While overall outage levels in the first quarter of 2012 remained consistent with outage levels in the first quarters of 2011 and 2010, the levels of forced outages increased in 2012 compared to 2011. This was primarily the result of the forced outage of San Onofre Nuclear Generating Station Unit 3. This outage, in conjunction with other generation and transmission outages, including the extended planned outage of SONGS Unit 2, increased the incidence of congestion in the markets.

Congestion

Congestion within the ISO system had an increased effect on overall prices in the first quarter in both the day-ahead and real-time markets. The impact of day-ahead and real-time congestion was relatively high in San Diego, representing over 5 percent and about 9 percent of the total price, respectively. This congestion occurred as a result of nomograms designed primarily to address reliability concerns related to the SONGS outage.

1.1 Energy market performance

Overall, price convergence was relatively good in the first quarter, continuing a trend that began in recent quarters. Figure 1.1 and Figure 1.2, below, show monthly system marginal energy prices for peak and off-peak periods, respectively.[2]

[2] 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 over the past quarter. 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

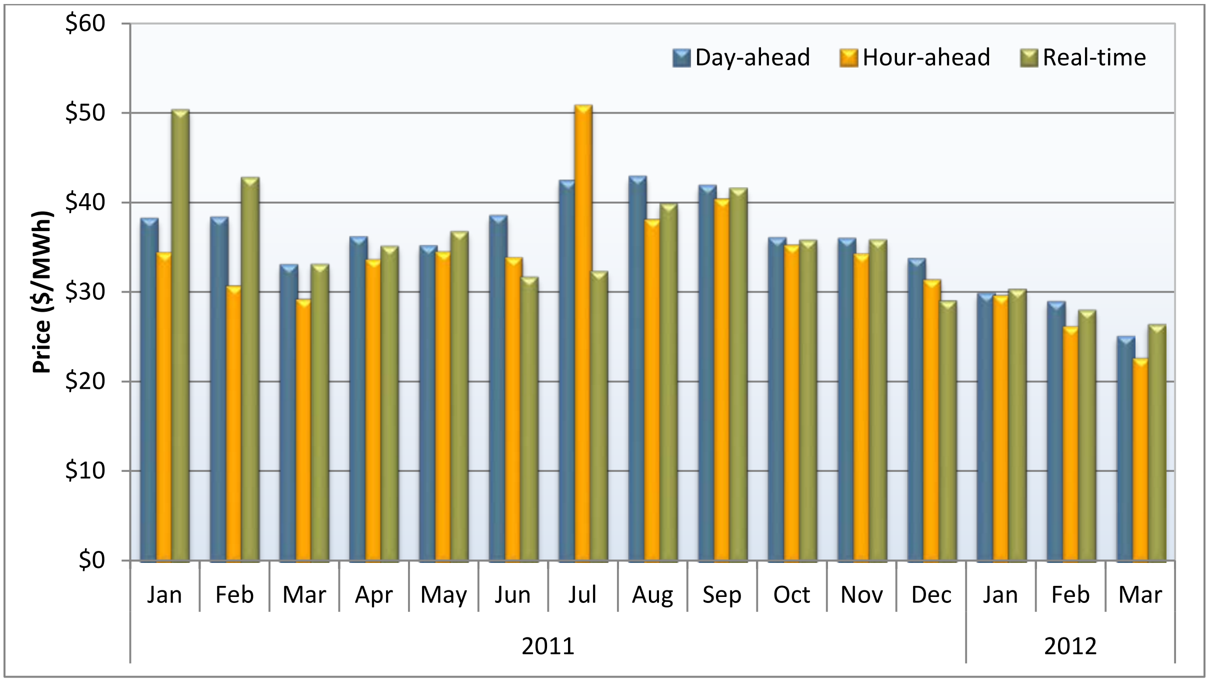
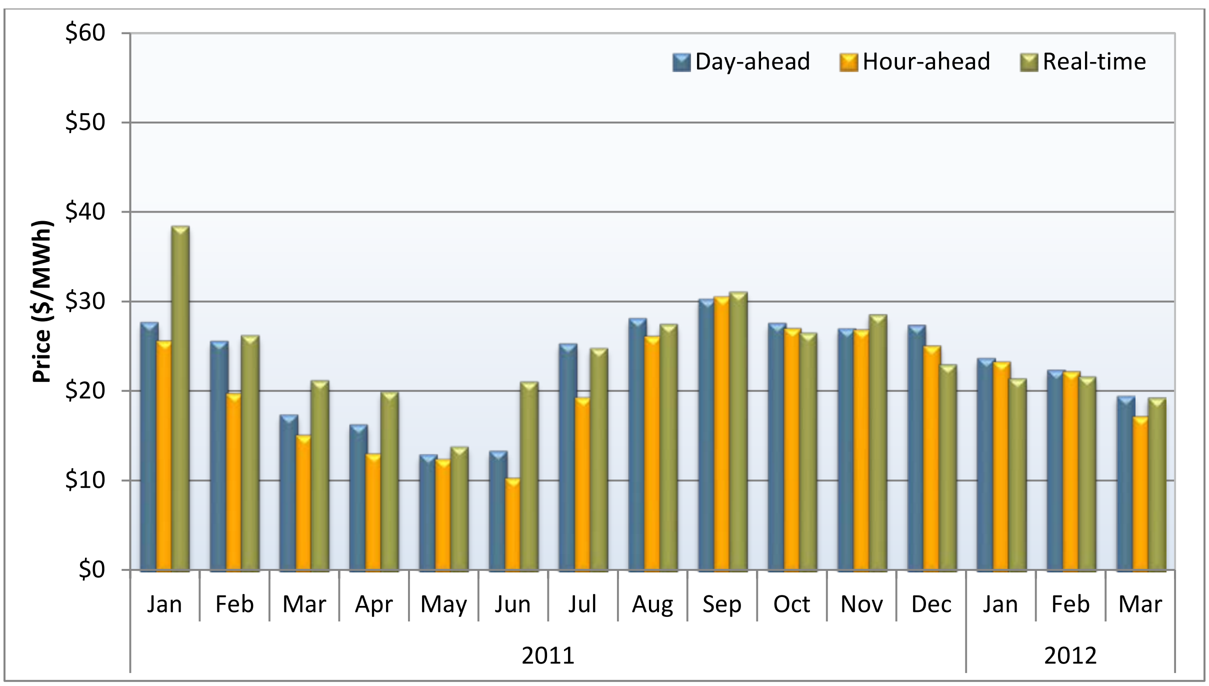


Figure 1.2 Average monthly off-peak prices – system marginal energy price



- In both peak and off-peak periods in the first quarter, hour-ahead prices remained lower than day-ahead prices. With the exception of peak hours in July and off-peak hours in September, this pattern has held for over the last year.

- 5-minute real-time market prices were lower than day-ahead prices in off-peak periods in the first quarter. Real-time prices were also lower than day-ahead prices in February in peak hours.

- Compared to hour-ahead prices, real-time prices were higher than hour-ahead prices in peak hours and lower in off-peak hours in January and February. In March, 5-minute real-time market prices were higher than hour-ahead prices in both peak and off-peak hours.

Figure 1.1 and Figure 1.2 suggest that average hour-ahead and real-time market prices were fairly close for much of the first quarter. Figure 1.3 and Figure 1.4 indicate continued price convergence in hour-ahead and real-time prices into the first quarter, though price divergence increased slightly in March.

- Figure 1.3 shows average hourly prices for the first quarter. Unlike previous periods, real-time prices were fairly close to the day-ahead and hour-ahead prices in many hours, except for the early morning hours ending 2 through 5 and in hours 8, 10 and 11. Hour-ahead prices were lower than both day-ahead and real-time prices for over half of the day. In particular, hour-ahead prices were lower in hours ending 7 through 14 and 18 through 20. However, even though the hour-ahead prices were lower than real-time prices, the difference in hour-ahead and real-time prices remained fairly small.

- Figure 1.4 highlights the magnitude of these differences by taking the average of the absolute difference in prices in the hour-ahead and real-time markets. When taking the simple average of prices (green line), price convergence remained fairly constant since August. In February, the average absolute price divergence fell to just over $4/MWh, about a third of the level during the first quarter of 2011.[3] Both the simple average and absolute average differences increased slightly in March as short-term upward ramping limitations caused prices to increase in the 5-minute real-time market.

Figure 1.5 shows a slight pickup in the amount of price spikes in the real-time market in the first quarter, with March having the highest percentage of price spikes (0.4 percent) since November. The overall level of price spikes remained significantly below the level during the same quarter last year. While the price spikes in February matched the lowest frequency set in December of last year (at 0.1 percent of intervals), the price levels in February were higher, averaging over $1,000/MWh.

[3] By taking the absolute value, the direction of the difference is eliminated and only the magnitude of the difference remains. 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 1.3 Hourly comparison of system marginal energy prices (January – March)

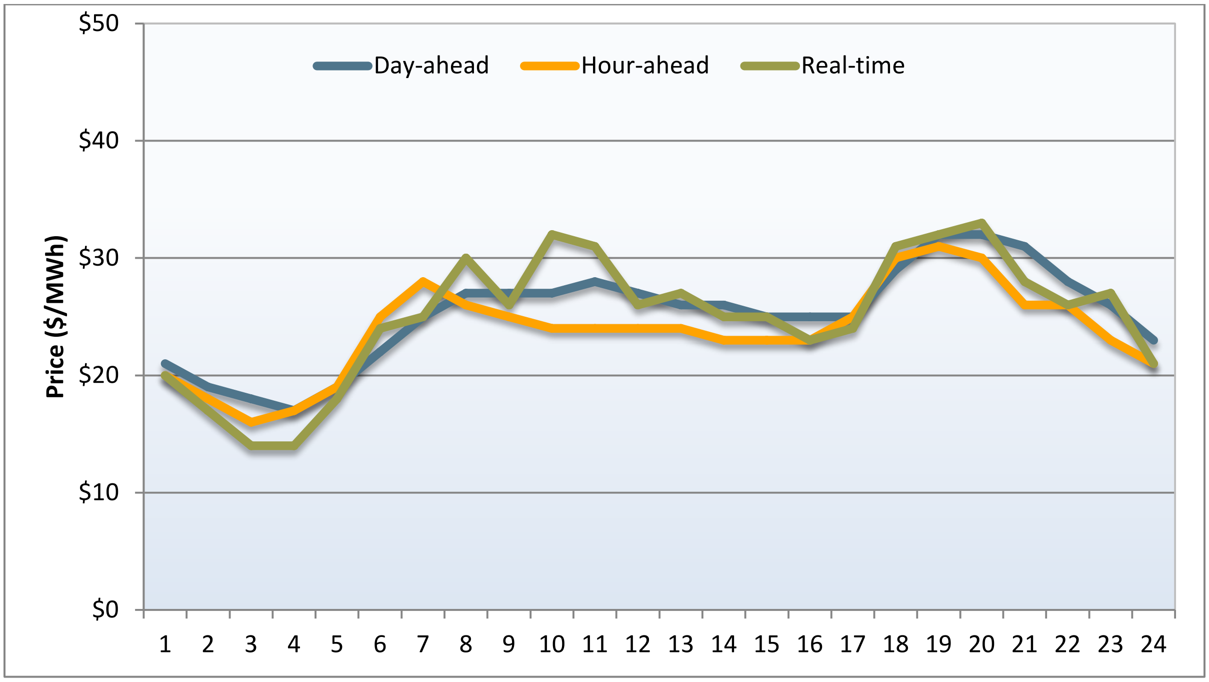


Figure 1.4 Difference in monthly hour-ahead and real-time prices based on simple average and absolute average of price differences (system marginal energy, all hours)

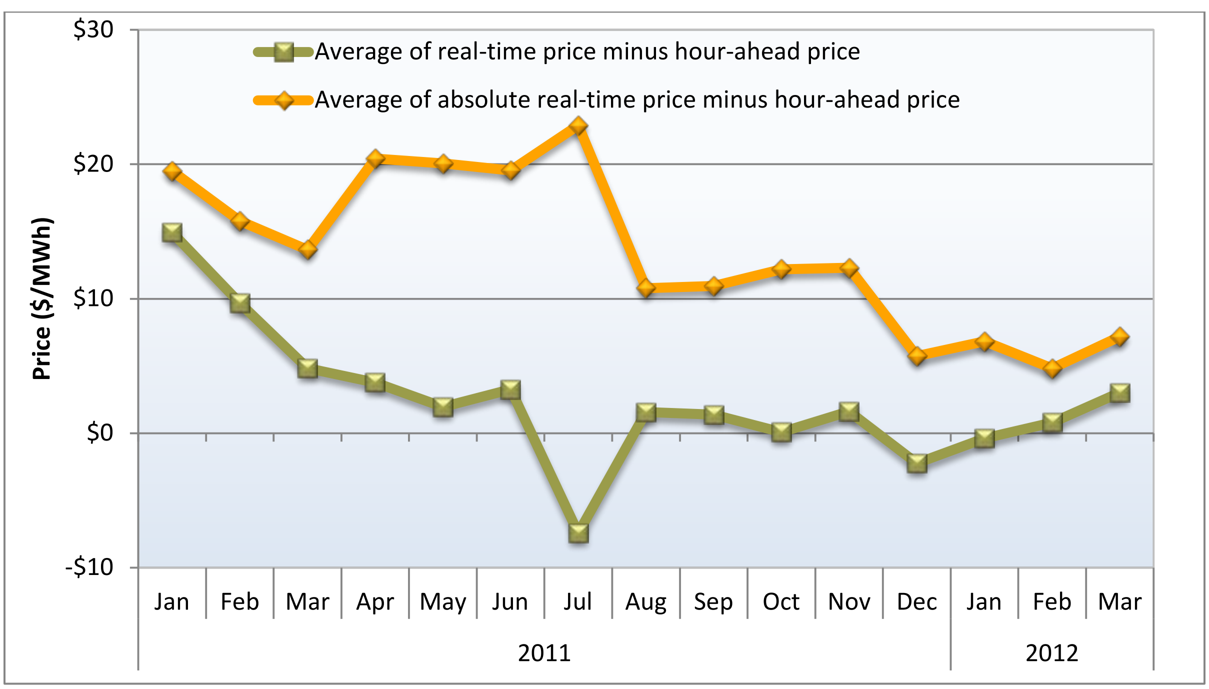
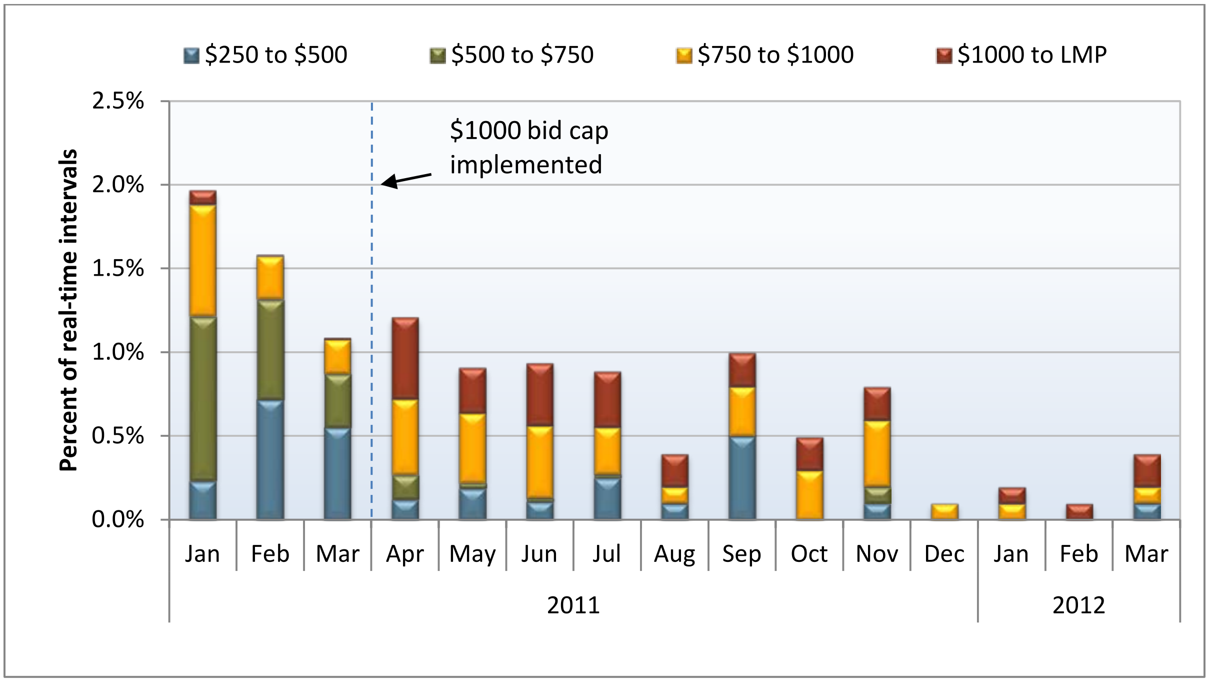


Figure 1.5 Frequency of price spikes (all LAP areas)



1.2 Power balance constraint

The system-wide real-time power balance constraint continues to contribute to both large positive and negative real-time prices, but less so than in previous periods for both upward and downward ramping limitations in the first quarter. Overall, power balance constraint relaxations show a decreasing trend that began in 2011. 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 first quarter of 2011.

- Figure 1.6 shows the number of relaxations in the first quarter continued a downward trend, reaching a multi-year low in February 2012. The constraint relaxations were dispersed over different hours of the day but were slightly more common between 4:00 p.m. and 8:00 p.m. during the evening load ramp and peak. Implementation of the flexible ramping constraint in mid-December appears to have contributed to reducing many of the upward ramping limitations that have historically caused power balance constraint relaxations in peak-load periods.

- Figure 1.7 shows a decrease in the number of real-time power balance constraint relaxations from insufficiencies of dispatchable decremental energy in the first quarter relative to the fourth quarter of 2011. Almost 90 percent of downward ramping limitations occurred in hours 1 through 8, occurring in over 4 percent of the intervals in these hours. Changes in expected wind output against the forecast contributed to the decremental dispatch insufficiencies in the early morning hours. The flexible ramping constraint is not expected to resolve relaxations from insufficiencies of dispatchable decremental energy as the flexible ramping constraint has only been applied in the upward direction.

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

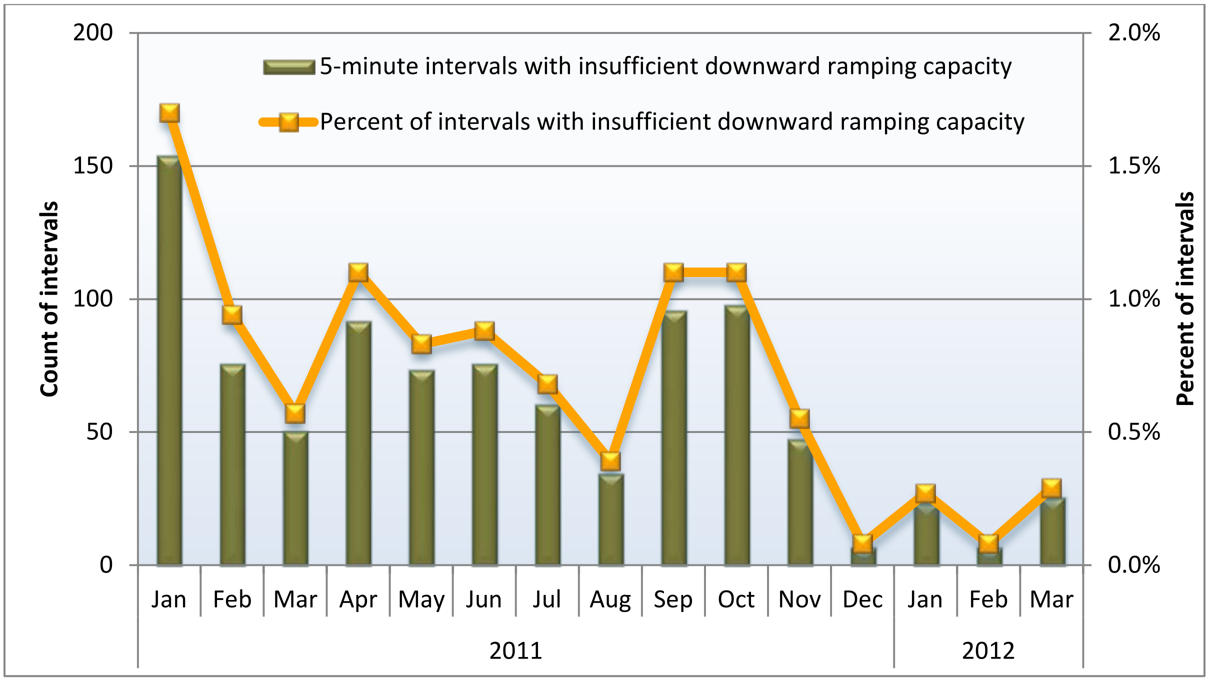
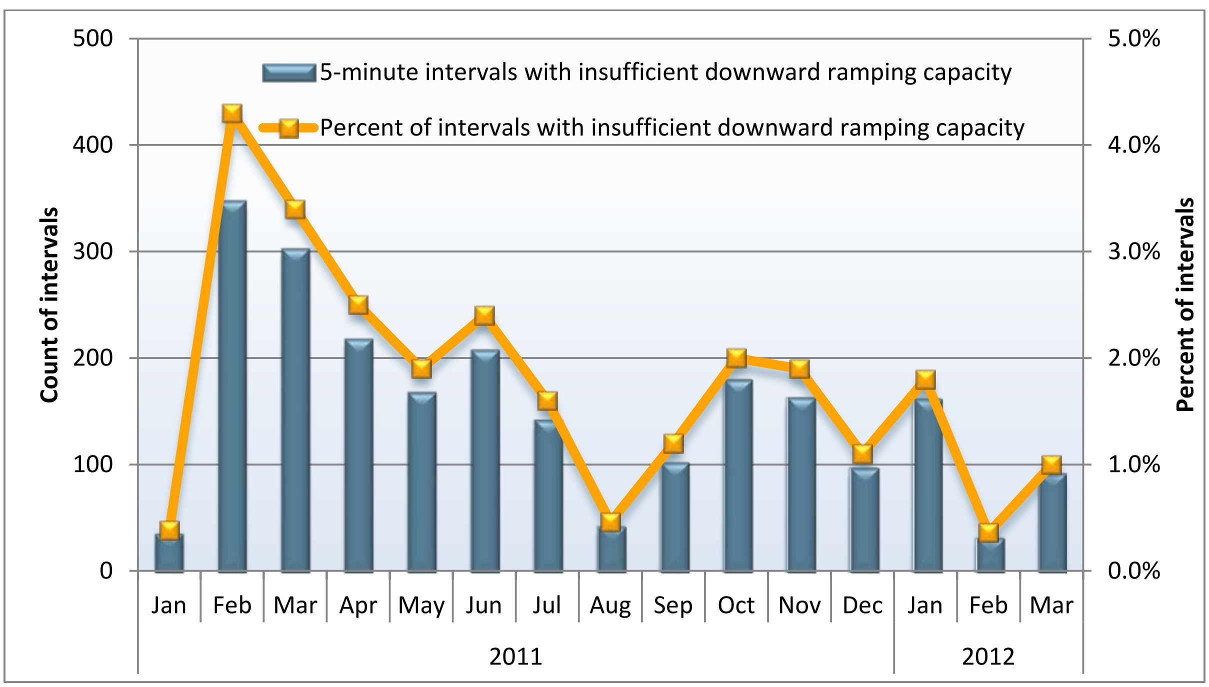


Figure 1.7 Relaxation of power balance constraint because of insufficient downward ramping capacity

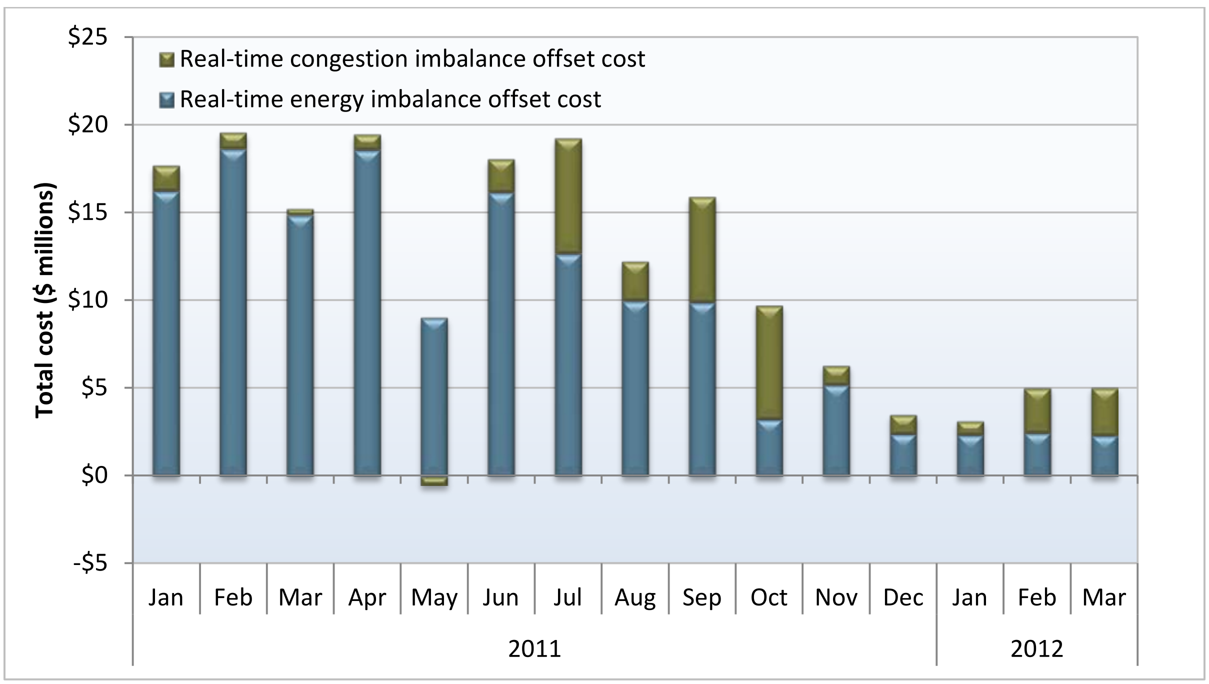


Most of these shortages of both upward and downward ramp limitations were very short-lived. For instance, about 89 percent of shortages of upward ramping capacity persisted for only one to three 5-minute intervals (or 5 to 15 minutes). Excluding the hours with power balance constraint relaxations, day-ahead prices remained slightly higher, on average, than both prices in the hour-ahead and 5-minute real-time markets in the first quarter. Moreover, when the price spikes are excluded, real-time prices are slightly lower, on average, than both the day-ahead prices and the hour-ahead prices.

1.3 Real-time imbalance offset costs

Real-time imbalance offset costs totaled $13 million in the first quarter, the lowest quarterly value since the nodal market began in April 2009. The next lowest value for real-time imbalance offset costs was $19 million in the first quarter of 2010. As seen in Figure 1.8, real-time energy imbalance offset costs were about $2.5 million, about the same value as in December 2011. DMM attributes this improvement primarily to improvements in price convergence and the suspension of inter-tie virtual bids. While real-time energy imbalance costs remained constant over the past few months, there was a slight increase in real-time congestion imbalance offset costs after the SONGS outage.

Figure 1.8 Real-time imbalance offset costs



1.4 Market competitiveness

DMM calculates competitive baseline prices by re-simulating the market using the day-ahead market software with bids reflecting the marginal cost of gas-fired units, using actual load, and removing convergence bids.[4] Overall, average day-ahead and real-time prices were approximately equal to competitive baseline prices that DMM estimates would result under perfectly competitive conditions.

In the first quarter of 2012, this analysis indicates that:

- The day-ahead market has continued to be very stable and competitive.
- Prices in the day-ahead market during each month of the first quarter continued to be approximately equal to or slightly lower than prices DMM estimates would result under perfectly competitive conditions.

Methodology

To assess the competitiveness of the day-ahead market, DMM runs two simulations using its stand-alone copy of the day-ahead software.

- The first is a re-run of the day-ahead software using data for the applicable save case (the ISO's archive of market and system inputs and settings saved after completion of the final day-ahead market run). Results of this initial re-run are benchmarked against actual day-ahead results to validate that the DMM stand-alone system is accurately reproducing results of the actual market software.[5] Days for which the stand-alone system does not produce results comparable to the actual market run are excluded from the analysis.[6]
- The second run of the stand-alone software is designed to represent a perfectly competitive scenario which provides a *competitive baseline* against which the re-run of actual day-ahead prices can be compared. In this second run, bids for gas-fired generating resources are replaced with their respective default energy bids (DEBs), which are designed to represent each unit's actual variable or opportunity costs.[7] The system demand is exogenously set to the actual system load. This run reflects the assumption that under perfectly competitive conditions, each resource would bid at their marginal operating or opportunity costs under the actual system load. Finally, DMM also removes all convergence bids. The percentage difference between actual market prices and prices resulting under this competitive baseline scenario represents the *price-cost mark-up index* for the

[4] DMM modified its competitive baseline methodology beginning in January by removing convergence bids. DMM believes that focusing only on physical positions provides a better competitive baseline. When the results of the new method were compared to the results with convergence bids included, the average difference in load aggregation point prices was near zero. On an hourly basis, there were only a few outliers with price differences exceeding $5/MWh between simulation scenarios.

[5] Results of the market software and DMM's stand-alone version can vary for several reasons. First, DMM had difficulties loading and re-running save cases for several months, thus the DMM system was re-run with subsequent versions of the network models and system updates. When model settings are changed, such as binding constraint corrections or multi-stage generation patches, a re-run may not duplicate the original day-ahead results.

[6] DMM expects the portion of re-runs that do not accurately replicate market outcomes (and are therefore excluded from such analyses) to decrease as updates to the day-ahead software decline, and as DMM is able to successfully perform a greater portion of re-runs with a smaller lag time from the date of actual market operation.

[7] Under the market power mitigation provisions of the ISO tariff, cost-based default energy bids are increased by 10 percent to reflect potential costs that may not be entirely captured in the standard fuel and variable cost calculations upon which cost-based default energy bids are based (Tariff Section 39.7.1.1). Units such as use-limited resources may also have a default energy bid that reflects their opportunity costs under the negotiated cost option of the ISO tariff (Tariff Section 39.7.1.3, and *Business Practice Manual for Market Instruments*, Version 16, Revised: Sep 19, 2011, D-3 to D-4).

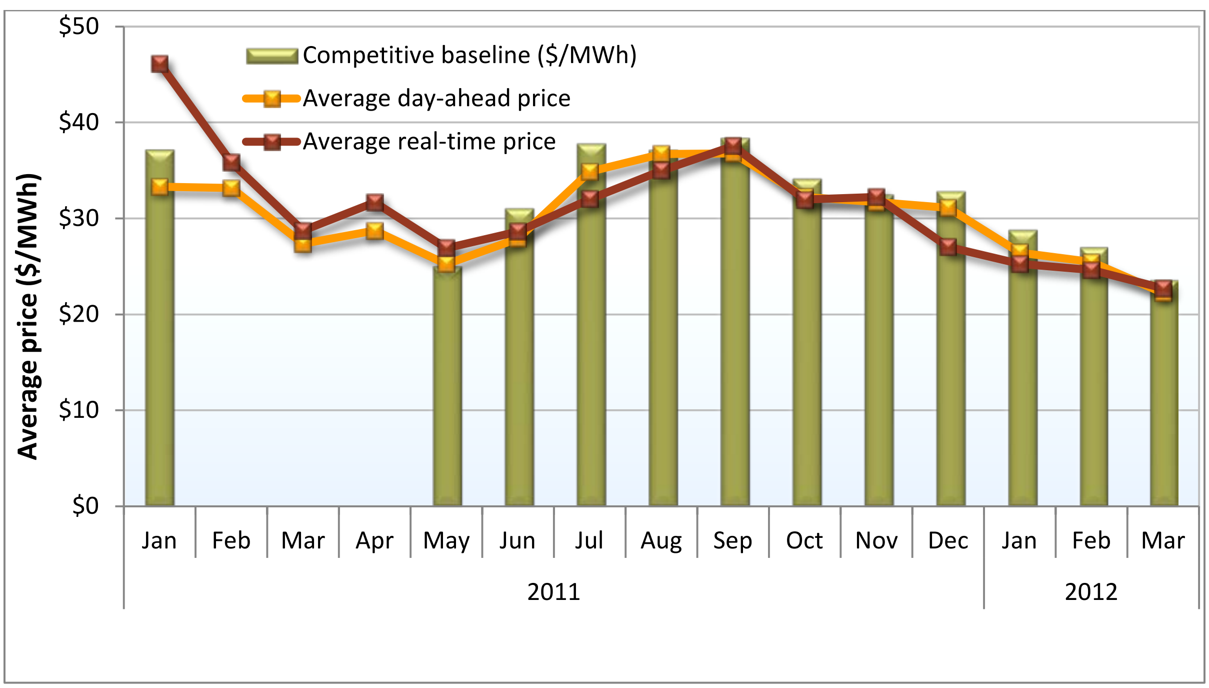
day-ahead market. Generally, DMM considers a market to be competitive if the index indicates no more than a 10 percent mark-up over the competitive baseline.

Figure 1.9 compares this competitive baseline price to average system-wide prices in the day-ahead and 5-minute real-time markets. As seen in Figure 1.9, prices in the day-ahead market have consistently been about equal to the competitive baseline prices. Since June, the competitive baseline prices exceeded the state-wide average prices by about 3 percent. Since May, average real-time prices have been closer to both average day-ahead prices and the competitive baseline than in 2010 and in January 2011. This improvement has mainly been the result of the decreased frequency of penalty prices associated with ramping limitations influencing real-time market prices (see Section 1.2).

In December 2011, real-time prices dropped below the competitive baseline prices by around $6/MWh and remained about $4/MWh lower in January. This is likely a function of the flexible ramping constraint as average real-time prices decreased in the second half of December.

A key cause driving the competitiveness of these markets is the high degree of forward contracting by load-serving entities. The high level of forward contracting significantly limits the ability and incentive for the exercise of market power in the day-ahead and real-time markets. Bids for the additional supply needed to meet remaining demand in the day-ahead and real-time energy markets have generally been highly competitive. Most additional supply needed to meet demand has been offered at prices close to default energy bids used in bid mitigation, which are designed to slightly exceed each unit's actual marginal or opportunity costs.

Figure 1.9 Comparison of competitive baseline with day-ahead and real-time prices



1.5 Outages

Generation outages are an important factor affecting the ISO markets. Outages reduce available capacity online and can threaten the ability to meet load during periods of system stress. They can have impacts on local reliability and congestion. While the ISO does make efforts to manage these concerns through outage planning, sudden unplanned outages can create short-term capacity shortages until replacement units are started.

1.5.1 Generation outages

Generation outages are reductions in available capacity from generating units. The ISO defines outages in four categories:[8]

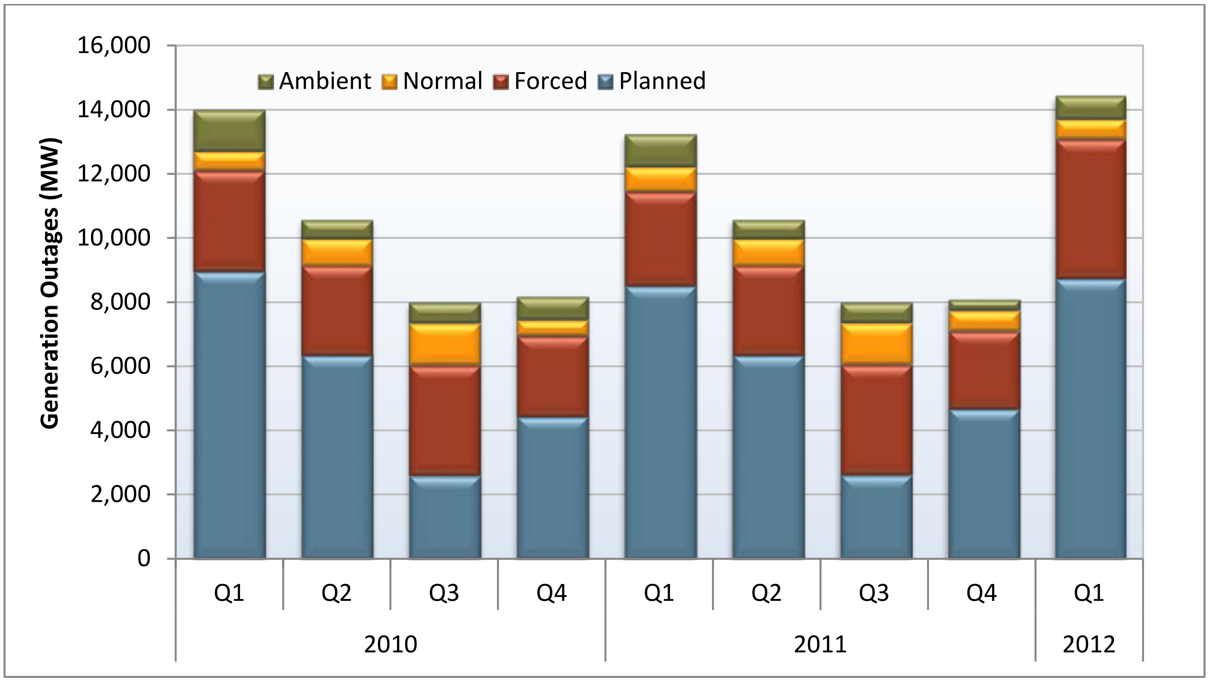
- ***Planned outages –*** Outages for scheduled maintenance are submitted by October 15 of the preceding year and are updated quarterly. Planned outages since 2010 have averaged around 5,900 MW per hour during peak hours.
- ***Forced outages –*** Unplanned reductions in capacity due to equipment failure, unforeseen required maintenance or other exigent circumstances. Forced outages since 2010 have averaged over 3,000 MW per hour during peak hours.
- ***Ambient outages –*** Reductions in available capacity due to air quality requirements. Ambient outages since 2010 have averaged about 730 MW per hour during peak hours.
- ***Normal outages –*** An outage where a planned, forced or ambient outage designation is not appropriate, such as the inability to respond to dispatch instructions due to some other physical limitations. These are referred to as *normal* outages since they are reported to the ISO using a SLIC *normal card*. Normal outages since 2010 have averaged almost 820 MW per hour during peak hours.

Overall, outages follow a seasonal pattern with the majority taking place in the first quarter and falling over the course of the year (see Figure 1.10). This pattern is primarily driven by planned outages, which increase in the first quarter as generators perform maintenance before temperatures and load begin to increase. While forced outages generally followed the overall pattern of outages, their magnitude and share of total outages was highest in the third quarter. This corresponds to high load months where extended periods of high temperatures can cause resource operating patterns that increase the incidence of mechanical problems or failure.

Figure 1.10 shows that while overall outages levels in the first quarter in 2012 remained consistent with outage levels in the first quarters of 2011 and 2010, the levels of forced outages increased in 2012 compared to 2011. Without the SONGS outages, outages in the first quarter of 2012 would likely have been lower than in the first quarter of 2011.

[8] For more details, see the ISO Operating Procedure for Scheduled and Forced Outages: http://www.caiso.com/Documents/3210.pdf. Also note that the maximum hourly outages do not necessarily occur in the same hour for all four outage types.

Figure 1.10 Average maximum hourly generation outages in peak hours



1.5.2 Impact of generation outages on congestion

Generation outages reduce the amount of capacity available to help resolve congestion. Congestion into transmission-constrained areas generally results in dispatch of more expensive bids than are available outside the area and results in a higher price within the constrained area. Generation outages can reduce the supply of energy that is used to help relieve that congestion and can result in an increase in the frequency of congestion. If the unavailable generation represents lower-priced energy, the outage will also contribute to a higher price impact from the congestion as the market is forced to dispatch higher-priced bids to manage the congestion and meet load in the constrained area. Significant generation outages can also create uncompetitive conditions in the constrained area where local market power could then be exercised. The ISO has local market power mitigation measures in place to prevent unduly high prices under these circumstances.

Table 1.1 shows the average hourly reduction in available effective counter-flow during binding hours for the 15 most frequently constrained transmission limits. The capacity reduction resulting from the outage is scaled by the shift factor from that resource to the constraint. This allows us to adjust the gross capacity on outage to reflect the amount of energy from that capacity that would have flowed to the constraint had it been available and dispatched. This represents the effective supply of counter-flow that could be used to manage congestion on that constraint.

There are other factors that contribute to congestion in addition to generation outages. Transmission derates can significantly impact the frequency and impact of congestion, as can various load levels or skewed offer prices between the constrained area and outside the constraint.

Table 1.1 Average reductions in effective counter-flow from generation outages[9]

Constraint Name	Counter-Flow Reduction (MW)
SLIC1852244PATH26LIOSS2N	4,336
SLIC1852244PATH26LIOSN2S	3,868
PATH26_S-N	3,799
PATH26_N-S	3,636
SCE_PCT_IMP_BG	3,078
SCIT_BG	2,620
LBN_S-N	2,318
SLIC 1883001_SDGE_OC_NG	1,951
LOSBANOSNORTH_BG	1,936
SOUTHLUGO_RV_BG	1,333
SLIC 1649002 VINCENT BANK	1,247
SDGE_CFEIMP_BG	715
BARRE-LEWIS_NG	504
SLIC 1902749 ELDORADO_LUGO-1	501
SLIC 1902748 ELDORADO_LUGO-1	433

The 5-minute real-time market is perhaps the most likely place where the impact of generation outages on congestion and energy prices can be measured. The first quarter of 2012, however, saw very little congestion at a local level where this relationship could be measured. Much of the congestion was on constraints that affected more zonal regions that are more regional and less local, where there is more likely sufficient capacity to make up for normal outage levels. In this circumstance, we expect to see little impact on congestion until the amount of effective megawatts grows large.[10] Given that outages can significantly affect both local (constrained area) prices and system prices, DMM closely monitors generation outages and their impact on market outcomes. The effect of congestion on prices is discussed further in Section 1.6.2.

1.6 Congestion

Congestion within the ISO system had an increased effect on overall prices in the first quarter in both the day-ahead and real-time markets. Much of the congestion was related to the forced outage of SONGS Unit 3, in conjunction with other generation and transmission outages.

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

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

9 Data reflect constraints in the 5-minute real-time market and contain only hours where the listed constraint was binding.

10 We did not have sufficient congestion at more local levels to provide an empirical relationship.

1.6.1 Congestion impacts of individual constraints

Day-ahead congestion

Congestion in the day-ahead market generally occurs more frequently than in real-time, but with minor price impacts. Table 1.2 provides a more detailed analysis for the first quarter and shows:

- At 8.6 percent of the hours, congestion on SLIC 1883001_SDGE_OC_NG was the highest for the quarter. This constraint also had a high price impact, increasing the price in the SDG&E area by $6.27/MWh when it was binding. The PG&E and SCE areas both had price decreases, -$0.65/MWh and -$0.06/MWh, respectively. This constraint is directly related to the outage of SONGS Unit 3.
- Path26_BG and SLIC1852244PATH26LIOSN2S were each congested in nearly 5 percent of the hours. These elements were congested in association with scheduled maintenance on the Midway-Vincent No. 3 500 kV line. These constraints decreased the prices in the PG&E area by nearly -$2.00/MWh and increased prices for SCE and SDG&E areas by about $1.50/MWh during congested hours.
- Congestion on 30900_GATES_230_30970_MIDWAY_230_BR_1_1 increased prices in the PG&E area by $1.24/MWh and decreased prices in the SCE and SDG&E areas by about -$1.00/MWh. This congestion was due to scheduled maintenance.

As shown in Table 1.2, congestion on other constraints significantly affected prices during hours when congestion occurred. However, since this internal congestion occurred infrequently, it had a minimal impact on overall day-ahead energy prices.

Table 1.2 Impact of congestion on day-ahead prices by load aggregation point

Area	Constraint	Frequency Q1	Q1 PGAE	Q1 SCE	Q1 SDG&E
PG&E	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	8.6%	$1.24	-$0.97	-$0.97
SCE	PATH26_BG	4.8%	-$1.63	$1.39	$1.39
	SLIC1852244PATH26LIOSN2S	4.7%	-$1.98	$1.66	$1.66
	SCE_PCT_IMP_BG	4.6%	-$1.31	$1.62	-$1.31
	SLIC 1883001 Miguel_BKS_NG_2	2.4%	-$0.07		$3.08
	BARRE-LEWIS_NG	1.6%	-$0.42	$0.52	
	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
	SLIC1889941PATH26LIOSN2S	0.6%	-$1.14	$0.96	$0.96
	SLIC1832262PATH26LIOSN2S	0.4%	-$2.40	$2.05	$2.05
SDG&E	SLIC 1883001_SDGE_OC_NG	14.2%	-$0.65	-$0.06	$6.27
	SDGE_CFEIMP_BG	9.0%	-$0.45	-$0.45	$4.19
	SLIC 1848345_23021_Outage	0.5%	-$1.17		$7.79
	SLIC 1846936_23021_Outage	0.5%	-$0.46		$3.04
	22832_SYCAMORE_230_22828_SYCAMORE_69.0_XF_2	0.1%			$24.09

Real-time congestion

Congestion in the real-time market differs slightly from the day-ahead market in that real-time congestion occurs less frequently, but often on more constraints and with a larger impact. Table 1.3 provides a detailed analysis for the first quarter and shows:

- Congestion on 30900_GATES_230_30970_MIDWAY_230_BR_1_1 occurred in over 3 percent of the time and increased prices in the PG&E area by $4.76/MWh and decreased prices in the SCE and SDG&E areas by -$3.65/MWh. This congestion was due to scheduled maintenance.

- Path26_N-S was congested in nearly 3 percent of the hours and was congested in association with scheduled maintenance on the Midway-Vincent No. 3 500 kV line. This congestion decreased the prices in the PG&E area by over -$17/MWh and increased prices for the SCE and SDG&E areas by about $14.65/MWh during congested hours.

- In over 5 percent of the hours, congestion on SLIC 1883001_SDGE_OC_NG was the highest for the quarter.[11] This constraint also had a high price effect, increasing the price in the SDG&E area about $24/MWh when it was binding. The PG&E and SCE areas both experienced a price decrease, -$2.64/MWh and -$0.08/MWh, respectively. This constraint is directly related to the outage of SONGS Unit 3.

Comparing Table 1.2 and Table 1.3 indicates that congestion is more frequent in the day-ahead market compared to the real-time market, but that the price impact 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.

For example, the PATH26_BG constraint was binding in nearly 5 percent of the hours in the day-ahead market. In real-time, the associated nomograms (PATH26_N-S and PATH26_S-N) are adjusted to mitigate the difference in market and actual flows as well as to provide a reliability margin. Even though the nomograms are binding less frequently (about 3 percent of the hours), the shadow prices are significantly larger indicating a greater impact on prices when the constraint is binding.

[11] For more information on transmission constraints, see the following technical bulletin: http://www.caiso.com/documents/TechnicalBulletin-Information-Modeling_TransmissionConstraints.pdf.

Table 1.3 Impact of congestion on real-time prices by load aggregation point

Area	Constraint	Frequency Q1	Q1 PGAE	Q1 SCE	Q1 SDG&E
PG&E	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	3.2%	$4.76	-$3.65	-$3.65
	SLIC 1902748 ELDORADO_LUGO-1	1.1%	$4.29	-$2.98	-$6.43
	SLIC 1902749 ELDORADO_LUGO-1	1.1%	$3.30	-$2.36	-$3.96
SCE	7680 Sylmar_1_NG	0.1%			-$60.31
	24114_PARDEE _230_24147_SYLMAR S_230_BR_2 _1	0.0%	-$18.58	$22.52	-$70.75
	PATH26_N-S	2.8%	-$17.37	$14.65	$14.65
	PATH26_S-N	0.3%	$30.46	-$25.84	-$25.84
	SCE_PCT_IMP_BG	0.2%	-$63.37	$79.72	-$63.37
	SCIT_BG	0.004%	-$530.40	$457.98	$490.62
	SLIC 1649002 VINCENT BANK	0.1%	-$106.03	$93.76	$61.42
SDG&E	22644_PENSQTOS_69.0_22492_MIRAMRTP_69.0_BR_1 _1	0.1%			$39.50
	SDGE_CFEIMP_BG	0.7%	-$3.91	-$3.91	$36.83
	SLIC 1846936_23021_Outage	0.4%	-$1.78		$12.45
	SLIC 1883001 Miguel_BKS_NG	1.0%			$14.23
	SLIC 1883001 Miguel_BKS_NG_2	1.2%			$14.54
	SLIC 1883001_SDGE_OC_NG	5.3%	-$2.64	-$0.08	$24.17
	SLIC 1908221_22_23028-9_NG	0.2%			-$33.54
	SLIC1852244PATH26LIOSN2S	2.8%	-$7.22	$6.02	$6.02
	SLIC1883001 MIGUEL BKS	1.4%			$20.10
	SOUTHEAST_IMPORTS	1.0%			$8.73
	SOUTHLUGO_RV_BG	0.1%	-$74.07	$59.77	$80.34

1.6.2 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 hours – including both congested and non-congested hours. This approach shows the impact of congestion taking into account the frequency that congestion occurs as well as the magnitude of the impact that congestion has when it occurs.[12]

Day-ahead price impacts

Table 1.4 shows the overall impact of day-ahead congestion on different constraints on average prices in each load aggregation area in the first quarter of 2012. These results show that:

- Prices in the San Diego area were impacted the most by internal congestion associated with the outage of SONGS Unit 3. Overall, congestion increased average day-ahead prices in the San Diego

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

area above the system average by nearly $1.50/MWh or about 5.5 percent. Nearly three-fourths of this increase is due to congestion on import limits directly into the SDG&E area.

- Congestion drove day-ahead prices in the SCE area above system average prices by about $0.13/MWh or around 0.5 percent. About 50 percent 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.[13] Another major portion was associated with congestion in the north-to-south direction on Path 26.

- The overall impact of congestion on day-ahead prices in the PG&E area was to reduce prices below the system average by about -$0.35/MWh or about -1 percent. This results from the fact that prices in the PG&E area are lowered when congestion occurs on the constraints that limit flows in the north-to-south direction on Path 26 and constraints limiting flows into the SCE and SDG&E areas.

Table 1.4 Impact of congestion on overall day-ahead prices

	PG&E		SCE		SDGE	
Constraint	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
SLIC 1883001_SDGE_OC_NG	-$0.09	-0.37%			$0.89	3.34%
SDGE_CFEIMP_BG	-$0.04	-0.16%	-$0.04	-0.16%	$0.38	1.42%
30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.11	0.42%	-$0.08	-0.33%	-$0.08	-0.31%
SLIC1852244PATH26LIOSN2S	-$0.09	-0.37%	$0.08	0.31%	$0.08	0.29%
PATH26_BG	-$0.08	-0.31%	$0.07	0.27%	$0.07	0.25%
SCE_PCT_IMP_BG	-$0.06	-0.24%	$0.07	0.30%	-$0.06	-0.23%
SLIC 1883001 Miguel_BKS_NG_2					$0.08	0.28%
SLIC1883001 MIGUEL BKS					$0.07	0.27%
SLIC 1848345_23021_Outage	-$0.01	-0.02%			$0.04	0.15%
22832_SYCAMORE_230_22828_SYCAMORE_69.0_XF_2					$0.03	0.12%
24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.01	-0.04%	$0.02	0.06%		
SLIC1832262PATH26LIOSN2S	-$0.01	-0.04%	$0.01	0.03%	$0.01	0.03%
SLIC1889941PATH26LIOSN2S	-$0.01	-0.03%	$0.01	0.02%	$0.01	0.02%
SLIC 1846936_23021_Outage					$0.01	0.05%
BARRE-LEWIS_NG	-$0.01	-0.03%	$0.01	0.03%		
Other					-$0.05	-0.18%
Total	-$0.30	-1.2%	$0.13	0.5%	$1.46	5.5%

Real-time price impacts

Table 1.5 shows the overall impact of real-time congestion on different constraints on average prices in each load aggregation area in the first quarter of 2012. These results show that:

- Prices in the San Diego area were impacted the most by internal congestion associated with the outage of SONGS Unit 3. Overall, congestion increased average prices in the San Diego area above the system average by nearly $2.50/MWh or about 9 percent. Nearly 80 percent of this increase is due to congestion on import limits directly into the SDG&E area.

[13] 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.

- Congestion drove prices in the SCE area above system average prices by about $0.66/MWh or around 2.6 percent. About a quarter 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.[14] Another major portion was associated with congestion in the north-to-south direction on Path 26.
- The overall impact of congestion on prices in the PG&E area was to reduce prices below the system average by about -$0.90/MWh or about -3.6 percent. This results from the fact that prices in the PG&E area are lowered when congestion occurs on the constraints that limit flows in the north-to-south direction on Path 26 and constraints limiting flows into the SCE and SDG&E areas.

The overall price impact of congestion increases in the real-time market compared to the day-ahead market. As mentioned earlier, the differences 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.

Table 1.5 Impact of congestion on overall real-time prices

	PG&E		SCE		SDGE	
Constraint	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
SLIC 1883001_SDGE_OC_NG	-$0.14	-0.57%	$0.00	0.00%	$1.27	4.64%
PATH26_N-S	-$0.49	-1.99%	$0.41	1.64%	$0.41	1.51%
SLIC1852244PATH26LIOSN2S	-$0.20	-0.81%	$0.17	0.66%	$0.17	0.61%
SCE_PCT_IMP_BG	-$0.13	-0.52%	$0.16	0.64%	-$0.13	-0.47%
30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.15	0.62%	-$0.12	-0.47%	-$0.12	-0.43%
SLIC 1649002 VINCENT BANK	-$0.14	-0.56%	$0.12	0.48%	$0.08	0.29%
SDGE_CFEIMP_BG	-$0.03	-0.11%	-$0.03	-0.10%	$0.25	0.91%
SLIC1883001 MIGUEL BKS					$0.28	1.03%
PATH26_S-N	$0.10	0.39%	-$0.08	-0.33%	-$0.08	-0.30%
SOUTHLUGO_RV_BG	-$0.07	-0.28%	$0.06	0.22%	$0.07	0.27%
SLIC 1883001 Miguel_BKS_NG_2					$0.18	0.65%
SLIC 1902748 ELDORADO_LUGO-1	$0.05	0.19%	-$0.03	-0.13%	-$0.07	-0.25%
SLIC 1883001 Miguel_BKS_NG					$0.14	0.52%
SLIC 1902749 ELDORADO_LUGO-1	$0.04	0.14%	-$0.03	-0.10%	-$0.04	-0.15%
SOUTHEAST_IMPORTS					$0.09	0.31%
7680 Sylmar_1_NG					-$0.06	-0.23%
SCIT_BG	-$0.02	-0.08%	$0.02	0.07%	$0.02	0.07%
SLIC 1908221_22_23028-9_NG					-$0.06	-0.20%
SLIC 1846936_23021_Outage	-$0.01	-0.03%			$0.05	0.17%
22644_PENSQTOS_69.0_22492_MIRAMRTP_69.0_BR_1 _1					$0.02	0.09%
24114_PARDEE _230_24147_SYLMAR S_230_BR_2 _1	$0.00	-0.01%	$0.00	0.02%	-$0.01	-0.05%
Other	-$0.01	-0.03%	$0.00	0.01%	$0.00	0.01%
Total	-$0.90	-3.6%	$0.66	2.6%	$2.47	9.0%

[14] 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 limit imports into SCE or decreases generation within the SCE area.

2 Convergence bidding

Convergence bidding was implemented in the day-ahead energy market in February 2011. This new market feature allows participants to place purely financial bids for supply or demand in the day-ahead energy market. Since these bids do not represent actual physical supply resources or loads, these are also referred to as *virtual bids*. Virtual bids accepted in the day-ahead market are automatically liquidated in the hour-ahead and real-time markets. Virtual bidding allows participants to profit from price differences in these different markets.

Total convergence bidding net profits were around $2 million in the first quarter of 2012. Most of these profits were for virtual supply bids at internal locations.[15] Internal virtual supply averaged around 1,300 MW while virtual demand averaged around 1,000 MW each hour. The average hourly net virtual position was 300 MW of virtual supply.

After reviewing monthly net cleared convergence bidding patterns in the first quarter, DMM finds that the average hourly net convergence bidding pattern at internal locations has been more consistent with converging day-ahead and real-time prices than during previous periods. In many hours, particularly during the off-peak periods and with improved consistency in peak hours, the net cleared virtual position was consistent with the day-ahead and real-time price differences. In previous periods, most notably prior to the suspension of convergence bidding at the inter-ties, internal virtual bidding positions were almost exclusively net virtual demand. These positions were often inconsistent with price convergence.

2.1 Convergence bidding trends

For the month of December, convergence bidding only occurred at scheduling locations within the ISO system. After dropping in December, convergence bidding volumes stabilized at a lower level in the first quarter of 2012. Overall, total cleared volumes continue to remain virtual supply.

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

- On average, 54 percent of virtual supply and demand bids offered into the market cleared in the first quarter of 2012.
- Cleared volumes of virtual supply outweighed cleared virtual demand in the first quarter by around 300 MW on average.
- Virtual supply exceeded virtual demand during off-peak hours by about 780 MW, compared to peak hours where volumes of virtual demand and supply were approximately the same, except for a slight increase in cleared virtual supply in hours ending 16 and 17.

[15] Virtual bidding at the inter-ties was temporarily suspended in late 2011, and remains suspended at this time. For more information see 137 FERC ¶ 61,157 (2011) accepting and temporarily suspending convergence bidding at the inter-ties. More information can also be found under FERC docket number ER11-4580-000.

Figure 2.1 Monthly average virtual bids offered and cleared

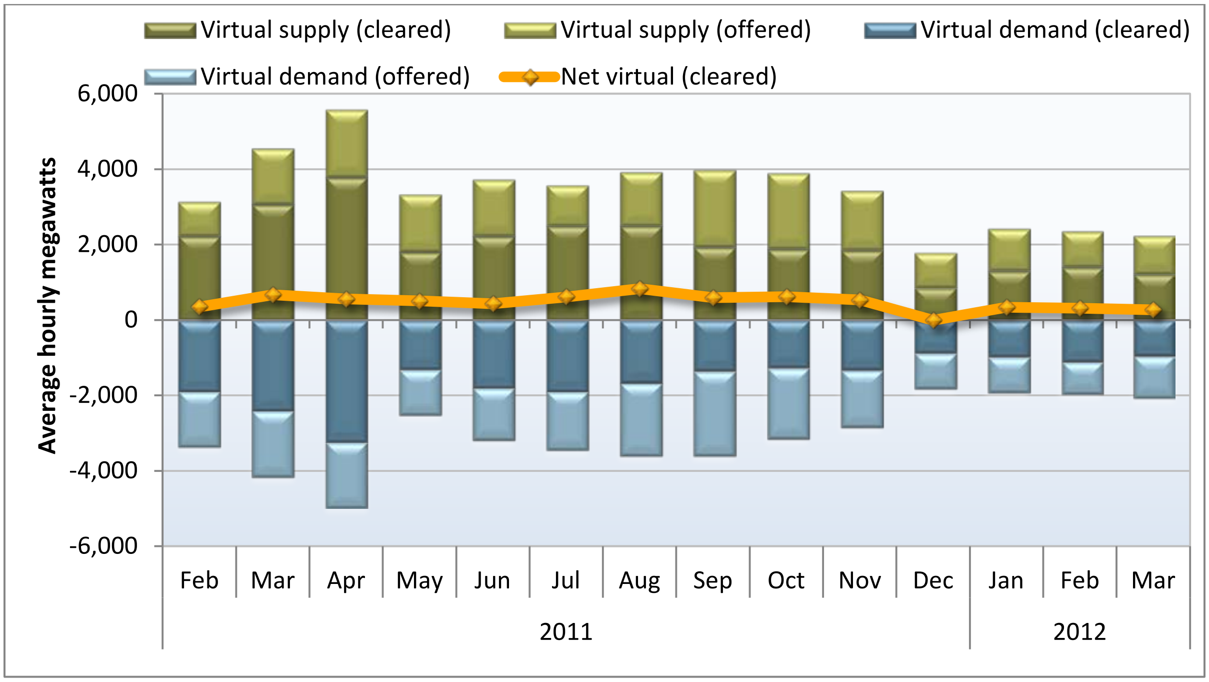


Figure 2.2 Hourly offered and cleared virtual activity (January – March)

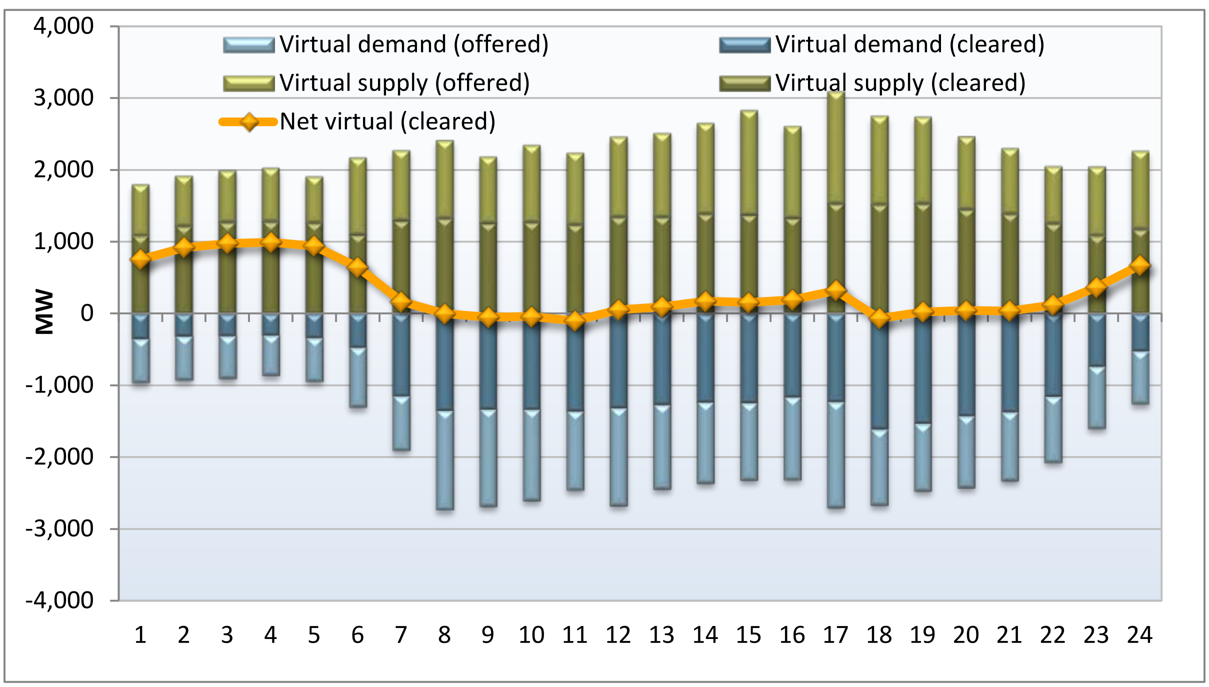


Figure 2.3 Average monthly cleared convergence bids at inter-ties and internal locations

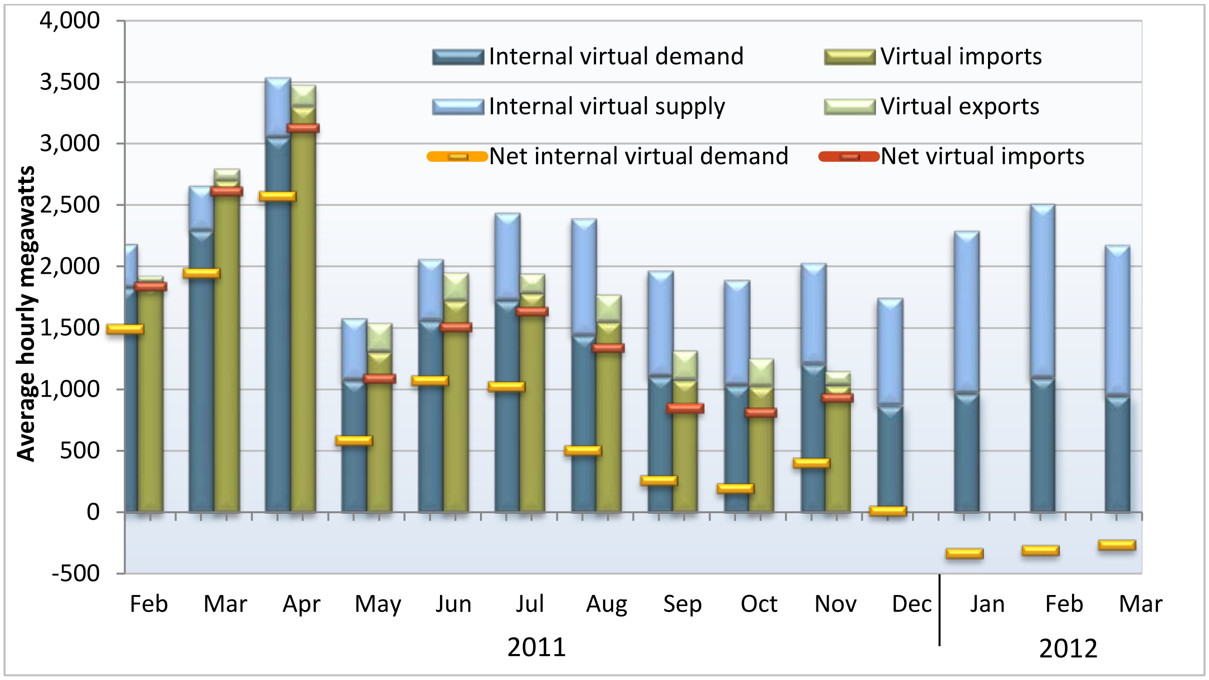


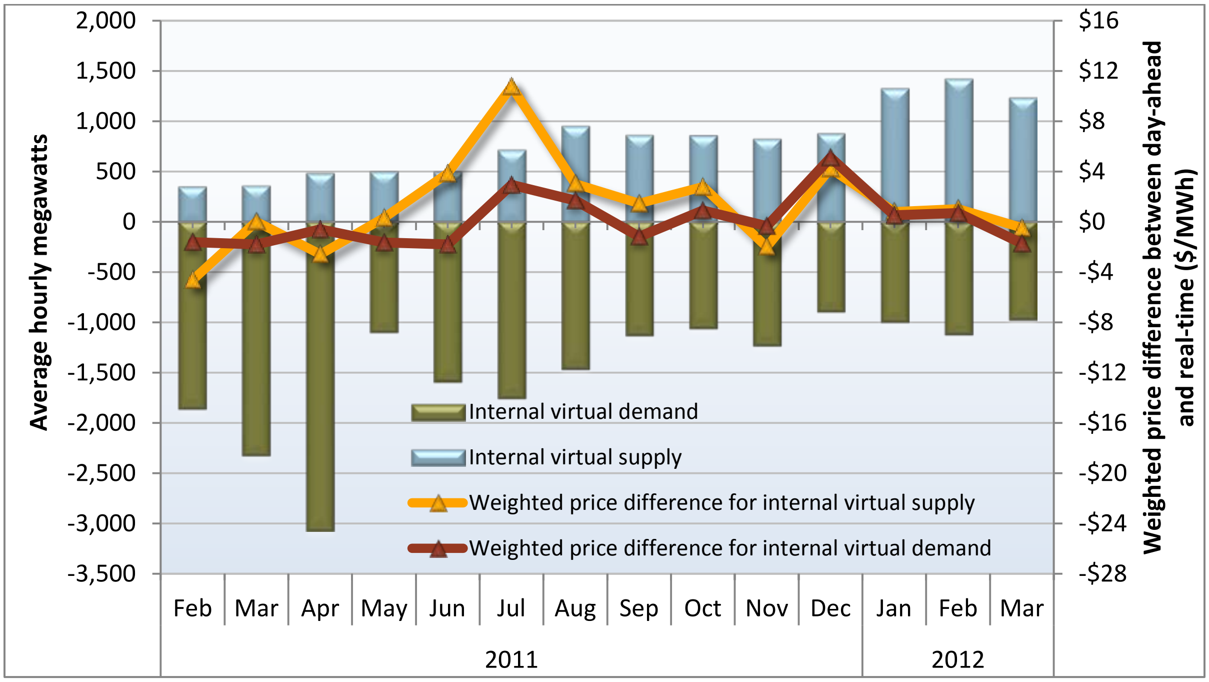
Figure 2.3 shows cleared positions at both internal and inter-tie positions. In the first quarter of 2012 convergence bidding on internal locations (shown in blue) shifted to net virtual supply after initially remaining virtual demand in early December. This virtual supply position at internal nodes has been more consistent with improving price convergence. Prior to the suspension of convergence bidding on the inter-ties, cleared internal positions had been primarily virtual demand.

Figure 2.4 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 2.4 represents the average price difference weighted by the amount of virtual bids clearing at different internal locations. As shown in Figure 2.4:

- During months when the red line in Figure 2.4 is negative, this 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 difference for the hours in which this virtual demand cleared the market in all months except July, August, October and December of 2011. In 2012, virtual demand positions were profitable only in March.
- During months when the yellow line in Figure 2.4 is positive, this indicates that the weighted average price paid for internal virtual supply in the day-ahead market was higher than the weighted average real-time price charged when this virtual supply was liquidated in the real-time market. Beginning in May and continuing through most of the rest of 2011, virtual supply at internal locations was consistently profitable. In 2012, this trend continued through February and reversed in March.
- As noted previously, 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 due to congestion.

Figure 2.4 Convergence bidding volumes and weighted price differences at internal locations



Average hourly convergence bidding volumes and prices indicate that net convergence bidding volumes at internal nodes have been better aligned with converging prices. Figure 2.5, Figure 2.6 and Figure 2.7 show average hourly net cleared convergence bidding volumes compared to the difference in the day-ahead and real-time system market energy prices in January, February and March, respectively. The blue bars represent the net cleared internal virtual position, whereas the green line represents that difference between the day-ahead and real-time system marginal energy prices.

- As shown in Figure 2.5, convergence bidding volumes in 20 hours in January were consistent on average with price convergence at internal locations. Most notably, the consistency between the convergence bidding volume direction and the price difference was highest in the off-peak hours.
- In February, as seen in Figure 2.6, convergence bidding volumes in a majority of hours were consistent on average with price convergence at internal locations. Consistency was again best in the off-peak hours. However, the convergence bidding patterns changed notably from the prior month as system conditions changed. For example, during the peak hour (hour ending 18), the convergence bidding volumes switched from virtual supply to virtual demand, which was consistent with average price differences.
- Figure 2.7 shows that in the month of March, convergence bidding volumes again adapted to changing differences between day-ahead and real-time prices. In particular, the consistency of net

cleared convergence bidding volumes with peak hour prices improved while the consistency of volumes with off-peak prices was not as good as in previous months.

Figure 2.5 Hourly convergence bidding volumes and prices – January

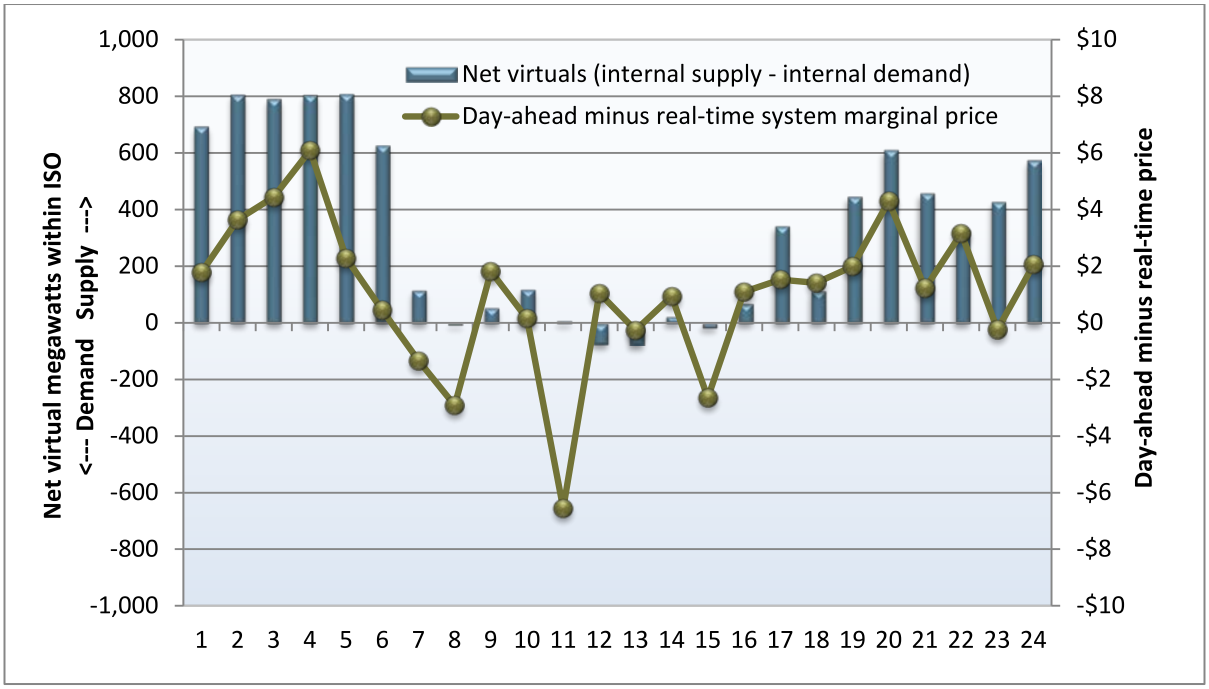


Figure 2.6 Hourly convergence bidding volumes and prices – February

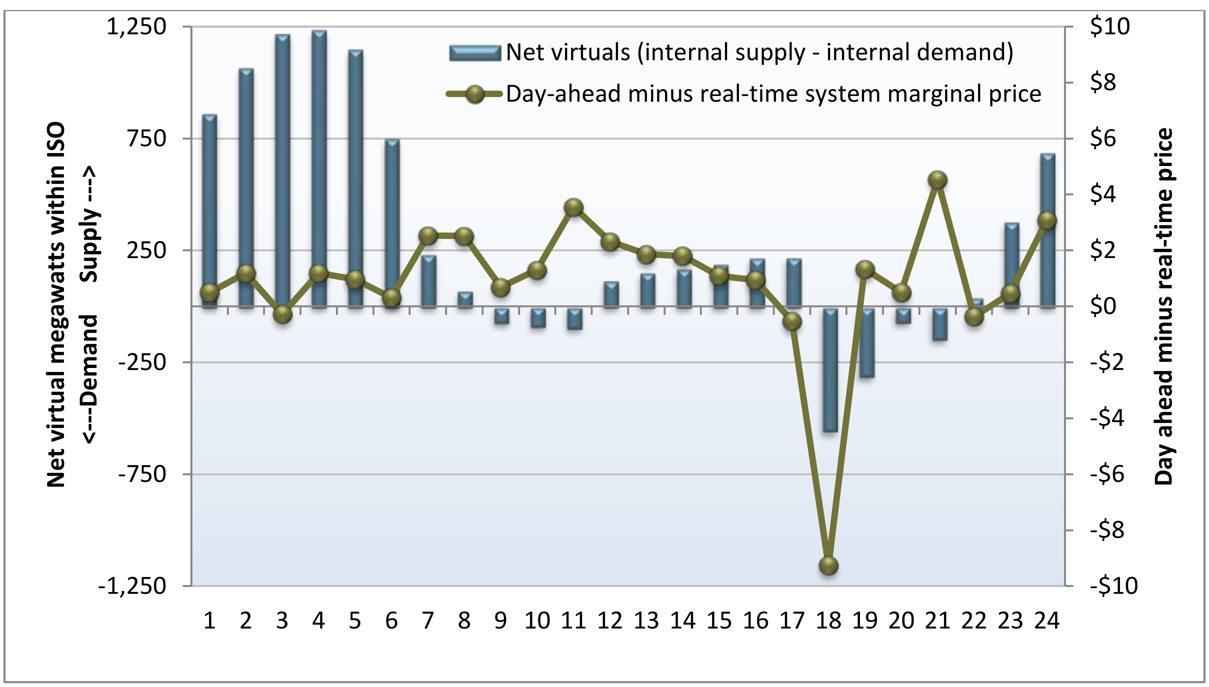
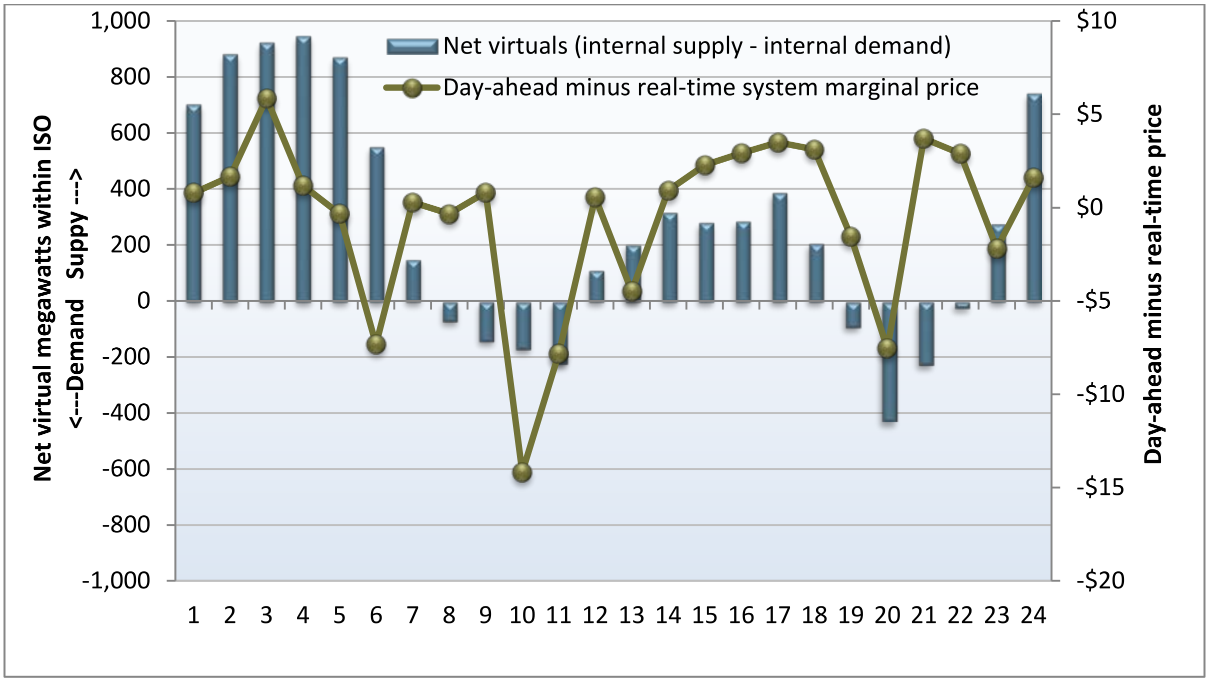


Figure 2.7 Hourly convergence bidding volumes and prices – March



Offsetting virtual supply and demand bids at internal points

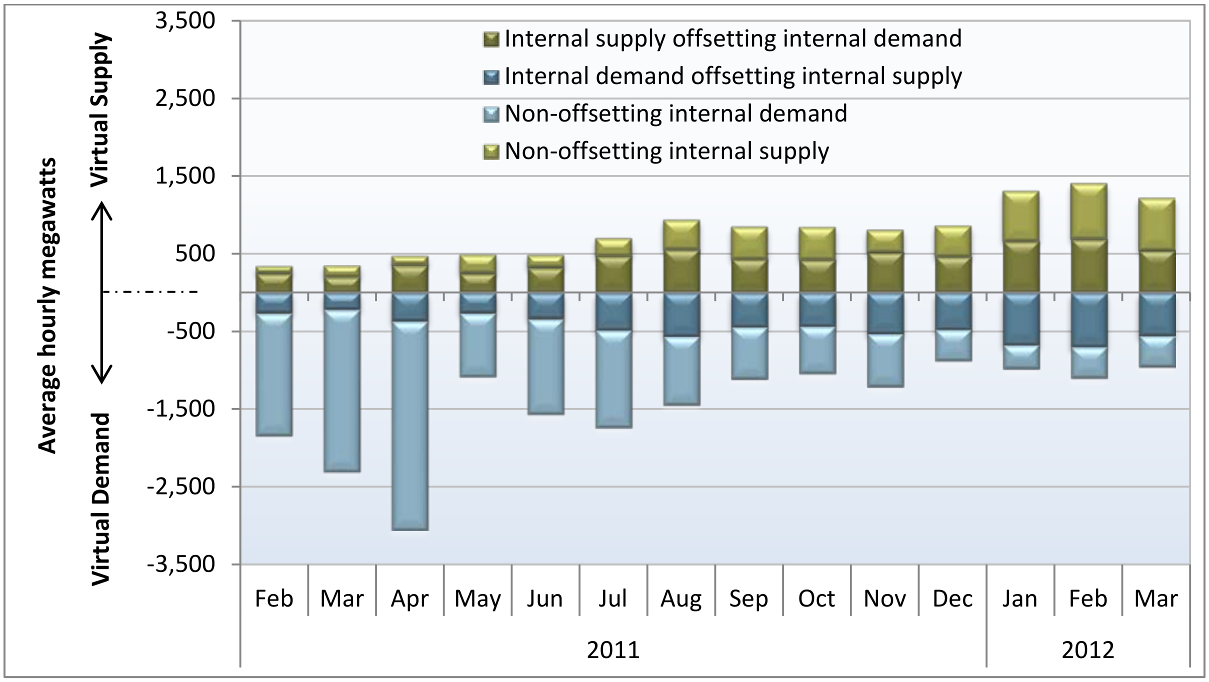
Market participants can also hedge congestion costs or earn revenues associated with differences in congestion between different points within the ISO by placing virtual demand and supply bids at different internal locations during the same hour.

Figure 2.8 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.[16] 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 2.8, this type of offsetting virtual position at internal locations accounted for about 75 percent of the positions in the first quarter of 2012, up from 43 percent in 2011 for all cleared internal virtual bids. After suspension of convergence bidding at the inter-ties, the amount of these offsetting internal virtual bidding positions taken by participants grew in volume and as a share of total internal virtual bids. This suggests that virtual bidding was increasingly used to hedge or profit from internal congestion.

[16] 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.

Figure 2.8 Average hourly offsetting virtual supply and demand positions at internal points

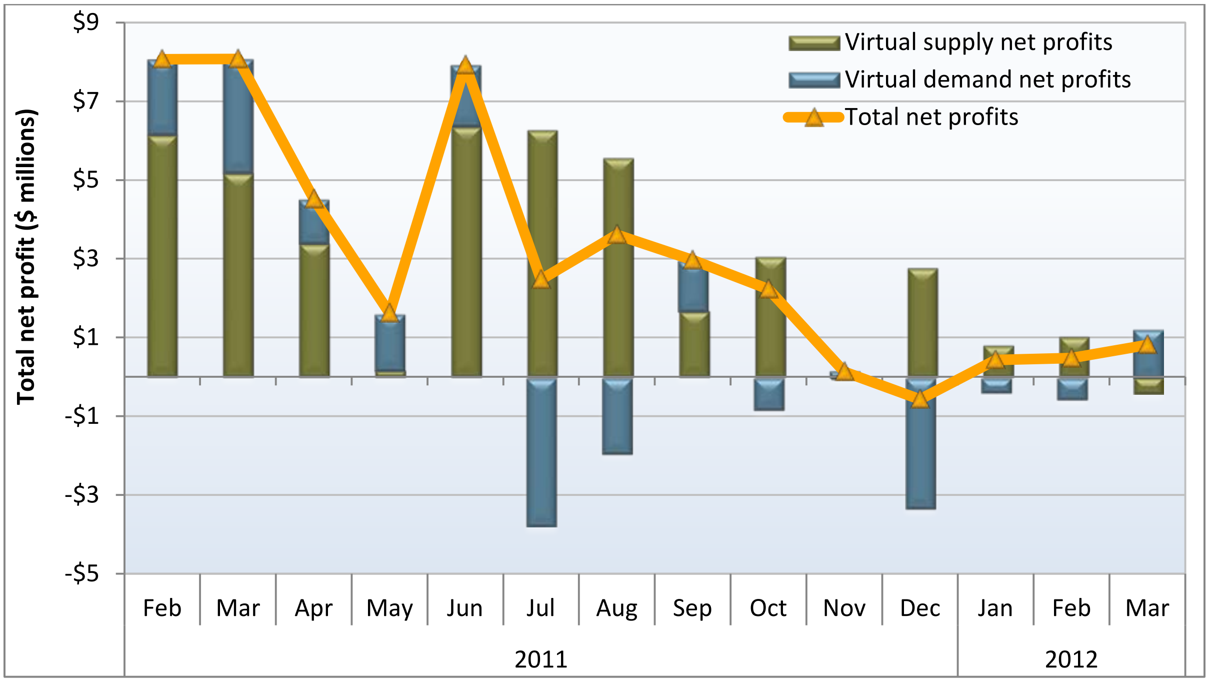


2.2 Convergence bidding profits

Figure 2.9 shows total monthly net profits paid for accepted virtual supply and demand bids. As shown in this figure:

- Virtual supply positions have resulted in net profits in all months, except in March 2012. In March, the higher frequency of real-time price spikes (see Section 1.1 for details) depressed revenues for virtual supply.
- Virtual demand positions were consistently profitable for the first five months of convergence bidding. Since June, profitability of virtual demand began to fluctuate. This trend reflects how real-time prices (or congestion prices) were lower than day-ahead prices during the first two months of 2012 and higher in March.
- Total profits paid to virtual bidders increased over the course of the first quarter. Total net profits were low in January and February. Profits increased in March due to the increased frequency of real-time price spikes (see Section 1.1 for further detail).
- Since the beginning of 2012, net profits paid to convergence bidding entities totaled around $2 million. These profits were received by virtual bids at internal locations. Most of these profits ($1.4 million) were for virtual supply bids at locations within the ISO system.

Figure 2.9 Total monthly net profits from convergence bidding



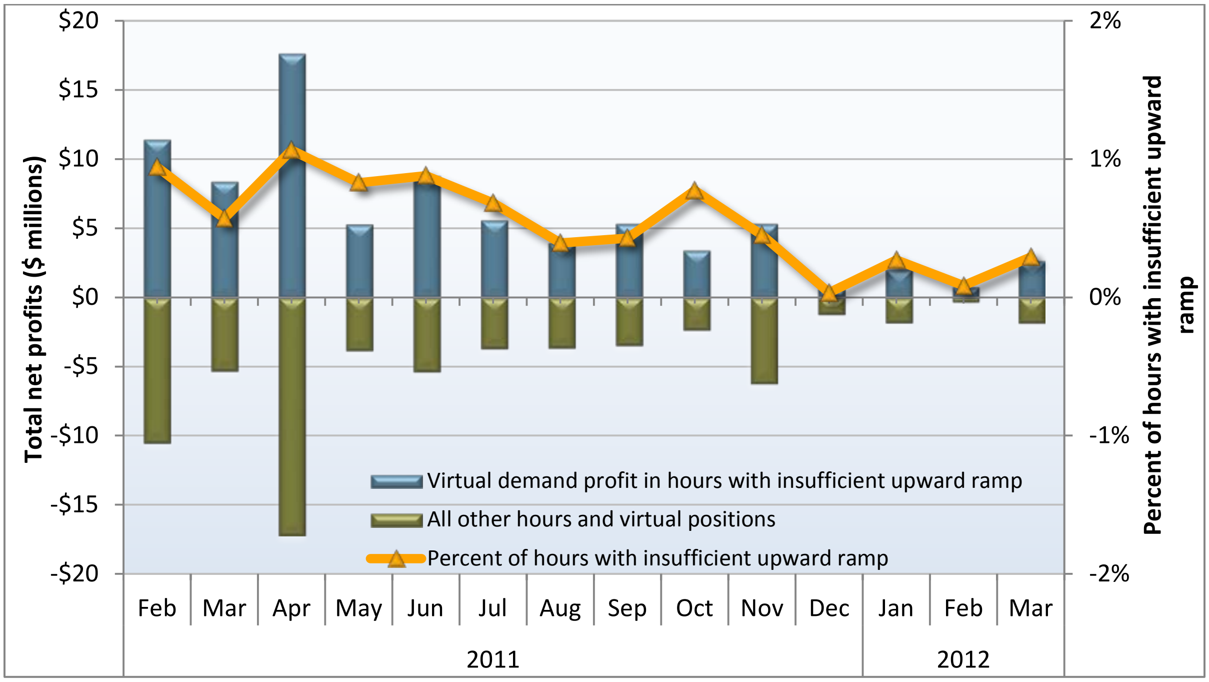
Net profits at internal scheduling points

In 2011, virtual demand accounted for about 70 percent of cleared bids at internal locations; in the first quarter of 2012 it dropped to 44 percent. Virtual demand bids at internal nodes are profitable when real-time prices spike in the 5-minute real-time market. Historically, almost all profits from these internal virtual demand positions have resulted from a relatively small portion of intervals when the system power balance constraint becomes binding due to insufficient upward ramping capacity.

Figure 2.10 compares total profits from internal virtual bids during hours when the power balance constraint was relaxed due to short-term shortages of upward ramping capacity with the overall profitability of internal virtual bids during all other hours. As shown in Figure 2.10:

- Although upward ramping capacity was insufficient during less than 1 percent of hours each month, these hours accounted for the net profits from internal virtual demand. Profits from 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 income to compensate for losses in the remaining hours of the day.
- During the other 99 percent of intervals when sufficient ramping capacity was available, virtual demand bids were highly unprofitable. In December 2011 and February 2012, the frequency of real-time price spikes decreased significantly. As result, the profitability of internal virtual demand bids decreased to about zero. In January and March 2012, the frequency of real-time price spikes increased due to conditions related to the outage of SONGS.

Figure 2.10 Convergence bidding profits from internal scheduling points



These price spikes are typically associated with brief shortages of ramping capacity. Virtual demand at internal scheduling points can potentially result in additional capacity being committed and available in the real-time market. In practice, however, the impact of internal virtual demand on real-time price spikes appears to have been limited by the fact that any additional capacity available to convergence bidding may not be enough to address the short-term ramping limitations.

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.

Improvements in operational practices, market software and implementation of the flexible ramping constraint helped decrease the frequency of extreme price spikes since December. In March, the frequency of the price spikes increased due to the SONGS outage (see Sections 1.1 and 3.2 for further details).

2.3 Changes in unit commitment

If physical generation resources clearing the day-ahead energy market are less than the ISO's forecasted demand, the residual unit commitment ensures that enough additional capacity is available to meet the forecasted demand. As previously shown, virtual supply clearing the day-ahead energy market consistently exceeded virtual demand in the first quarter. As a result, more residual unit commitment capacity was needed to replace the net virtual supply with physical supply. Total direct residual unit commitment costs were around $350,000 in the first quarter of 2012, down from $430,000 in the final quarter of 2011. Bid cost recovery payments for capacity committed in the residual unit commitment process were around $1.1 million, down from $1.8 million in the final quarter of 2011. This decline can be attributed, in part, to the increased use of minimum online constraints (see Section 3.2) for reliability purposes.

3 Special Issues

3.1 Real-time flexible ramp constraint performance

In December 2011, the ISO began enforcing the flexible ramping constraint in the upward ramping direction in both 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.[17]

Application of the constraint in the real-time pre-dispatch market ensures that enough capacity is procured to meet the flexible ramping requirement. In addition to procuring flexible ramping capacity, the ISO procures additional incremental regulating and operating reserves in the 15-minute market. The 15-minute market also provides unit commitment of fast start units prior to the 5-minute dispatch. Application of the constraint in the 5-minute real-time market is to ensure that the cleared quantity is available for dispatch in the subsequent 5-minute intervals of the trading hour. The flexible ramping constraint in the 5-minute real-time market is resolved from the same set of resources that resolved the constraint in the 15-minute market.

The ISO originally suggested allocating the cost of the flexible ramping constraint to measured demand citing parity with ancillary services cost allocation.[18] Although the FERC has approved the implementation of the flexible ramping constraint in the 5-minute real-time market, the methodology to allocate the associated cost has not yet been approved by FERC.[19] The total system cost during the first quarter was around $5.8 million; this compares with a monthly average cost of $3 million for spinning reserves during the same period.

A majority of the spinning reserves available in the ISO market are contingent, which means that they cannot be deployed unless there is a severe forced outage in the system and the operators have to implement a contingency dispatch. The flexible ramping constraint was implemented to account for the non-contingency based variations in supply, demand and the transmission network between the 15-minute real-time pre-dispatch and the 5-minute real-time dispatch. The additional flexible ramping capacity will 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 commits additional resources (mostly short-start units) for energy to free up capacity from the existing set of resources. The short-

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

[18] See CAISO FERC filing part III (Description of Stakeholder process) and section C (Cost Allocation) at: http://www.caiso.com/Documents/2011-10-07_ER12-50_FlexiRampConstraint_Amend.pdf.

[19] FERC will hold a settlement conference on May 22, 2012 to address the cost allocation of the flexible ramping constraint: http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/FlexibleRampingConstraint.aspx.

start units can be eligible for bid cost recovery payments in real-time.[20] An infeasibility or procurement shortfall will occur with a shortage of available supply bids to meet the flexible ramping constraint.

Analysis of the flexible ramping constraint

The ISO determines the amount of needed flexible ramping capacity on an hourly basis. After initially setting the flexible ramping requirement to 700 MW for each hour of the day, the baseline requirement is now set to 450 MW. Beginning in January, operators have been instructed to use their discretion in adjusting the hourly requirement levels based on the prevailing system conditions and considering the utilization of the procured flexible ramping capacity.

Since implementation, DMM has monitored the daily flexible-ramping constraint activity and cost. For the purpose of the report, DMM has provided a weekly summary of the overall flexible ramping constraint activity and a summary of the hourly compensation profile to generators for providing flexible-ramping capacity.

Table 3.1 provides a review of the weekly flexible ramping constraint activity in the 15-minute real-time market since implementation in December. The table shows the total overall payment to generators, percentage of binding 15-minute real-time pre-dispatch intervals, the average shadow price during constrained intervals, and the number of weekly flexible ramping procurement shortfalls when the flexible ramping constraint procurement did not meet the requirement. The table highlights the following:

- The frequency of the flexible ramping constraint binding has varied since the lowering of the flexible ramping requirement during the last week of December, ranging from 5 to 21 percent of 15-minute intervals and averaging 12 percent of 15-minute intervals in the first quarter.
- The total payments to generators for the flexible-ramping constraint decreased in the third week after implementation, dropping to an average payment of around a half million dollars per week. Since then, the weekly payments have varied between a quarter to a half million dollars per week.

Figure 3.1 provides a graphical representation of the weekly flexible ramping payments to generators, which is the total procured volume times the shadow price of the constraint. The total daily payments in the first quarter varied from a low of $0 on February 4, 2012 to a high of about $293,200 on March 14, 2012.

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[20] 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.

Table 3.1 Flexible ramping constraint weekly summary

Week beginning	Total payments to generators ($ millions)	15-minute intervals constraint was binding (%)	15-minute intervals with procurement shortfall	Average shadow price when binding ($/MWh)
13-Dec-11	$1.41	25%	6	$45.27
20-Dec-11	$1.12	24%	7	$38.01
27-Dec-11	$0.56	14%	3	$59.41
03-Jan-12	$0.53	19%	7	$37.84
10-Jan-12	$0.56	11%	5	$44.95
17-Jan-12	$0.66	21%	11	$37.34
24-Jan-12	$0.37	14%	3	$30.95
31-Jan-12	$0.29	7%	8	$46.95
07-Feb-12	$0.28	5%	12	$115.03
14-Feb-12	$0.44	12%	8	$53.33
21-Feb-12	$0.46	8%	10	$102.16
28-Feb-12	$0.39	8%	8	$46.11
06-Mar-12	$0.49	9%	8	$76.27
13-Mar-12	$0.56	19%	6	$38.95
20-Mar-12	$0.28	9%	8	$30.38
27-Mar-12	$0.31	11%	5	$25.64

Figure 3.1 Weekly flexible ramping constraint payments to generators

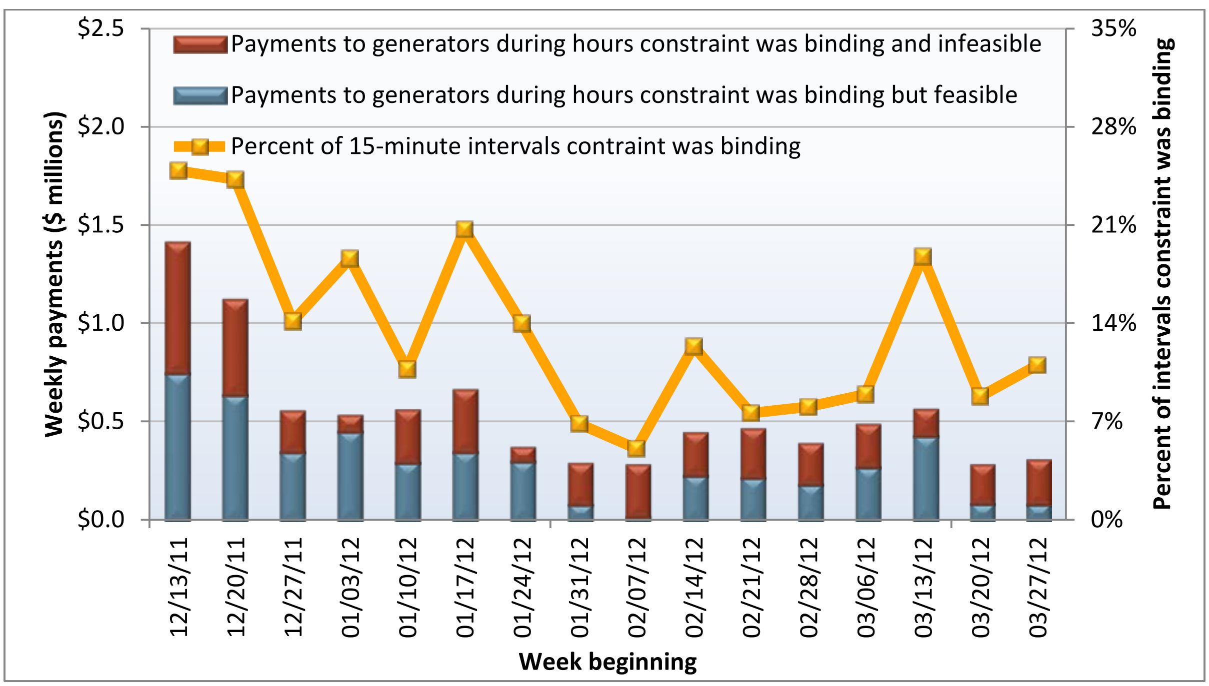


Figure 3.2 provides a representation of the hourly flexible ramping payment distribution during the first quarter of the year. As shown in the figure, most payments resulting from this constraint have been for ramping capacity during the morning and, to a further extent, the evening ramping hours. Natural gas-fired capacity accounted for about 64 percent of these payments, with hydro-electric capacity accounting for most of the remaining 36 percent.

DMM has utilized the ISO's methodology along with settlement data to calculate the flexible ramping capacity utilization during the first quarter. The metric determines how much of the procured flexible ramping capacity in the 15-minute real-time pre-dispatch is utilized in the 5-minute real-time dispatch. Figure 3.3 shows the minimum, average and maximum hourly utilization of procured flexible ramping capacity in the 5-minute real-time dispatch. The average utilization of procured flexible ramping varies from 2 percent in hour ending 5, to a high of 26 percent in hour ending 20. The utilization is a function of prevailing system conditions, including load and generation levels, and generation and transmission availability. The range of hourly average utilization varied from a low of 0 percent to a high of about 87 percent during the quarter. The utilization was at 100 percent at individual 5-minute intervals during load ramping hours.

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.

Figure 3.2 Hourly flexible ramping constraint payments to generators (January – March)

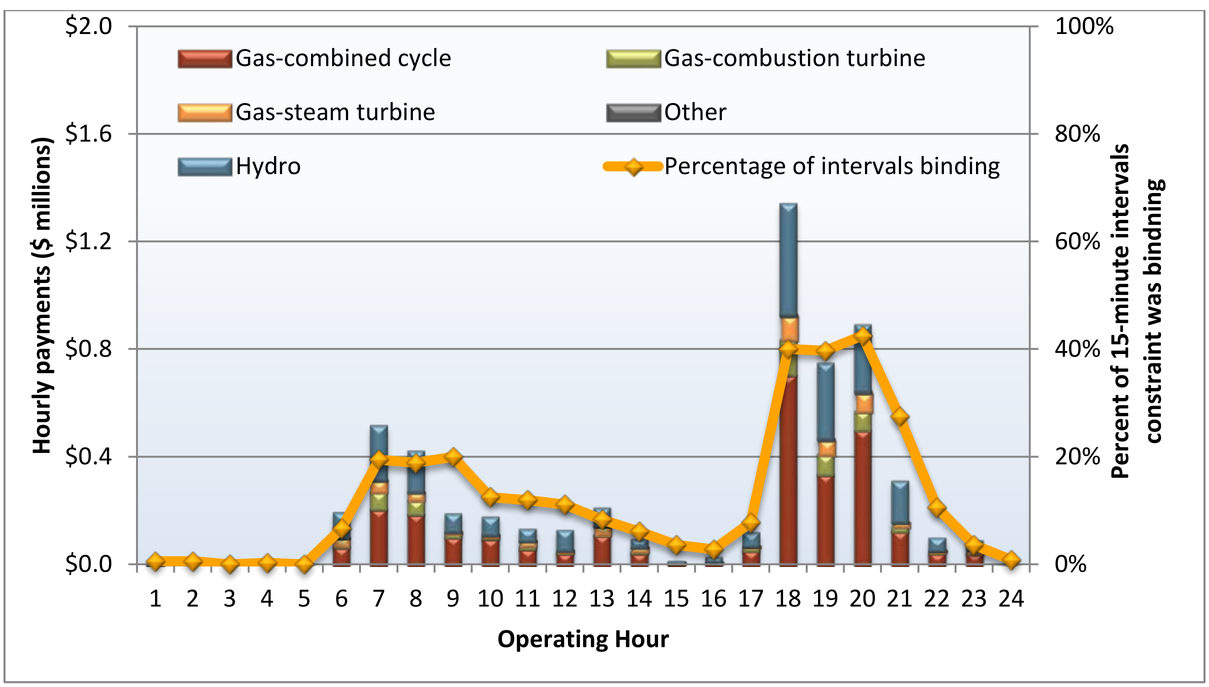
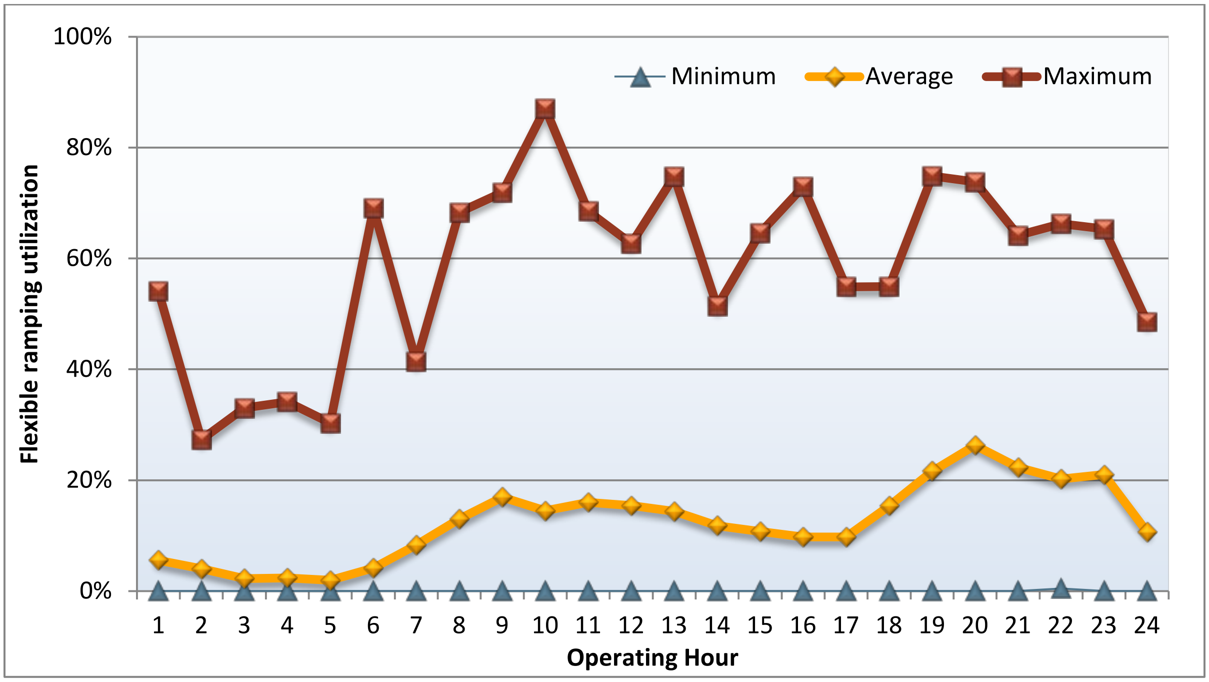


Figure 3.3 Flexible ramping utilization by hour



3.2 San Onofre Nuclear Generating Station outage

San Onofre Nuclear Generating Station Units 2 and 3 were offline for most of the first quarter due to a combination of both planned and forced outages as well as for testing of critical systems. These combined outages have created local and system reliability concerns as well as local congestion in the SDG&E area and in other parts of Southern California. The congestion has contributed to 5-minute real-time price spikes in SDG&E and SCE areas (see Section 1.1).

In response to the outages, the ISO has used minimum online constraints and exceptional dispatches to enhance local and system reliability. These tools have caused units to be committed to provide reliability. These units are entitled to receive bid cost recovery payments, which ensure that the generators receive enough market revenues to cover the cost of all their accepted bids, including minimum load and start-up costs. As a result, bid cost recovery payments in the first quarter of 2012 have increased compared to the final quarter of 2011.

Background

At the beginning of January, SONGS' operator SCE took Unit 2 offline for planned maintenance for refueling and technology upgrades. The unit was expected to be offline for less than a couple months. On January 30, SCE shut down SONGS Unit 3 due to a leak. After further review of the leak, both units have been kept offline due to safety concerns. As a result, the return timetable of these units is unknown. This presents a challenge for the ISO as both of these units provide local reliability to parts of Southern California and San Diego, especially during the summer peak load periods. Due to the uncertainty concerning the length of the SONGS outage, the ISO is planning for this summer's peak demand conditions without these units.

Local congestion is the immediate impact of the SONGS outage on the markets. A large portion of congestion has been due to the outage of SONGS Units 2 and 3 in combination with additional forced and maintenance outages (see Section 1.6).

Minimum online constraints and exceptional dispatches

Over the past few years, the ISO has reduced the volumes of exceptional dispatches by incorporating additional constraints into the market model. Some of the reduction in exceptional dispatch has been from the incorporation of 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.[21] These constraints are set in the day-ahead and residual unit commitment markets. They make sure that the system has enough longer start capacity on-line to meet locational voltage requirements and respond to contingencies that cannot be directly modeled. If a unit is online, its full available capacity can be used to meet these requirements. Thus, the ISO can schedule this capacity to meet this requirement and to provide energy. In some cases, capacity from different units is multiplied by different effectiveness factors that reflect effectiveness of each unit at meeting the constraint. The effectiveness of different units can vary based on their location and ability to provide voltage support.

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 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, after the ISO engineers study the expected results of an outage, the ISO may create new minimum online capacity requirements for potential contingencies and locational voltage requirements.

In the first quarter, the ISO created new minimum online constraint requirements to deal with the local or system-level congestion and reliability issues mainly resulting from the outage of the SONGS units. DMM estimates that the direct cost of minimum online constraints related to the SONGS outage, in terms of bid cost recovery payments, was around $6 million.[22]

The ISO also uses real-time exceptional dispatches to deal with reliability concerns if they cannot be resolved completely by the units committed by the minimum online constraints and the market. Initially, there was a considerable increase in exceptionally dispatched energy in February as the ISO used exceptional dispatches for local reliability purposes after the SONGS outage. In February, hourly average exceptionally dispatched energy was about 160 MW, which was four times higher than the average in January. As the ISO was able to further develop and refine minimum online constraints, exceptional dispatched energy decreased in March by 37 percent to about 100 MW in March. DMM

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

[22] Minimum online constraints directly affect only the day-ahead portion of the bid cost recovery payments.

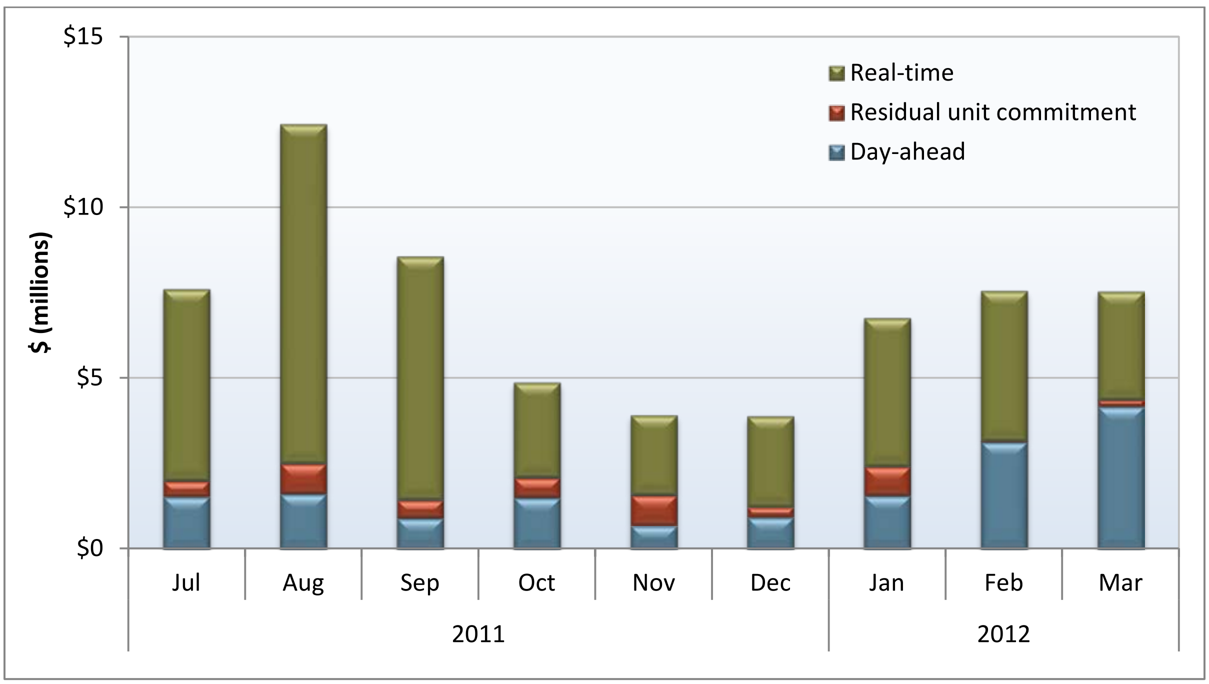
estimates the direct impact of exceptional dispatches related to the SONGS outage on the bid cost recovery payments to be around $6 million.

Bid cost recovery payments

Bid cost recovery payments totaled around $22 million in the first quarter, compared to $13 million in the final quarter of 2011. DMM estimates that about $12 million of the bid cost recovery payments in the first quarter resulted from a combination of minimum online unit commitments and real-time exceptional dispatches.

Figure 3.4 shows that bid cost recovery payments increased after the SONGS outage in late January. The real-time bid cost recovery payments were higher in February, consistent with the exceptional dispatch commitments, whereas the day-ahead bid cost recovery payments were highest, associated with the minimum online constraints. Also, bid cost recovery payments from the residual commitment market decreased because the use of minimum online constraints and post-day-ahead exceptional dispatches decreased the need for unit commitments in the residual unit commitment market.

Figure 3.4 Monthly bid cost recovery payments



Capacity procurement mechanism

In response to the outages of the SONGS units, the ISO issued an exceptional dispatch designation to Huntington Beach Unit 1 on February 8, 2012. As a result, the generator was designated for 20 MW of capacity for a 30-day term. The estimated capacity cost from the 30-day designation of the Huntington Beach Unit 1 was almost $122,000.[23]

The ISO also issued exceptional dispatch designations to Huntington Beach Unit 1 and Encina Unit 4 on March 1, 2012. Huntington Beach Unit 1 was designated for 98 MW of capacity and Encina Unit 4 was designated for 300 MW of capacity for a 60-day term under the exceptional dispatch capacity procurement mechanism provisions of the tariff to address a non-system reliability need.[24] The capacity cost is estimated to be about $1.3 million for Huntington Beach Unit 1 and $3.8 million for Encina Unit 4.[25]

As a part of the summer mitigation plan, the ISO issued exceptional dispatch designations to the two previously retired units, Huntington Beach Units 3 and 4, on May 11, 2012. The units will provide 440 MW of capacity to support grid reliability in the Los Angeles Basin and San Diego regions. This initial designation is for a term of 30 days and it is done as a significant event designation in response to the outages of the SONGS units. The term can be extended as necessary and the expected duration of the designation is 90 days.

Mitigation plans for summer 2012

The ISO updated its annual 2012 Summer Loads and Resources Assessment, assuming that both SONGS units may remain offline in summer 2012. If both units remain offline, the ISO expects that San Diego and parts of Los Angeles Basin may face local reliability issues.[26] Moreover, these reliability issues can become even more severe as a result of potentially lower hydro-electric generation or exceptionally severe summer heat waves. The ISO is working on a contingency plan that includes calling Huntington Beach Units 3 and 4 back into service, full utilization of available demand response programs and acceleration of completion of the Barre-Ellis transmission upgrade project and Sunrise Powerlink transmission project.[27] The return of the two Huntington Beach units adds about 440 MW of capacity in the LA Basin and provides 350 MW of additional import transfer capability into the San Diego area.[28]

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[23] This estimate is based on the price of $55/kW-year, which was in effect from February 8 through February 15, and the price of $67.50/kW-year, which was in effect from February 16 through March 8, 2012.

[24] The ISO conducted an engineering analysis to determine the quantity of capacity needed to address the non-system reliability need in southern Orange County and the San Diego area. After analyzing the available resource adequacy capacity for March 2012 and the expected peak load for that month, the study identified a shortage of 398 megawatts of generation capacity in the area. The analysis considered the next contingency following the loss of the most severe contingency.

[25] This estimate is based on the price of $67.50/kW-year. The estimated amount from all the designations assumes 100 percent availability of the unit. The $67.50/kW-year price became effective on February 16, 2012 when FERC issued an order (Docket Nos. ER11-2256-000 and ER11-2256-002) that approved the settlement in the ISO's capacity procurement mechanism proceeding.

[26] For more information, see the ISO news release: http://www.caiso.com/Documents/SummerGridOutlookComplicated-PossibleExtendedOutage-NuclearPowerPlant.pdf.

[27] The Sunrise Powerlink transmission project is planned to construct a 117-mile long 500 kV power line that will bring 1,000 MW of renewable energy from the Imperial Valley to the San Diego area. The line is scheduled to be in service in 2012.

[28] Huntington Beach Unit 3 and 4 came back into service on May 11, 2012.