California Independent System Operator Corporation

# California ISO

# Q4 2013 Report on Market Issues and Performance

**February 10, 2014**

Prepared by: Department of Market Monitoring

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# Executive summary

This report provides an overview of general market performance during the fourth quarter of 2013 (October – December) by the Department of Market Monitoring (DMM). Key trends in market performance include the following:

- Electricity market prices in the fourth quarter have been higher than the third quarter of 2013 and the fourth quarter of 2012 for several reasons.
    - Gas prices were more than 8 percent higher in the fourth quarter than in the third quarter. In 2013, gas prices were about 30 percent higher than the unusually low gas prices that occurred in 2012. This accounts for most of the increase in electricity market prices.
    - Most of the remaining increase in electricity market prices in 2013 can be attributed to implementation of the state's greenhouse gas cap-and-trade program. DMM estimates that, on average in 2013, day-ahead market prices were about $6/MWh higher with implementation of this program.[1]
    - Another factor causing upward pressure on electricity market prices is a decrease in hydro-electric generation for 2013, compared to the year before. In the fourth quarter, hydro-electric generation was more than 40 percent lower than the same period in 2012.
- Day-ahead natural gas prices spiked on December 10, ending the day at over $7/MMBtu at the SoCal Citygate hub, almost doubling in price from the first of the month. The price spike occurred as a result of a cold snap and tight natural gas supply conditions, especially in the San Diego area, over the weekend leading up to December 10. The ISO restricted maintenance and, in coordination with natural gas pipeline operators, issued out-of-market instructions to generators to reduce demand for natural gas in areas with tight gas supply conditions. Participants adjusted their bids into the ISO day-ahead and real-time markets, accordingly, to reflect fuel supply conditions. As the cold snap abated and gas supply conditions improved, gas prices fell. Even so, gas prices settled at a higher level than before the spike. This was consistent with an increase in national natural gas prices driven by weather conditions, and relatively high demand within the ISO system.
- Congestion continued to impact overall energy prices, but to a much smaller extent than in previous quarters. Congestion raised day-ahead prices in the Southern California Edison area by around 0.4 percent and in the San Diego Gas & Electric area by 2.1 percent, while lowering prices in the Pacific Gas and Electric area by 0.3 percent.
- Real-time energy and congestion imbalance offset charges decreased in the fourth quarter to about $44 million. Charges were primarily due to congestion offset costs incurred on just 12 days from unscheduled flows and transmission outages. Congestion imbalance costs have decreased in the fourth quarter of 2013 ($31 million) compared to the same period in 2012 ($57 million). In 2013, real-time imbalance offset costs totaled about $176 million, down more than 25 percent from 2012 ($235 million). This decrease was driven by a decline in congestion offset costs. Total annual real-time congestion offset costs fell from $187 million in 2012 to $120 million in 2013, more than offsetting an increase in real-time energy offset costs, which increased from $48 million to $56 million.

[1] This $6/MWh price impact is highly consistent with the cost of carbon emission credits and the efficiency of gas units typically setting prices in the day-ahead market during this period. The impact of higher wholesale prices on retail electric rates will

- Overall bid cost recovery payments remained unchanged from the previous quarter, driven by unit commitment resulting from continued use of minimum online constraints and exceptional dispatches. For the year, bid cost recovery payments totaled about $107 million, with real-time payments making up roughly half of the total. Although the 2013 payments were slightly higher than the $104 million in 2012, payments associated with residual unit commitment have increased nearly threefold to $23 million in 2013 from $8 million in 2012.
- Convergence bidders were paid net revenues of about $6.6 million, up from about $2.9 million in the third quarter. For the year, convergence bidding net revenues were around $25 million, down from about $56 million in 2012. Most of the net revenues in 2013 were related to virtual supply positions, accounting for about $52 million, while virtual demand positions had losses of about $26 million. In the fourth quarter, both virtual supply and demand positions were profitable. Convergence bidders were paid revenues of about $9.3 million, up from about $5.5 million in the third quarter. Virtual supply positions were allocated bid cost recovery charges of around $2.7 million. Taking these charges into account, net overall revenues received by virtual bidders in the fourth quarter were about $6.6 million.
- Total payments for flexible ramping resources were around $5 million, up from around $3 million in the third quarter of 2013. Flexible ramping costs in 2013 were around $25 million, compared to about $19 million for 2012. Most payments for ramping capacity occurred during the evening peak hours.
- The volume of imports offered and clearing the market decreased by about 10 percent and 18 percent, respectively, in the second half of 2013 compared to the same period in 2012. This follows a period of increases in imports during the first half of 2013. The decrease in imports in the latter half of the year appears to have been driven by decreases in hydro generation in the Pacific Northwest and increases in power prices at the Mid-Columbia and Palo Verde trading hubs. Compared to 2011, cleared import levels in 2013 were similar and offered levels were similar in the second halves of 2011 and 2013.

## Energy market performance

This section provides a more detailed summary of energy market performance in the fourth quarter.

**Prices remained competitive.** Overall, prices in ISO energy markets in the fourth quarter were close to what DMM estimates would result under highly competitive conditions.

**Price levels remain higher in 2013 compared to 2012.** Average system energy prices in the ISO markets rose in the fourth quarter compared to price levels in 2011 and 2012 (see Figure E.1). This increase was primarily the result of an 8 percent increase in regional natural gas prices in the fourth quarter from prices in the third quarter. Figure E.1 illustrates the close relationship between average monthly day-ahead system marginal energy costs and natural gas prices (SoCal Citygate). Most of the remainder of the increase in prices can be attributed to compliance costs associated with the state's cap-and-trade program. DMM estimates that the cap-and-trade program has added about $6/MWh to the system energy price in 2013. Another factor causing upward pressure on electricity market prices was a decrease in hydro-electric generation within the ISO system, which fell to just over half of third quarter production and less than 60 percent of hydro production in the fourth quarter of 2012. Prices increased markedly in December, to the highest average levels observed in over two years, driven by a surge in gas prices as discussed above.

**Figure E.1 Average day-ahead system marginal energy prices rise with natural gas prices**

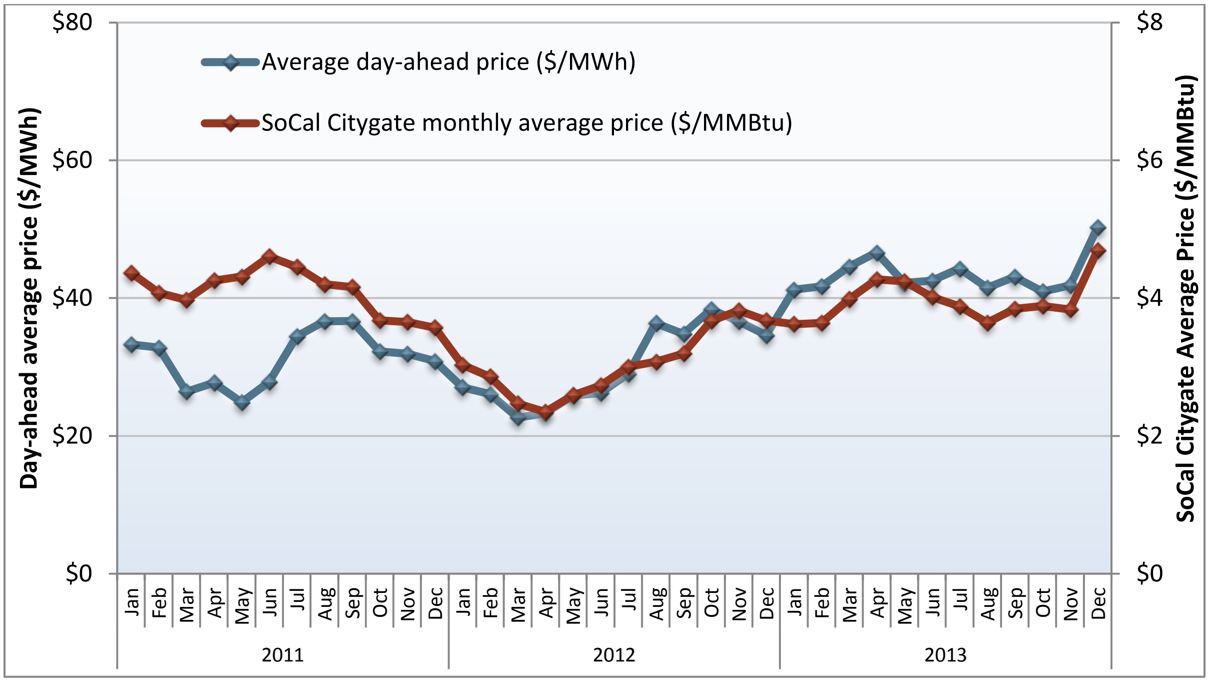
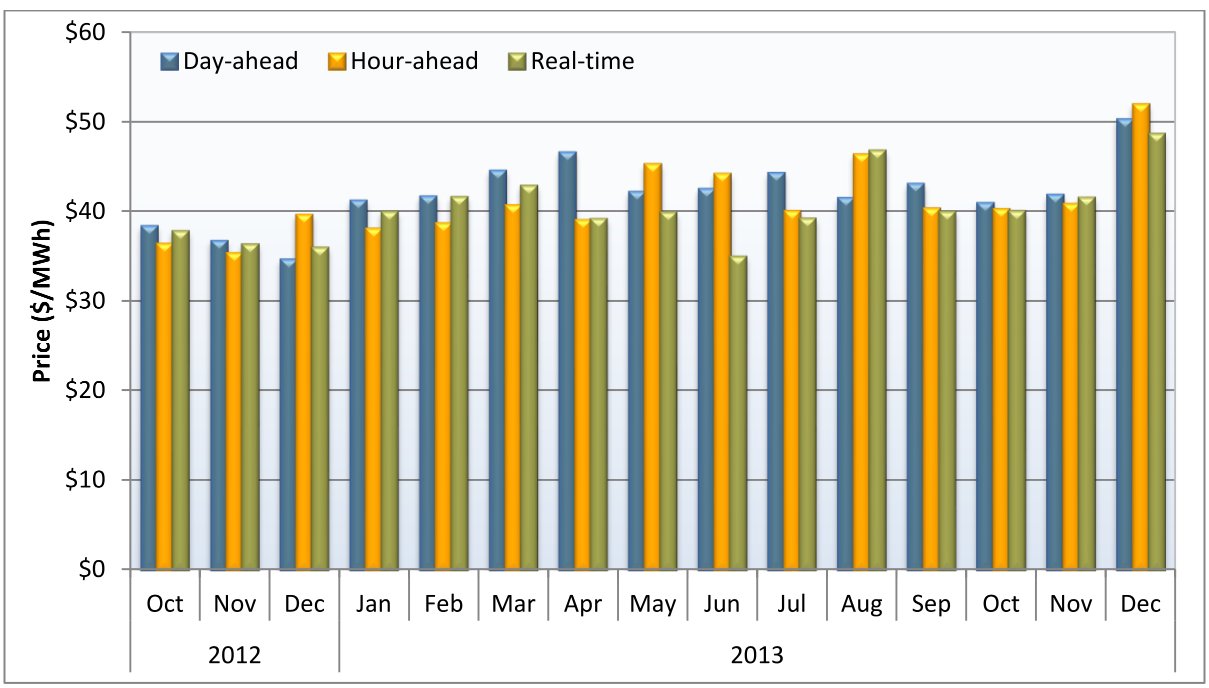



**Figure E.2 Average monthly system marginal energy prices (all hours)**



**Reduced divergence between average day-ahead and real-time system energy prices.** Average system energy prices in the real-time market (excluding congestion) were lower than average prices in the day-ahead market for the quarter, but to a lesser degree than in previous periods (see Figure E.2). The overall price divergence was due, in part, to a substantial amount of renewable energy in the real-time market that was not scheduled in the day-ahead. To a lesser extent, energy from units committed after the day-ahead market through the residual unit commitment process and exceptional dispatches also contributed to this divergence.

**The impact of congestion on day-ahead and real-time prices declined in the fourth quarter.** Congestion decreased substantially in the fourth quarter, particularly in the Southern California Edison area. Much of the congestion that did occur was related to flow adjustments in the Fresno area (related to Helms Pump operations), retirement of the San Onofre Nuclear Generating Station (SONGS) units 2 and 3 and other generation and transmission events. Congestion affected overall day-ahead market prices by about 0.3 percent to 2 percent and real-time market prices by less than 1 percent. For the quarter, day-ahead congestion caused Southern California Edison and San Diego Gas & Electric prices to increase, and caused overall prices in the Pacific Gas and Electric area to decrease. Real-time congestion caused prices in the Pacific Gas and Electric area to increase and prices in Southern California Edison and San Diego Gas & Electric areas to decrease, but had a smaller impact than day-ahead congestion.

**Real-time congestion and energy imbalance offset costs declined in the fourth quarter.** Real-time imbalance offset costs totaled about $44 million in the fourth quarter, down from $57 million in the third quarter (Section 1.6). Congestion offset costs accounted for approximately 70 percent of the total imbalance costs during the fourth quarter, totaling about $31 million. More than 7 percent of these offset costs occurred on a single day, November 13, due to unscheduled flows and a transmission outage. Real-time energy imbalance offset costs fell to $13 million, down from about $15 million in the previous quarter.

**Bid cost recovery payments remained unchanged.** Bid cost recovery payments totaled around $26 million in the fourth quarter, about the same as in the third quarter. The reduced use of minimum online commitments and exceptional dispatch commitments for summer testing caused lower day-ahead and real-time bid cost recovery payments compared to the second quarter ($33 million). The residual unit commitment portion of bid cost recovery payments was also similar to the prior quarter at just under $5 million. ISO operators have continued making adjustments to residual unit commitment requirements to mitigate potential contingencies and to account for differences in scheduled and forecast wind and solar supply. Virtual supply positions were allocated $2.7 million of the $5 million in bid cost recovery charges for residual unit commitment.

**Flexible ramping constraint payments increased.** The flexible ramping constraint is designed to help mitigate short-term deviations in load and supply between the real-time commitment and dispatch models (such as load and wind forecast variations and deviations between generation schedules and output). The constraint procures ramping capacity in the 15-minute real-time pre-dispatch that is subsequently made available for use in the 5-minute real-time dispatch. Total payments to generators for the flexible ramping constraint were around $5 million, compared to around $3 million in the previous quarter. By comparison, payments for spinning reserve totaled about $6.4 million for the same period. ISO operators consistently increased the flexible ramping requirement during the ramping periods of the day in the fourth quarter.

### Convergence bidding

Convergence bidding provides a mechanism for participants to hedge or speculate based on potential price differences of congestion at different locations or in system energy prices between the day-ahead and real-time markets. Convergence bidding was first implemented in February 2011. In November 2011, convergence bidding was temporarily suspended on the inter-ties and in May 2013, the FERC made this decision permanent under certain conditions. The ISO now intends to allow convergence bidding on the inter-ties as part of its implementation of FERC Order No. 764.[2]

Convergence bidding activity was marked by several key trends in the fourth quarter.

**The total volume of convergence bids remained high, but was lower than record levels in the third quarter.** Average hourly cleared volumes decreased to 4,160 MW in the fourth quarter from 4,560 MW in the third quarter. Although cleared virtual positions were primarily virtual supply, as they were in the last quarter, the proportion of both cleared and offered virtual demand bids increased (see Figure E.3).

**Continued use of offsetting convergence bids designed to take advantage of congestion.** Market participants can hedge (or speculate) on potential congestion between 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 1,560 MW per hour of virtual demand offset by over 1,560 MW of virtual supply at other locations in the fourth quarter, similar to the third quarter. These offsetting bids represented about 75 percent of all cleared bids in the fourth quarter, an increase from 67 percent in the third quarter as the total volume of convergence bidding fell.

**Increased net revenues associated with virtual positions.** Based only on virtual bidding settlements relating to differences in day-ahead and real-time market prices, virtual supply received net revenues of about $6.6 million, while virtual demand accounted for a gain of around $2.7 million. This represents net revenues of about $9.3 million in this quarter, compared to about $5.5 million in the previous quarter. However, net virtual supply positions were allocated bid cost recovery charges resulting from residual unit commitment of around $2.7 million. Taking these charges into account, net overall revenues received by virtual bidders were about $6.6 million (see Figure E.4).

[2] For more information, see Tariff Amendment to Implement Real-Time Market Design Enhancements Related to Order No. 764: http://www.caiso.com/Documents/Nov26_2013_TariffAmendment-Real-TimeMarketDesignEnhancementsRelated-Order764_ER14-480.pdf.

**Figure E.3 Monthly average virtual bids offered and cleared**

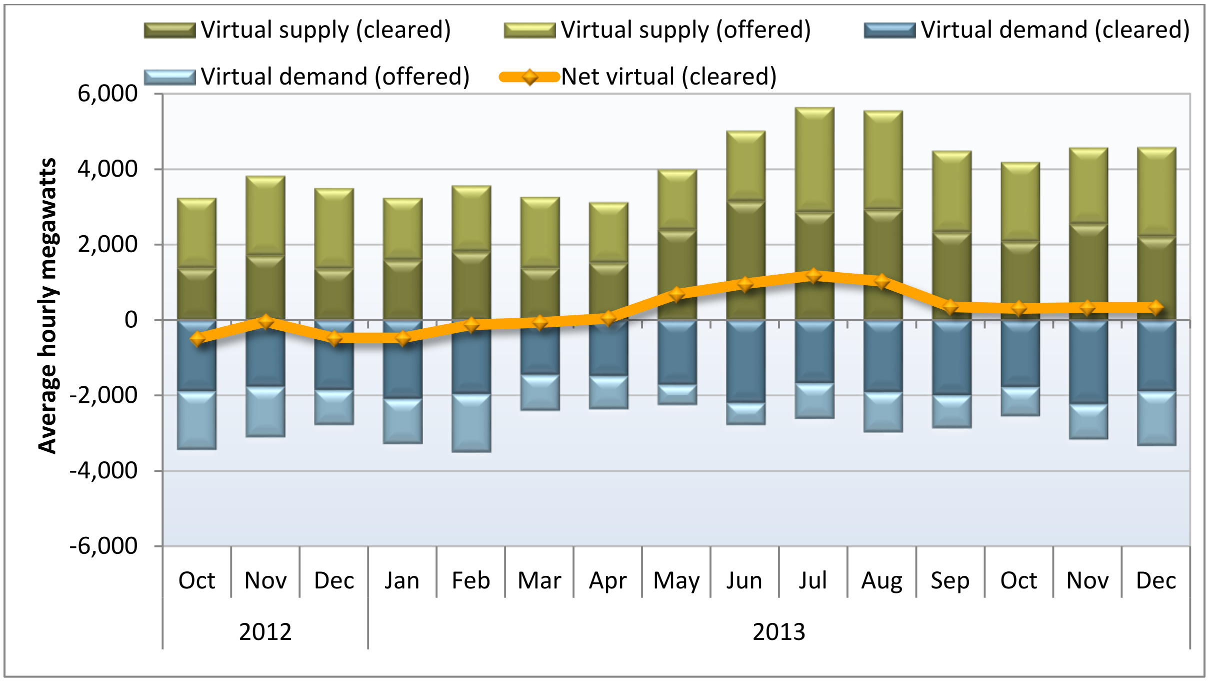
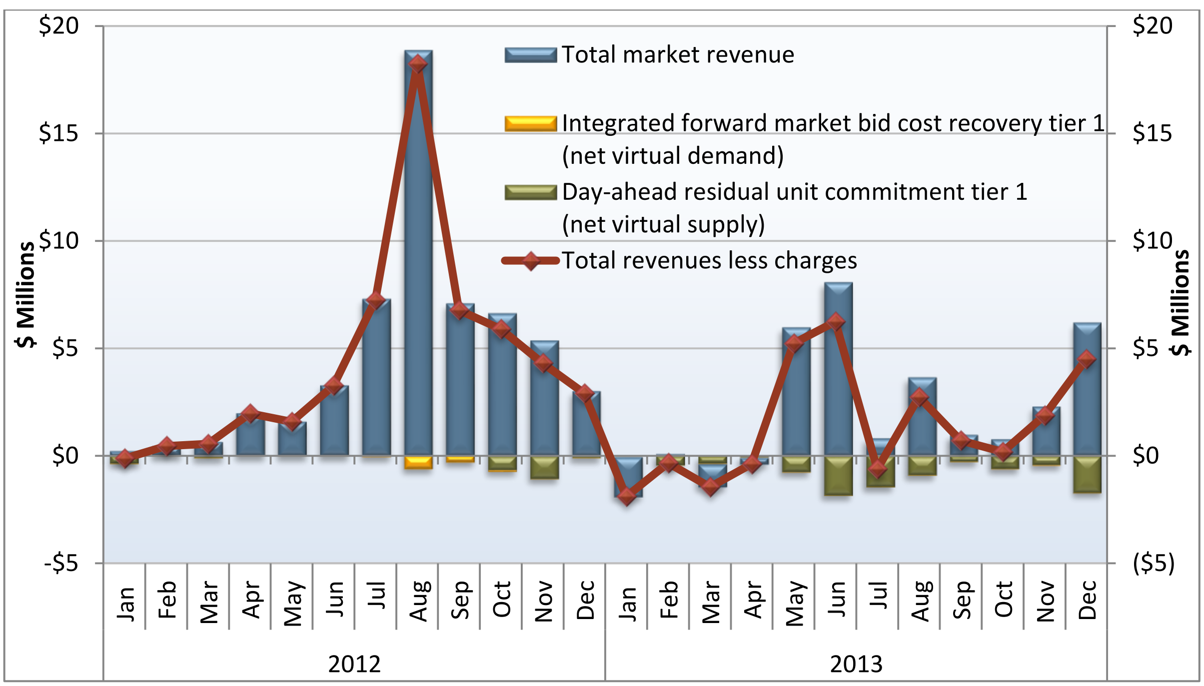



**Figure E.4 Convergence bidding revenues and costs associated with bid cost recovery tier 1 and residual unit commitment tier 1**



## Special issues

**Congestion revenue rights revenue adequacy declined in the fourth quarter.** The congestion revenue rights (CRR) process generated a $3 million net revenue surplus in 2013. In the first half of 2013, the congestion revenue rights generated $29 million in net revenue surplus. However, in the third quarter, the process generated a shortfall of around $8 million followed by a greater shortfall of around $18 million in the fourth quarter. Overall in 2013, revenues from the congestion revenue rights auctions covered relatively high revenue shortfalls. Revenue inadequacy is mainly due to differences between the network transmission model used in the congestion revenue rights allocation and auction processes and the final day-ahead market model.

**Effect of cap-and-trade on ISO markets.** Resources in the ISO market became subject to the state's greenhouse gas cap-and-trade program compliance requirements starting in January 2013. The cost of greenhouse gas allowances in bilateral markets fell in the fourth quarter to an average of \$11.86/mt$CO_2$e, ending the quarter at slightly over \$11.75/mt$CO_2$e.[3] This is down from the first three quarters of the year, when emission costs averaged \$14.55/mt$CO_2$e, \$14.59/mt$CO_2$e, and \$13.27/mt$CO_2$e, respectively. DMM estimates that these greenhouse gas compliance costs have increased the average wholesale electricity price in 2013 by about \$6/MWh. This is consistent with the additional emissions costs for gas units typically setting prices in the ISO market. In addition, the total amount of imports offered to the market decreased for each month in the third and fourth quarters of 2013 compared to the fourth quarter of 2012. During this period, imports offered decreased by 12 percent compared to the same period in 2012. DMM does not attribute the drop in offered imports in the second half of 2013 to the cap-and-trade program as there are many other potential factors driving this change. Notably, decreases in offered and cleared import megawatts were larger coming from the north. These changes may be due to decreases in hydro-electric generation in the Pacific Northwest and increases in power prices at the Mid-Columbia and Palo Verde trading hubs.

[3] mt$CO_2$e stands for metric tons of carbon dioxide equivalent, a standard emissions measurement.

# 1 Market performance

This section highlights key performance indicators of the markets in the fourth quarter:

- Energy market prices remained competitive through the fourth quarter.
- Day-ahead and real-time prices were higher in the fourth quarter, particularly in December, due to increasing gas prices.
- Day-ahead prices were slightly higher than real-time prices, during both peak and off-peak hours. This represents much better convergence than in previous quarters.
- The frequency of high real-time price spikes remained low.
- The frequency of negative real-time prices and periods of over-generation remained low.
- Both the day-ahead and real-time markets had reduced congestion.
- Real-time imbalance offset costs were lower, driven by lower congestion imbalance offset costs.
- Bid cost recovery payments remained low, resulting from relatively low levels of minimum online commitments and exceptional dispatches.

## 1.1 Overall market competitiveness

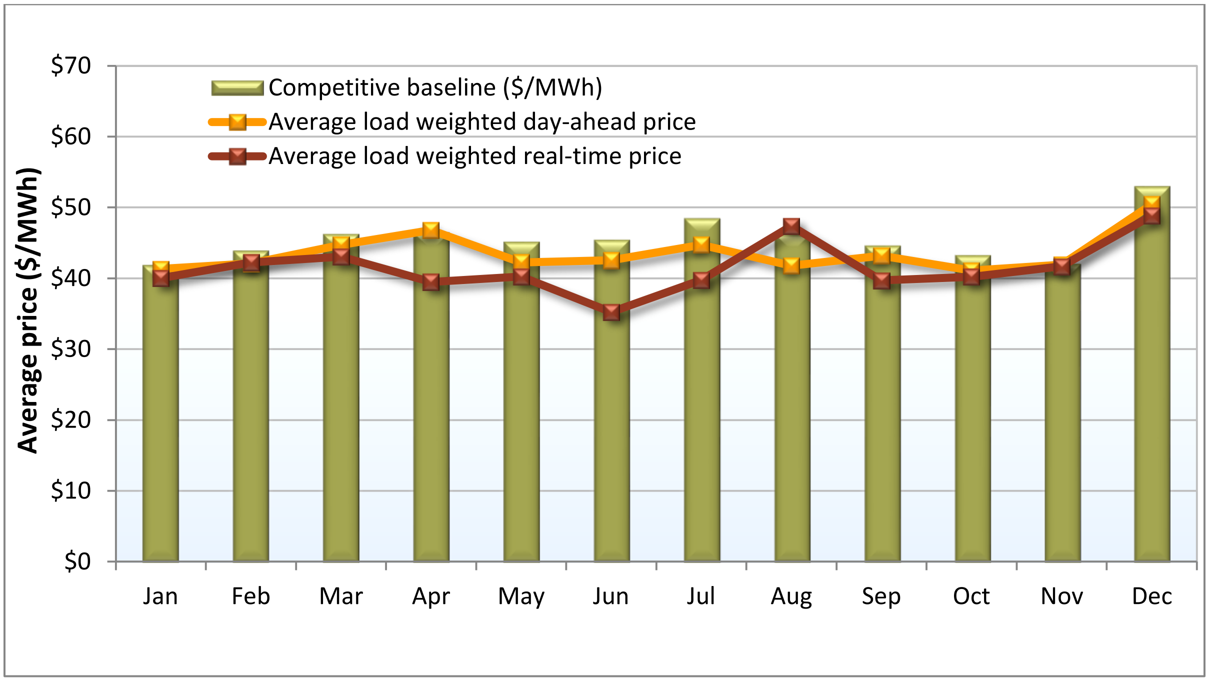
To assess the competitiveness of the ISO energy markets, DMM compares actual market prices to competitive benchmark prices we estimate would result under highly competitive conditions. DMM estimates competitive baseline prices by re-simulating the market using the day-ahead market software with bids reflecting the actual marginal cost of gas-fired units, no convergence bids, and actual load.[4] Figure 1.1 compares this competitive baseline price to load weighted prices in the day-ahead and 5-minute real-time markets. When comparing these prices, it is important to note that baseline prices are calculated using the day-ahead market software under highly competitive conditions, which does not reflect all of the system conditions and limitations that impact real-time prices.

As shown in Figure 1.1, prices in the day-ahead market were similar to competitive baseline prices in most months in 2013. Day-ahead prices exceeded the competitive benchmark in April by about $0.27/MWh and were lower in all other months. In the real-time market, average prices were lower than the competitive baseline in 2013 in most months except for August. A major factor contributing to these lower real-time prices was the substantial amount of real-time energy that was not scheduled in

[4] The competitive baseline is a scenario setting the bids for gas-fired generation equal to default energy bids (DEBs), removing convergence bids and setting system demand equal to actual system load. This scenario represents the combination of perfect load forecast along with physical and competitive bidding of price-setting resources. For January through April, DMM used PROBE to re-simulate the day-ahead market. While the PROBE simulator can produce a reasonably accurate solution when compared to the original market solution, it has limitations in modeling multi-stage generators and congestion. For the rest of the year, DMM calculated the competitive baseline using its version of the actual market software.

the day-ahead market.[5] In August, real-time prices were driven higher than day-ahead prices and slightly over the average competitive baseline price by periods of high loads and wildfire related transmission outages. In the fourth quarter, day-ahead prices and real-time prices were very close to the competitive benchmark.

**Figure 1.1 Comparison of competitive baseline with day-ahead and real-time load-weighted prices**




DMM also calculates an overall price-cost mark-up by comparing competitive baseline prices to total average wholesale energy costs.[6] Total costs used in this analysis represent a load-weighted average price of all energy transactions in the day-ahead, hour-ahead and real-time markets.[7] Thus, this analysis combines energy procured at higher day-ahead prices, as well as net energy sales in the hour-ahead and real-time market at lower prices.

As shown in Figure 1.2, the overall combined average of day-ahead market and real-time prices was about $1.50/MWh or about 3.8 percent lower than the competitive baseline price. This represents a

[5] This unscheduled energy was the combined result of a variety of factors, rather than being driven by any single source. Various sources of additional real-time energy included minimum load energy from units committed after the day-ahead market through the residual unit commitment process and exceptional dispatches, additional must-take energy from thermal generating resources, and unscheduled energy from intermittent renewable energy. A detailed analysis of this issue will be provided in DMM's 2013 annual report.

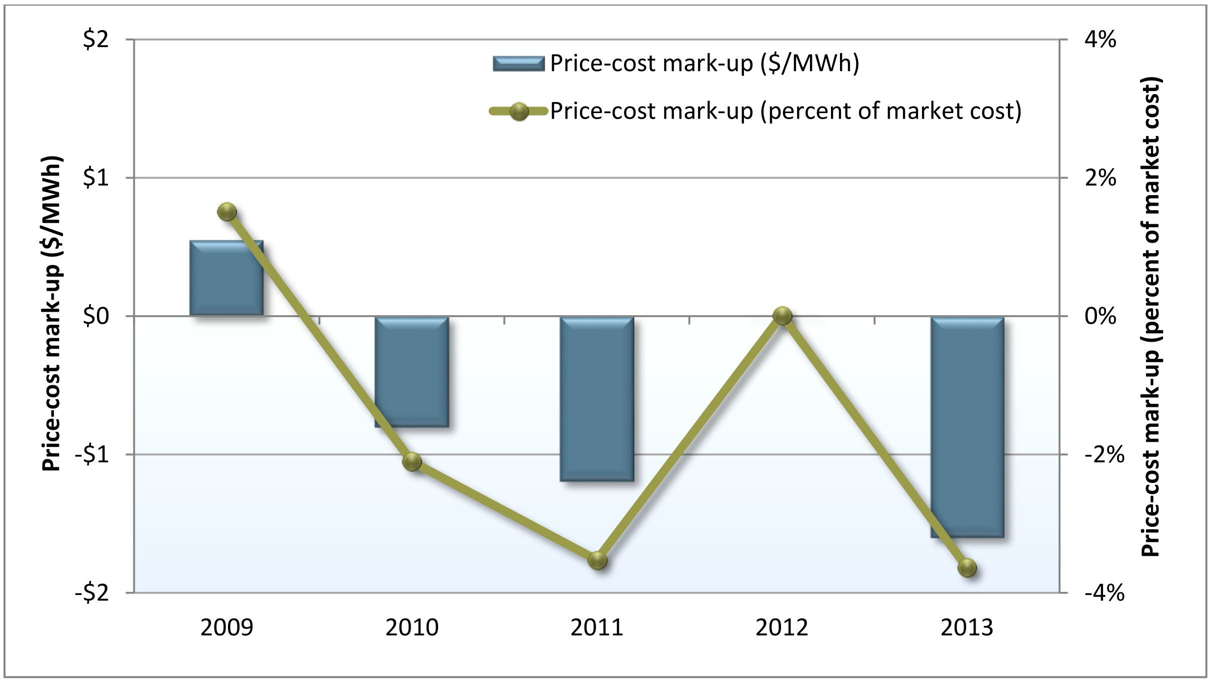
[6] DMM calculates the price-cost mark-up index as the percentage difference between actual market prices and prices resulting under this competitive baseline scenario. For example, if market prices averaged $55/MWh during a month and the competitive baseline price was $50/MWh, this would represent a price-cost mark-up of 10 percent.

[7] The wholesale costs of energy are pro-rated calculations of the day-ahead, hour-ahead and real-time prices weighted by the corresponding schedules. For the months of November and December, the wholesale cost is based on the day-ahead and hour-ahead prices alone due to data related issues.

slight drop in the price-cost mark-up in 2013 and is consistent with the slightly negative price-cost mark-ups observed in 2010 and 2011. Slightly negative price-cost mark-ups can reflect the fact that some suppliers bid somewhat lower than their default energy bids – which include a 10 percent adder above estimated marginal costs. In 2012, the overall price-cost mark-up was slightly positive (0.01 percent).

The price-cost mark-up and other analyses in this report indicate that prices have been extremely competitive, overall, since implementation of the nodal market in 2009.

**Figure 1.2 Price-cost mark-up (2009-2013)**




## 1.2 Energy market performance

This section assesses the efficiency of the energy market based on an analysis of the system energy component of day-ahead, hour-ahead and real-time market prices. Price convergence between these markets may help promote efficient commitment of internal and external generating resources.

Average real-time price levels were similar in both the day-ahead and real-time markets for the quarter. In December, average hour-head prices were driven higher than real-time and day-ahead prices, in part, due to load adjustments in response to unseasonably cold weather. Figure 1.3 and Figure 1.4 show monthly system marginal energy prices for peak and off-peak periods, respectively.

**Figure 1.3 Average monthly on-peak prices – system marginal energy price**

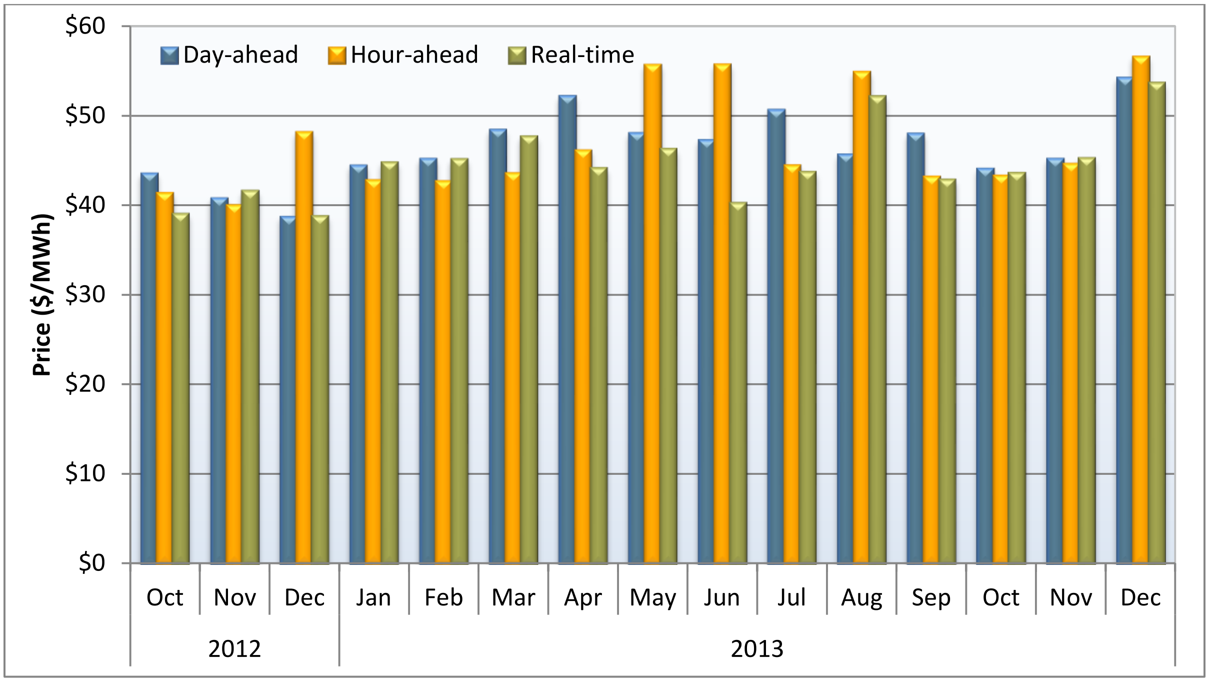
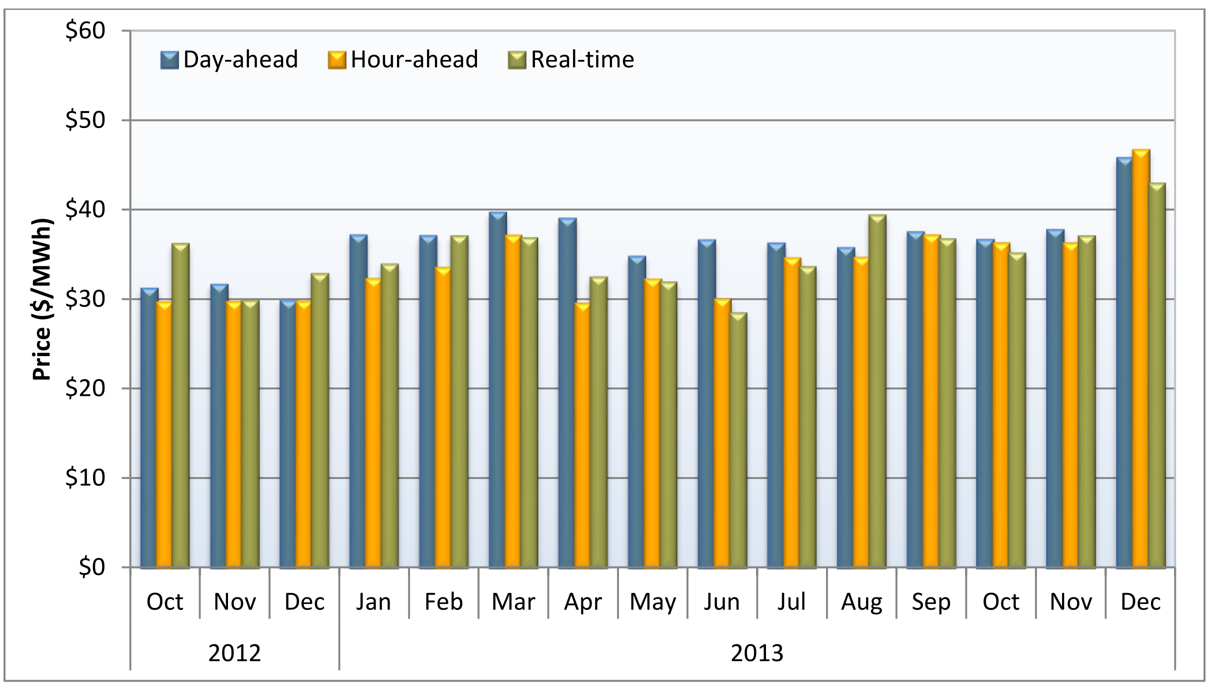



**Figure 1.4 Average monthly off-peak prices – system marginal energy price**



- On a monthly average basis, peak hour-ahead prices were less than $1/MWh lower than day-ahead prices in October and November, but were higher in December by about $2/MWh. Higher values for peak hours in December were due to a relatively small number of hours (between 30 and 40) in which hour-ahead prices significantly exceeded day-ahead prices. When these hours are excluded, the results indicate a greater convergence between the day-ahead and hour-ahead prices. Off-peak hour-ahead prices were less than about $1.50/MWh lower than day-ahead for October and November, but were about $1/MW higher in December.
- In October and December, average system prices in the 5-minute real-time market were lower than day-ahead market prices by about $0.50/MWh during peak periods. In November, prices were very consistent between the markets. Real-time prices in off-peak periods were lower than day-ahead prices in all months of the quarter, peaking in December at about a $3/MWh difference.
- In December, peak period average system prices in the 5-minute real-time market were lower than prices in the hour-ahead market by about $3/MWh. In October and November, real-time and hour-ahead prices were very similar. Off-peak peak prices in the 5-minute real-time market were lower than hour-ahead in October and December by about $1/MWh and $3.75/MWh, respectively, whereas November prices were about $0.80/MWh higher.

Figure 1.5 and Figure 1.6 illustrate the improvement in price convergence in the fourth quarter. In Figure 1.5, the average hourly hour-ahead prices for the fourth quarter were similar to day-ahead prices in all hours. Real-time prices were also similar to hour-ahead prices in most hours with the exception of hours ending 7 and 8 when real-time prices exceeded hour-ahead prices by about $8/MWh. Day-ahead prices were similar to real-time prices in most hours, but tended to exceed real-time prices in the late morning and early afternoon hours by nearly $3/MWh as net load decreased, in part, due to solar generation.[8]

Figure 1.6 highlights the magnitude of the system marginal price differences for all hours in the day-ahead and real-time markets based on a simple average of price differences in these markets. The green line shows that the simple average price difference between the day-ahead and real-time markets. While day-ahead and real-time prices diverged significantly from April through August, the chart shows that the simple average price differences improved since September.

Figure 1.6 also shows the average absolute price difference between the day-ahead and real-time markets (gold line).[9] Even though the simple average was near zero for most of the period shown, the absolute average difference indicated that the overall magnitude of the differences was higher. Thus, the simple average masks the nature of the differences indicating convergence overall, when there are offsetting positive and negative differences in different hours. In the fourth quarter, the absolute average difference was about $8/MWh, down from $12/MWh in the previous quarter. This is the lowest absolute quarterly price difference since the first quarter of 2012.

[8] Net load is the hourly total load less the hourly production of wind and solar generating facilities.

[9] 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 1.6 if both negative and 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 1.5 Hourly comparison of system marginal energy prices (October – December)**

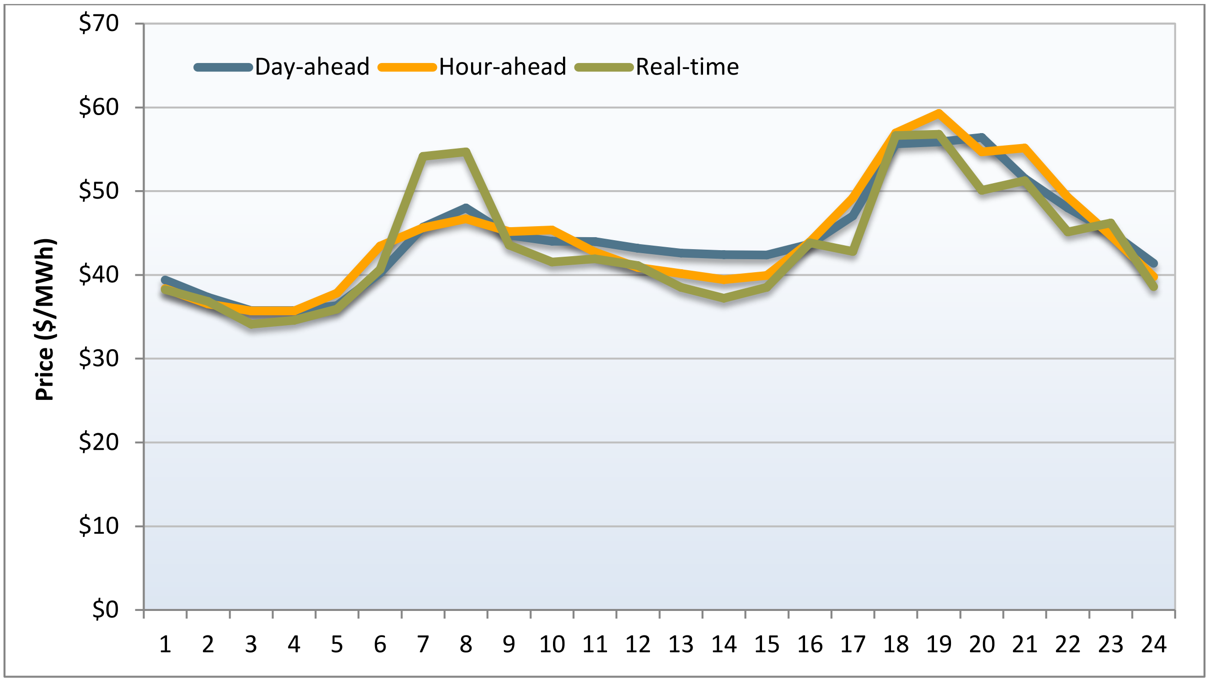
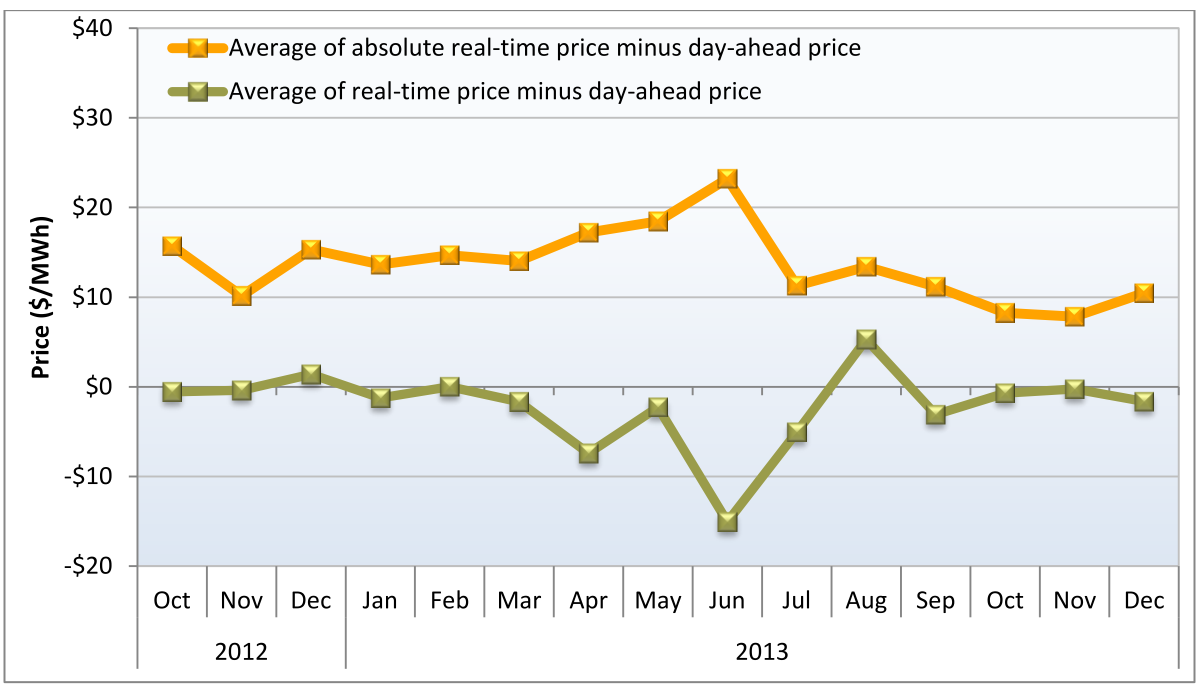



**Figure 1.6 Difference in monthly day-ahead and real-time prices based on simple average and absolute average of price differences (system marginal energy, all hours)**

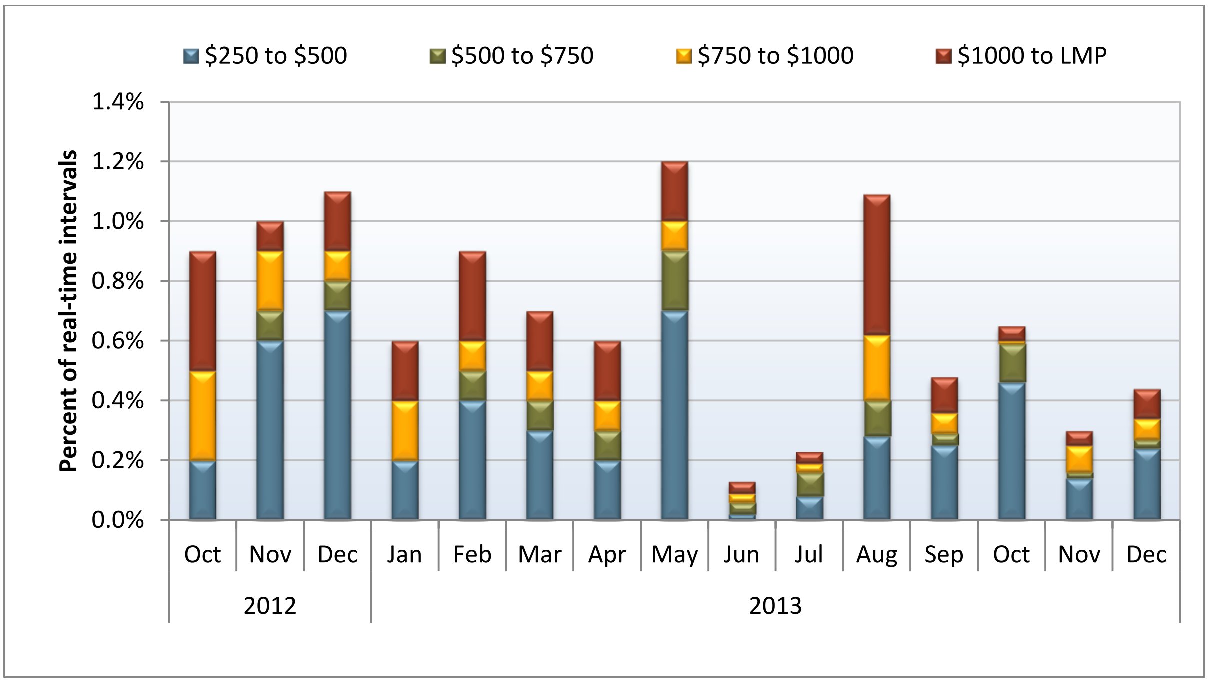


## 1.3 Real-time price variability

Historically, real-time market prices have been highly variable. This section highlights real-time market prices and provides explanations of real-time price variation.

Figure 1.7 shows the frequency of price spikes that occur in the real-time market. In the fourth quarter, the frequency was about 0.5 percent, slightly below the value in the third quarter and continuing a downward trend in real-time price spikes. As in the previous three quarters, the ISO continued to increase the flexible ramping constraint requirements during the evening ramping hours. This has contributed to the decline in the frequency of real-time price spikes.

**Figure 1.7 Frequency of price spikes (all LAP areas)**



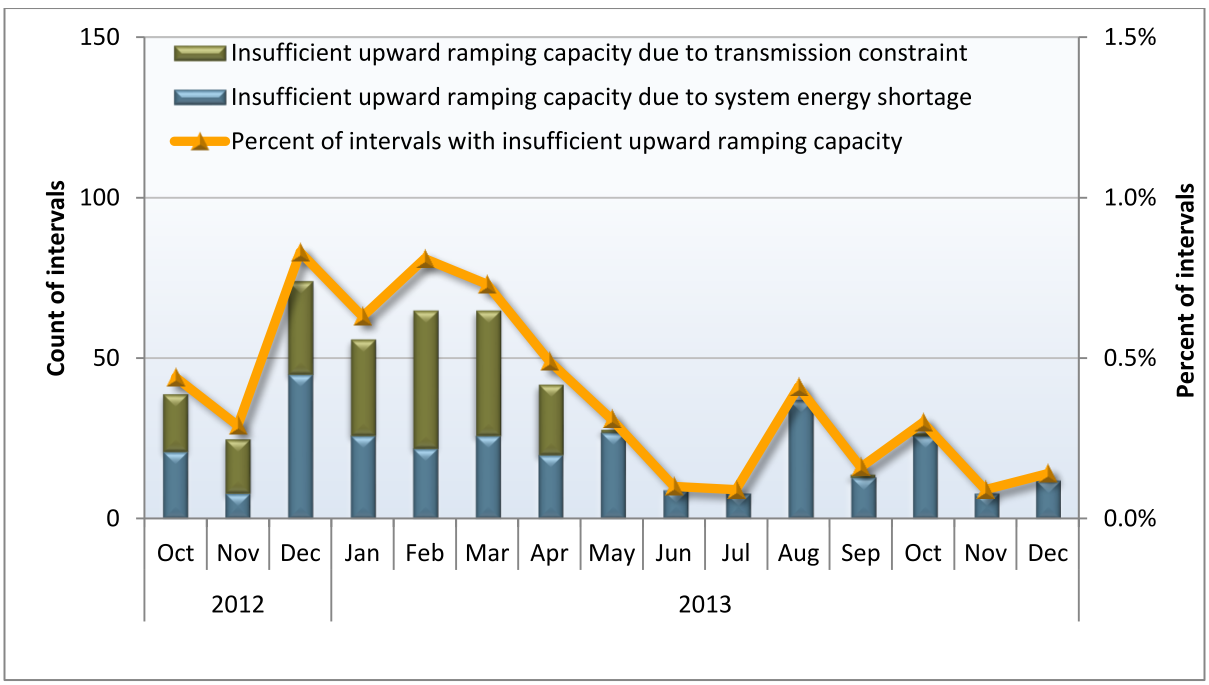

Power balance constraint relaxation at the interval level can significantly affect average real-time market prices over longer periods of time, such as a month. This is particularly true when positive power balance constraint relaxation events occur, often resulting in system prices at $1,000/MWh. Furthermore, average prices are also affected by negative power balance constraints, due to over-generation, resulting in prices at -$30/MWh.

The number of power balance constraint relaxation intervals resulting from insufficient upward ramping capacity also continued to decrease in the fourth quarter compared to previous quarters and from the fourth quarter of 2012, as seen in Figure 1.8. Power balance constraint relaxations can also occur in the presence of congestion. In the third and fourth quarters, only 2 percent of the power balance constraint relaxation events resulted from extreme regional congestion compared to about 30 percent in the second quarter and about 60 percent in the first quarter.[10]

The number of power balance constraint relaxation events from infeasible decremental energy continued to be low in the fourth quarter, as shown in Figure 1.9. This is a result of a lower share of real-time generation from variable resources, particularly wind, and atypically low hydro-electric generation. Almost all of the decremental power balance constraint relaxations resulted from system-wide over-generation conditions.

Around 55 percent of high real-time prices were caused by congestion or a combination of power balance constraint relaxation and congestion in the fourth quarter. About 50 percent of these prices can be attributed to congestion alone, while about 40 percent were a result of system-wide power balance relaxation. High priced bids resulted in only 8 percent of the high prices in the quarter. Figure 1.10 highlights the different factors driving high real-time prices at a regional level. The prices in this figure include all intervals in which the real-time price for a load aggregation point approached the bid cap.[11]

**Figure 1.8 Relaxation of power balance constraint because of insufficient upward ramping capacity**




[10] Sometimes extreme congestion on constraints within the ISO system can limit the availability of significant amounts of supply. This can cause system-wide limitations in upward ramping capacity, and thus cause relaxations in the power balance constraint. In these cases, the cost of relaxing the system power balance constraint is less expensive than the cost of relaxing the internal constraint. Therefore, the system power balance constraint is relaxed to deal with upward ramping limitations in the congested portion of the ISO system. This is primarily true for large regional constraints. For very small local constraints, the opposite is true. In the case of local constraints, the cost of relaxing the local constraint is less expensive than the cost of relaxing the system power balance constraint. Thus, the local constraint is relaxed instead of the power balance constraint.

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

**Figure 1.9 Relaxation of power balance constraint because of insufficient downward ramping capacity**

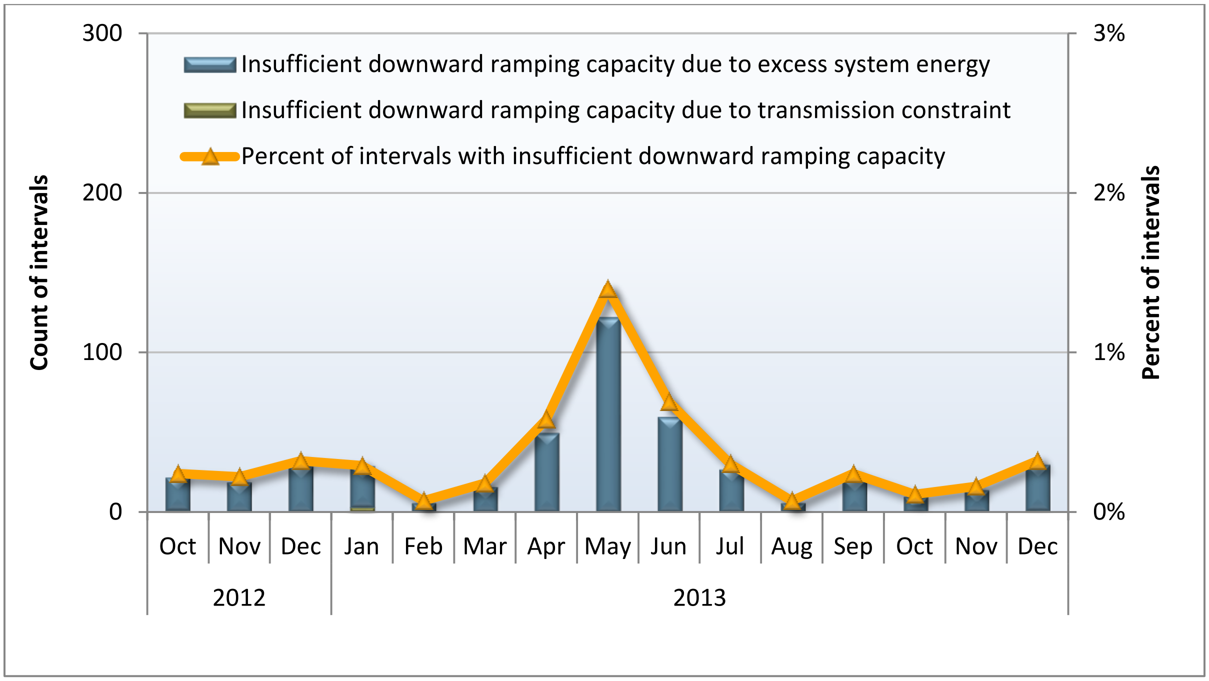
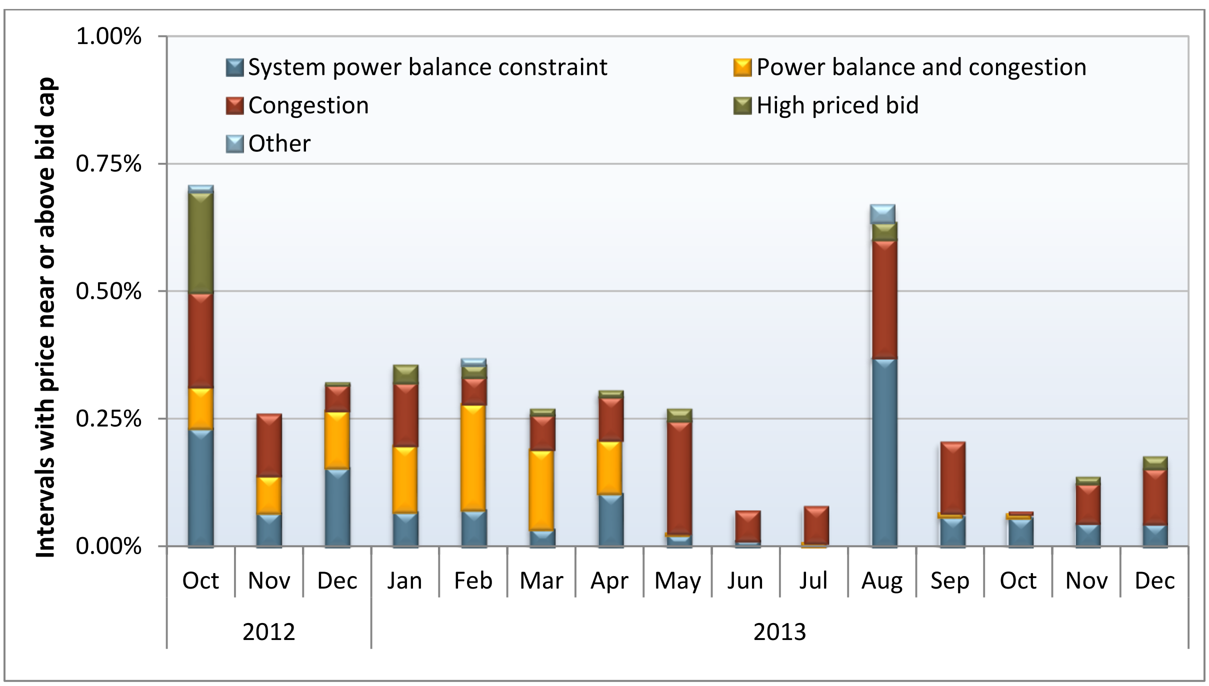
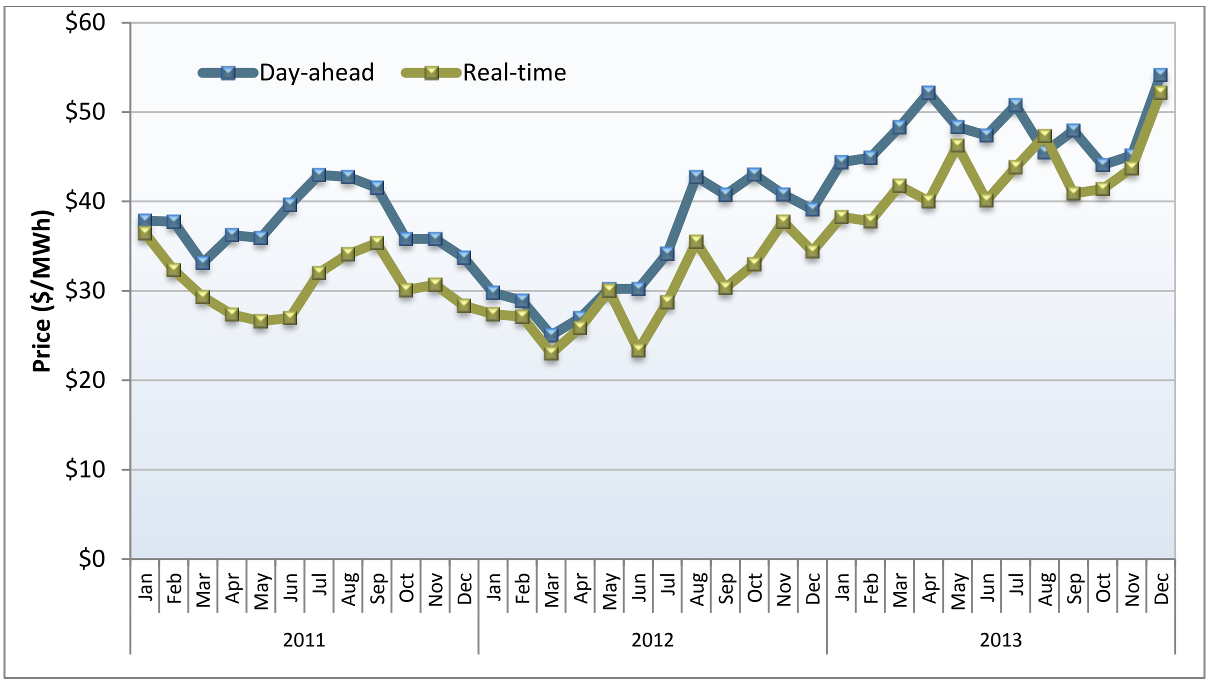



**Figure 1.10 Factors causing high real-time prices**



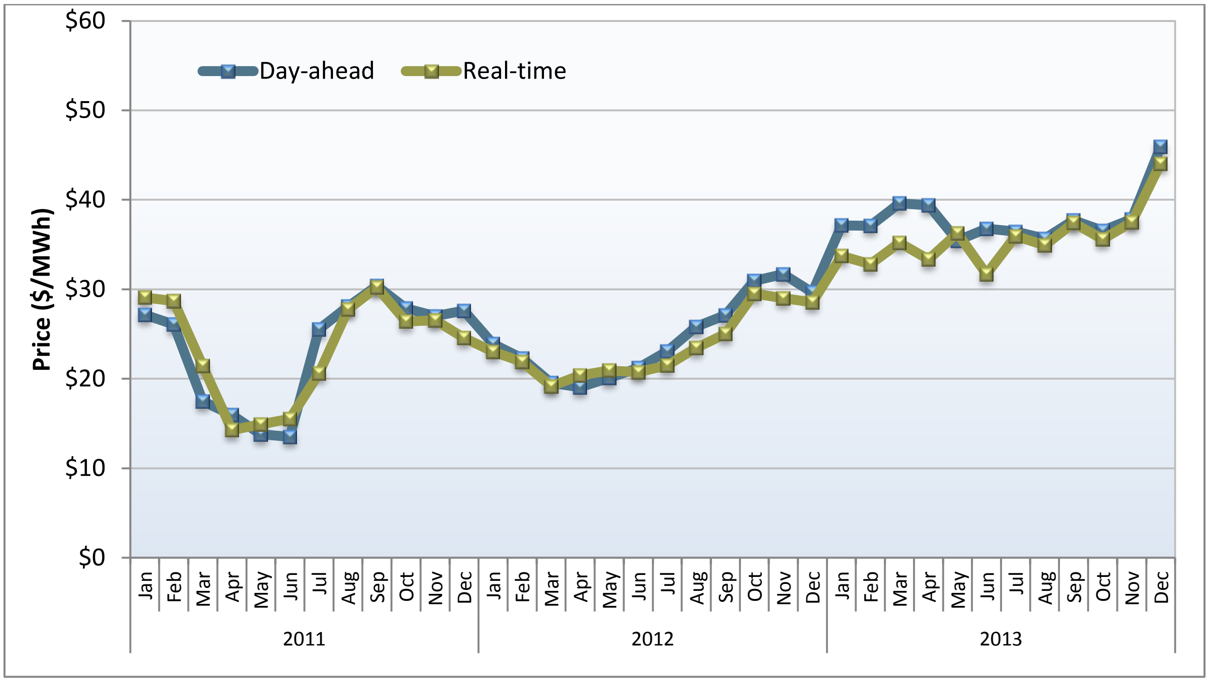
As shown in previous reports, controlling for power balance constraint relaxations can be helpful in showing the underlying nature of the price relationship between market prices.[12] After removing all hours with real-time power balance constraint relaxations between January 2011 and December 2013, the average real-time system marginal energy prices in peak hours has been consistently lower than the average day-ahead peak prices (see Figure 1.11), with the exception of August 2013. In the fourth quarter, the greatest price convergence occurred between the two markets since the beginning of 2011. Off-peak prices in the day-ahead and real-time markets, as seen in Figure 1.12, have been much closer, with the exception of the first four months of 2013.

**Figure 1.11 Peak average system marginal energy prices excluding power balance constraint**




[12] For further information see *2010 Annual Report on Market Issues and Performance*, Department of Market Monitoring, Section 8.6, http://www.caiso.com/2b66/2b66baa562860.pdf.

**Figure 1.12 Off-peak average system marginal energy prices excluding power balance constraint**




## 1.4 Flexible ramping constraint performance

This section highlights the performance of the flexible ramping constraint over the last quarter. Key trends include the following:

- Flexible ramping costs were around $5 million in the fourth quarter, up from around $3 million in the third quarter. Flexible ramping costs in 2013 were around $25 million, up from $19 million in 2012.[13]
- ISO operators increased the flexible ramping requirement consistently during the morning and evening ramping periods in the fourth quarter, averaging nearly 650 MW during ramping hours. This caused both the procurement level and flexible ramping shadow prices to remain high. This pattern was similar to the flexible ramping requirements in the previous quarter.
- Overall, more than 75 percent of flexible ramping capacity was procured in the northern part of the state, which can be stranded when congestion occurs in the southern part of the state. Such congestion occurred much less frequently in the fourth quarter than it had in prior quarters.

[13] In November 2012, the ISO implemented changes to the settlement rules for the flexible ramping constraint. These changes have been incorporated in the revenue calculations. See the following document for further details: http://www.caiso.com/Documents/October242012Amendment-ImplementFlexibleRampingConstraint-DocketNoER12-50-000.pdf.

### Background

In December 2011, the ISO began enforcing the flexible ramping constraint in the upward ramping direction in the 15-minute real-time pre-dispatch market.[14] The constraint is only applied to internal generation and proxy demand response resources and not to external resources. The default requirement is currently set to 300 MW, but it is frequently adjusted to 900 MW, typically in the morning and evening ramping hours.

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. Units committed to meet the flexible ramping requirement can be eligible for bid cost recovery payments in real-time. A procurement shortfall of flexible ramping capacity will occur when 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.[15]

### Payments to the generators

Total payments for flexible ramping resources in the fourth quarter were around $5 million, up from around $3 million in the previous quarter.[16]

Table 1.1 provides a review of monthly flexible ramping constraint activity in the 15-minute real-time market. The table highlights the following:

- The frequency of intervals where the flexible ramping constraint was binding was around 15 percent, up from 10 percent in the previous quarter.
- The frequency of procurement shortfalls was 0.7 percent of all 15-minute intervals in the fourth quarter, up from 0.4 percent in the previous quarter.
- The average shadow price when the flexible ramping constraint was binding was about $31/MWh, down from $38/MWh in the previous quarter.

Most payments for ramping capacity occurred during the evening peak hours. Figure 1.13 shows the hourly flexible ramping payment by technology type during the fourth quarter. As shown in the graph, the highest payment periods were during hours ending 7 and 17 through 19. Natural gas fired capacity accounted for about 46 percent of these payments with hydro-electric capacity accounting for 52 percent.

[14] The flexible ramping constraint is also binding in the second, but not the first, interval of the real-time dispatch market.

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

[16] There are also secondary costs, such as those related to bid cost recovery payments to cover the commitment costs of the units committed by the constraint and additional ancillary services payments. Assessment of these costs is complex and beyond the scope of this analysis.

**Table 1.1 Flexible ramping constraint monthly summary**

| Year | Month | Total payments to generators ($ millions) | 15-minute intervals constraint was binding (%) | 15-minute intervals with procurement shortfall (%) | Average shadow price when binding ($/MWh) |
|---|---|---|---|---|---|
| 2012 | Oct | $0.93 | 9% | 1.0% | $46.01 |
| 2012 | Nov | $0.23 | 4% | 0.5% | $44.85 |
| 2012 | Dec | $1.09 | 9% | 1.6% | $72.60 |
| 2013 | Jan | $1.62 | 14% | 2.2% | $58.61 |
| 2013 | Feb | $3.45 | 19% | 2.0% | $57.90 |
| 2013 | Mar | $4.85 | 19% | 3.1% | $68.39 |
| 2013 | Apr | $2.51 | 15% | 1.6% | $54.62 |
| 2013 | May | $2.73 | 13% | 2.0% | $68.50 |
| 2013 | Jun | $1.95 | 9% | 1.3% | $72.97 |
| 2013 | Jul | $0.90 | 10% | 0.4% | $36.19 |
| 2013 | Aug | $1.51 | 14% | 0.7% | $42.22 |
| 2013 | Sep | $0.84 | 7% | 0.2% | $34.83 |
| 2013 | Oct | $1.90 | 15% | 0.7% | $40.39 |
| 2013 | Nov | $0.80 | 13% | 0.1% | $17.15 |
| 2013 | Dec | $2.64 | 17% | 1.2% | $36.00 |

**Figure 1.13 Hourly flexible ramping constraint payments to generators (October – December)**

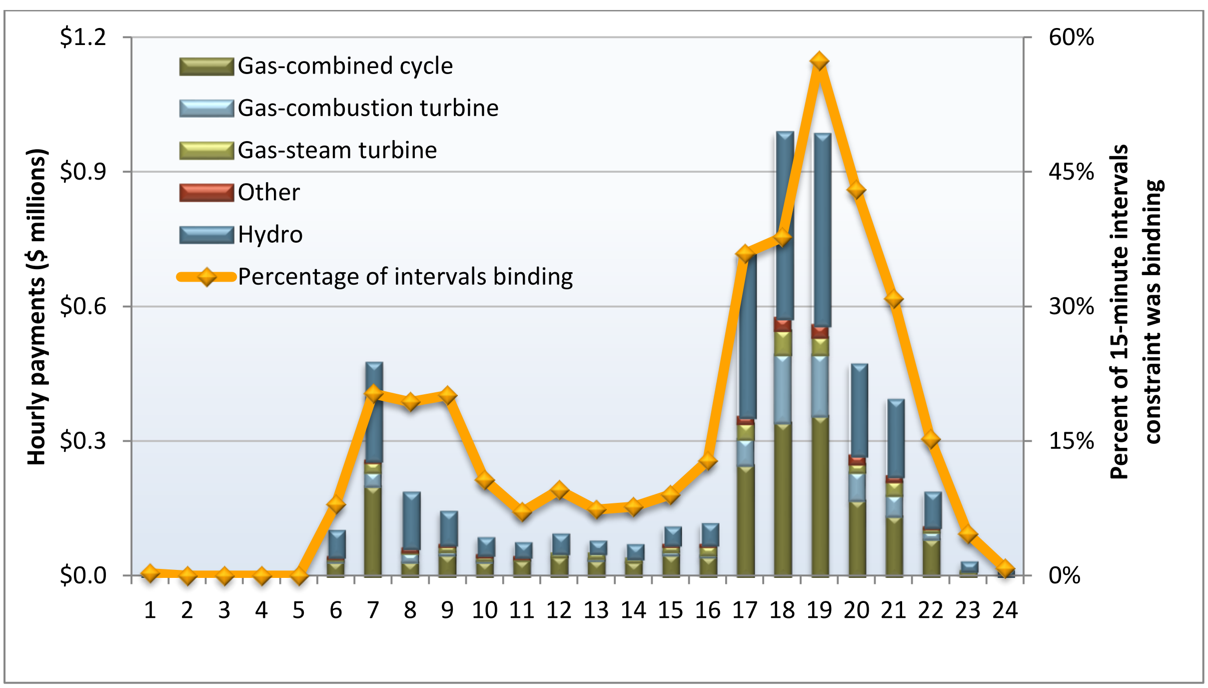
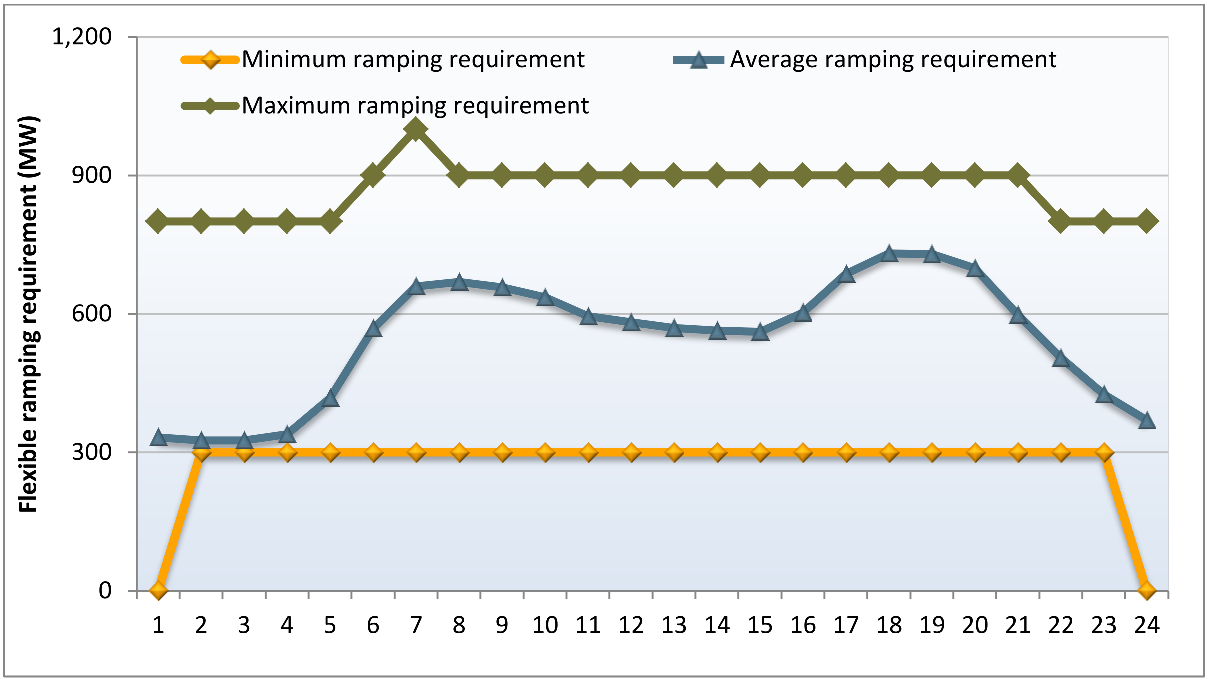


**Figure 1.14 Hourly average flexible ramping requirement values (October – December)**




The ISO continues its efforts to decrease the frequency and volume of exceptional dispatch. As a result, ISO operators use market tools such as the flexible ramping constraint to deal with reliability concerns. Figure 1.14 shows the hourly average flexible ramping requirement values in the fourth quarter. The hourly ramping requirement ranged from a minimum of 0 MW to a maximum of 1,000 MW. On average, the requirement was set to around 300 MW in the pre-dawn early morning hours and about 650 MW in the morning and evening load-ramping hours. This pattern was similar to the flexible ramping requirements in the previous quarter, although there appears to be an increase in levels during the morning ramp and evening peak hours.

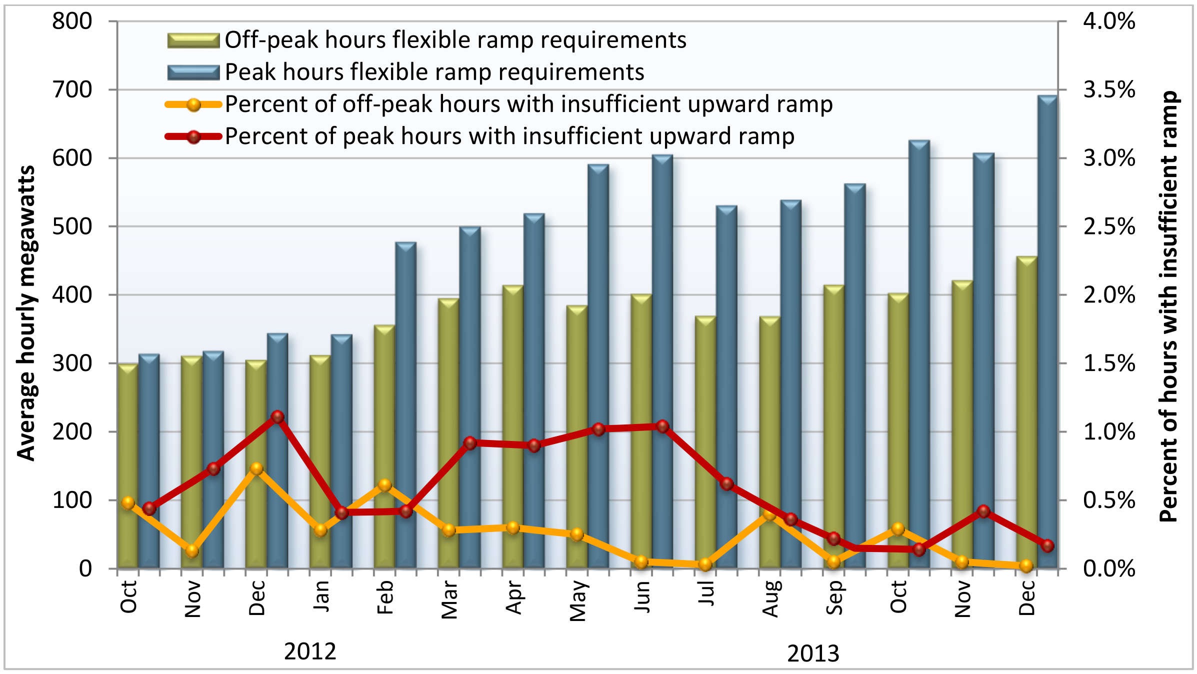
### Real-time utilization of flexible ramping capacity

One measure of the flexible ramping constraint's potential effectiveness in procuring ramping capacity when needed is the real-time utilization of this ramping capacity. DMM uses the ISO's methodology along with settlement data to calculate flexible ramping capacity utilization. This 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 of flexible ramping capacity is a function of prevailing system conditions, including load and generation levels. The average utilization of procured flexible ramping capacity ranged from 15 percent in the early morning to 45 percent in the evening. This pattern was similar to the previous quarter and the overall pattern in 2012.

Another measure of flexible ramping constraint effectiveness is the relationship between the frequency of upward ramping infeasibilities in the real-time market and the flexible ramping constraint requirement level. Figure 1.15 shows the monthly average flexible ramping requirement as well as the percent of insufficient ramp in peak and off-peak hours. The green bars represent flexible ramp requirements during off-peak hours; the blue bars represent flexible ramp requirements during peak hours. Peak and off-peak upward ramp shortage frequencies are represented by the red and yellow lines, respectively.

Since February 2013, the ISO has increased flexible ramping requirements for peak hours to more than 600 MW and off-peak requirements to about 400 MW from about 300 MW in earlier months. Fourth quarter flexible ramping requirements were higher than all prior quarters in both peak and off-peak hours. The frequency of insufficient upward ramp infeasibilities was generally highest during peak hours, but has decreased substantially as the flexible ramping requirement increased.

**Figure 1.15 Flexible ramping requirements and frequency of insufficient ramp intervals**



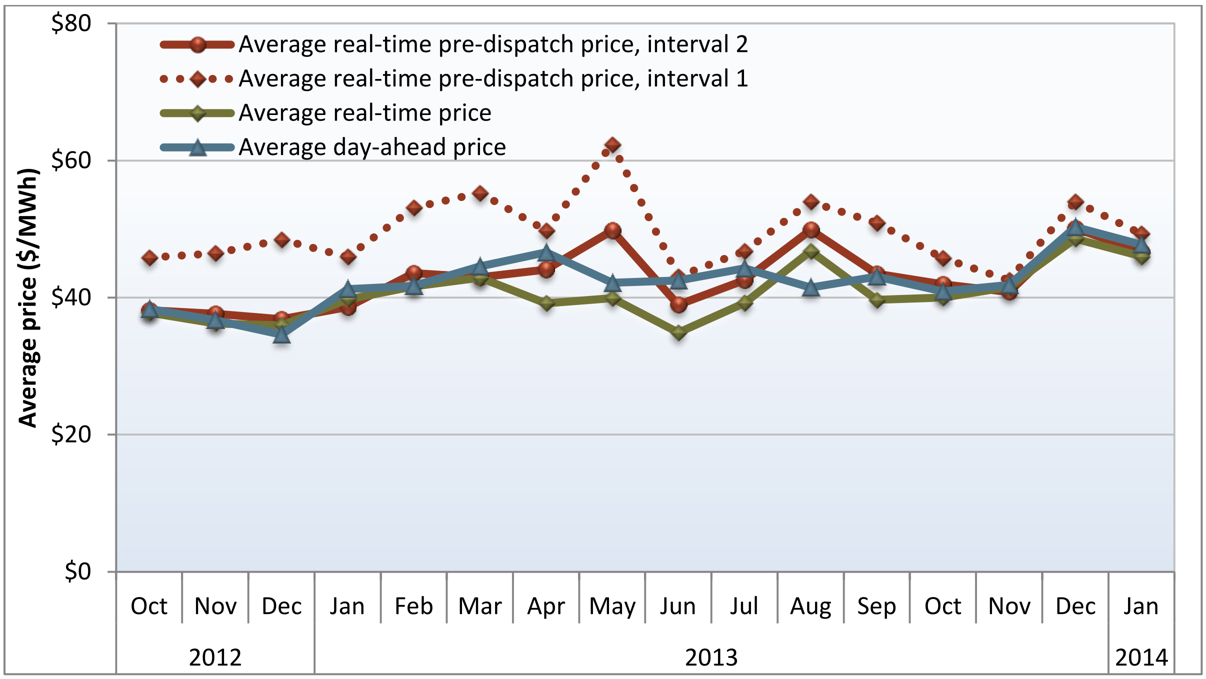

### The flexible ramping constraint and 15-minute real-time pre-dispatch prices

In spring 2014, the ISO is scheduled to implement a new 15-minute market. Specifically, the ISO is proposing to change inter-tie scheduling and settlement from an hourly to a 15-minute basis, and establish a 15-minute settlement for internal resources and convergence bids. The ISO proposal also includes retaining the existing 5-minute dispatch to provide real-time balancing.

The ISO's current 15-minute real-time pre-dispatch market already produces energy prices for each 15-minute interval which are non-binding (i.e., not used in any financial settlement). Analysis of current and past 15-minute real-time pre-dispatch prices is informative, but may not predict how the new 15-minute market prices would behave. In DMM's 2013 third quarter report, DMM provided a comparison of these 15-minute non-binding prices to day-ahead and 5-minute real-time prices. This comparison showed that these 15-minute prices had been consistently significantly higher than day-ahead and real-time prices dating back to at least 2012.

When the changes to the 15-minute market are implemented, market prices will actually be based on the second 15-minute interval of the 15-minute process, which looks out several intervals over two and a half hours. As illustrated in Figure 1.16, average second interval 15-minute prices (represented by the solid red line) have been consistently lower than first interval 15-minute prices (dashed red line). Moreover, the second interval prices of the 15-minute process do not appear to be consistently higher than either day-ahead or real-time prices. Prices in this second 15-minute interval have fewer price spikes driven by the flexible ramping constraint than the first 15-minute interval, since there is more ramping capacity and flexibility available over this additional 15 minute period.

**Figure 1.16 Average system marginal 15-minute real-time pre-dispatch compared to day-ahead and real-time prices**




The ISO is prepared to closely monitor, manage and modify operating practices as the new 15-minute market is implemented to help achieve an efficient balance between the day-ahead, 15-minute and 5-minute market prices. For example:

- The requirement that is set for flexible ramping capacity will be closely monitored and adjusted if necessary as the new 15-minute market is implemented. The ISO may consider lowering the requirement if analysis shows that doing so would not cause excessively frequent power balance constraint relaxation.
- The ISO will also monitor and adjust the use of load adjustments in the 15-minute market. Grid operators may address reliability concerns by increasing the projected system load in the 15-minute pre-dispatch process to ensure commitment of additional short-start units. This can impact the 15-minute prices, which will be used for settlement. Thus, the use of load adjustments and the impact it has on pricing will be closely monitored by the ISO as it implements the new 15-minute market.
- Another factor that is expected to help mitigate extreme price spikes with implementation of the new 15-minute market is a reduction in the penalty price for the flexible ramping constraint. The ISO is currently evaluating and considering what, if any, modification to the current value

from $247/MW is appropriate. Lowering the penalty price would tend to reduce the level of extreme price spikes when the constraint is binding.

DMM will continue to work closely with the ISO before and after implementation of the new 15-minute market this spring to monitor market performance and make any adjustments that may be appropriate to manage and ensure the efficiency of this new market.

## 1.5 Congestion

Congestion within the ISO system in the fourth quarter affected overall prices in the day-ahead and real-time markets less than in the third and second quarters. In particular, congestion decreased substantially in the Southern California Edison area. Much of the congestion that did occur was related to adjustments of flows in the Fresno area (Helms Pump operations), retirement of the San Onofre Nuclear Generating Station (SONGS) units 2 and 3, and other generation and transmission events.

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.

Congestion on constraints in Southern California often increases prices within the Southern California Edison and San Diego Gas & Electric areas, but decreases prices in the Pacific Gas and Electric area. Congestion in Northern California often has the opposite effect. Also, the price impacts on individual constraints can differ between the day-ahead and real-time markets, as seen in the following sections.

### 1.5.1 Congestion impacts of individual constraints

#### Day-ahead congestion

Both the frequency and impact of congestion in the day-ahead market decreased in the fourth quarter. Table 1.2 provides information related to the frequency and magnitude of day-ahead market congestion.

In the PG&E area, 30880_HENTAP2 _230_30900_GATES_230_BR_2 _1 was the most congested constraint in the day-ahead market. This constraint was binding in nearly 10 percent of hours. During these hours, prices in the PG&E area increased by about $0.47/MWh and prices in the SCE and SDG&E areas did not change. This constraint, located in the Fresno area, is heavily dependent on imports from the 230 kV system through the McCall, Herndon, Henrietta banks, and local hydro generation. The constraint is adjusted to protect thermal overload from the contingency loss of the Panoche-Helms 230 kV line. The second most congested constraint increasing prices in the PG&E area was SLIC 2100489_PVDV_Out_EDLG at about 8 percent of hours. This constraint, located in the SDG&E area, was activated to protect the Lugo-Victorville 500 kV line for the loss of the Eldorado-Lugo 500 kV line during the planned outage on the Palo Verde to Devers 500 kV line.

In the SCE area, the Barre-Lewis nomogram and the 24087_MAGUNDEN_230_24153_VESTAL _230_BR_2_1 constraint were binding in the fourth quarter. The Barre-Lewis nomogram was congested in about 3 percent of hours, down from about 5 percent in the previous quarter. When congestion occurred on this constraint, prices in the SCE area increased by about $0.55/MWh, prices in the SDG&E area increased by $0.19/MWh, and prices in the PG&E area decreased by about $0.42/MWh. The

24087_MAGUNDEN_230_24153_VESTAL constraint was binding in about 1 percent of the hours. When congestion occurred on this constraint, prices in the SCE area increased by about $4/MWh with no impact on either SDG&E area or PG&E area prices.

**Table 1.2 Impact of congestion on day-ahead prices by load aggregation point in congested hours**

| | | Frequency | | | | Q1 | | | Q2 | | | Q3 | | | Q4 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Area | Constraint | Q1 | Q2 | Q3 | Q4 | PG&E | SCE | SDG&E | PG&E | SCE | SDG&E | PG&E | SCE | SDG&E | PG&E | SCE | SDG&E |
| PG&E | 30880_HENTAP2 _230_30900_GATES _230_BR_2 _1 | | | | 9.7% | | | | | | | | | | $0.47 | | |
| | SLIC 2100489_PVDV_Out_EDLG | | | | 8.2% | | | | | | | | | | $0.38 | -$0.24 | -$0.71 |
| | PATH15_BG | 7.7% | 9.8% | 0.5% | 2.2% | $1.68 | -$1.43 | -$1.43 | $1.60 | -$1.32 | -$1.32 | $2.26 | -$1.86 | -$1.86 | $2.34 | -$1.86 | -$1.86 |
| | 30790_PANOCHE _230_30900_GATES _230_BR_1 _1 | | | 0.7% | 0.5% | | | | | | | $1.08 | -$0.84 | -$0.84 | $1.90 | -$1.45 | -$1.45 |
| | SLIC 2165838 ELDORADO_BUS_NG | | | | 0.4% | | | | | | | | | | $0.86 | -$0.65 | -$0.91 |
| | 30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1 | | 1.9% | 28.2% | | | | | $0.57 | -$0.45 | -$0.45 | $0.59 | -$0.42 | -$0.42 | | | |
| | 6110_TM_BNK_FLO_TMS_DLO_NG | | 0.6% | 19.0% | | | | | $0.39 | | | $0.94 | -$0.88 | -$0.88 | | | |
| | LOSBANOSNORTH_BG | | 1.2% | 0.1% | | | | | $2.74 | -$2.09 | -$2.09 | $1.66 | -$1.60 | -$1.60 | | | |
| | 30735_METCALF _230_30042_METCALF _500_XF_13 | | 1.3% | | | | | | $2.26 | -$1.92 | -$1.92 | | | | | | |
| SCE | BARRE-LEWIS_NG | 23.9% | 5.3% | 5.2% | 3.1% | -$1.32 | $1.84 | $0.21 | -$1.06 | $1.29 | $0.91 | -$0.40 | $0.51 | $0.15 | -$0.42 | $0.55 | $0.19 |
| | 24087_MAGUNDEN_230_24153_VESTAL _230_BR_2 _1 | | 0.8% | 22.8% | 1.3% | -$0.11 | $2.14 | -$0.11 | | | | -$0.30 | $0.93 | -$0.30 | | $3.97 | |
| | SCE_PCT_IMP_BG | 71.2% | 51.2% | 16.3% | | -$3.93 | $4.85 | -$3.89 | -$3.66 | $4.29 | -$3.63 | -$2.00 | $2.20 | -$1.89 | | | |
| | PATH26_BG | 1.1% | | 1.9% | | -$1.83 | $1.47 | $1.47 | | | | -$3.08 | $1.97 | $1.97 | | | |
| | SLIC 2146366_VINCENTBUS | | | 0.3% | | | | | | | | -$3.14 | $2.18 | $2.57 | | | |
| | SLIC 2088287_BARRE-LEWIS_NG | 0.7% | | | | -$1.28 | $2.13 | | | | | | | | | | |
| SDG&E | SLIC 2100489_PVDV_Out_LGVN | | | | 5.1% | | | | | | | | | | -$1.39 | $0.99 | $1.27 |
| | SOUTHLUGO_RV_BG | 0.4% | 3.3% | 0.7% | 4.1% | -$3.24 | $2.47 | $4.42 | -$5.15 | $3.56 | $5.43 | -$4.60 | $2.94 | $4.33 | -$3.68 | $2.58 | $3.69 |
| | SLIC 2138237 TL50003_CFE_NG | | | | 2.4% | | | | | | | | | | | | $12.13 |
| | 22372_KEARNY _69.0_22496_MISSION _69.0_BR_1 _1 | | | | 1.9% | | | | | | | | | | | | $5.09 |
| | 22831_SYCAMORE_138_22117_CARLTHT2_138_BR_1 _1 | | | | 1.4% | | | | | | | | | | | | $6.63 |
| | 22828_SYCAMORE_69.0_22756_SCRIPPS _69.0_BR_1 _1 | | 0.1% | 1.5% | 1.4% | | | | | | $1.18 | | | $1.31 | | | $0.94 |
| | SLIC 2164068 TL50001_NG | | | | 1.3% | | | | | | | | | | | | $11.65 |
| | 7820_TL 230S_OVERLOAD_NG | | 13.6% | | 1.0% | | | | -$1.01 | | $7.69 | -$0.59 | | $5.31 | -$0.22 | | $2.23 |
| | 22500_MISSION _138_22117_CARLTHT2_138_BR_1 _1 | | | | 0.8% | | | | | | | | | | | | $5.29 |
| | 22831_SYCAMORE_138_22124_CHCARITA_138_BR_1 _1 | | | | 0.6% | | | | | | | | | | | | $8.33 |
| | 22886_SUNCREST_230_22832_SYCAMORE_230_BR_1 _1 | | | | 0.3% | | | | | | | | | | -$0.51 | | $3.53 |
| | T-135 VICTVLUGO_LGVNDLO_NG | | | 4.3% | | | | | | | | -$2.14 | $1.40 | $1.75 | | | |
| | 22768_SOUTHBAY_69.0_22604_OTAY _69.0_BR_2 _1 | | 5.5% | | | | | | | | $0.96 | | | $0.26 | | | |
| | 24138_SERRANO _500_24137_SERRANO _230_XF_2 _P | | 0.9% | 0.3% | | | | | -$3.53 | $1.88 | $7.28 | -$1.08 | $0.64 | $2.41 | | | |
| | SLIC 2148149 TL23050_NG | | | 0.3% | | | | | | | | | | $11.36 | | | |
| | 24016_BARRE _230_24044_ELLIS _230_BR_3 _1 | | 0.7% | 0.1% | | | | | -$0.47 | | $2.34 | -$0.27 | | $1.19 | | | |
| | SDGE_PCT_UF_IMP_BG | | 2.2% | | | | | | -$0.76 | -$0.76 | $7.58 | | | | | | |
| | 24016_BARRE _230_24044_ELLIS _230_BR_1 _1 | | 1.7% | | | | | | -$2.46 | -$0.67 | $15.70 | | | | | | |
| | SLIC 2122013 BARRE-ELLIS-230S_NG | | 1.6% | | | | | | -$0.46 | | $4.91 | | | | | | |
| | 24016_BARRE _230_24044_ELLIS _230_BR_4 _1 | | 1.6% | | | | | | -$0.45 | | $2.17 | | | | | | |
| | 7830_SXCYN_CHILLS_NG | 0.1% | 1.3% | | | | | $0.56 | | | $9.51 | | | | | | |
| | 24138_SERRANO _500_24137_SERRANO _230_XF_1 _P | | 0.8% | | | | | | -$3.02 | $1.67 | $6.02 | | | | | | |
| | SLIC 2077347 TL50003_NG | | 0.6% | | | | | | | | $6.05 | | | | | | |
| | SLIC 2067610 TL50001_NG | | 0.6% | | | | | | | | $12.23 | | | | | | |
| | SLIC 2122013 Barre-Ellis DLO | | 0.6% | | | | | | -$2.54 | | $15.20 | | | | | | |
| | SLIC 2111709_IV500North_BUS_NG | | 0.5% | | | | | | | | $20.93 | | | | | | |
| | SLIC 2122013 Barre-Ellis DLO_20 | | 0.4% | | | | | | -$1.97 | | $12.42 | | | | | | |
| | 22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1 | 3.4% | 0.2% | | | | | $4.27 | | | $6.81 | | | | | | |
| | IVALLYBANK_XFBG | 2.6% | | | | | | $0.84 | | | | | | | | | |
| | SLIC 2051445 TL23050_NG | 2.3% | | | | | | $6.31 | | | | | | | | | |
| | SLIC 2090466 and 2090467 SOL | 2.3% | | | | | | $15.29 | | | | | | | | | |
| | SLIC 2112931 EL CENTRO BK1_NG | 1.2% | | | | | | $5.05 | | | | | | | | | |
| | MIGUEL_BKs_MXFLW_NG | 0.4% | | | | -$1.04 | | $11.65 | | | | | | | | | |
| | 24138_SERRANO _500_24137_SERRANO _230_XF_3 | 0.4% | | | | -$17.48 | | $41.61 | | | | | | | | | |
| | SLIC 2094078 IV Bank81_NG | 0.2% | | | | -$3.54 | | $24.91 | | | | | | | | | |

In the SDG&E area, the constraint with the largest impact was SLIC 2100489_PVDV_Out_LGVN. This constraint was binding in over 5 percent of hours and increased prices in the SDG&E and SCE areas by $1.27/MWh and $0.99/MWh, respectively, while decreasing prices in the PG&E area by $1.39/MWh. This nomogram was activated during the planned outage of the Palo Verde to Devers 500 kV line. Other significant binding constraints in the third quarter included the SOUTHLUGO_RV_BG constraint that protects the South of Lugo path from overloading, the SLIC 2138237 TL50003_CFE_NG line due to an outage of the Ocotillo-Suncrest 500 kV line, and the constraints in place to ensure the system is reliable for the loss of the remaining 500 kV line from Imperial Valley-Miguel.

As shown in Table 1.2, with the exception of the SOUTHLUGO_RV_BG and the Fresno area constraints, internal congestion occurred infrequently and typically had a minimal impact on overall day-ahead energy prices.

### Real-time congestion

Congestion in the real-time market occurs less frequently than in the day-ahead market, but often has a larger price effect in the intervals when it does. Table 1.3 shows the frequency and magnitude of congestion in the fourth quarter.

**Table 1.3 Impact of congestion on real-time prices by load aggregation point in congested intervals**

| | | Frequency | | | | Q1 | | | Q2 | | | Q3 | | | Q4 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Area | Constraint | Q1 | Q2 | Q3 | Q4 | PG&E | SCE | SDG&E | PG&E | SCE | SDG&E | PG&E | SCE | SDG&E | PG&E | SCE | SDG&E |
| PG&E | 30880_HENTAP2 _230_30900_GATES _230_BR_2 _1 | | | | 6.6% | | | | | | | | | | $8.94 | -$6.03 | -$6.03 |
| | PATH15_S-N | 2.1% | 4.5% | 1.0% | 1.0% | $52.05 | -$43.98 | -$43.98 | $17.53 | -$14.29 | -$14.29 | $12.27 | -$9.59 | -$9.59 | $33.48 | -$28.64 | -$28.64 |
| | SLIC 2100489_PVDV_Out_EDLG | | | | 1.0% | | | | | | | | | | $4.74 | -$2.58 | -$9.10 |
| | 30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1 | | 1.0% | 14.4% | 0.8% | | | | $1.21 | -$1.20 | -$1.20 | $1.25 | -$1.47 | -$1.47 | $2.12 | -$2.03 | -$2.03 |
| | T-135 VICTVLUGO_EDLG_NG | | | | 0.3% | | | | | | | | | | $2.67 | -$11.88 | -$5.12 |
| | SLIC 2200107 ELDORADO-LUGO_1_NG | | | | 0.2% | | | | | | | | | | $17.36 | -$12.05 | -$25.38 |
| | SLIC 2165837 ELDORADO_BUS_NG | | | | 0.2% | | | | | | | | | | $19.21 | -$14.33 | -$33.46 |
| | SLIC 2100489_PVDV LGMV_Out_EDLG | | | | 0.1% | | | | | | | | | | $36.70 | -$20.81 | -$83.64 |
| | 6110_TM_BNK_FLO_TMS_DLO_NG | | 1.2% | 1.9% | | | | | $7.51 | -$3.80 | -$3.80 | $5.63 | -$6.85 | -$6.85 | | | |
| | 30055_GATES1 _500_30900_GATES _230_XF_11_P | | 0.2% | 0.4% | | | | | $7.58 | -$6.64 | -$6.64 | $3.52 | -$3.50 | -$3.50 | | | |
| | LBN_S-N | | 0.9% | 0.2% | | | | | $28.13 | -$23.22 | -$23.22 | $43.77 | -$34.82 | -$34.82 | | | |
| | 30790_PANOCHE _230_30900_GATES _230_BR_1 _1 | | | 0.2% | | | | | | | | $14.19 | -$10.92 | -$10.92 | | | |
| | TRACY500_BG | | 2.3% | | | | | | -$9.51 | $7.42 | $7.42 | | | | | | |
| | 30735_METCALF _230_30042_METCALF _500_XF_13 | | 2.2% | | | | | | $29.35 | -$31.17 | -$31.17 | | | | | | |
| | 30735_METCALF _230_30750_MOSSLD _230_BR_1 _1 | | 0.6% | | | | | | $23.95 | -$23.75 | -$23.75 | | | | | | |
| | T-135 VICTVLUGO_PVDV_NG | 0.1% | 0.01% | | | $33.40 | -$38.73 | | $1.06 | | -$1.57 | | | | | | |
| SCE | BARRE-LEWIS_NG | 5.4% | 0.2% | 2.2% | 0.5% | -$8.62 | $5.60 | -$6.64 | -$5.70 | $5.30 | $1.97 | -$2.60 | $2.20 | | -$3.30 | $1.80 | $9.52 |
| | SCIT_BG | | | | 0.4% | | | | | | | | | | -$55.61 | $48.06 | $51.52 |
| | NSONGS_BG | | | | 0.1% | | | | | | | | | | $28.54 | $37.71 | -$314.02 |
| | 22260_ESCNDIDO_230_22844_TALEGA _230_BR_1 _1 | | | | 0.1% | | | | | | | | | | $4.22 | $6.44 | -$47.72 |
| | SYLMAR-AC_BG | | | | 0.02% | | | | | | | | | | -$30.89 | $32.72 | -$75.91 |
| | SCE_PCT_IMP_BG | 10.0% | 2.2% | 2.4% | | -$33.78 | $41.04 | -$33.48 | -$47.91 | $58.30 | -$47.41 | -$16.30 | $17.84 | -$13.31 | | | |
| | PATH26_N-S | 2.0% | 1.2% | 1.0% | | -$23.96 | $19.63 | $19.63 | -$72.06 | $58.65 | $58.65 | -$25.07 | $17.70 | $17.70 | | | |
| | 24155_VINCENT _230_24091_MESA CAL_230_BR_1 _1 | | 0.4% | | | | | | -$11.16 | $9.31 | $8.74 | | | | | | |
| | PATH15_N-S | 0.03% | | | | -$56.37 | $47.06 | $47.06 | | | | | | | | | |
| SDG&E | SOUTH_OF_LUGO | | 0.4% | 0.3% | 2.3% | | | | -$20.66 | $16.05 | $22.56 | -$81.01 | $57.91 | $93.04 | -$18.33 | $14.22 | $19.72 |
| | 7820_TL 230S_OVERLOAD_NG | 0.4% | 2.6% | 1.6% | 0.5% | | | $29.90 | -$1.75 | | $34.48 | -$4.82 | | $36.06 | -$4.34 | | $44.99 |
| | SLIC 2164068 TL50001_NG | | | | 0.4% | | | | | | | | | | | | $43.04 |
| | SLIC 2138237 TL50003_CFE_NG | | | | 0.3% | | | | | | | | | | | | $68.72 |
| | 22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1 | | | | 0.3% | | | | | | | | | | | | -$23.84 |
| | 22886_SUNCREST_230_22832_SYCAMORE_230_BR_1 _1 | | | | 0.2% | | | | | | | | | | -$6.89 | | $46.92 |
| | 22708_SANLUSRY_69.0_22712_SANLUSRY_138_XF_3 | | | | 0.1% | | | | | | | | | | | | -$15.17 |
| | SLIC 2161499 DEVERS-VISTA 2_NG | | | 0.34% | | | | | | | | -$46.58 | $33.15 | $76.75 | | | |
| | 24138_SERRANO _500_24137_SERRANO _230_XF_2 _P | 0.1% | 0.4% | 0.3% | | -$37.04 | | $92.29 | -$23.63 | $14.79 | $51.60 | -$8.27 | $6.54 | $18.73 | | | |
| | 24138_SERRANO _500_24137_SERRANO _230_XF_3 | 0.1% | | 0.2% | | -$32.00 | | $80.19 | | | | -$10.43 | $5.24 | $18.47 | | | |
| | 24138_SERRANO _500_24137_SERRANO _230_XF_1 _P | | | 0.1% | | | | | | | | -$21.51 | $10.35 | $38.20 | | | |
| | 22342_HDWSH _500_22536_N.GILA _500_BR_1 _1 | | 0.2% | 0.05% | | | | | -$8.74 | | $55.06 | -$2.09 | | $14.07 | | | |
| | SOUTHLUGO_RV_BG | 0.01% | 0.2% | 0.03% | | -$2.45 | $1.74 | $3.24 | -$157.14 | $110.45 | $160.42 | -$67.97 | $61.86 | $79.45 | | | |
| | SLIC 2122013 Barre-Ellis DLO_16 | | 0.6% | | | | | | -$3.44 | -$0.90 | $23.02 | | | | | | |
| | SLIC 2122013 Barre-Ellis DLO_17 | | 0.6% | | | | | | -$4.49 | -$1.25 | $29.85 | | | | | | |
| | SLIC 2122013 Barre-Ellis DLO_21 | | 0.5% | | | | | | -$2.20 | | $14.49 | | | | | | |
| | SLIC 2077347 TL50003_NG | | 0.5% | | | | | | $0.83 | | $54.19 | | | | | | |
| | 24016_BARRE _230_24044_ELLIS _230_BR_1 _1 | | 0.4% | | | | | | -$1.52 | -$0.55 | $9.86 | | | | | | |
| | 7830_SXCYN_CHILLS_NG | | 0.3% | | | | | | | | $19.99 | | | | | | |
| | SLIC 2126995 SONGS_NG1 | | 0.1% | | | | | | -$47.35 | | $441.78 | | | | | | |
| | SDGE_PCT_UF_IMP_BG | | 0.1% | | | | | | -$13.32 | -$13.32 | $141.64 | | | | | | |
| | IVALLYBANK_XFBG | 3.1% | | | | | | $2.55 | | | | | | | | | |
| | 7830_TL 230S_IV-SX-OUT_NG | 0.5% | | | | | | $51.47 | | | | | | | | | |
| | 22464_MIGUEL _230_22468_MIGUEL _500_XF_81 | 0.4% | | | | -$2.22 | -$5.25 | $15.46 | | | | | | | | | |
| | SLIC 2090466 and 2090467 SOL | 0.3% | | | | | | $30.74 | | | | | | | | | |
| | SLIC 2051445 TL23050_NG | 0.2% | | | | | | $46.55 | | | | | | | | | |
| | SLIC 2112931 EL CENTRO BK1_NG | 0.2% | | | | | | $49.40 | | | | | | | | | |
| | 30060_MIDWAY _500_24156_VINCENT _500_BR_2 _2 | 0.03% | | | | -$320.31 | $267.35 | $267.35 | | | | | | | | | |

Overall, the most frequently congested constraint was 30880_HENTAP2_230_30900_GATES_230_BR_2_1 located in the PG&E area, which was binding about 7 percent of the time in the fourth quarter. This constraint increased prices by about $9/MWh in the PG&E area and decreased prices in the SCE and SDG&E areas by $6/MWh. This constraint was influenced by imports from the 230 kV system through the McCall, Herndon, Henrietta banks, and local hydro generation.

Congestion on the Barre-Lewis nomogram, which occurred in 0.5 percent of hours, increased prices in the SCE and SDG&E areas by about $10/MWh and $2/MWh, respectively. It decreased prices in the PG&E area by about $3/MWh. This constraint was impacted by the San Onofre retirement as well as other outages.

The second significant constraint in the SCE territory was the SCIT_BG constraint, which was binding in about 0.5 percent of hours. This constraint increased prices in the SCE and SDG&E areas by $48/MWh and $52/MWh, respectively. It decreased prices in the PG&E area by $56/MWh. This constraint was used to manage the interaction between SCIT and the East-of-River nomogram.

Prices in the SDG&E area were affected by multiple constraints in the fourth quarter. The constraint with the greatest impact in SDG&E was SOUTH_OF_LUGO, located within the SCE area, which was congested in nearly 2.3 percent of intervals. This constraint alone increased real-time prices in SDG&E by almost $20/MWh in congested periods, while prices in the SCE area increased by just over $14/MWh and prices in the PG&E area decreased by over $18/MWh. This constraint was affected by planned outages on the Lugo-Rancho Vista and Lugo-Mira Loma lines.

The 7820_TL 230S_OVERLOAD_NG nomogram drove real-time prices in the SDG&E area up by about $45/MWh and decreased PG&E prices by over $4/MWh. The other remaining constraints in SDG&E area were binding in less than 0.5 percent of the intervals, but had significant price impact on the SDG&E area prices when they were binding. These constraints include the TL50001_NG, the TL50003_CFE_NG, the Doublet Tap-Friars 138 kV line, and the SANLUSRY transformer.

Overall, congestion occurred more frequently in the day-ahead market than in the real-time market, as shown by a comparison of Table 1.2 and Table 1.3. In the fourth quarter, the price impact on the most significant binding elements was larger in the real-time market than the day-ahead market. For instance, the 30880_HENTAP2 _230_30900_GATES_230_BR_2 _1 constraint was binding in roughly 10 percent of hours in the day-ahead market compared to around 7 percent of intervals in the real-time market. While this constraint increased day-ahead prices in the PG&E area by nearly $0.47/MWh, it increased prices by over $9/MWh in the real-time market. A similar pattern can also be seen with the Barre-Lewis nomogram.

Differences in congestion in the day-ahead and real-time markets occur as system conditions change, virtual bids liquidate, and constraints are adjusted to account for discrepancies between market and actual flows and to provide a reliability margin.

### 1.5.2 Impact of congestion on average prices

This section provides an assessment of differences between overall average regional 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 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 both the frequency with which congestion occurs and the magnitude of the impact of that congestion when it occurs.[17] The price impact of congestion differs across load areas and markets.

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

In the fourth quarter, day-ahead congestion increased prices in the SCE and SDG&E areas and decreased prices in the PG&E area. Real-time congestion had a relatively small impact, increasing PG&E area prices by about $0.28/MWh, with almost no impact on other areas.[18]

### Day-ahead price impacts

Table 1.4 shows the overall impact of day-ahead congestion on average prices in each load area in the fourth quarter by constraint.

The overall impact of congestion on day-ahead prices in the PG&E area was a decrease of about $0.15/MWh or about 0.3 percent from the system average, and an increase in SCE area prices by about $0.18/MWh (0.04 percent) and in SDG&E area prices by about $0.94/MWh (2.1 percent). Compared to the third quarter, PG&E congestion fell by half from $0.30/MWh, SCE congestion decreased to one quarter from $0.74/MWh, while SDG&E congestion doubled from $0.47/MWh.

The SOUTHLUGO_RV_BG constraint had the largest overall impact on prices in the fourth quarter. This constraint increased day-ahead prices in the SDG&E area above system average prices by $0.15/MWh or 0.33 percent, up from $0.03/MWh (0.07 percent) in the previous quarter. Prices decreased by about $0.15/MWh (0.34 percent) in the PG&E area and increased by about $0.11 (0.24 percent) in the SCE area. This constraint is intended to protect the Lugo-Rancho Vista branch group from an overload during planned outages in the Lugo area.

In the PG&E area, the PATH15_BG constraint increased prices by $0.05/MWh or 0.11 percent and decreased prices in SCE and SDG&E by $0.04/MWh or 0.1 percent. In SCE, day-ahead prices were driven by the Barre-Lewis nomogram. This nomogram increased prices by only $0.02/MWh or around 0.04 percent.

[18] As mentioned before, congestion in the real-time market often has a larger price effect in intervals when it occurs. However, the overall price impact of congestion depends on the frequency of congestion along with the magnitude of the price effect.

### Table 1.4 Impact of congestion on overall day-ahead prices

| | PG&E | | SCE | | SDG&E | |
|---|---|---|---|---|---|---|
| Constraint | $/MWh | Percent | $/MWh | Percent | $/MWh | Percent |
| SOUTHLUGO_RV_BG | -$0.15 | -0.34% | $0.11 | 0.24% | $0.15 | 0.33% |
| SLIC 2138237 TL50003_CFE_NG | | | | | $0.29 | 0.64% |
| SLIC 2100489_PVDV_Out_LGVN | -$0.07 | -0.16% | $0.05 | 0.11% | $0.07 | 0.14% |
| SLIC 2164068 TL50001_NG | | | | | $0.15 | 0.33% |
| PATH15_BG | $0.05 | 0.11% | -$0.04 | -0.09% | -$0.04 | -0.09% |
| SLIC 2100489_PVDV_Out_EDLG | $0.03 | 0.07% | -$0.02 | -0.04% | -$0.06 | -0.13% |
| 22372_KEARNY _69.0_22496_MISSION _69.0_BR_1 _1 | | | | | $0.10 | 0.22% |
| 22831_SYCAMORE_138_22117_CARLTHT2_138_BR_1 _1 | | | | | $0.09 | 0.21% |
| 24087_MAGUNDEN_230_24153_VESTAL _230_BR_2 _1 | | | $0.05 | 0.12% | | |
| 22831_SYCAMORE_138_22124_CHCARITA_138_BR_1 _1 | | | | | $0.05 | 0.11% |
| 30880_HENTAP2 _230_30900_GATES _230_BR_2 _1 | $0.05 | 0.10% | | | | |
| 22500_MISSION _138_22117_CARLTHT2_138_BR_1 _1 | | | | | $0.04 | 0.09% |
| BARRE-LEWIS_NG | -$0.01 | -0.03% | $0.02 | 0.04% | $0.00 | 0.00% |
| 7820_TL 230S_OVERLOAD_NG | | | | | $0.02 | 0.05% |
| 30790_PANOCHE _230_30900_GATES _230_BR_1 _1 | $0.01 | 0.02% | -$0.01 | -0.02% | -$0.01 | -0.02% |
| 22828_SYCAMORE_69.0_22756_SCRIPPS _69.0_BR_1 _1 | | | | | $0.01 | 0.03% |
| 22886_SUNCREST_230_22832_SYCAMORE_230_BR_1 _1 | -0.1% | | | | $0.01 | 0.02% |
| SLIC 2165838 ELDORADO_BUS_NG | | 0.01% | $0.00 | -0.01% | $0.00 | -0.01% |
| Other | -$0.05 | -0.11% | $0.02 | 0.05% | $0.06 | 0.14% |
| Total | -$0.15 | -0.3% | $0.18 | 0.4% | $0.94 | 2.1% |

## Real-time price impacts

Table 1.5 shows the overall impact of real-time congestion on average prices in each load area in the fourth quarter by constraint. The following real-time congestion effects occurred in each load area:

- Congestion on the SCIT_BG constraint drove prices in the SCE area up by $0.17/MWh (0.4 percent). The overall impact of congestion on prices in the SCE area was not significant at $0.03 (0.1 percent).
- In the SDG&E area, the constraint with the greatest impact on real-time prices was SOUTH_OF_LUGO. However, when combined with other constraints, the overall impact of congestion was minimal at $0.02/MWh.
- In the PG&E area, the overall impact of congestion on real-time prices was an increase of about $0.28/MWh, or about 0.6 percent above system energy price. The largest price impact was associated with congestion on 30880_HENTAP2_230_30900_GATES_230_BR_2_1, which increased prices by about $0.60/MWh (1.4 percent).

**Table 1.5 Impact of congestion on overall real-time prices**

| | PG&E | | SCE | | SDG&E | |
|---|---|---|---|---|---|---|
| **Constraint** | **$/MWh** | **Percent** | **$/MWh** | **Percent** | **$/MWh** | **Percent** |
| 30880_HENTAP2 _230_30900_GATES _230_BR_2 _1 | $0.60 | 1.36% | -$0.39 | -0.91% | -$0.39 | -0.91% |
| SOUTH_OF_LUGO | -$0.43 | -0.97% | $0.33 | 0.77% | $0.46 | 1.06% |
| PATH15_S-N | $0.33 | 0.76% | -$0.28 | -0.66% | -$0.28 | -0.66% |
| PATH26_N-S | -$0.23 | -0.52% | $0.20 | 0.45% | $0.20 | 0.45% |
| SCIT_BG | -$0.20 | -0.46% | $0.17 | 0.40% | $0.19 | 0.43% |
| NSONGS_BG | $0.04 | 0.09% | $0.05 | 0.12% | -$0.43 | -0.99% |
| 7820_TL 230S_OVERLOAD_NG | -$0.02 | -0.04% | | | $0.23 | 0.54% |
| SLIC 2138237 TL50003_CFE_NG | | | | | $0.23 | 0.53% |
| SLIC 2164068 TL50001_NG | | | | | $0.18 | 0.42% |
| SLIC 2100489_PVDV_Out_EDLG | $0.05 | 0.10% | -$0.03 | -0.06% | -$0.09 | -0.20% |
| SLIC 2100489_PVDV LGMV_Out_EDLG | $0.03 | 0.07% | -$0.02 | -0.04% | -$0.07 | -0.16% |
| SLIC 2200107 ELDORADO-LUGO_1_NG | $0.04 | 0.08% | -$0.03 | -0.06% | -$0.05 | -0.12% |
| SLIC 2165837 ELDORADO_BUS_NG | $0.03 | 0.07% | -$0.02 | -0.05% | -$0.05 | -0.13% |
| 22886_SUNCREST_230_22832_SYCAMORE_230_BR_1 _1 | -$0.01 | -0.03% | | | $0.09 | 0.21% |
| 22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1 | | | | | -$0.08 | -0.19% |
| 22260_ESCNDIDO_230_22844_TALEGA _230_BR_1 _1 | | | | | -$0.03 | -0.08% |
| T-135 VICTVLUGO_EDLG_NG | $0.01 | 0.02% | | | -$0.02 | -0.04% |
| SYLMAR-AC_BG | -$0.01 | -0.01% | $0.01 | 0.01% | -$0.01 | -0.03% |
| BARRE-LEWIS_NG | -$0.02 | -0.04% | $0.01 | 0.02% | $0.002 | 0.01% |
| 30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1 | $0.02 | 0.04% | -$0.004 | -0.01% | -$0.004 | -0.01% |
| 22708_SANLUSRY_69.0_22712_SANLUSRY_138_XF_3 | | | | | -$0.02 | -0.05% |
| Other | $0.05 | 0.11% | -$0.03 | -0.07% | -$0.07 | -0.16% |
| Total | $0.28 | 0.6% | -$0.03 | -0.1% | -$0.02 | -0.1% |

Overall, the frequency of real-time congestion decreased significantly in the fourth quarter. Real-time congestion had a relatively small impact, increasing PG&E area prices by about $0.28/MWh, with almost no impact on other areas. In the previous quarter, congestion shifted the prices by about $1/MWh in every load area. As mentioned earlier, differences in congestion can be attributed to differences in market conditions and changes associated with conforming line limits to make market flows reflect actual flows, as well as to provide a reliability margin.

In terms of both simple and absolute averages, congestion differences have declined substantially between the day-ahead and real-time markets in the fourth quarter compared to the third and second quarters, as the frequency and impact of congestion decreased. Congestion differences also decreased between day-ahead, real-time and hour-ahead markets as price convergence improved in the fourth quarter.

### SCIT adjustments

Beginning on November 1, 2013, the ISO began adjusting the SCIT_BG constraint down to manage the interaction between SCIT and the East-of-River (EOR) nomogram constraint during the planned outage of the Palo Verde-Devers 500 kV line. These adjustments reached 50 percent of the line rating. As a result, there were several congestion related price spikes affecting the SCE and SDG&E areas in some hours. DMM noted the congestion and inquired with ISO operations as to the effectiveness of the adjustments. Upon review, the ISO determined that the SCIT_BG adjustments were not as effective as intended and identified a more effective alternative approach to better manage the SCIT and East-of-River nomogram congestion. The alternative approach, using transmission reliability margins on the Palo Verde branch group to account for flow interaction between SCIT and East-of-River while decreasing generation on the other side of the constraint, was implemented on November 6. As a result, the incidence of dramatic and ineffective congestion related price spikes in the SDG&E and SCE areas reduced.

### SCE import branch group constraints

Starting October 1, 2013, the ISO un-enforced the SCE import percent branch group (SCE_PCT_ IMP_BG) transmission constraint in the ISO markets. This constraint limited the total volume of imports as a percentage of load into the SCE area. This limit ensured that SCE imports did not exceed 60 percent of load, to maintain supply and demand balance in the event that the SCE system were to separate from the rest of the ISO grid due to a significant under-frequency event. This constraint was intended to maintain sufficient resource supply balance within the SCE area. The ISO enforced the limit on November 11, 2010. A joint study performed by the ISO and SCE in 2013 concluded that there were greater reliability benefits from modifying the physical Under Frequency Load Shedding (UFLS) Relay scheme. As a result of the scheme modification, the ISO removed the SCE_PCT_IMP_BG from both the day-ahead and real-time markets. The ISO removed this constraint from the monthly congestion revenue right model beginning with November 2013. The constraint, however, was included in the 2014 annual congestion revenue right model since the annual process began in August 2013.

This constraint was the most congested constraint in the ISO system in the day-ahead and real-time markets in 2012 and the first two quarters of 2013. In 2012 and the first two quarters of 2013, in the day-ahead market, this constraint increased SCE area prices by about $3/MWh on average, and decreased SDG&E and PG&E area prices when binding. In the real-time market for the same period, the SCE_PCT_IMP_BG increased prices in the SCE area by about $55/MWh when binding.

### SDG&E import branch group constraints

Starting November 15, 2013, the ISO removed the SDG&E import percent branch group (SDGE_PCT_UF_IMP_BG) constraint.[19] This limit ensured that internal generation did not go below 25 percent of SDG&E area load. Following the scheme modification mentioned above, the SDGE_PCT_UF_IMP_BG was removed from both the day-ahead and real-time markets. This constraint was removed from the monthly congestion revenue right model starting from December 2013. However, it was included in the 2014 annual congestion revenue right model, since the annual process began in August 2013.

The overall impact of the SDGE_PCT_UF_IMP_BG was significantly smaller than the SCE_PCT_IMP_BG. In the day-ahead market it was binding in about 1 percent of hours during the last three quarters of 2012 and about 2 percent of the hours in the second quarter of 2013. In the real-time market, it was binding in less than 0.25 percent of hours for the same period.

[19] The SDGEIMP_BG and the SDGE_CFEIMP_BG constraints remain enforced as they are voltage stability limits in the San Diego area.

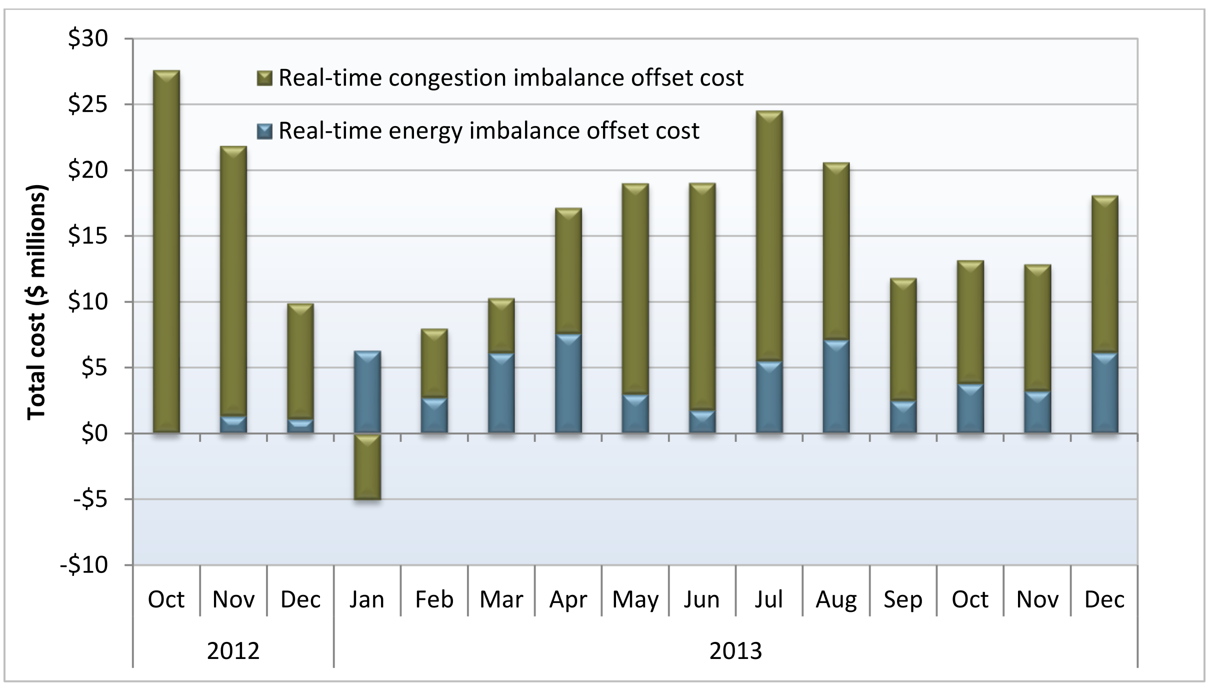
The fourth quarter was the first quarter when both the SCE_PCT_ IMP_BG and SDGE_PCT_UF_IMP_BG constraints were not binding. For most of the last year, much of the difference between NP15 and SP15 prices reflected import related congestion such as the SCE_PCT_IMP_BG. Since January, congestion from north-to-south decreased gradually in both the day-ahead and real-time markets. Since November, the prevailing congestion pattern switched to south-to-north. Compared to 2012, the magnitude of congestion fluctuated, but the prevailing direction of the congestion was mostly from north-to-south.

## 1.6 Real-time imbalance offset costs

Real-time imbalance offset costs totaled about $44 million, down from $57 million in the third quarter due to reductions in both congestion and energy offset costs. This value is slightly below the average quarterly offset cost for 2011 and 2012 of about $50 million. Congestion offset costs accounted for approximately 70 percent of the total imbalance costs during the fourth quarter, totaling about $31 million (see Figure 1.17). The remaining $13 million were from energy imbalance offset costs, which remained relatively consistent with previous periods.

In 2013, real-time imbalance offset costs totaled about $176 million, down more than 25 percent from the total costs in 2012 ($235 million). The decrease was driven by a decline in congestion offset costs of more than one third. Total annual real-time congestion offset costs fell from $187 million in 2012 to $120 million in 2013, which more than offset an increase in real-time energy offset costs from $48 million to $56 million.

**Figure 1.17 Real-time imbalance offset costs**



Real-time congestion offset costs in the fourth quarter were primarily due to unscheduled flows and market modeling differences. Together, costs incurred on 12 days accounted for more than one-half of congestion offset costs for the quarter.

- On November 13, congestion offset costs reached $2.4 million, more than 7 percent of the quarterly total. This is due to unscheduled flows and a transmission outage that affected the SCIT constraint.
- The 11 days with the next highest real-time congestion offset cost accounted for a combined total of about $14 million. On three of these days, including December 10 and December 11 during the natural gas price spike, congestion shadow prices were higher in the hour-ahead market than in real-time.[20] On the remaining eight days, real-time congestion exceeded the hour-ahead due to transmission outages and unscheduled flows. Congestion offset on these eight days alone totaled almost $10 million.

The ISO's efforts to address systematic modeling differences between the day-ahead and real-time markets, including better alignment of day-ahead and real-time transmission limits and modification of the constraint relaxation parameter, have contributed to reducing real-time imbalance costs compared to the summer of 2012. This appears to have significantly improved imbalance congestion offset costs between 2012 and 2013 as real-time congestion imbalance costs were $57 million in the fourth quarter of 2012 and $31 million in the fourth quarter of 2013. Even with these improvements, the possibility of high real-time imbalance offset costs continues to exist.

## 1.7 Residual unit commitment

Despite relatively low residual commitment volumes, the direct costs of procuring residual unit commitment rose dramatically in the fourth quarter to $697,000 from $200,000 in the third quarter. Even so, 2013 fourth quarter costs were only 55 percent of fourth quarter costs in 2012. The total direct cost of residual unit commitment was about $2.3 million in 2013, an almost 40 percent increase over the direct cost in 2012 of $1.6 million. As in prior quarters, increased residual unit commitment costs have primarily been driven by an increase in residual unit commitment requirements from liquidation of cleared net virtual supply.

Much of this capacity does not incur direct costs but does account for a portion of the bid cost recovery payments discussed in detail in Section 1.8. Figure 1.18 illustrates average hourly direct non-resource adequacy costs by month in addition to the average hourly residual unit commitment procurement, categorized as either non-resource adequacy or resource adequacy and minimum load.

The purpose of the residual unit commitment market is to ensure that there is sufficient capacity online or reserved to meet forecast load in real time. The ISO runs the residual unit commitment market right after the day-ahead market and procures capacity sufficient to bridge the gap between the physical capacity that cleared in the day-ahead market and the day-ahead forecast load. ISO operators are able to increase the amount of residual unit commitment requirements for reliability purposes and used this tool frequently in 2013.

[20] This can occur due to differences in constraint shadow prices in the hour-ahead and 5-minute markets. For instance, the cap on real-time shadow prices is $1,500, whereas the cap on hour-ahead market shadow prices is $5,000. For more detail and analysis see the discussion paper "Real-time Revenue Imbalance in California ISO Markets" at: http://www.caiso.com/Documents/DiscussionPaper-Real-timeRevenueImbalance_CaliforniaISO_Markets.pdf.

**Figure 1.18 Residual unit commitment costs and volume**

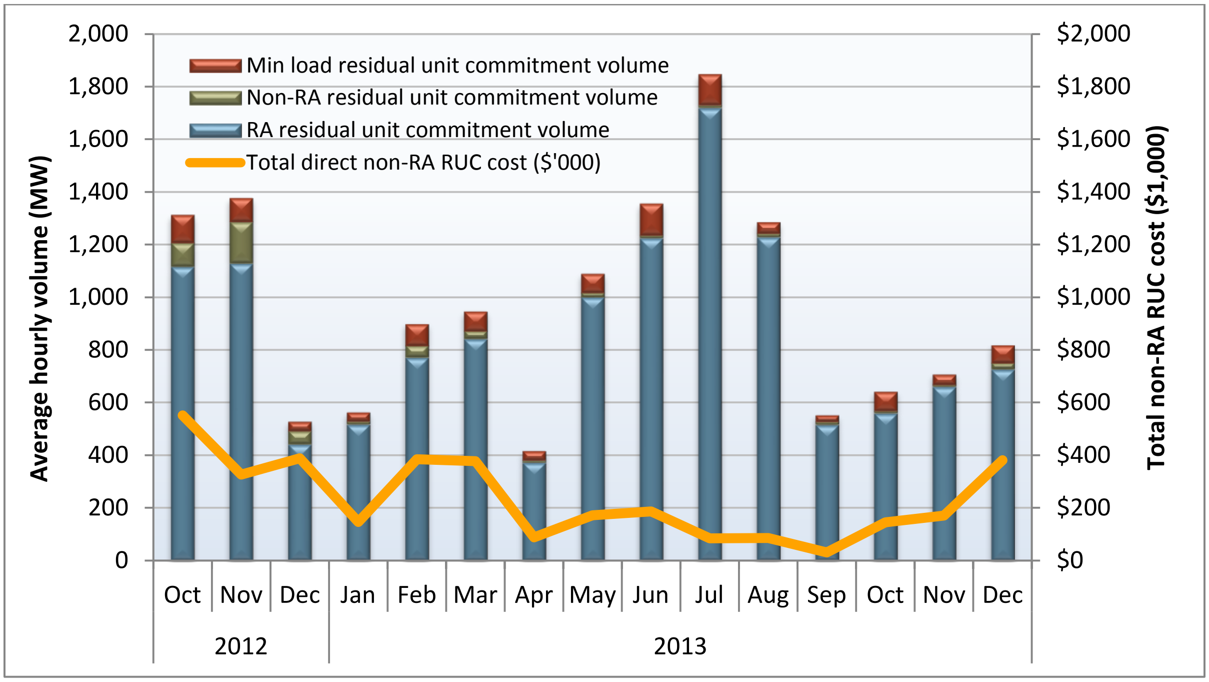
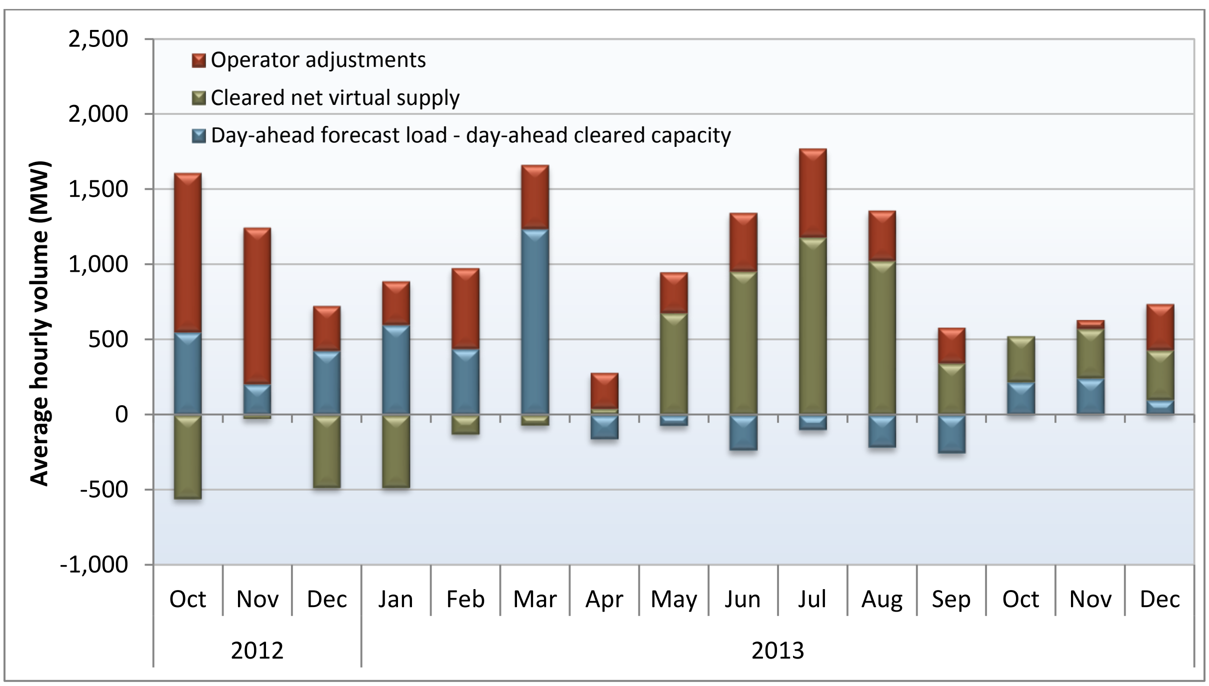



**Figure 1.19 Determinants of residual unit commitment procurement**




As illustrated in Figure 1.19, residual unit commitment procurement appears to be driven in large part by the need to replace cleared net virtual supply bids which will not appear in the real-time market. On average, cleared virtual supply (green bar) has had a greater presence in the fourth quarter of 2013 than it did in the same quarter of 2012. Operator adjustments to the residual unit commitment process (red bar) have also played a part in the growth of residual unit commitment procurement in 2013, but were lower in the fourth quarter of 2013 than in 2012.

The increase in the residual unit commitment requirement made by operators during 2013 was partly related to decreased reliance on exceptional dispatch, which increased the use of alternative means of ensuring adequate capacity and ramping in real time. In addition, the ISO factors in forecasted variable generation, which can reduce the volume of operator adjustments.[21]

The day-ahead forecasted load versus cleared day-ahead capacity (blue bar) represents the difference in cleared supply (both physical and virtual) compared to the ISO's load forecast. On average, this factor has increased residual unit commitment in the fourth quarter. However, this effect in the fourth quarter of 2013 remained significantly smaller than in the fourth quarter of 2012 and first quarter of 2013.

## 1.8 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.[22] Bid cost recovery payments totaled around $26 million in the fourth quarter, about the same total as in the third quarter (see Figure 1.20 for monthly figures). For the year, bid cost recovery payments totaled about $107 million with real-time payments making up roughly half of the total. Although the 2013 payments are slightly higher than the $104 million in 2012, the payment share associated with real-time unit commitment has increased nearly threefold to $23 million in 2013.

With the exception of November, day-ahead bid cost recovery costs continued to decrease compared to the third quarter. The day-ahead cost increase in November was related to transmission outages and can be largely attributed to increased minimum online commitments and exceptional dispatch commitments. The portion of bid cost recovery resulting from residual unit commitment dropped slightly in the fourth quarter to around $4.7 million from about $5 million in the previous quarter. Bid cost recovery payments from day-ahead commitments were slightly higher at about $8 million in the fourth quarter compared to $7.7 million in the third quarter. Around $3.5 million of the real-time commitment costs resulted from unit commitments through exceptional dispatch.

Bid cost recovery payments for residual unit commitment costs mainly resulted from increased scheduled virtual supply and operator adjustments to the residual unit commitment requirements due to load forecast and variable resource generation uncertainty. Similar to the last quarter, the net virtual position was virtual supply in the majority of hours (see Section 2.1). When the market clears net virtual supply, the residual unit commitment process will replace the virtual supply with physical resources not committed in the day-ahead market. Virtual bidders accounted for nearly 60 percent ($2.7 million) of the residual unit commitment payments in the quarter (for further detail see Section 2.2).

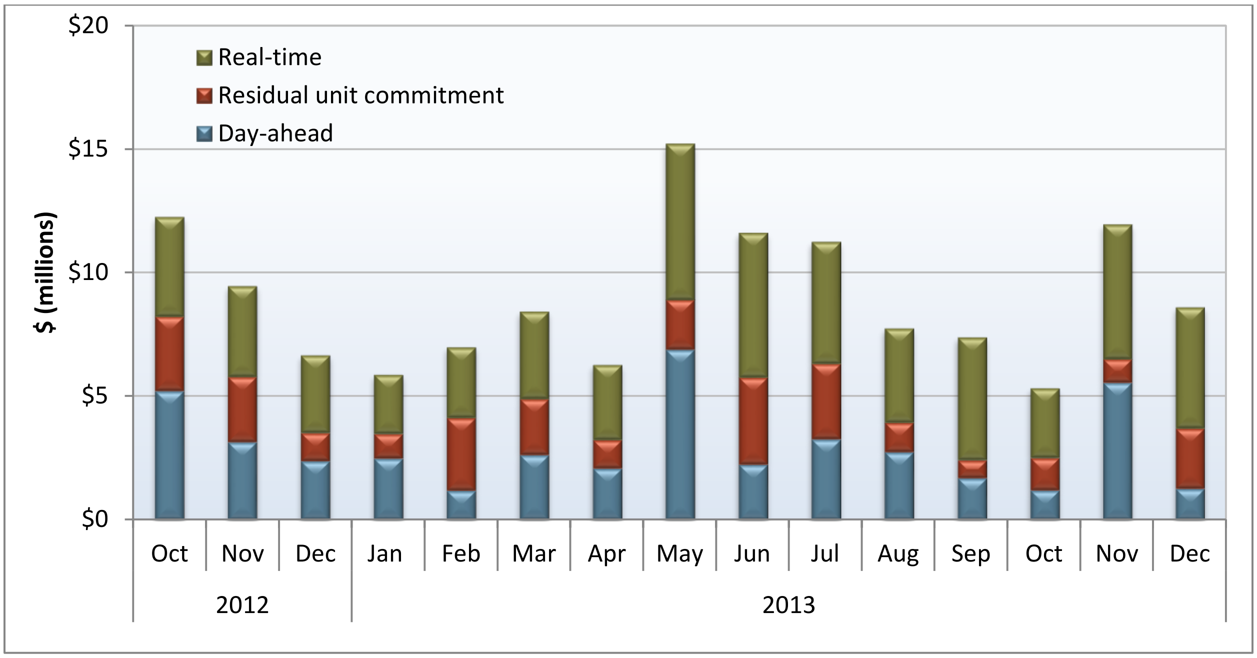
ISO operators have continued making adjustments to the system or regional residual unit commitment requirements to mitigate potential contingencies. These changes were concentrated in the late

[21] On February 4, 2014, the ISO implemented a new Eligible Intermittent Resource Adjustment to account for the sum of all wind and solar resources that self-schedule below their resource level forecast.

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

afternoon and early evening hours during the steep ramping period in real time. Frequently, units were committed in the residual unit commitment process to meet these system needs. However, these units were at times uneconomic in real time, requiring recovery of their bid costs.

**Figure 1.20 Monthly bid cost recovery payments**



# 2 Convergence bidding

Virtual bidding is a part of the Federal Energy Regulatory Commission's standard market design and is in place at all ISOs with day-ahead energy markets. In the California ISO markets, virtual bidding is formally referred to as *convergence bidding*. The ISO implemented convergence bidding in the day-ahead market on February 1, 2011. Virtual bidding on inter-ties was temporarily suspended in November 2011. In May 2013, FERC issued an order conditionally accepting elimination of convergence bidding on inter-ties.[23] The ISO intends to reinstate convergence bidding on the inter-ties as part of its implementation of FERC Order No. 764.[24]

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

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

Participants engaging in convergence bidding continued to earn positive returns from participation in ISO markets in the fourth quarter. Total net revenue for convergence bidding positions during this quarter was around $9.3 million. Virtual supply generated net revenues of about $6.6 million, while virtual demand accounted for around $2.7 million. However, total payment to convergence bidders fell to $6.6 million after taking into account virtual bidding bid cost recovery charges ($2.7 million).

Most positive convergence bidding revenues resulted from offsetting virtual demand and supply bids at different internal locations designed to profit from higher anticipated congestion between these locations in real-time. This type of offsetting internal bid represented over 75 percent of all accepted virtual bids in the fourth quarter, which is an increase from 67 percent in the previous quarter.

Total hourly trading volumes decreased to 4,160 MW in the fourth quarter from the all-time peak of 4,560 MW in the third quarter. Internal virtual supply averaged around 2,240 MW while virtual demand averaged around 1,920 MW during each hour of the quarter. Thus, the average hourly net virtual position in the fourth quarter was 320 MW of virtual supply, a decrease from 850 MW of net virtual supply in the previous quarter.

Net virtual demand within the ISO may increase market efficiency by reducing real-time prices and increasing the efficiency of day-ahead unit commitment and scheduling. For the quarter, net revenue for net virtual demand positions was positive due to high returns during relatively infrequent real-time price spikes. Net revenue from net virtual supply positions was also positive as prices were slightly higher in the day-ahead market than the real-time market, as shown in Section 1.2. The lower volumes of virtual supply in the fourth quarter may be due to better convergence of real-time prices with day-ahead market prices compared to previous quarters.

[23] More information can also be found under FERC docket number ER11-4580-000.

[24] For more information see Tariff Amendment to Implement Real-Time Market Design Enhancements Related to Order No. 764: http://www.caiso.com/Documents/Nov26_2013_TariffAmendment-Real-TimeMarketDesignEnhancementsRelated-Order764_ER14-480.pdf.

### Background

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

- Participants with virtual demand bids cleared in the day-ahead market pay the day-ahead price for virtual demand and are then paid the real-time price for these bids.
- Participants with cleared virtual supply bids are paid the day-ahead price for this virtual supply and are then charged the real-time price for this supply.

Thus, virtual bidding allows participants to profit from any 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 by 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 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.[25] 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.

The degree to which convergence bidding has actually increased market efficiency by improving unit commitment and dispatches has not been fully assessed. However, there are settlement charges associated with virtual bidding that may prevent full price convergence between the day-ahead and real-time markets.

## 2.1 Convergence bidding trends

Total hourly trading volumes decreased slightly in the fourth quarter to 4,160 MW from an all-time peak of 4,560 MW in the third quarter.

[25] Net virtual supply will not create a reliability issue because the residual unit commitment process occurs after the integrated forward market run. The residual unit commitment process removes convergence bids and re-optimizes the market to meet ISO forecasted load. If additional units are needed, the residual unit commitment process will commit more resources.

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

- On average, about 57 percent of virtual supply and demand bids offered into the market cleared in the fourth quarter. This is similar to the previous quarter.
- Cleared volumes of virtual supply outweighed cleared virtual demand in the fourth quarter by around 320 MW on average, a decrease from 850 MW of net virtual supply in the previous quarter.
- As in the previous quarter, virtual supply exceeded virtual demand during both peak and off-peak hours, by about 220 MW and 530 MW respectively. However, during select afternoon peak ramping periods virtual demand exceeded virtual supply.

**Figure 2.1 Monthly average virtual bids offered and cleared**

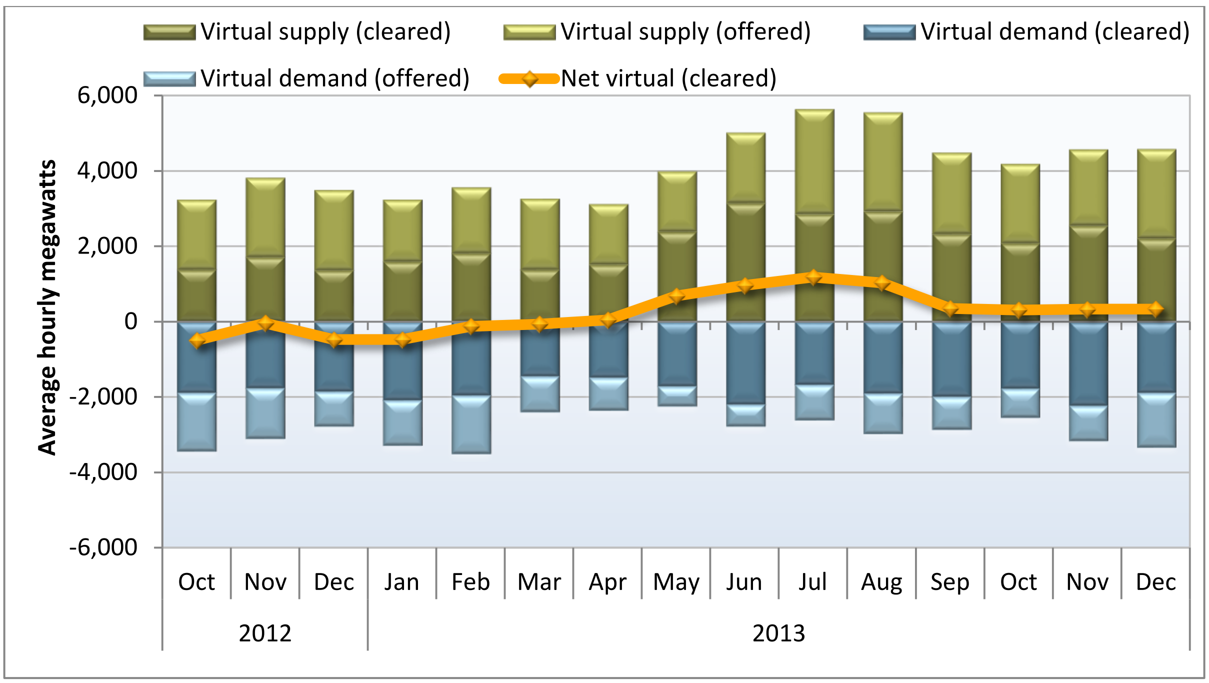
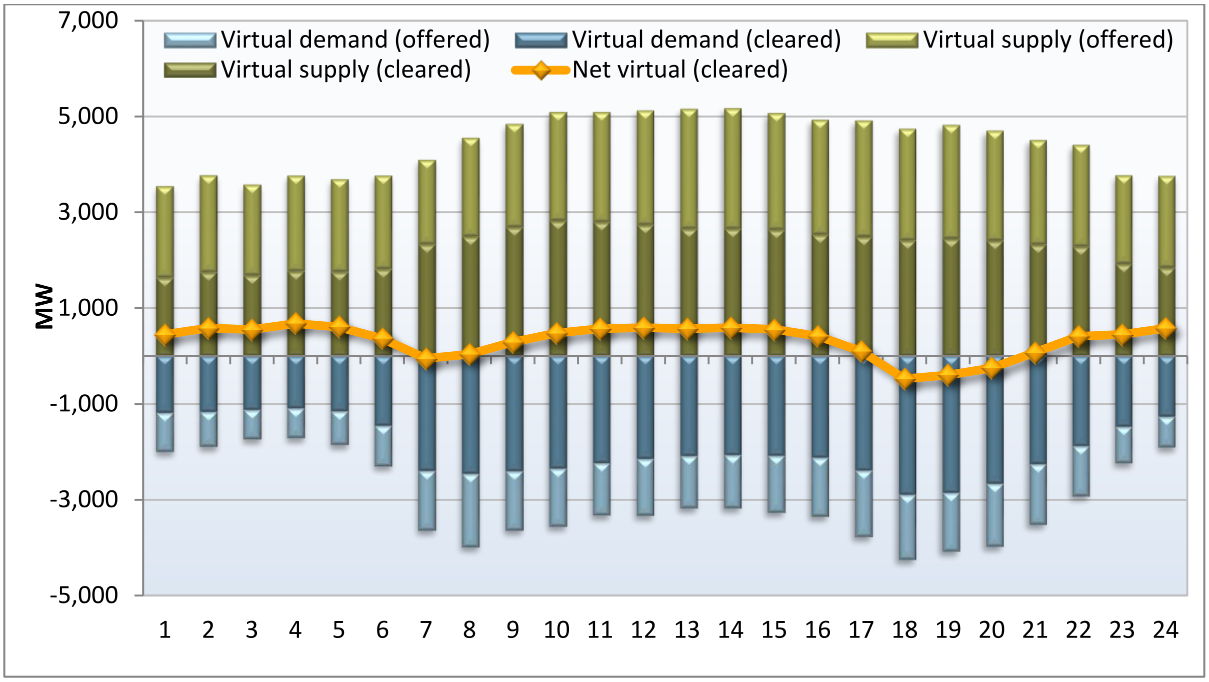


**Figure 2.2 Hourly offered and cleared virtual activity (October – December)**




## Consistency of price differences and volumes

Convergence bidding is designed to align day-ahead and real-time prices when the net market virtual position is directionally consistent (and profitable) with the price difference between the two markets. Net convergence bidding volumes were consistent with price differences between day-ahead and real-time markets in only 13 hours in October and November. In December, however, net convergence bidding volumes were consistent with price differences in 20 hours.

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

When the red line is positive, it indicates that the weighted average price charged for internal virtual demand in the day-ahead market was higher than the weighted average real-time price paid for this virtual demand. When positive, it indicates that a virtual demand strategy was not profitable, and thus was directionally inconsistent with weighted average price differences.

Virtual demand volumes were consistent with weighted average price differences for the hours in which virtual demand cleared the market in November and December. Ramping limitations during peak hours in November and unseasonably cold weather and higher than normal loads on a few days in December caused extremely high real-time prices, which made overall virtual demand positions profitable.

Virtual supply positions continued to be consistent with the weighted average difference between day-ahead and real-time prices. The yellow line in Figure 2.3 represents the difference between the day-ahead price paid to virtual supply and the real-time price at which virtual supply positions are liquidated, weighted by cleared virtual supply bids by time interval and location. On average, virtual supply positions at internal locations have been consistently profitable since July 2012, with the exception of August 2013.

As noted earlier, 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 arbitraging spatial price differences caused by internal congestion within the ISO as well as avoiding bid cost recovery settlement charges.[26] 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 2.3 Convergence bidding volumes and weighted price differences at internal locations**

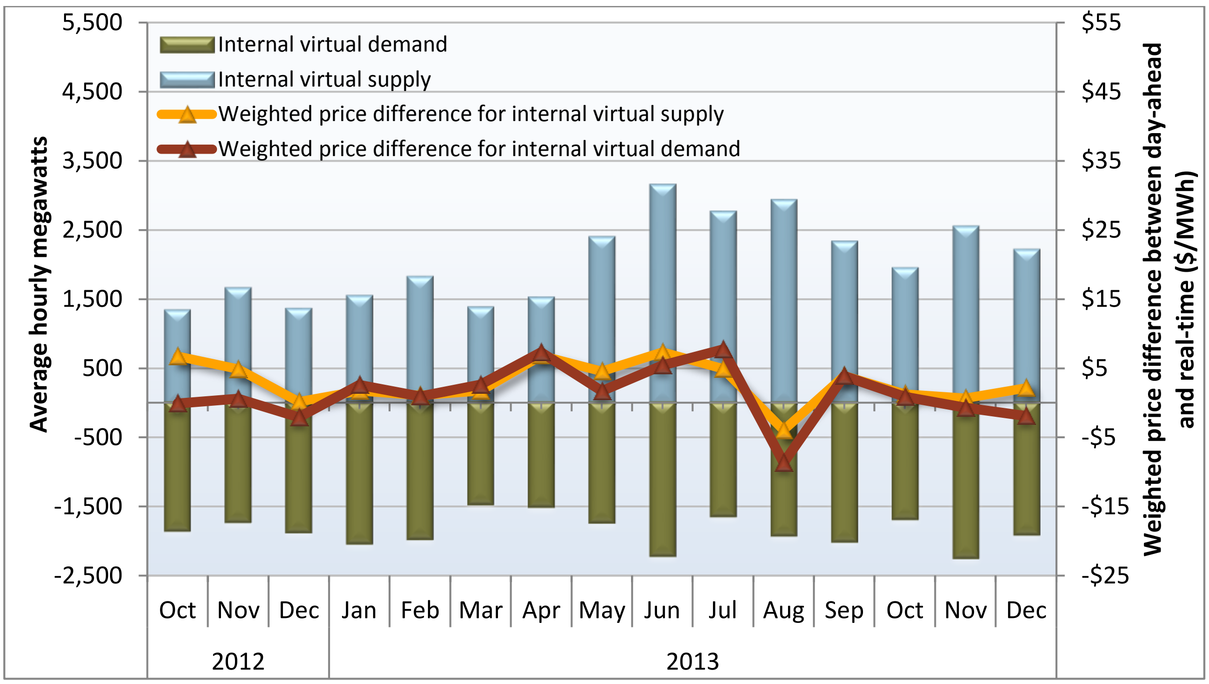



Figure 2.4, Figure 2.5, and Figure 2.6 show average hourly net cleared convergence bidding volumes compared to the difference between day-ahead and real-time system marginal energy prices in October, November, and December, respectively. The blue bars represent the net cleared internal virtual position; the green line represents the difference between the day-ahead and real-time system marginal energy prices. Historically, market participants have bid virtual demand in peak hours in anticipation of real-time price spikes. Even though spikes are infrequent, virtual demand revenues have historically outweighed losses. In the fourth quarter, real-time price spikes typically occurred during steep ramping periods and virtual bidding positions during these periods shifted to primarily virtual demand.

As shown in Figure 2.4 and Figure 2.5, convergence bidding volumes in October and November were less consistent with differences between day-ahead and real-time prices. In these months, there were only 13 hours where net convergence bidding volumes were consistent with day-ahead and real-time price differences.

[26] Please refer to the section at the end of the chapter for detailed analysis of bid cost recovery charges to convergence bidders.

**Figure 2.4 Hourly convergence bidding volumes and prices – October**

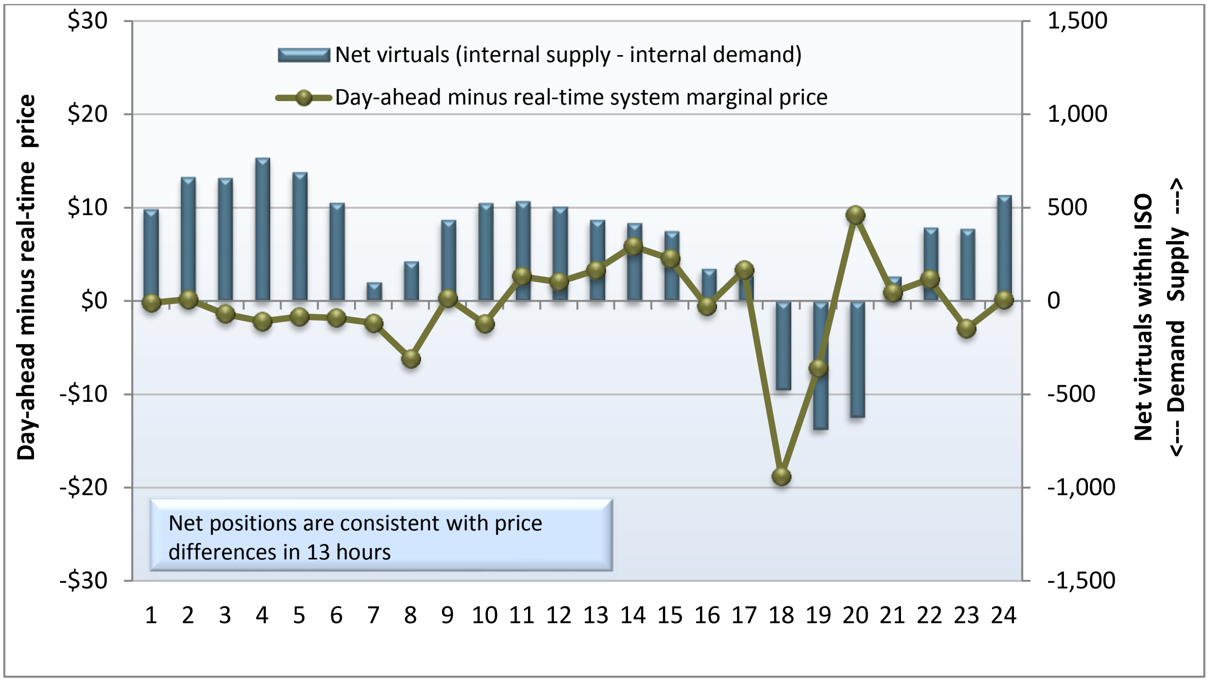



**Figure 2.5 Hourly convergence bidding volumes and prices – November**

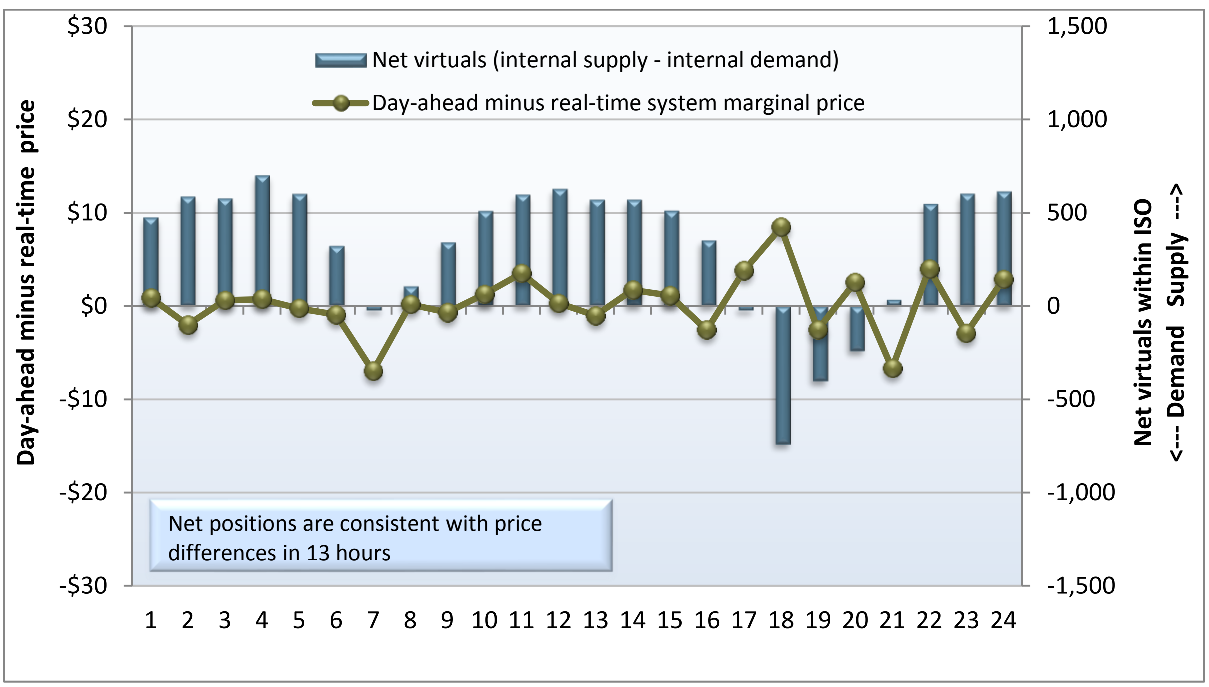
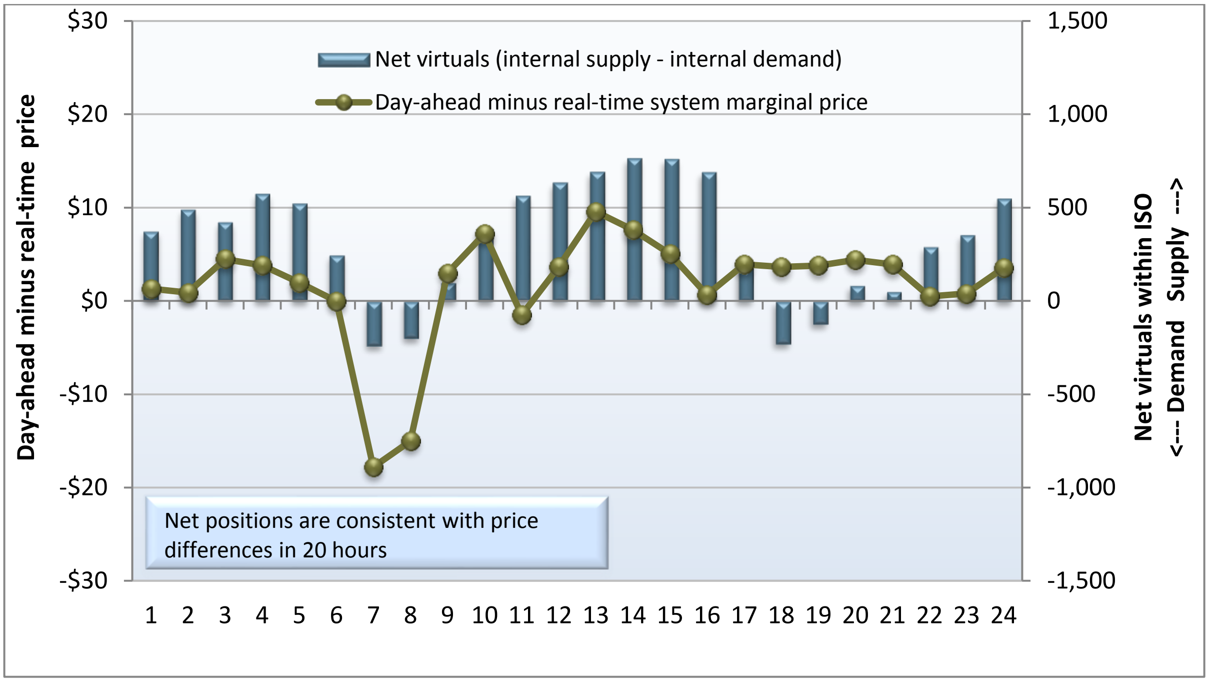


**Figure 2.6 Hourly convergence bidding volumes and prices – December**




In December, as seen in Figure 2.6, the convergence bidding volumes began to be more consistent with differences between day-ahead and real-time prices. There were 20 hours where net convergence bidding volumes were consistent with day-ahead and real-time price differences.

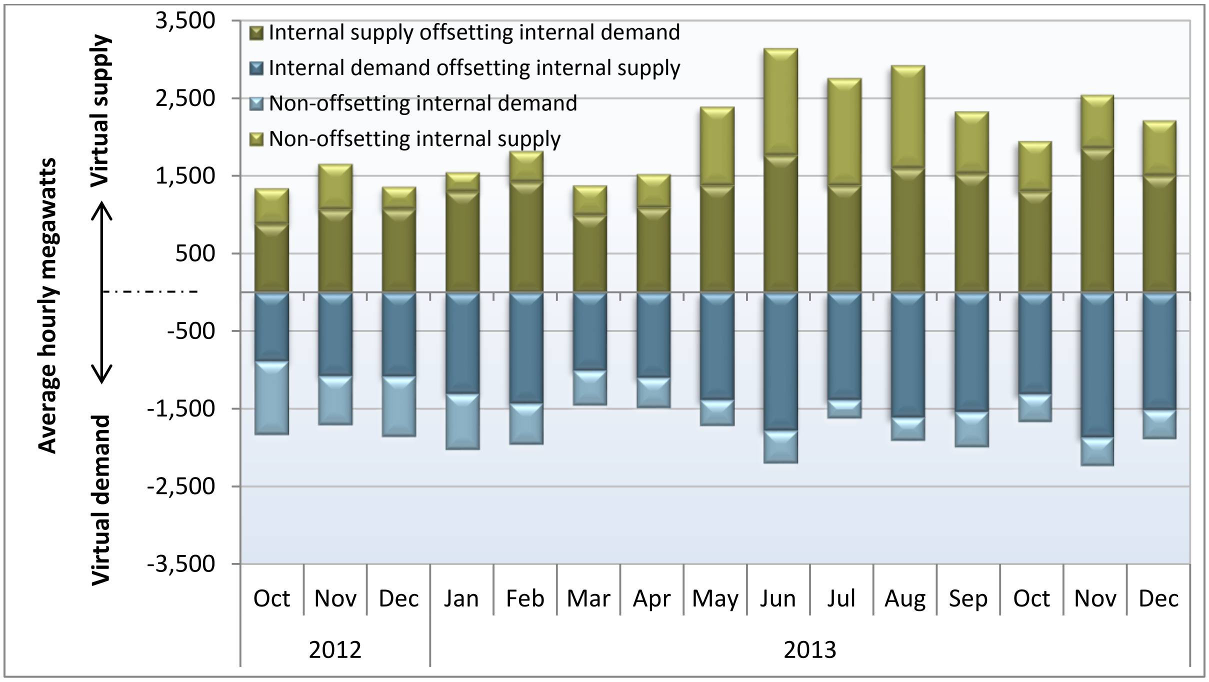
### Offsetting virtual supply and demand bids at internal points

Market participants can also hedge congestion costs or earn revenues associated with differences in congestion between different points within the ISO system by placing virtual demand and supply bids at different internal locations during the same hour. These virtual demand and supply bids offset each other in terms of system energy. However, the combination of these offsetting bids can be profitable if there are differences in price caused by congestion in the day-ahead and real-time markets between these two locations.

In the fourth quarter, the majority of cleared virtual bids were offsetting bids. The amount of non-offsetting internal supply continued to be relatively high compared to the same quarter the previous year. 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 overlap between internal demand and internal supply by the same participants. The lighter portion of each bar represents the remaining portion of internal virtual supply (green) and demand (blue) that was not offset by internal virtual demand or supply by the same participants.

As shown in Figure 2.7, offsetting virtual positions at internal locations accounted for an average of about 1,560 MW of virtual demand offset by 1,560 MW of virtual supply in each hour of the fourth quarter. These offsetting bids represent about 75 percent of all cleared internal virtual bids in the fourth quarter, an increase from 67 percent in the previous quarter. This suggests that virtual bidding continues to be used to hedge or profit from internal congestion.

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




## 2.2 Convergence bidding revenues

This section highlights sources of net revenues (or payments) received (or paid) by convergence bidders. As with the previous quarter, participants engaged in convergence bidding in the ISO markets earned positive returns. In the fourth quarter net revenues were about $9.3 million, with most of the positive revenue associated with virtual supply bids. For the year, convergence bidding net revenues were around $25 million, down from about $56 million in 2012. Most of the net revenues in 2013 were related to virtual supply positions, accounting for about $52 million while virtual demand positions had losses of $26 million. In 2012, virtual demand revenues totaled about $39 million and virtual supply revenues totaled just over $18 million.

**Figure 2.8 Total monthly net revenues paid from convergence bidding**

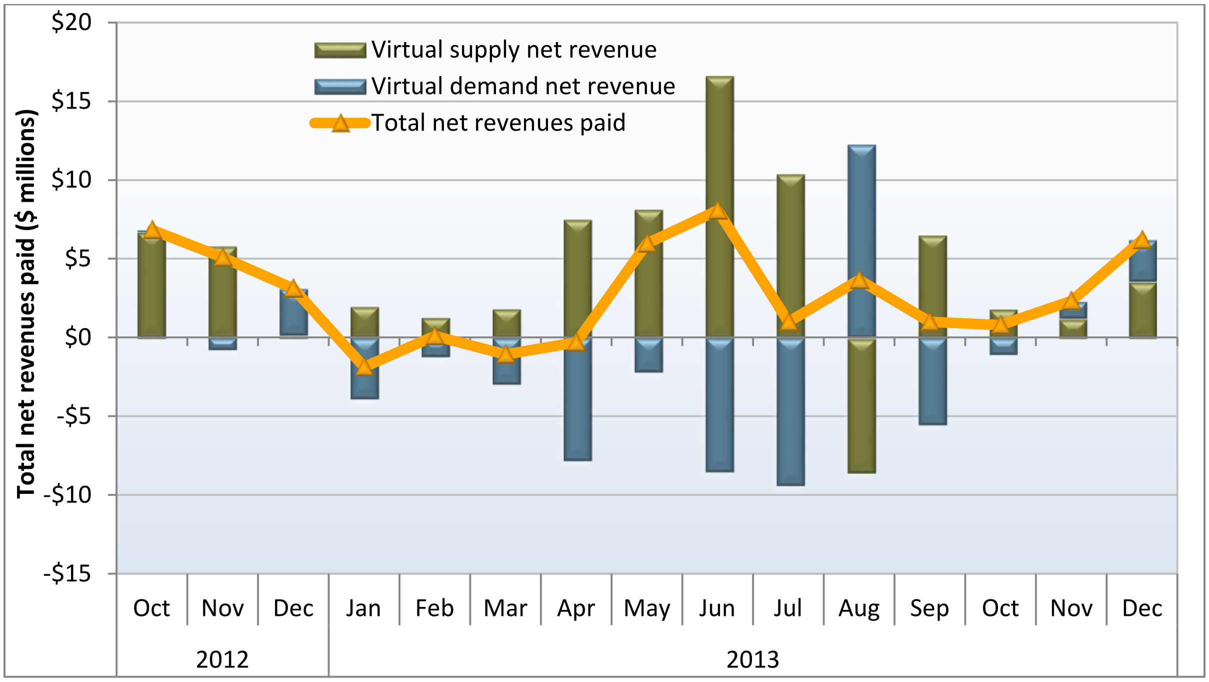



Figure 2.8 shows total monthly net revenues for cleared virtual supply and demand. This figure shows the following:

- The net revenues from the market were about $9.3 million in this quarter, compared to about $5.5 million in the previous quarter.
- Virtual supply revenues were profitable in every month of the fourth quarter and can be attributed to day-ahead prices being generally higher than real-time prices. In total, virtual supply accounted for net payments of about $6.6 million for the quarter.
- Virtual demand was profitable in November and December. In total, virtual demand accounted for approximately $2.7 million in net payments from the ISO markets for the quarter.
- Although trading volumes decreased from the last quarter, total net revenues paid to virtual bidders increased significantly. This change was driven by gains on both virtual supply and demand positions. Virtual demand positions were able to incur large revenue gains associated with a period of unseasonably cold weather and higher than normal gas prices which caused extremely high real-time prices on a few days in December.
- In the fourth quarter, convergence bidders were paid close to $6.6 million, after taking into account virtual bid cost recovery charges of around $2.7 million for the quarter.

### Net revenues at internal scheduling points

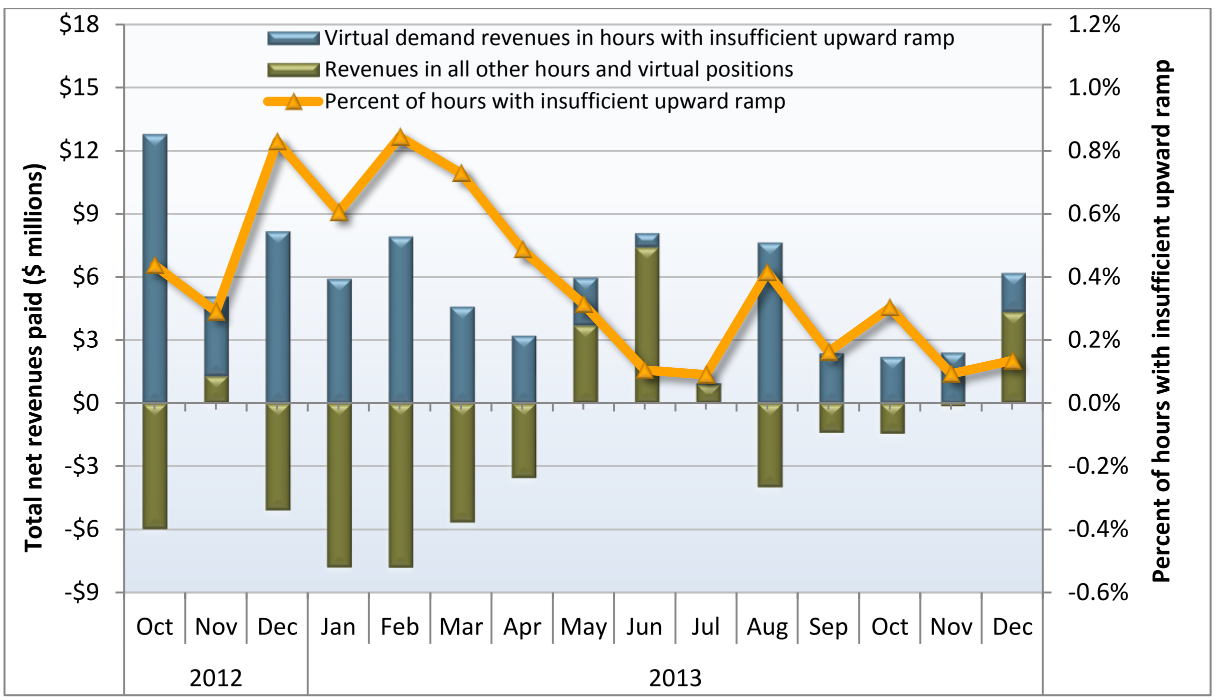
In the fourth quarter, 66 percent of bid-in virtual demand cleared at internal locations, similar to the third quarter. Virtual demand bids at internal nodes are often profitable when real-time prices spike in the 5-minute real-time market. Almost all net revenues paid for these internal virtual demand 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 congestion. Virtual supply bids are profitable when real-time prices drop below day-ahead prices. Historically, this has happened during off-peak hours when over-generation can drive the real-time prices down.

Figure 2.9 compares total net revenues paid out for internal virtual demand 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 under 0.3 percent of the hours in the quarter, these hours accounted for the majority of 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. However, unlike previous quarters, fourth quarter revenues paid out during these periods were sufficient to offset virtual demand losses in other periods.

- Total net revenues were around $9.3 million. Virtual demand net revenues were around $6.5 million during intervals of insufficient upward ramp. Virtual revenues in all other intervals were around $2.8 million, driven by positive revenues of about $6.6 million in virtual supply and negative revenues of just under $4 million in virtual demand during these intervals in the fourth quarter.

**Figure 2.9 Net revenues paid for convergence bids at internal scheduling points during hours with energy power balance constraint relaxations due to shortages of upward ramping**




Real-time 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 a number of factors, including the following:

- As discussed in prior sections of this chapter, the impact of virtual internal demand in the day-ahead market was offset by virtual supply.
- Any additional capacity potentially made available by convergence bidding may not be enough to address the short-term ramping limitations in the real-time market.

Also, in the event of over-generation, real-time prices can be negative, but rarely fall below the bid floor of -$30/MWh.[27] This diminishes the risk of market participants losing substantial money by bidding virtual demand and reduces the potential benefits to virtual supply bids at internal nodes.

### Net revenues and volumes by participant type

DMM's analysis finds that most convergence bidding activity is conducted by entities engaging in pure financial trading that do not serve load or transact physical supply. These entities accounted for $8 million (85 percent) of the total convergence bidding settlements and a vast majority of revenue gains in the fourth quarter.

Table 2.1 compares the distribution of convergence bidding volumes and revenues among different groups of convergence bidding participants. The trading volumes show cleared virtual positions along with the corresponding net revenues in millions of dollars.

DMM has defined financial entities as participants who own no physical power and participate in the convergence bidding and congestion revenue rights markets only. Physical generation and load are represented by participants that primarily participate in the ISO markets as physical generators and load-serving entities, respectively. Marketers include participants on the inter-ties and participants whose portfolios are not primarily focused on physical or financial participation in the ISO market.

As shown in Table 2.1, financial participants represent the largest segment of the virtual market, accounting for about 84 percent of volumes and about 85 percent of settlement dollars. Marketers represent about 7 percent of the trading volumes and 6 percent of the settlement dollars. Generation owners and load-serving entities represent a small segment of the virtual market in terms of volumes (about 9 percent) and settlements (8 percent).

**Table 2.1 Convergence bidding volumes and revenues by participant type (October – December)**

| Trading entities | Average hourly megawatts | | | Revenues\Losses ($ millions) | | |
|---|---|---|---|---|---|---|
| | Virtual demand | Virtual supply | Total | Virtual demand | Virtual supply | Total |
| Financial | 1,719 | 1,793 | 3,513 | $2.6 | $5.4 | $8.0 |
| Marketer | 108 | 179 | 287 | $0.3 | $0.3 | $0.6 |
| Physical generation | 95 | 127 | 223 | -$0.2 | $1.0 | $0.8 |
| Physical load | 0 | 138 | 138 | $0.0 | -$0.1 | -$0.1 |
| **Total** | **1,923** | **2,238** | **4,160** | **$2.7** | **$6.6** | **$9.3** |

[27] The floor will drop to -$150/MWh in April 2014.

### Virtual bid cost recovery charges

As previously noted, virtual supply and demand bids are treated similarly to physical supply and demand in the day-ahead market. However, virtual bids are excluded from the day-ahead market processes for price mitigation and grid reliability (local market power mitigation and residual unit commitment). This impacts how physical supply is committed in both the integrated forward market and in the residual unit commitment process.[28] When the ISO commits units, it may pay market participants through the bid cost recovery mechanism to ensure that market participants are able to recover start-up costs, minimum load costs, transition costs, and energy bid costs.[29]

Because virtual bids can influence unit commitment, they share in the associated costs. Specifically, virtual bids can be charged for bid cost recovery payments under two charge codes.[30]

- Integrated forward market bid cost recovery tier 1 allocation addresses costs associated with situations when the market clears with positive net virtual demand.[31] In this case, virtual demand leads to increased unit commitment in the day-ahead market, which may not be economic.
- Day-ahead residual unit commitment tier 1 allocation relates to situations where the day-ahead market clears with positive net virtual supply.[32] In this case, virtual supply leads to decreased unit commitment in the day-ahead market and increased unit commitment in the residual unit commitment, which may not be economic.

As shown in Figure 2.10, the day-ahead residual unit commitment tier 1 allocation charge associated with virtual bids exceeded the previous high point from the summer, in percentage terms, by reaching a

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[28] If physical generation resources clearing the day-ahead energy market are less than the ISO's forecasted demand, the residual unit commitment process ensures that enough additional physical capacity is available to meet the forecasted demand. Convergence bidding increases unit commitment requirements to ensure sufficient generation in real time when the net position is virtual supply. The opposite is true when virtual demand exceeds virtual supply.

[29] Generating units, pumped-storage units, or resource-specific system resources are eligible for receiving bid cost recovery payments.

[30] Both charge codes are calculated by hour and charged on a daily basis.

[31] Total integrated forward market (IFM) load and convergence bidding entities with a net virtual demand position may be charged an IFM Tier 1 uplift charge. This is triggered when the system-wide virtual demand is positive. Market participants with portfolios that clear with positive net virtual demand are charged. Market participants will not be charged if physical demand plus virtual demand minus virtual supply is equal to or less than measured demand. Specifically, the uplift obligation for virtual demand is based on how much additional unit commitment was driven by net virtual demand that resulted in the integrated forward market clearing above what was needed to satisfy measured demand. Physical load and virtual demand pay the same IFM uplift rate. The rate is calculated on an hourly basis and charged daily. For further detail, see Business Practice Manual configuration guides for charge code (CC) 6636, IFM Bid Cost Recovery Tier1 Allocation_5.1a: http://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing.

[32] There are two payments associated with the day-ahead residual unit commitment. One is the residual unit commitment availability payment at the residual unit commitment price, and the other is residual unit commitment bid cost recovery. During the day-ahead market, if the scheduled demand is less than the forecast, residual unit commitment availability is procured to ensure that enough committed capacity is available and online to meet the forecasted demand. Awarded capacity is paid at the residual price. The residual unit commitment bid cost recovery uplift obligation is allocated when system-wide net virtual supply is positive. The virtual supply obligation to pay a residual unit commitment bid cost recovery tier 1 uplift is based on the pro-rata share of the total obligation as determined by market participants' total net virtual supply awards. Allocation of residual unit commitment compensation costs is calculated by hour and charged by the day. For further detail, see Business Practice Manual configuration guides for charge code (CC) 6806, Day Ahead Residual Unit Commitment (RUC) Tier 1 Allocation_5.5: http://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing.

peak of about 20 percent of total bid cost recovery charges in December compared to the previous high of 16 percent in June. This is consistent with an increase in the number of individual net virtual supply hours and associated residual unit commitment costs in December compared to previous months. Market participants with net virtual supply, which contributes to residual unit commitment costs, share in the associated bid cost recovery charges. The integrated forward market bid cost recovery costs associated with net virtual demand remained low in the fourth quarter. This charge reached its high in the third quarter of 2012 when the market was significantly net virtual demand.

Figure 2.11 shows estimated total convergence bidding revenues, total revenues less bid cost recovery charges and costs associated with the two bid cost recovery charge codes. The total convergence bidding bid cost recovery costs for the fourth quarter were close to $2.7 million. As noted earlier, the total estimated net revenue for convergence bidding was around $9.3 million. Total convergence bidding revenue adjusted for bid cost recovery costs was around $6.6 million.

For the year, total convergence bidding bid cost recovery costs were nearly $9 million, compared to about $3.5 million in 2012. Adjusting convergence bidding revenues for total convergence bid cost recovery costs results in total revenues of around $16 million in 2013, compared to about $52.5 million in 2012.

**Figure 2.10 Convergence bidding costs associated with bid cost recovery tier 1 and residual unit commitment tier 1 as a percent of total bid cost recovery**

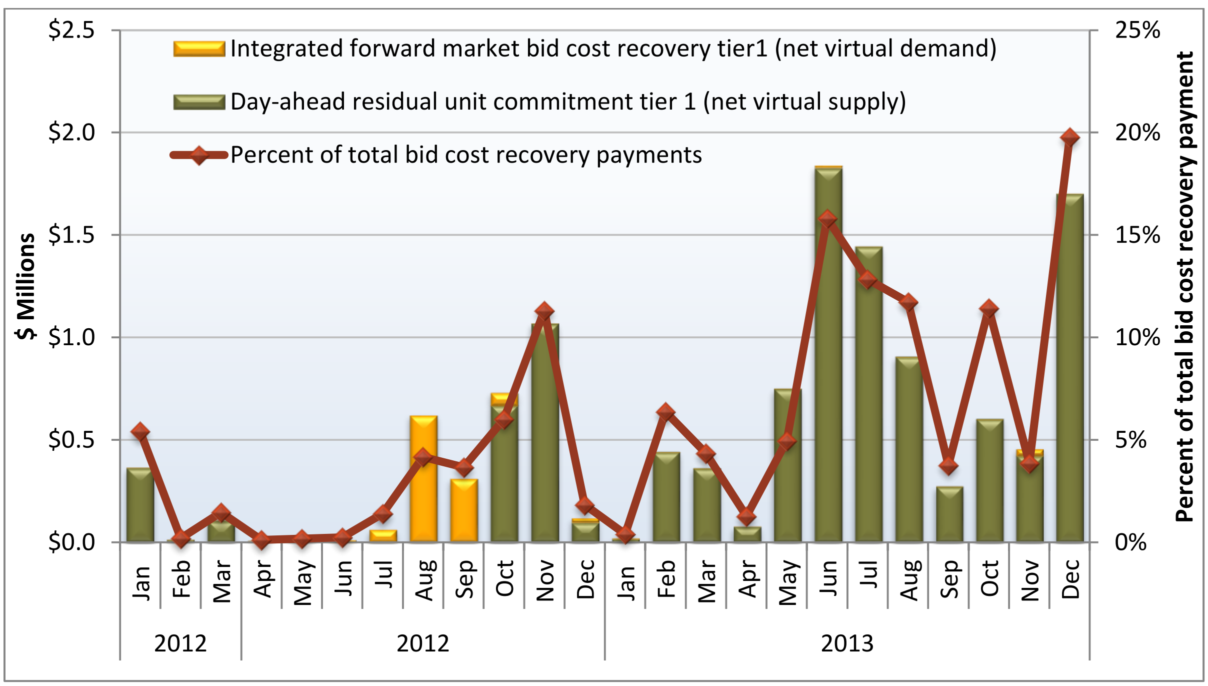
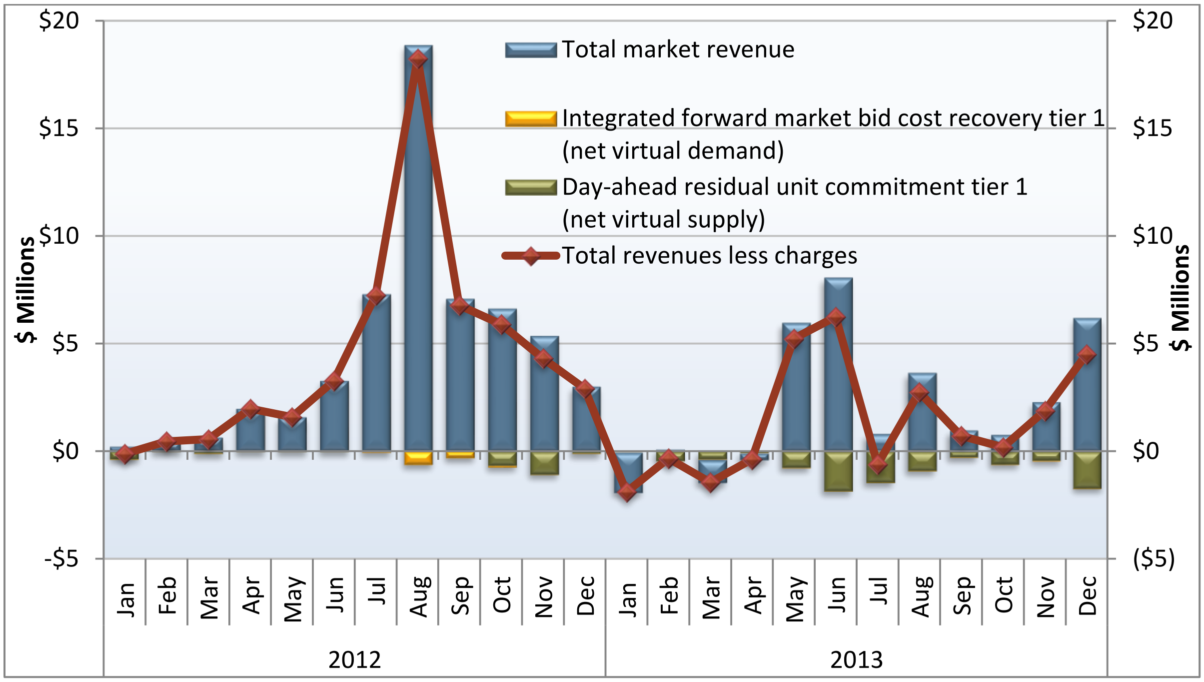


**Figure 2.11 Convergence bidding revenues and costs associated with bid cost recovery tier 1 and residual unit commitment tier 1**



# 3 Special Issues

## 3.1 Congestion revenue rights revenue adequacy

On an annual basis, the congestion revenue rights process generated a $3 million net revenue surplus in 2013, a substantial reduction from the $23 million surpluses in both 2011 and 2012. In the first half of 2013, congestion revenue rights generated a $29 million net revenue surplus. However, in the third quarter, the process generated a shortfall of around $8 million followed by a greater shortfall of around $18 million in the fourth quarter. Overall, in 2013, revenues from the congestion revenue rights auctions covered the relatively high revenue shortfalls. This section analyzes the reasons behind the decline in congestion revenue right revenue adequacy in the second half of the year.

Congestion revenue rights are financial instruments that allow participants to hedge against congestion costs in the day-ahead market. The market for congestion revenue rights is designed such that congestion rent collected from the day-ahead energy market is sufficient to cover payments to congestion revenue rights holders. This is referred to as revenue adequacy.[33]

Despite these limits, congestion rents collected in the day-ahead market may not be sufficient to cover payments to congestion revenue rights holders. Revenue inadequacy is mainly due to differences between the network transmission model used in the congestion revenue rights process and the final day-ahead market model. For example, outages that cannot be captured by the 30-day reporting rule, such as unscheduled or forced outages, cannot be explicitly reflected in the congestion revenue rights release process. Under actual market conditions, events such as transmission outages and de-rates can create revenue deficiencies and surpluses even when the congestion expectations in the auction and in the day-ahead market are identical. Therefore, all revenues from the annual and monthly auction processes are included in the congestion revenue rights balancing account to help ensure revenue adequacy, if needed. Any shortfall or surplus in the balancing account at the end of each month is allocated to measured demand.

The ISO releases its initial full-network model for the monthly congestion revenue right market around the 25$^{th}$ of each month. The released model is used for the month that is two months out from the release month. The model can be adjusted several times before the ISO finalizes its full network model, which is typically released around the 9$^{th}$ or 10$^{th}$ of each month. For example, the initial release of the February 2014 congestion revenue right full network model was posted on December 24 and the final version was posted on January 10. The ISO can make additional edits if necessary for transmission elements that are already in the full network model topology. Therefore, in general, there is an inherent timing difference between incorporation of transmission modeling into the congestion revenue rights process and the day-ahead market.

In general, the day-ahead model is expected to be more restrictive than the congestion revenue right model because transmission changes unanticipated at finalization of the congestion revenue right model are more likely to reduce available transmission capacity than to increase it, as transmission flows are

[33] For a more detailed explanation of congestion revenue rights revenue adequacy and the simultaneous feasibility test, please see the ISO's 2013 reports on congestion revenue rights at: http://www.caiso.com/market/Pages/ProductsServices/CongestionRevenueRights/Default.aspx.

de-rated to account for outages and other unanticipated conditions. In addition, new nomograms not in place when the congestion revenue rights full network model is finalized may impose limits on transmission capacity in the day-ahead market.[34] Therefore, the quantity of congestion revenue rights released in the monthly and annual congestion revenue rights processes for a path may be higher than the actual transmission capacity available in the day-ahead market, increasing the potential for revenue inadequacy.

Figure 3.1 shows the revenues, payments and overall revenue adequacy of the congestion revenue rights market by quarter for the last three years. The dark blue bars represent congestion rent, which accounts for the main source of revenues in the balancing account. Light blue bars show net revenues from the annual and monthly auctions for congestion revenue rights corresponding to each quarter. This includes revenues paid for positively priced congestion revenue rights in the direction of expected prevailing congestion, less payment made to entities purchasing negatively priced counter-flow congestion revenue rights. Dark green bars show net payments made to holders of congestion revenue rights. This includes payments made to holders of rights in the prevailing direction of congestion plus revenues collected from entities purchasing counter-flow congestion revenue rights. The orange line shows the sum of monthly total revenue adequacy for the three months in each quarter when revenues from the auction are included.

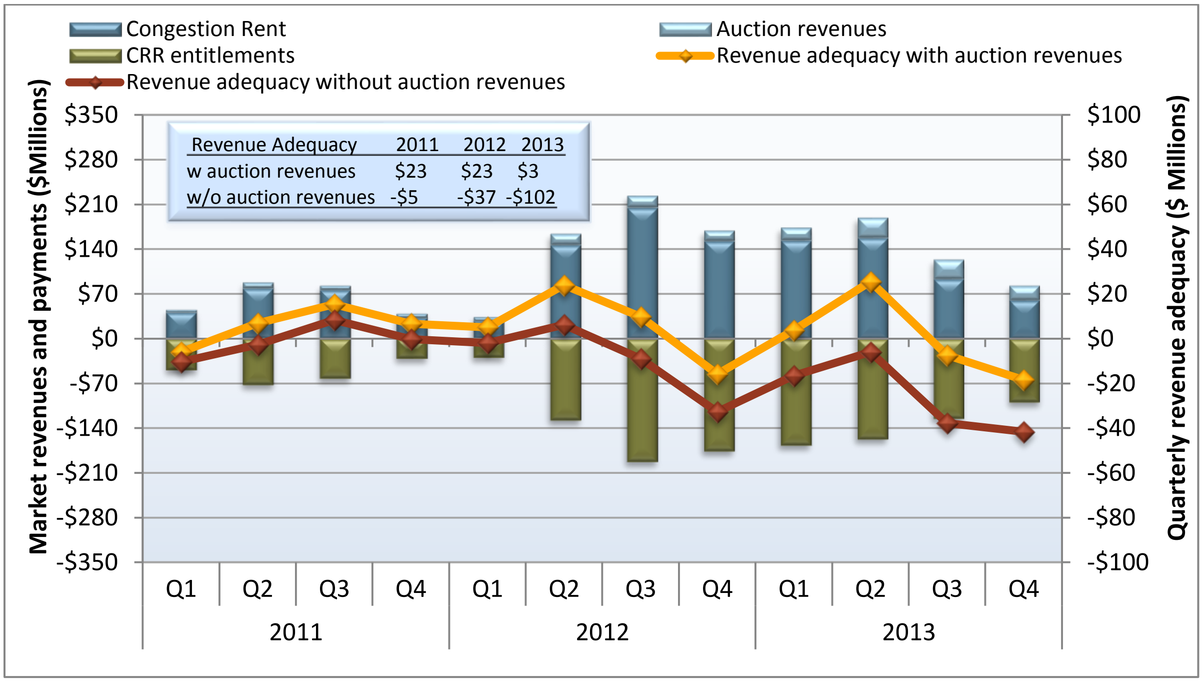
As shown in Figure 3.1, congestion revenue rights before auction revenues had significant levels of revenue shortfall in the second half of 2013. Shortfalls were due in part to the following differences between the network transmission model used in the congestion revenue rights process and the day-ahead market model:

- **Nomograms and constraints created due to a planned outage of the Devers-Palo Verde 500 kV line**: The Devers nomograms restrict flow through 115 kV to 230 kV transformers outside the ISO grid. Transfer through these transformers was not constrained in the congestion revenue right model until December.
    - **Palo Verde inter-tie:** This de-rate took the limit of the interface below the amount released in the seasonal congestion revenue right process for the fourth quarter. As a result, congestion revenue right revenue was inadequate in all congested hours, most notably in November.
    - **SLIC_2161499_DEVERS-VISTA_NG nomogram**: This nomogram led to revenue shortfalls of around $6 million in August, September and October.
- **6110_TM_BNK_FLO_TMS_DLO_NG nomogram**: In July, a revenue shortfall of around $11 million occurred on the 6110_TM_BNK_FLO_TMS_DLO_NG nomogram due to the difference between the value of the limit considered in the congestion revenue right model and the more restrictive limit used in the day-ahead market to account for anticipated loop flow.
- **7430_SOL-8_NO_HELMS_PUMP_NG nomogram**: This nomogram was intended to be an intermittent constraint that would not be enforced all the time in the day-ahead market. Therefore, the constraint was not initially implemented in the congestion revenue right model. However, further studies determined that the impact of the constraint on congestion

[34] A monthly meeting between operations engineers and the congestion revenue right group is planned to review long-term outages and the modeling of these outages within the congestion revenue rights model.

revenue rights was significant enough to include it in the congestion revenue right model. The constraint was enforced beginning with the October 2013 monthly congestion revenue right process. Total revenue shortfall on this constraint was around $9 million in July, August and September.

**Figure 3.1 Congestion revenue right quarterly revenue adequacy**




## 3.2 California greenhouse gas allowance market

Generating resources became subject to California's greenhouse gas cap-and-trade program compliance requirements starting on January 1, 2013. This section highlights the impact of these requirements in 2013. These highlights include the following:

- The cost of greenhouse gas emissions permits fell in the fourth quarter to an average of \$11.86/mt$CO_2$e, ending the quarter at \$11.75/mt$CO_2$e. This is down from the first, second, and third quarter prices, which averaged \$14.55/mt$CO_2$e, \$14.59/mt$CO_2$e, and \$13.27/mt$CO_2$e, respectively.[35]

- Total imports offered to the market decreased by 12 percent in the final half of 2013 compared to the same period in 2012. This follows increases in the first half of the year when the total amount of import megawatts offered to the market increased for each month in 2013 compared to the first half of 2012. Fourth quarter imports were, however, similar to 2011 levels. DMM does not attribute the drop in offered imports in the second half of 2013 to the cap-and-trade program as there are many other potential factors driving this change.

[35] mt$CO_2$e stands for metric tons of carbon dioxide equivalent, a standard emissions measurement.

- Based on statistical analysis of changes in day-ahead market energy prices following cap-and-trade implementation, DMM estimates that average wholesale prices are about $6/MWh higher due to cap-and-trade compliance costs for the year. This is consistent with the emissions costs for gas units typically setting prices in the ISO market.

### Background

California Assembly Bill 32 (AB 32), the Global Warming Solutions Act of 2006, directs the California Air Resources Board (CARB) to develop regulation to reduce greenhouse gas emissions to 1990 levels by 2020. The cap-and-trade program is one of a suite of regulatory measures adopted by CARB to achieve this goal.

The cap-and-trade program covers major sources of greenhouse gas emissions including power plants.[36] The program includes an enforceable emissions cap that will decline over time. California will directly distribute and auction allowances, which are tradable permits equal to the emissions allowed under the cap.

The impact of higher wholesale prices on retail electric rates will depend on policies adopted by the CPUC and other state entities. As part of the cap-and-trade program, the CARB allocated allowances to the state's electric distribution utilities to help compensate electricity customers for the costs that will be incurred under the cap-and-trade program. The investor-owned electric utilities are required to sell all of their allowances at CARB's quarterly auctions, and the proceeds from the auction are to be used for the benefit of retail ratepayers, consistent with the goals of AB 32. Under a 2012 CPUC decision, revenue from carbon emission allowances sold at auction will be used to offset impacts on retail costs.[37]

One allowance represents one metric ton of $CO_2e$. Sources with compliance obligations are required to surrender allowances and offsets equal to their emissions at the end of each compliance period, with a partial annual surrender in the interim years. Imports from unspecified sources and electric generation resources emitting more than 25,000 metric tons of greenhouse gas annually, either within California or as imports into California, are covered under the first phase of the cap-and-trade program, which started on January 1, 2012, with enforceable compliance obligations beginning with emissions during 2013.

AB 32 requires CARB to minimize *leakage*, which is a reduction in greenhouse gas emissions within California that is offset by an increase in greenhouse gas emissions outside of California. The cap-and-trade program limits leakage in part by prohibiting *resource shuffling*, or substituting imports of lower greenhouse gas emitting resources for imports actually sourced from higher emitting resources to avoid the cost of allowances. Proposed cap-and-trade regulation changes that incorporate resource shuffling

[36] The cap-and-trade program covers major sources of greenhouse gas emissions in California such as refineries, power plants, industrial facilities, and transportation fuels. For the electricity sector, the covered entity is the first deliverer of electricity. The first deliverer is defined in the regulation as the operator of an in-state electricity generator, or an electricity importer. The compliance obligation for first deliverers is based on the emissions that are a result of the electricity they place on the grid. The threshold for inclusion in the program for electricity generated from an in-state facility, and for imported electricity from a specified source, is 25,000 metric tons of annual greenhouse gas emissions. For imported electricity from unspecified sources, there is no threshold and all emissions are covered.

[37] Pursuant to CPUC decision Docket #R.11-03-012, the investor-owned utilities will distribute this revenue to emissions-intensive and trade-exposed businesses, to small businesses, and to residential ratepayers to mitigate carbon costs. Remaining revenues will be given to residential customers as an equal semi-annual bill credit. See http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M039/K594/39594673.PDF.

definitions into the regulation and clarify resource shuffling safe harbors were released in draft form in July and presented to CARB's board for public comment and consideration on October 25.[38] The proposed rule changes would also permanently eliminate a temporarily waived requirement that market participants attest each year that they have not engaged in resource shuffling.[39]

Generators and importers that are covered by the regulations are required to submit allowances covering 30 percent of emissions in each year and the remainder of their emissions in the final year of each three year compliance period. In addition to allowances, covered generators and importers may submit emissions offsets to cover up to 8 percent of their emissions.[40] The total cap on emissions is set to decline 2 percent annually through 2014 and then about 3 percent annually through 2020.

Allowances are available at quarterly auctions held by the Air Resources Board and may also be traded bilaterally. In addition, financial derivatives based on allowance prices are traded on public exchanges such as the InterContinental Exchange (ICE). Allowances are associated with a specific year, which is known as the *vintage*. Allowances are *bankable*, meaning that an allowance may be submitted for compliance in years subsequent to the vintage of the allowance.[41] *Borrowing* of allowances is not allowed, meaning that permits for future years cannot satisfy compliance requirements in an earlier year.[42]

The cap-and-trade program affects wholesale electricity market prices in two ways. First, market participants covered by the program will presumably increase bids to account for the incremental cost of greenhouse gas allowances. Second, the ISO amended its tariff, effective January 1, 2013, to include greenhouse gas compliance cost in the calculation of each of the following:

- Resource commitment costs (start-up and minimum load costs);
- Default energy bids, which are bids used in the automated local market power mitigation process; and
- Generated bids (bids generated on behalf of resource adequacy resources and as otherwise specified in the ISO tariff).[43]

[38] The proposed regulation changes are posted here: http://www.arb.ca.gov/cc/capandtrade/meetings/071813/ct_reg_2013_discussion_draft.pdf. A presentation describing the proposed cap-and-trade program regulation changes is available here: http://www.arb.ca.gov/cc/capandtrade/meetings/071813/workshoppresentation.pdf. The draft resolution presented at the October 25 CARB board meeting is available here: http://www.arb.ca.gov/cc/capandtrade/oct-25-drft-brd-res.pdf. Also, see CARB Regulatory Guidance document: *What is Resource Shuffling*, dated November 2012: http://www.arb.ca.gov/cc/capandtrade/guidance/appendix_a.pdf.

[39] The pending amendments are expected to become effective mid-2014. See proposed regulation cited above and the letter from the CARB Chairman Mary Nichols to Commissioner Moeller of the Federal Energy Regulatory Commission dated August 16, 2012: http://www.arb.ca.gov/newsrel/images/2012/response.pdf.

[40] The first offsets were issued in September: http://www.arb.ca.gov/newsrel/newsrelease.php?id=504.

[41] For example, a vintage 2013 allowance may be used for compliance during either the first (2013-2014), second (2015-2017), or third (2018-2020) compliance periods.

[42] The proposed cap-and-trade regulation changes add an exception to allow limited borrowing for *true-up* allowances for industrial entities, allowances allocated for production changes or allowance allocation not properly accounted for in prior allocations. http://www.arb.ca.gov/cc/capandtrade/meetings/071813/ct_reg_2013_discussion_draft.pdf.

[43] Details on each of the calculations may be found in the ISO Business Practice Manual for Market Instruments, Appendix K: http://bpmcm.caiso.com/BPM Document Library/Market Instruments/BPM_for_Market_Instruments_v26_clean.doc.

The ISO uses a calculated greenhouse gas allowance index price as a daily measure of the cost of greenhouse gas allowances. The ISO greenhouse gas allowance price is calculated as the average of two market based indices.[44] Daily values of the ISO greenhouse gas allowance index are plotted in Figure 3.2. In the fourth quarter, allowance costs fell to an average \$11.86/mt$CO_2$e, ending the quarter at \$11.75/mt$CO_2$e, one of the lowest values observed this year. Allowance prices fell following CARB's final auction of 2013 on November 19 in which 2013 allowances cleared at \$11.48/mt$CO_2$e. 2016 allowances cleared even lower at \$11.10/mt$CO_2$e.

**Figure 3.2 ISO's greenhouse gas allowance price index**


## Changes in import levels and participation

Nearly 30 percent of ISO load was served by imports from outside the ISO system in 2012, with most of these imports coming from outside California.[45] Prior to the implementation of the cap-and-trade program, stakeholders and regulators were concerned that certain rules related to resource shuffling would result in reduced imports into California as some participants would elect to exit the import

[44] The indices are ICE and ARGUS Air Daily. As the ISO noted in a market notice issued on May 8, the ICE index is a settlement price but the ARGUS price was updated from a settlement price to a volume weighted price in mid-April of this year. For more information, see the ISO notice: http://www.caiso.com/Documents/GreenhouseGasAllowancePriceSourcesRevisedMay8_2013.htm.

[45] See the DMM *2012 Annual Report on Market Issues and Performance*, Section 1.2, on supply conditions: http://www.caiso.com/Documents/2012AnnualReport-MarketIssue-Performance.pdf.

market.[46] Ultimately, while the mix of participants importing power into California has changed slightly in 2013, the levels of imports offered to the market have increased by 1 percent compared to 2012.[47]

Figure 3.3 shows the quantity of imports bid in at inter-ties and cleared in the day-ahead market in 2012 and 2013.[48] Percentages in the boxes in Figure 3.3 highlight the percentage change in total volume of import bids offered each month in 2013 compared to the same month in 2012. Total import megawatts offered increased by around 13 percent in the first six months of 2013 compared to the same period in 2012.

In the second half of 2013, imports offered decreased by 10 percent compared to the same period in 2012. DMM does not attribute the drop in offered imports in the second half of 2013 to the cap-and-trade program as there are many other potential factors driving this change. In fact, offered imports in the second half of 2013 exceeded second half 2011 levels. While DMM does not have detailed information with respect to supply and demand conditions outside of the ISO system, DMM is aware that, especially in the second half of 2013, hydro-electric generation in the Pacific Northwest decreased compared to the same period in 2012, offering a partial explanation for the decrease in offered imports.

As shown by the darker bars in Figure 3.3, the volume of import bids that cleared the market increased in the first four months of 2013 compared to 2012 and decreased in the remaining months of 2013. In the second half of 2013, import megawatts cleared in the market decreased by around 18 percent compared to the same period in 2012. This change is likely to be affected by relative price differences between prices inside and outside of California. DMM observed that bilateral prices at the Mid-Columbia and Palo Verde hubs were much closer to California hub prices during the second part of 2013, especially in July, August and December, compared to the first half, which could partially explain the change in cleared imports.

In the second half of 2013, the decrease in offered and cleared import megawatts was most pronounced for imports from the north. This may be mainly due to reduced hydro generation in the Pacific Northwest. Decreases in overall imports can be attributed to demand conditions inside and outside of California as well as prices inside and outside the ISO system. For the year, import megawatts offered increased by 1 percent and import megawatts cleared in the market decreased by 6 percent compared to 2012.

Bid prices for imports have increased notably in 2013 compared to 2012. However, DMM attributes most of this increase to higher gas prices, which have risen by about 30 percent over this period. Given the significant change in gas prices over this period, DMM has not sought to quantify the portion of higher import bid prices that may be attributable to greenhouse gas allowance costs.

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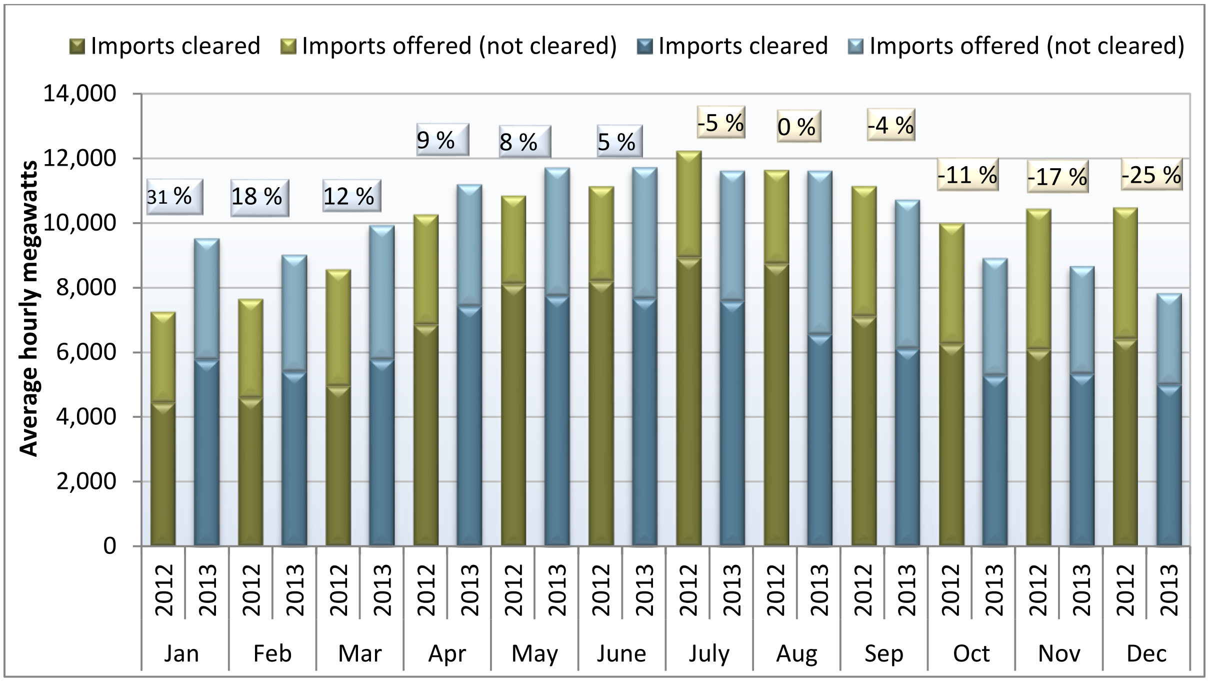
[46] See the August 6 letter from FERC Commissioner Moeller to Governor Brown: [http://www.ferc.gov/about/com-mem/moeller/moeller-08-06-12.pdf](http://www.ferc.gov/about/com-mem/moeller/moeller-08-06-12.pdf).

[47] There were a small number of participants, specifically, public entities, and their associated imports into California, which explicitly stopped importing as a result of the program. However, new market entrants have begun to import into California and include a mix of public entities and private companies.

[48] This analysis excludes imports from dynamic system units and wheels.

**Figure 3.3 Inter-tie imports offered and cleared in the day-ahead market[49]**




## Changes in market prices

Greenhouse gas compliance costs are expected to increase wholesale electricity costs as both market participant bids and the ISO's own calculation of default energy bids, resource commitment costs and generated bids increase to reflect the additional incremental variable cost of greenhouse gas compliance.

DMM has adopted a statistical approach to estimate the impact of greenhouse gas costs on day-ahead market prices during the first year of greenhouse gas compliance. This approach relies on the comparison of market data before cap-and-trade implementation with data from 2013.[50] DMM used a similar model in the prior quarters, but has improved upon it to control for differences in convergence

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[49] Percentages in the boxes highlight the percentage change in total volume of import bids offered each month in 2013 compared to the same month in 2012.

[50] As demonstrated in Figure 3.4, the ISO's estimated greenhouse gas compliance cost does not exhibit sufficient variation to determine the impact based on minor fluctuations in this value alone.

bidding volumes, assumed to be exogenous.[51] As in the third quarter analysis, DMM has limited the sample to days in which the implied heat rate in every hour is less than 20,000 Btu/kWh.[52]

The energy price DMM chose to analyze was the day-ahead system marginal energy cost.[53] DMM chose to analyze changes in this value to limit the effects of transmission congestion when trying to isolate the effect of the greenhouse gas costs. While the system marginal energy cost does not eliminate transmission congestion effects, it can act as a reasonable benchmark for system prices.[54]

DMM estimates the impact of greenhouse gas compliance on wholesale energy prices by estimating average daily system energy prices as a linear function of a measure of greenhouse gas compliance cost, a weighted gas price index, a non-linear function of expected load, indicator variables for holidays, Saturday and Sunday, net virtual supply, scheduled generation availability for fuel types that we assume to be exogenous (hydro, wind, solar, geo-thermal, and nuclear), and imports (as modeled by exogenous gas price indices).[55]

$$\begin{aligned}\text{Average Electricity Price} = {} & \beta_0 + \beta 1\ \text{GHG} + \beta_2\text{Load} + \beta_3\text{Load}^2 + \beta_4\text{Load}^3 + \beta_5\text{Gas}_{\text{Weighted}} + \\ & \beta_6\text{Holiday} + \beta_7\text{Saturday} + \beta_8\text{Sunday} + \beta_9\text{NetVS} + \beta_{10}\text{Wind} + \\ & \beta_{11}\text{Solar} + \beta_{12}\text{Hydro} + \beta_{13}\text{Nuclear} + \beta_{14}\text{Geothermal} + \\ & + \beta_{15}\text{Imports\_IV} + \varepsilon\end{aligned}$$

51 For this analysis, DMM assumes that convergence bidding volumes are determinants of rather than determined by day-ahead energy prices. Virtual bids are assumed to be based on expectations of energy prices, and are thus exogenous. A summary of our earlier analysis is available in the *Quarterly Report on Market Issues and Performance* for Q3 2013: http://www.caiso.com/Documents/2013ThirdQuarterReport-MarketIssues_Performance-Nov2013.pdf.

52 This selection eliminates 36 days in the 24 month period containing hours that DMM has determined to be outliers. In these hours, the day-ahead system marginal energy cost exceeds the marginal gas and greenhouse gas emissions cost of units with a heat rate of 20,000 Btu/kWh, a value far above the heat rate of all but a very few peaking units in the ISO market. In each hour, the greenhouse gas adjusted implied heat rate is calculated by dividing the system marginal energy costs by the sum of a weighted average gas price and an estimated greenhouse gas cost. In each hour, the gas price is a weighted average of three regional gas price indices (weights are given in parentheses): PGE2 (0.4), SCE1 (0.5), and SCE2 (0.1). These gas price indices are used by the ISO in calculating default energy bids and other market calculations. The estimated greenhouse gas cost is calculated as the product of the ISO's daily greenhouse gas allowance cost and 0.053165, the EPA's default emissions rate. Prices in the outlying hours may be driven by factors other than incremental variable cost, and, as such, an alternative to DMM's model might be more appropriate to explain changes in price in this subset of hours.

53 This is the energy component of each of the locational marginal prices within the ISO system and excludes both congestion and transmission loss related costs.

54 For further discussion on the system marginal energy price, please see Appendix C of the ISO tariff: http://www.caiso.com/Documents/CombinedConformedTariff_Mar20_2013.pdf.

55 If import supply is elastic, imports may be endogenous. That is, scheduled imports may themselves be a function of electricity prices. Including an endogenous variable in the regression could bias our results, so DMM has used an instrumental variable approach to estimate the impact of greenhouse gas emission costs in a consistent manner. A useful set of instruments has two properties. First, the set should be a powerful predictor of the endogenous factor: imports. Second, the instruments should not be endogenous themselves. For this analysis, DMM uses daily gas price indices for multiple hubs outside of the ISO to instrument import levels. DMM's model is estimated using two stage least squares estimated with the ivreg() function of the AER package (Christian Kleiber and Achim Zeileis (2008). Applied Econometrics with R. New York: Springer-Verlag. ISBN 978-0-387-77316-2. http://CRAN.R-project.org/package=AER.) available in R (R Core Team (2013). R: A language and environment for statistical computing. R Foundation for Statistical Computing, Vienna, Austria. http://www.R-project.org/.)

Using this model, DMM estimates that in 2013 the average impact of greenhouse gas compliance was about \$5.97/MWh or \$0.42 per dollar of the allowance price.[56] DMM also performed this analysis by quarter, developing the following estimates of greenhouse gas compliance impact: \$5.05/MWh in the first quarter, \$8.24/MWh in the second, \$4.22/MWh in the third, and \$2.58/MWh in the fourth.[57] Although rough, our model predicts the average ISO day-ahead system energy prices fairly well, explaining approximately 94 percent of the variation in this measure in both annual models.[58] This analysis may be refined as further data become available.

The statistical approach outlined above produces estimates that are consistent with expectations of the impact of greenhouse gas compliance costs on wholesale electricity costs during a period when market prices are being set close to the marginal operating cost of relatively efficient units. For example, a gas-fired unit with a heat rate of 8,000 Btu/kWh would have an expected emissions cost of 42.5 cents per dollar of greenhouse gas allowance costs. The 42 cents per dollar of the allowance price estimate represents the additional emissions cost of a unit with a heat rate of 7,865 Btu/kWh.[59]

Figure 3.4 illustrates average monthly implied heat rates with and without an adjustment for greenhouse gas compliance costs. The implied heat rate is a standard measure of the maximum heat rate that would be profitable to operate given electricity prices and fuel costs, ignoring all non-fuel costs. The implied heat rate is calculated by dividing the electricity price, in this case the hourly day-ahead system marginal energy price, by fuel price. Because natural gas is often on the margin in the ISO market, we use a weighted average of daily natural gas prices.[60]

[56] Two alternative greenhouse gas measures are used. The first is an indicator variable equal to 1 in the greenhouse gas compliance period and 0 before that period. In this case, the coefficient estimate ($\beta_1$ in the equation above) may be interpreted as the estimated average impact of greenhouse gas compliance on electricity prices (\$/MWh). The second greenhouse gas measure is the ISO's index of the greenhouse gas allowance value, set equal to zero before the compliance period. In this case, the coefficient estimate may be interpreted as the estimated impact of greenhouse gas compliance per allowance cost (\$/MWh divided by \$/mt$CO_2$e). DMM's regression results are based on values from January 2012 through December 2013 to limit bias introduced by factors not yet included in the model. Load is the ISO's hourly day-ahead forecast of ISO load. We assume that the load forecast, which is based on weather indices and historical time series data, is not price responsive in the short-term, which allows us to estimate this model using ordinary least squares, rather than as a system of demand and supply equations. We also assume that the greenhouse gas allowance index price is exogenous rather than endogenously determined by electricity prices. Resource specific day-ahead schedules are summed by fuel type to calculate generation from wind, geothermal, nuclear, solar, hydro, and import sources. The gas price is a weighted average of three regional gas price indices (weights are given in parentheses): PGE2 (0.4), SCE1 (0.5), and SCE2 (0.1). These gas price indices are used by the ISO in calculating default energy bids and other market calculations. Net virtual supply is the average of the hourly difference between cleared virtual supply and virtual demand in each hour.

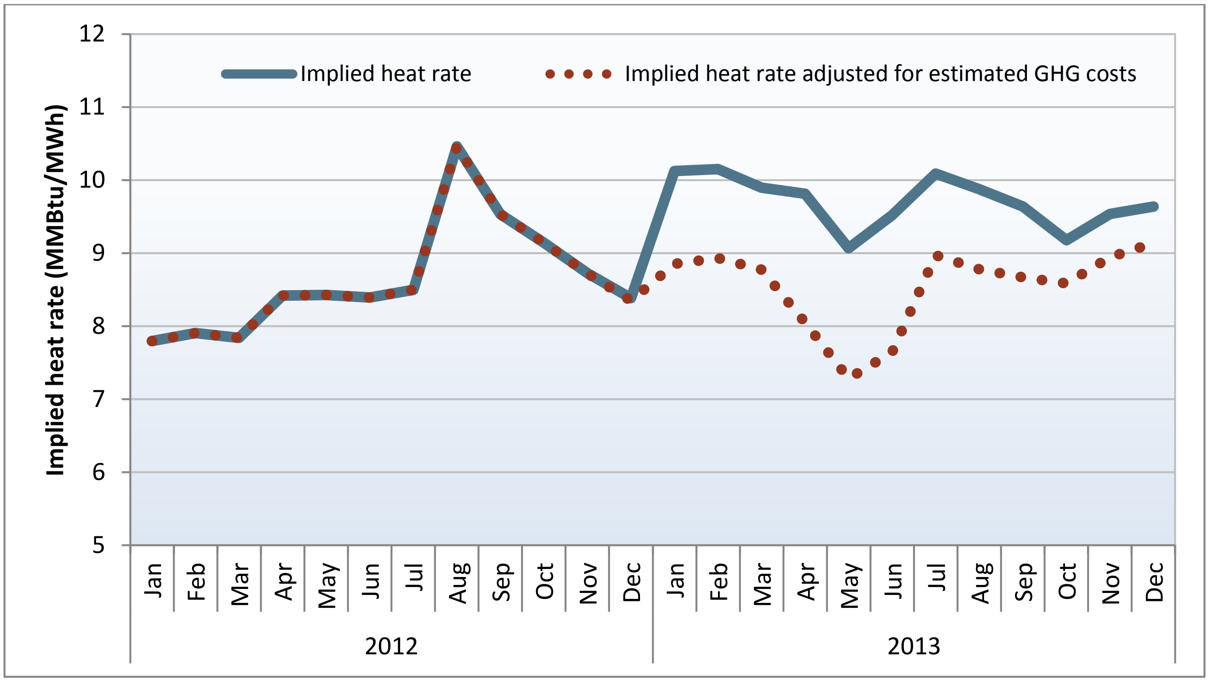
[57] These estimates were generated by using a set of four quarterly indicator variables multiplied by the greenhouse gas measure in place of a single greenhouse gas measure.

[58] In the first case, $R^2$ = 0.9339 and the adjusted $R^2$ = 0.9324. In the second case, $R^2$ = 0.9367 and the adjusted $R^2$ = 0.9353.

[59] 0.0530731 mt$CO_2$e /MMBtu x 8,000 Btu/kWh = \$0.425/\$ Greenhouse gas allowance price. The emissions factor, 0.0530731 mt$CO_2$e /MMBtu , is calculated as follows: 53.02 kg CO2/MMBtu + [(0.001 kg CH4/MMBtu)*21 kg CO2/kg CH4)] + [0.0001 kgN2O/MMBtu *310 kg CO2/kg N2O)] = 53.0731. The N20 and CH4 global warming potential values (310 and 21, respectively) are from table A1 of [http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl](http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl). Default emissions factors are available in tables C1 and C2 of the same source. DMM thanks ARB staff for their assistance with this calculation. \$0.41744 divided by an emissions factor of 0.0530731 = 7.86538.

[60] For this calculation, DMM is using a weighted average of three regional gas price indices (weights are given in parentheses): PGE2 (0.4), SCE1 (0.5), and SCE2 (0.1). These gas price indices are used by the ISO in calculating default energy bids and other market calculations.

**Figure 3.4 Implied heat rates with and without greenhouse gas compliance costs**




DMM calculates the implied heat rate adjusted for greenhouse gas compliance costs by subtracting our estimate of the greenhouse gas compliance cost price impact derived above from the energy price and then dividing the result by the gas price index. In this case, DMM chose to use quarterly estimates of the greenhouse gas impact: $0.35 per dollar of allowance cost in the first quarter, $0.57 in the second quarter, $0.35 in the third quarter, and $0.22 in the fourth quarter.[61] DMM has noted that, as seen in the quarterly estimates, the greenhouse gas impact appears to be negatively correlated with periods of relatively high day-ahead prices.

The implied heat rate analysis shows that changes in gas prices and greenhouse gas compliance costs account for most of the electricity price increase between 2012 and 2013. Adjusted implied heat rates in the fourth quarter of 2013 were similar to those in the fourth quarter of 2012.

[61] These estimates were generated by using a set of four quarterly indicator variables multiplied by the greenhouse gas measure in place of a single greenhouse gas measure.