California Independent System Operator Corporation

California ISO

Q1 2014 Report on Market Issues and Performance

May 22, 2014

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Executive summary

This report provides an overview of general market performance during the first quarter of 2014 (January – March) by the Department of Market Monitoring (DMM). Key trends in market performance include the following:

- Energy market prices remained highly competitive through the first quarter of 2014. The overall combined wholesale cost of energy was about equal to the competitive baseline price that DMM calculates, using the day-ahead market software to estimate prices that would result under highly competitive conditions when suppliers bid at or near marginal costs.

- Electricity market prices in the first quarter were higher than the third and fourth quarters of 2013 primarily as a result of natural gas price increases of about 25 percent. Gas prices increased as a result of periods of significant cold throughout the country, which affected natural gas storage inventories and, at times, natural gas supplies as well.

- The ISO experienced significant reliability concerns related to natural gas pipeline supply issues on February 6. ISO operators took numerous actions to protect electric system reliability and help manage gas pipeline limitations. These actions included (1) issuing exceptional dispatches to limit output from gas-fired generation within gas constrained areas of Southern California, (2) procuring more imports in the hour-ahead market by manually adjusting the load forecast upwards, (3) procuring more imports after the hour-ahead market through exceptional dispatches, and (4) calling upon interruptible load programs operated by the state's major electric utilities.[1] Following this event, the ISO took multiple steps to better align day-ahead market minimum load and start-up costs with gas market prices for the remainder of the winter period.

- DMM estimates that day-ahead market prices were about $4/MWh higher in the first quarter as a result of the state's greenhouse gas program.[2]

- Congestion continued to have a small impact on overall energy prices. Congestion raised day-ahead prices in the Southern California Edison and San Diego Gas & Electric areas by 0.5 percent, while lowering prices in the Pacific Gas and Electric area by 0.3 percent.

- Real-time imbalance offset costs totaled about $40 million in the first quarter of 2014, down from $44 million in the fourth quarter of 2013. Energy imbalance offsets totaled about $22 million, while congestion offset costs accounted for about $18 million.

- Bid cost recovery payments, which are designed to ensure sufficient revenues for generators to cover their bid costs, totaled around $21 million in the first quarter, a decrease of about $5 million in payments from the fourth quarter of 2013. These payments consisted of day-ahead bid cost

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[1] A more detailed description and analysis of the market impacts of these events is provided in a technical bulletin issued by the ISO on May 19, 2014: http://www.caiso.com/Documents/TechnicalBulletinGasEvents_MarketResults_Feb6_2014.pdf.

[2] This $4/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 depend on policies adopted by the California Public Utilities Commission (CPUC) and other state entities. Under a 2012 CPUC decision, revenue from carbon emission allowances sold at auction will be used to offset impacts on retail costs. More detailed information is provided in Section 3.2 of this report.

recovery of about $7 million, residual unit commitment bid cost recovery of about $3 million and real-time bid cost recovery of about $11 million.

- Convergence bidders were paid net revenues for accepted virtual bids of about $3.8 million, down from about $9.3 million in the previous quarter. Most of these net revenues were related to virtual supply positions, which accounted for about $11 million in payments, while virtual demand positions resulted in losses of about $7.2 million. Virtual supply positions were allocated bid cost recovery charges of around $3 million. Taking these charges into account, net overall revenues received by virtual bidders in the first quarter were about $0.8 million.
- Payments for resources helping to meet flexible ramping requirements were around $3 million in the first quarter, down from around $5 million in the previous quarter. The ISO lowered the maximum requirement for the flexible ramping constraint from 900 MW to 600 MW at the end of January. As a result, the average ramping requirement during the morning and evening hours decreased to about 480 MW in the first quarter from 650 MW in the fourth quarter.

Energy market performance

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

Prices remained competitive. The overall combined wholesale cost of energy was about equal to the competitive baseline price that DMM calculates using the day-ahead market software. DMM calculates this competitive baseline price by re-running the day-ahead market software using bids for gas-fired generating units that reflect each unit's marginal operating costs. This represents estimated prices that would result under highly competitive conditions when suppliers bid at or near marginal costs.

Price levels increased in the first quarter of 2014. Average system energy prices in the ISO markets rose in the first quarter compared to price levels in all quarters of the previous year (see Figure E.1). This increase was primarily the result of unseasonably cold weather throughout the country reducing natural gas supplies. The natural gas price more than tripled on February 6, reaching about $25/MMBtu at the PG&E Citygate trading hub. As a result, ISO prices in the current quarter reached the highest average levels observed in over two years.

Decreased convergence 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 (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 market. 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.

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

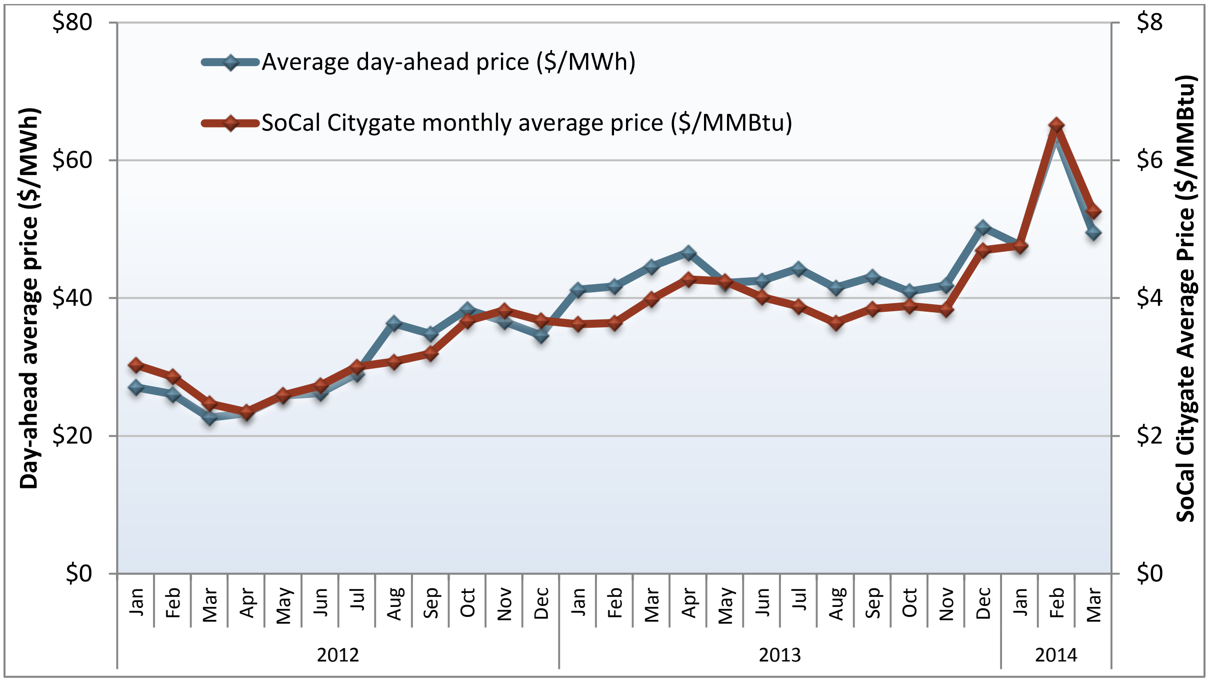
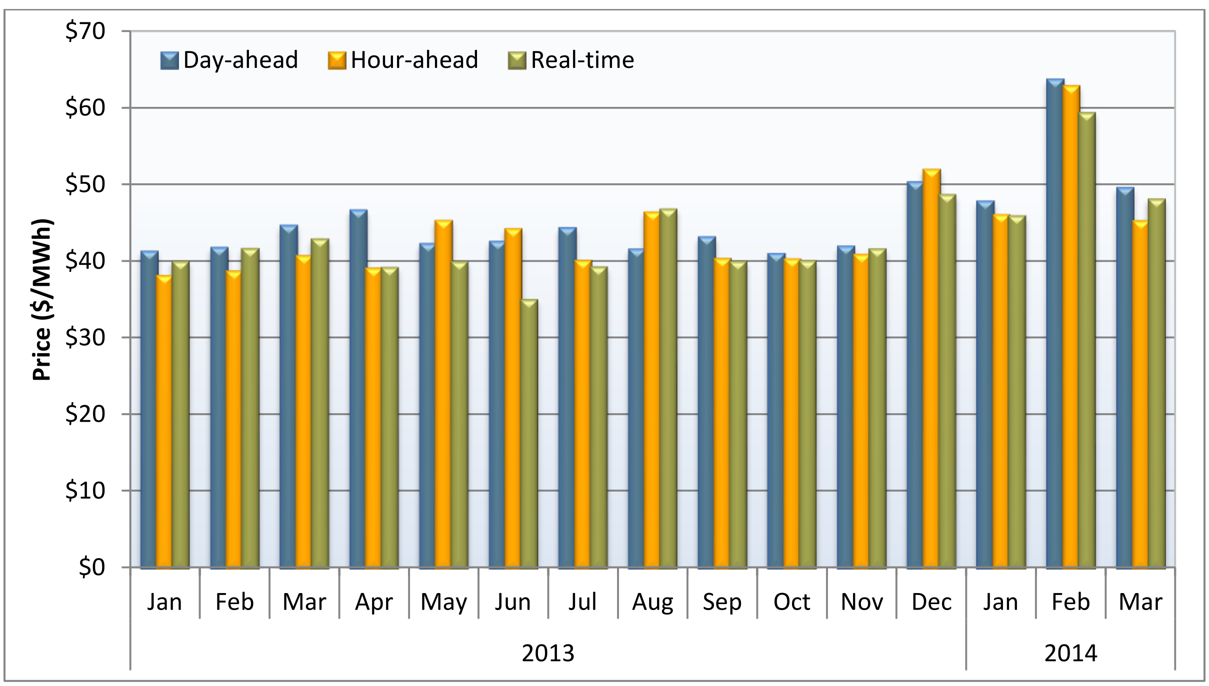


Figure E.2 Average monthly system marginal energy prices (all hours)



The impact of congestion on day-ahead and real-time prices remained low. Overall congestion remained low in the first quarter, even though it increased slightly in the SCE area. Much of the congestion that did occur was related to modeled flow adjustments in the Fresno area (related to Helms Pump operations). For the quarter, day-ahead congestion caused SCE and SDG&E prices to increase, and caused overall prices in the PG&E area to decrease in both the day-ahead and real-time markets.

Real-time congestion and energy imbalance offset costs declined in the first quarter. Real-time imbalance offset costs totaled about $40 million in the first quarter, down from $44 million in the previous quarter. About $6.7 million of these offset costs occurred on February 6 due to the natural gas challenges discussed in Section 3.1. Congestion offset costs accounted for approximately 44 percent of the total imbalance costs during the first quarter, totaling about $17 million. Real-time energy imbalance offset costs increased to $22 million, up from about $13 million in the previous quarter.

Bid cost recovery payments decreased. Bid cost recovery payments totaled around $21 million in the first quarter, down from $26 million in the previous quarter. The largest component of these payments was attributed to real-time bid cost recovery payments at about $11 million. The day-ahead portion of these payments accounted for about $7 million. Virtual supply positions were allocated $3 million in bid cost recovery charges for residual unit commitment.

Flexible ramping constraint payments decreased. 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 ISO lowered the maximum adjustment for the flexible ramping constraint from 900 MW to 600 MW at the end of January. The ISO discovered that excessive adjustment of the flexible ramping requirement can lead to ineffective procurement. Total payments to generators for the flexible ramping constraint were around $3 million, compared to around $5 million in the previous quarter.

Convergence bidding

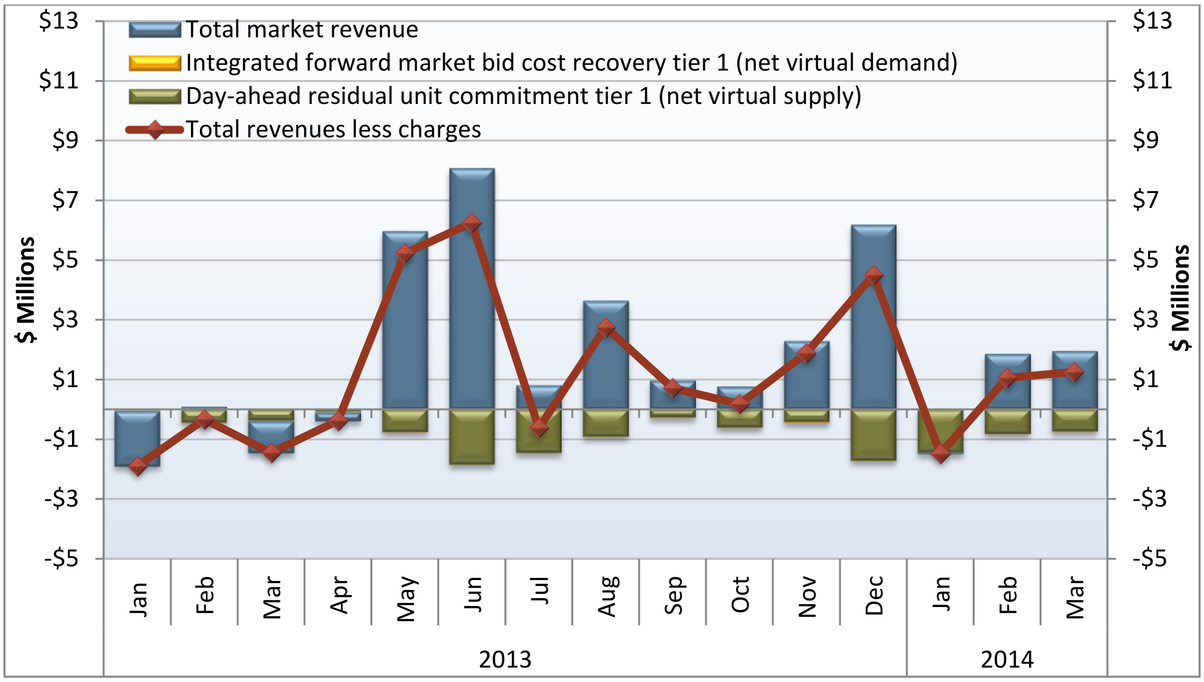
Convergence bidding activity was marked by several key trends in the first quarter.

The total volume of convergence bids decreased and shifted further in the direction of virtual supply. Average hourly cleared volumes decreased to 3,010 MW in the first quarter from 4,160 MW in the previous quarter. These cleared volumes resulted in an increased net virtual supply position. Net virtual supply volumes increased to 590 MW in the first quarter from 320 MW in the fourth quarter.

Offsetting convergence bids decreased in the absence 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 1,020 MW per hour of virtual demand offset by over 1,020 MW of virtual supply at other locations in the first quarter, down from 1,560 MW in the previous quarter. These offsetting bids represented about 68 percent of all cleared bids in the first quarter, a decrease from 75 percent in the third quarter as the total volume of convergence bidding fell.

Decreased 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 $11 million, while virtual demand accounted for a loss of around $7.2 million. This represents net revenues of about $3.8 million in this quarter, compared to about $9.3 million in the previous quarter. However, net virtual supply positions were allocated bid cost recovery charges resulting from residual unit commitment of around $3 million. Taking these charges into account, net overall revenues received by virtual bidders were only about $0.8 million (see Figure E.3).

Figure E.3 Convergence bidding revenues and costs associated with bid cost recovery tier 1 and residual unit commitment



Special issues

Winter events in the natural gas market

Natural gas pipeline conditions were tight during critical events on December 6 through 12, 2013 and on and around February 6, 2014. In early December, unusually cold weather in California caused pipeline limitations that exposed some generators to potential penalties of up $100/MMcf. On February 6, much of the country outside California experienced severe cold weather. As a result, natural gas demand outside California created competition for the gas supply. This shortage caused significantly high prices for natural gas, reaching up to almost $13/MMBtu at the SoCal Citygate trading hub and $25/MMBtu at the PG&E Citygate trading hub.

To help manage pipeline issues, ISO operators exceptionally dispatched internal generation at locations with adequate gas supply, called on interruptible demand and adjusted external transactions. Electricity prices were higher during these events, reflecting increases in incremental energy bids made by market participants. The ISO released a market notice with more detailed information addressing issues raised by stakeholders about ISO actions and market conditions during the February 6, 2014 events.[3]

[3] See details at http://www.caiso.com/Documents/ElectionProxyCostOptionTreatment-Event-GasPriceSpikeMar21_2014.htm.

DMM has supported the ISO efforts to improve gas and electric market coordination in the aftermath of February 6.[4] DMM is currently involved in the ISO stakeholder process on commitment cost changes to further develop a more permanent solution for gas market issues in the future. DMM recommends incremental changes to address gas and electric coordination and cautions that other changes may create significant market power concerns.

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 rose slightly in the first quarter to an average of \$12.10/mtCO_2e, ending the quarter at \$12.00/mtCO_2e.[5] This is an increase from the previous quarter at \$11.86/mtCO_2e, but below the yearly average for 2013 of \$13.55/mtCO_2e. DMM estimates that these greenhouse gas compliance costs increased the average wholesale electricity price in 2013 by about \$4/MWh. This is consistent with the additional emissions costs for gas units typically setting prices in the ISO market.

[4] In early March, the ISO made an emergency filing with FERC to waive tariff provisions to use more updated gas price information as part of the day-ahead market run. Specifically, the ISO asked FERC to allow it to use only one natural gas index in the event that the natural gas markets moved by more than 150 percent of the previous day's price.

[5] mtCO_2e stands for metric tons of carbon dioxide equivalent, a standard emissions measurement.

1 Market performance

This section highlights key performance indicators of first quarter market performance:

- Energy market prices remained highly competitive through the first quarter.
- Day-ahead and real-time prices were higher in the first quarter, particularly in February, due to increasing gas prices related to unseasonably cold weather throughout the country.
- Day-ahead prices were consistently higher than real-time prices, during both peak and off-peak hours.
- The frequency of high real-time price spikes remained low.
- The frequency of negative real-time prices and periods of over-generation remained low, except for March when wind and solar generation increased.
- Both day-ahead and real-time market congestion remained low.
- Real-time imbalance offset costs were lower, driven by lower real-time congestion 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 that 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.[6]

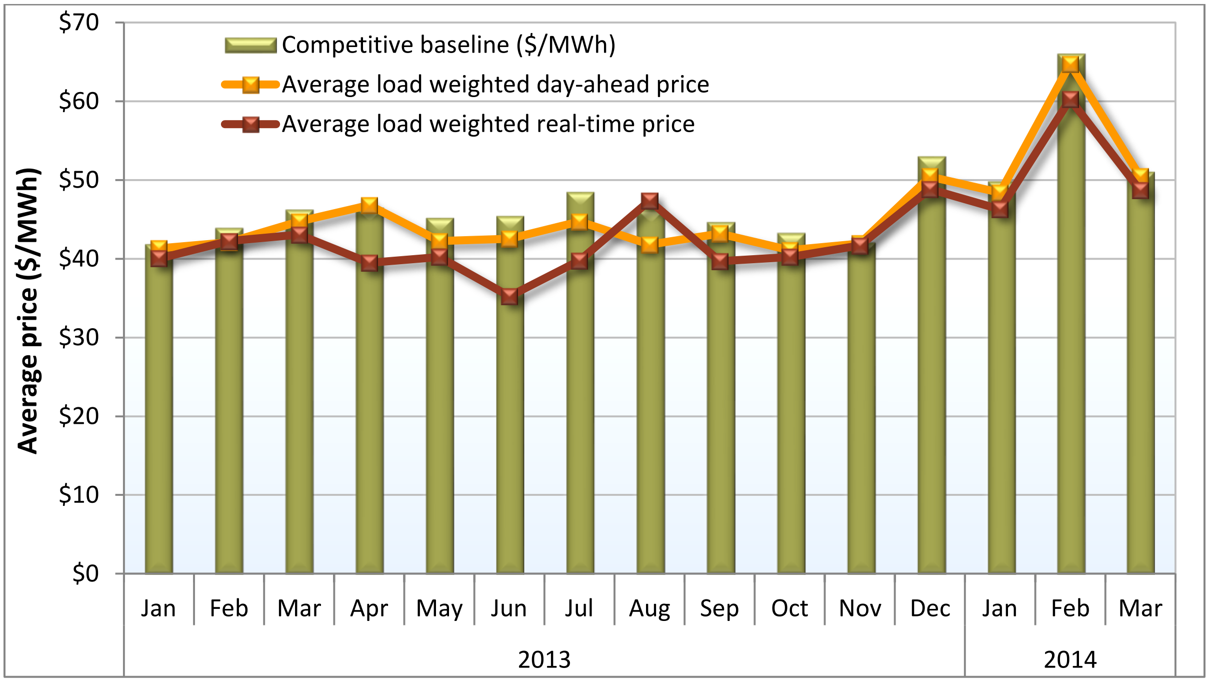
Figure 1.1 compares this competitive baseline price to load-weighted prices in the day-ahead and 5-minute real-time markets. When comparing these prices, it is important to note that baseline prices are calculated using the day-ahead market software under highly competitive conditions, which does not 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 the first quarter. Both day-ahead prices and real-time prices were below the competitive benchmark in all

[6] 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. DMM calculated the competitive baseline using its version of the actual market software for all days in the first quarter.

months of the current quarter. A major factor contributing to these lower real-time prices was the substantial amount of real-time energy that was not scheduled in the day-ahead market.[7]

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.[8] 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.[9] 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 and real-time market prices was almost 3 percent or $1.50/MWh less than the competitive baseline price in the first quarter of 2014. This is similar to the previous quarter and a slight increase in the mark-up as compared to the previous

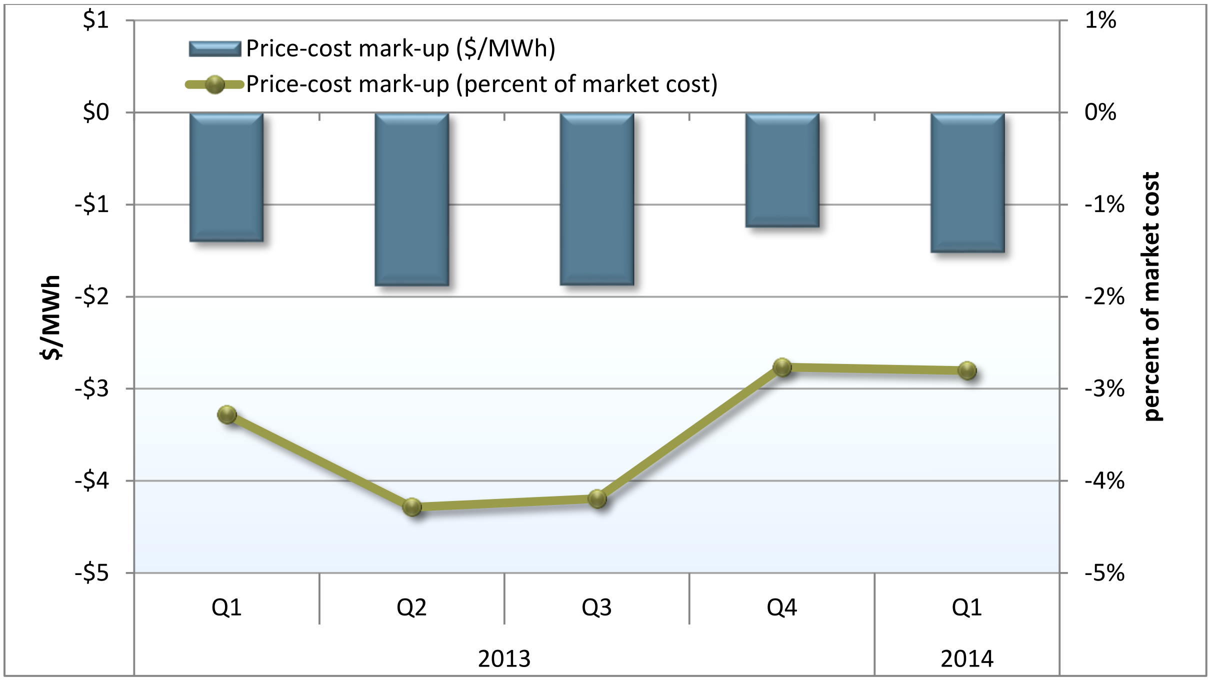
[7] This unscheduled energy was the combined result of a variety of factors, rather than being driven by any single source. Various sources of additional real-time energy included minimum load energy from units committed after the day-ahead market through the residual unit commitment process and exceptional dispatches, additional must-take energy from thermal generating resources, and unscheduled energy from intermittent renewable energy. A detailed analysis of this issue was provided in Chapter 3 of DMM's 2013 annual report: http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf.

[8] 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.

[9] The wholesale costs of energy are pro-rated calculations of the day-ahead, hour-ahead and real-time prices weighted by the corresponding schedules.

year. 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.

Figure 1.2 Price-cost mark-up as a percent of market cost and $/MWh



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.

Figure 1.3 and Figure 1.4 show monthly system marginal energy prices for peak and off-peak periods, respectively. As seen in these figures, average day-ahead price levels were higher than both the hour-ahead and real-time markets for the quarter. In February, average hour-head prices during peak hours slightly exceeded real-time prices. This was primarily associated with unseasonably cold weather throughout the country reducing natural gas supplies and dramatically increasing prices.

- On a monthly average basis, peak hour-ahead prices were lower than day-ahead prices in January and March, by approximately $2/MWh and $4/MWh respectively, but were about $0.60/MWh higher in February. Higher hour-ahead prices for peak hours in February were due to a handful of hours on February 6 in which hour-ahead prices significantly exceeded day-ahead prices. Off-peak hour-ahead prices were lower than day-ahead for the entire quarter, averaging nearly $3/MWh lower. The greatest price difference occurred in March at $4.50/MWh.
- During the first quarter, average system prices in the 5-minute real-time market were consistently lower than day-ahead market prices by about $2.75/MWh during peak periods. Real-time prices in

off-peak periods were also lower than day-ahead prices in all months of the quarter, with the largest difference in February at $4.50/MWh.

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

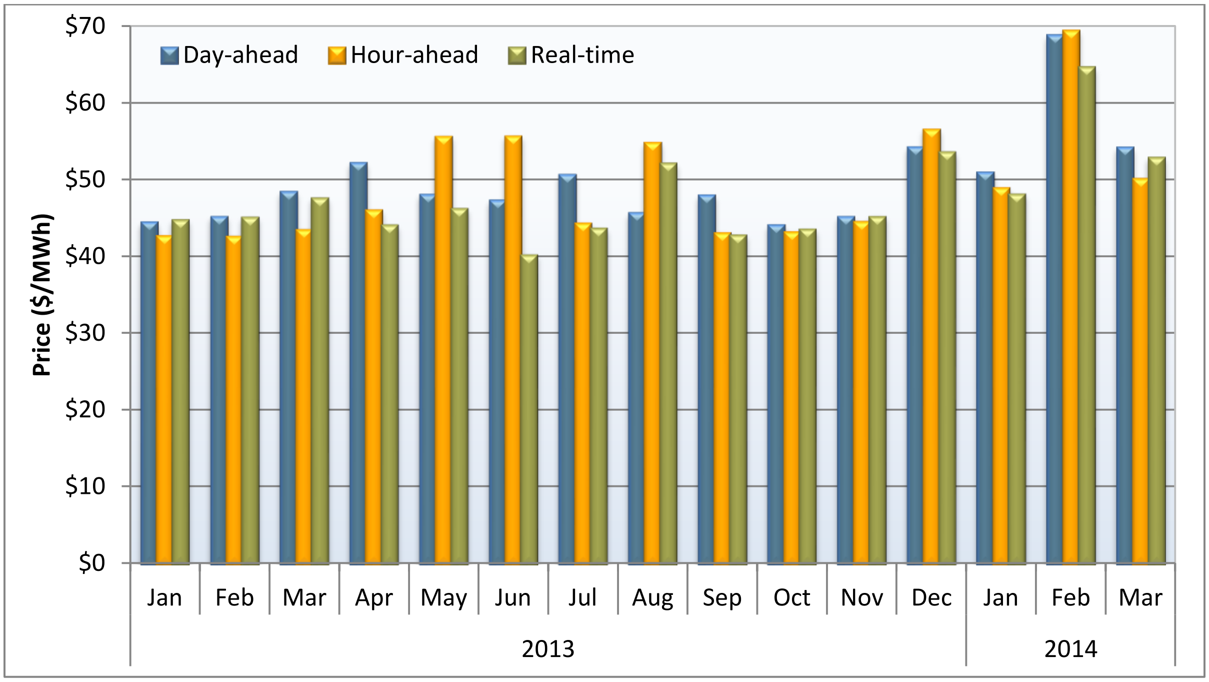
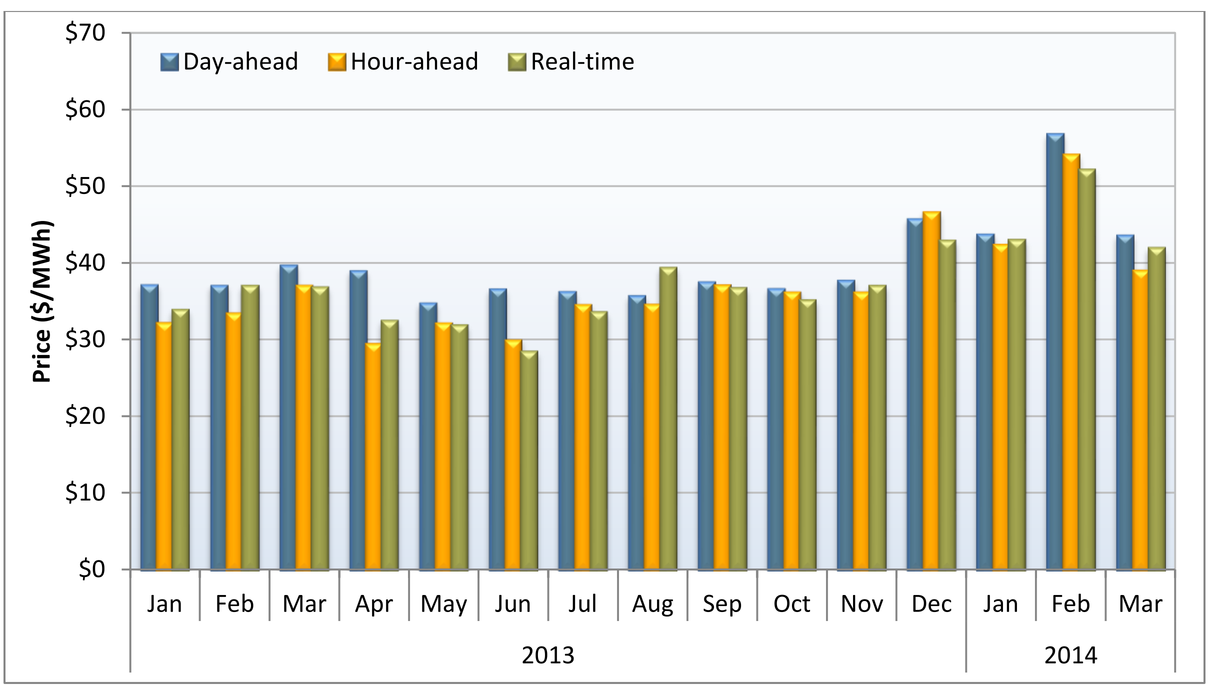


Figure 1.4 Average monthly off-peak prices – system marginal energy price



- In January, real-time and hour-ahead prices were very close during both peak and off-peak hours. In February, peak period average system prices in the 5-minute real-time market were lower than prices in the hour-ahead market by about \$4.80/MWh while March prices were about \$2.70/MWh higher. Excluding the extreme peak prices on February 6, hour-ahead prices were about \$1.40/MWh lower than the real-time prices in February. Off-peak prices in the 5-minute real-time market were higher than hour-ahead in January and March, by about \$0.60/MWh and \$2.88/MWh, respectively, whereas February prices were nearly \$2/MWh lower.

Figure 1.5 and Figure 1.6 further illustrate increasing price divergence in the first quarter. In Figure 1.5, the average hourly day-ahead prices for the first quarter were higher than both the hour-ahead and real-time prices during most peak hours. This occurs with increased volumes of renewable generation from wind and solar. Day-ahead prices were consistently higher than real-time prices between hour ending 9 and 15, and up to \$10/MWh greater in hour ending 11. Day-ahead prices were higher than hour-ahead prices in hour ending 11 to 17 but lower in hour ending 18 through 20. Off-peak prices showed better convergence between the day-ahead, hour-ahead and real-time prices.

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 the simple average price difference between the day-ahead and real-time markets. The simple average price differences were similar to the previous quarter in January and March, but were almost \$4.50/MWh different in February.

Figure 1.6 also shows the average absolute price difference between the day-ahead and real-time markets (gold line).[10] 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 trending higher. Thus, the simple average masks the nature of the differences when there are offsetting positive and negative differences in different hours. In the first quarter, the absolute average difference was about \$12/MWh, up from \$8/MWh in the previous quarter. In March, the absolute average difference reached almost \$16/MWh, the largest difference since June 2013, indicating increasing price divergence from hour to hour compared to previous months.

[10] 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 (January – March)

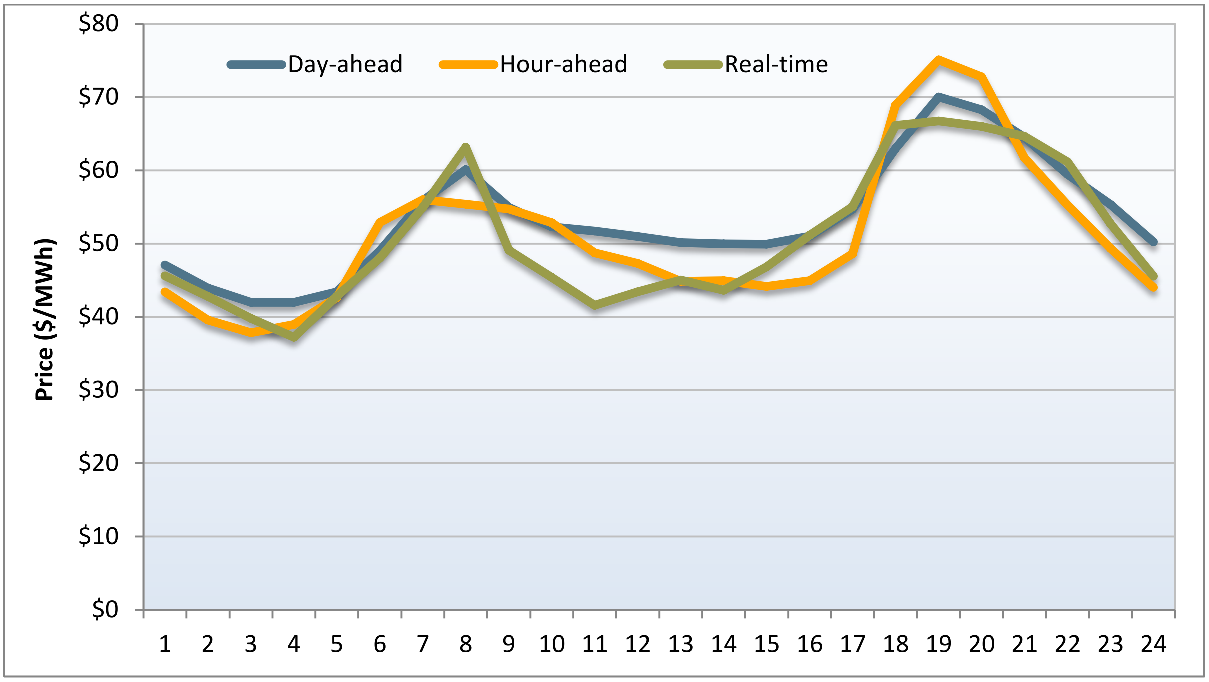
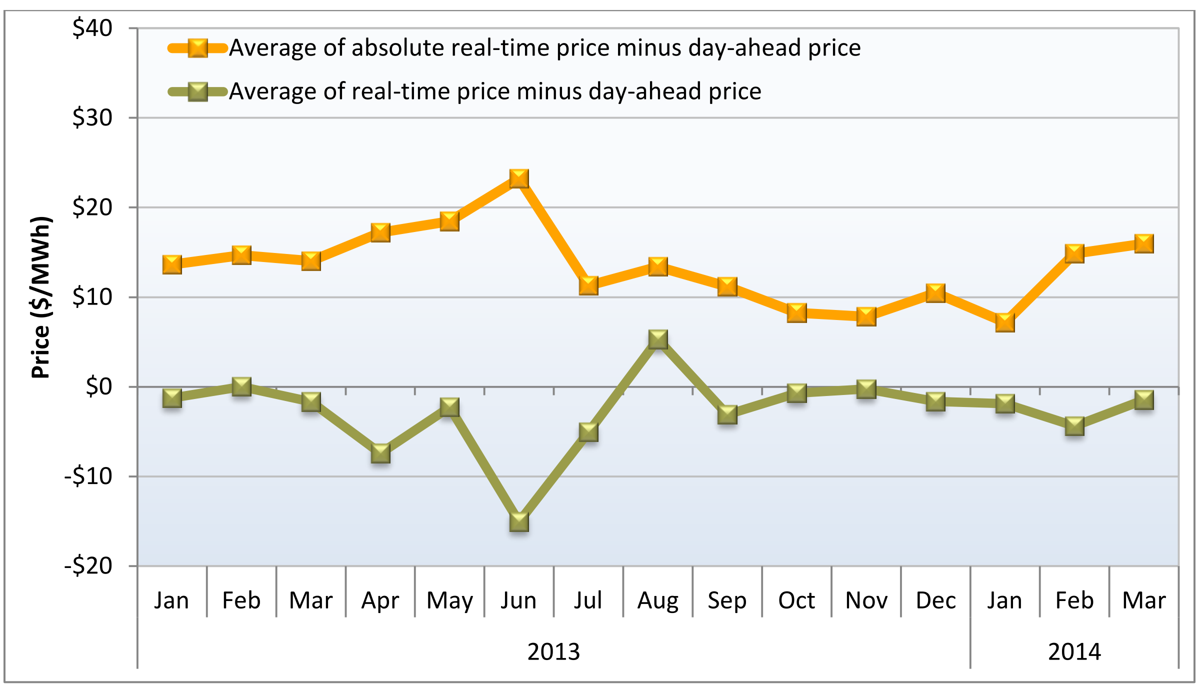


Figure 1.6 Difference in monthly day-ahead and real-time prices based on simple average and absolute average of price differences (system marginal energy, all hours)



1.3 Real-time price variability

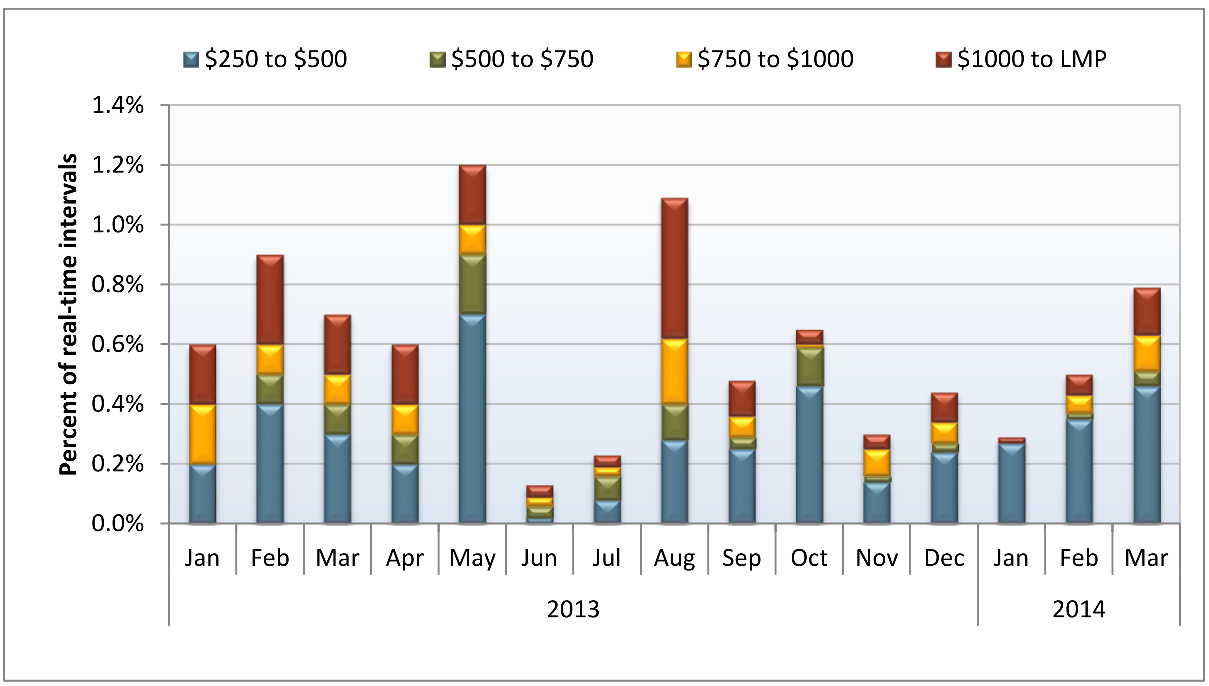
Historically, real-time market prices have been highly volatile. This section highlights real-time market prices and provides explanations of real-time price variation.

Figure 1.7 shows the frequency of positive price spikes that occur in the real-time market. In the first quarter, the frequency was about 0.5 percent, slightly higher than the value in the fourth quarter of 2013. As in the previous quarters, the ISO continued to adjust the flexible ramping constraint requirements during the evening ramping hours. This has contributed to the overall decline in the frequency of real-time price spikes. The figure shows an increase in the frequency of price spikes in March. This was partly due to ramping limitations resulting from unexpected drops in wind generation.

Figure 1.8 shows the frequency of negative price spikes in the real-time market. There was a notable increase in the frequency of negative prices in the first quarter. This was mainly due to periods of over-generation resulting from unscheduled wind and solar generation. In the first quarter, combined real-time wind and solar generation reached up to 7,300 MWh and occasionally provided more than 30 percent of real-time generation.

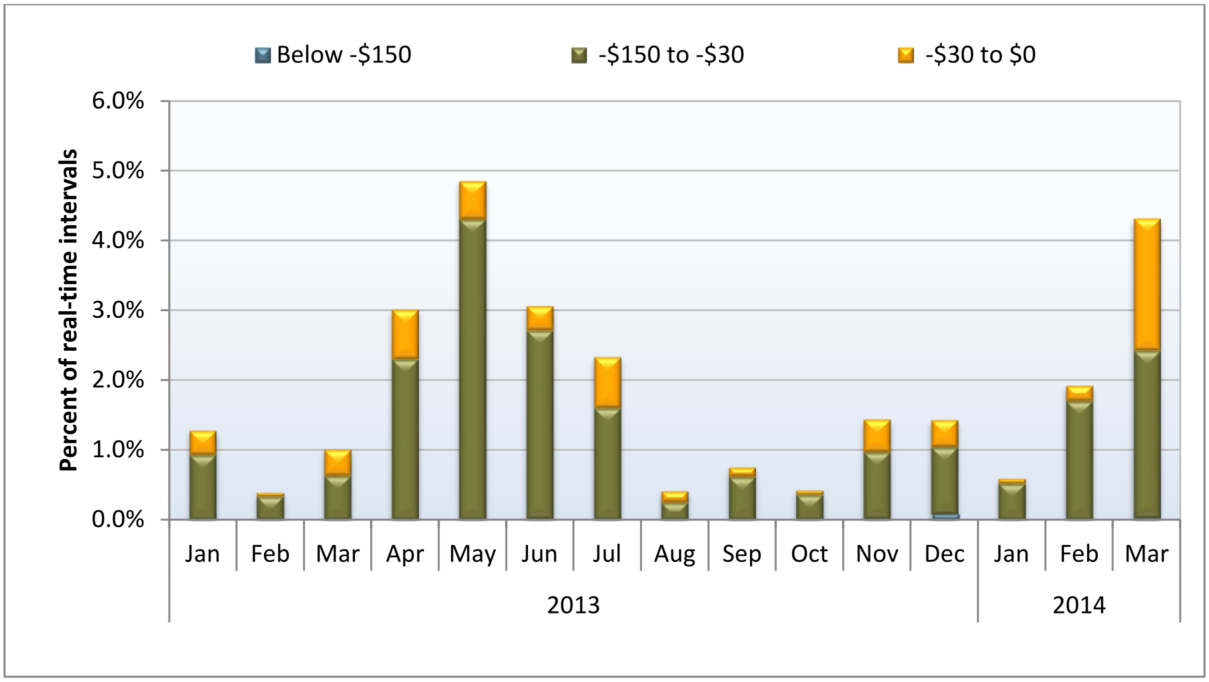
The bid floor in the first quarter was -$30/MWh, and dropped to -$150/MWh on May 1.[11] Depending on market bidding behavior, this may also change the level of negative price spikes going forward.

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



[11] The bid floor of -$30/MWh was a soft floor, meaning that participants could bid below the level of the floor and be paid consistent with their bid if they justified their bids costs to FERC. The -$150/MWh floor is a hard floor, meaning no bids will be accepted below the floor.

Figure 1.8 Frequency of negative price spikes (all LAP areas)



Power balance constraint relaxations 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 constraint relaxations, due to over-generation, resulting in prices at -$30/MWh.

The number of power balance constraint relaxation intervals resulting from insufficient upward ramping capacity remained low over the past year, as seen in Figure 1.9. Power balance constraint relaxations can also occur in the presence of congestion. However, in the first quarter, no power balance constraint relaxation events resulted from extreme regional congestion.[12]

The number of power balance constraint relaxation events from infeasible decremental energy increased significantly in the first quarter, as shown in Figure 1.10. This is a result of increasing generation in real-time from variable resources, particularly wind and solar. All of the decremental power balance constraint relaxations resulted from system-wide over-generation conditions.

[12] 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.

Figure 1.9 Relaxation of power balance constraint because of insufficient upward ramping capacity

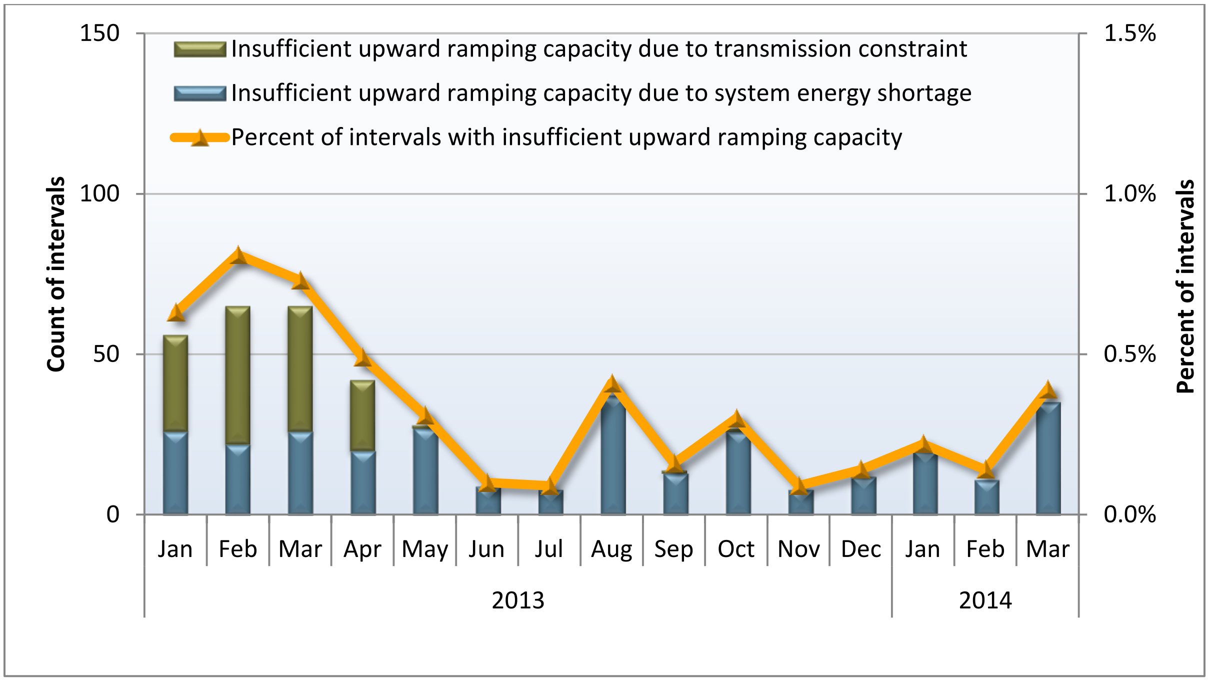
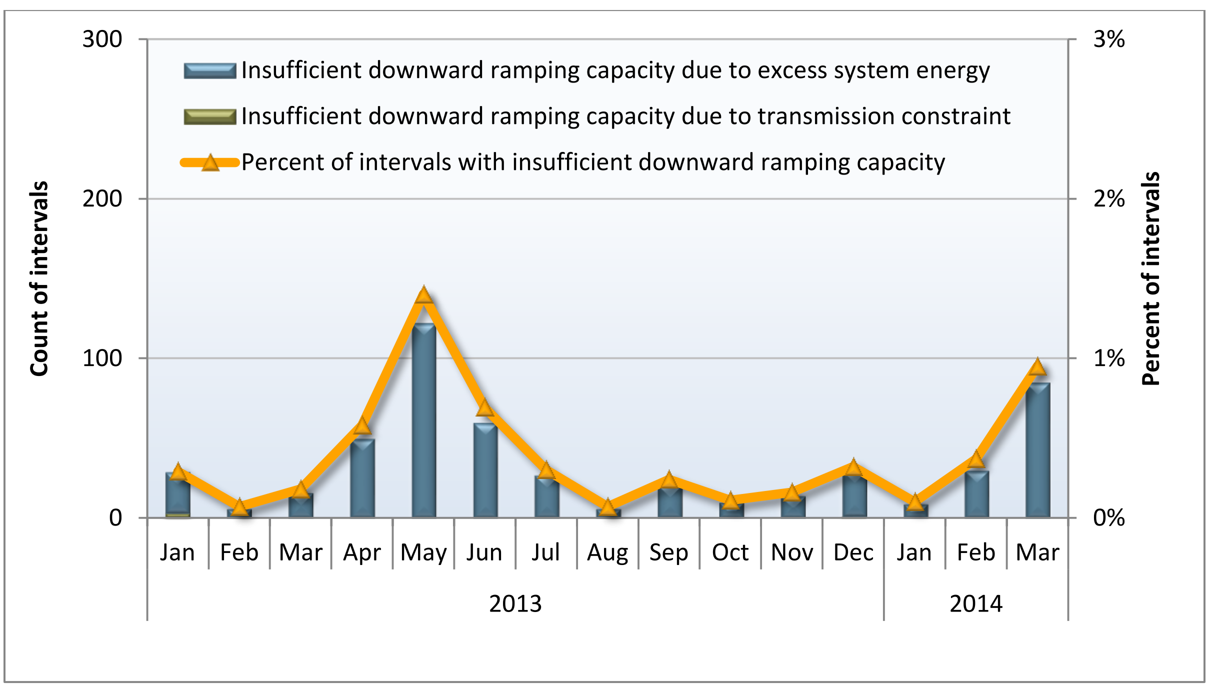


Figure 1.10 Relaxation of power balance constraint because of insufficient downward ramping capacity



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 $3 million in the first quarter, down from around $5 million in the previous quarter.
- The ISO lowered the maximum adjustment for the flexible ramping constraint from 900 MW to 600 MW at the end of January.
- ISO operators decreased the flexible ramping requirement consistently during the morning and evening ramping periods in the first quarter, averaging nearly 480 MW during ramping hours down from 650 MW in the previous quarter.

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.[13] The constraint is only applied to internal generation, dynamic inter-ties and proxy demand response resources and not to other resources. The default requirement is currently set to 300 MW, but it is frequently adjusted to 600 MW,[14] 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 first quarter were around $3 million, down from around $5 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:

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

[14] The ISO decreased the maximum flexible ramping threshold to 600 MW from 900 MW at the end of January. Further details are presented later in this section.

[15] The penalty price associated with procurement shortfalls was set to just under $250 in the first quarter.

[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.

- The frequency of intervals where the flexible ramping constraint was binding was around 9 percent, down from 15 percent in the previous quarter.
- The frequency of procurement shortfalls was 0.3 percent of all 15-minute intervals in the first quarter, down from 0.7 percent in the previous quarter.
- The average shadow price when the flexible ramping constraint was binding was about $36/MWh, up from $31/MWh in the previous quarter.

Most payments for ramping capacity occurred during the evening peak hours. Figure 1.11 shows the hourly flexible ramping payment by technology type during the first quarter. As shown in this figure, the highest payment periods were during hours ending 7 and 17 through 19. Natural gas fired capacity accounted for about 52 percent of these payments with hydro-electric capacity accounting for 46 percent.

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)
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
2014	Jan	$1.27	10%	0.1%	$28.37
2014	Feb	$0.56	4%	0.4%	$45.68
2014	Mar	$1.20	12%	0.3%	$34.37

Figure 1.11 Hourly flexible ramping constraint payments to generators (January – March)

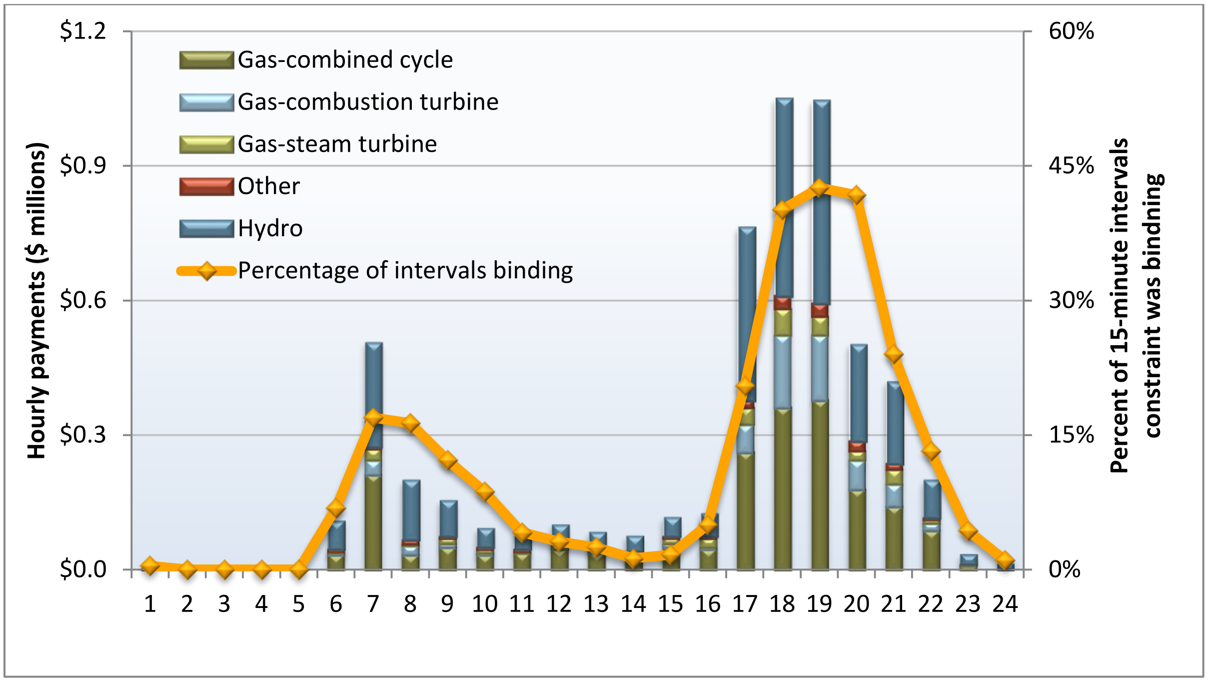
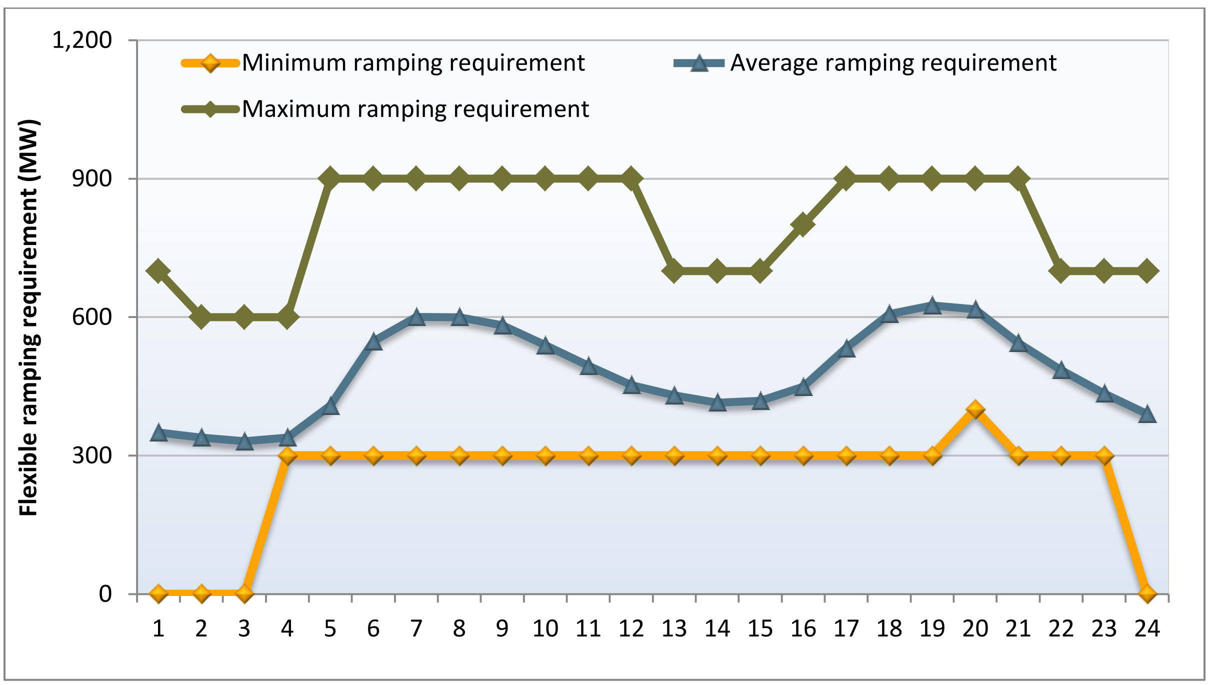


Figure 1.12 Hourly average flexible ramping requirement values (January – March)



ISO operators adjust the flexible ramping requirement level to ensure enough upward ramping flexibility, particularly during ramping periods. Figure 1.12 shows the hourly average flexible ramping requirement values in the first quarter. The hourly ramping requirement ranged from a minimum of 0 MW to a maximum of 900 MW. On average, the requirement was set to around 300 MW in the pre-dawn early morning hours and about 600 MW in the morning and evening load-ramping hours.

At the end of January, the ISO lowered the maximum adjustment for the flexible ramping constraint from 900 MW to 600 MW. The ISO conducted a study to measure the effectiveness of the flexible ramping adjustment. The study discovered that excessive adjustment can become ineffective in the real-time market. When flexible resources are reserved in the 15-minute market two things happen:

- the pre-dispatch market commits additional generators; and
- some resources shift dispatch levels into a lower ramp range or configuration.

The increase in the commitment is beneficial, since it provides additional ramping capacity. However, shifting dispatch levels in the 15-minute market can be ineffective as they do not necessarily result in additional ramping in the 5-minute market. This is because the ramp disappears in the 5-minute real-time market when resources are re-dispatched. The ISO's empirical study found that a reduction of the maximum adjustment to 600 MW should be sufficient to provide additional ramping capacity under current system conditions.[17]

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 7 percent in the early morning hours to 26 percent in the evening hours. In the previous quarter, utilization levels were almost two times larger, ranging from 15 percent in the early morning to 45 percent in the evening hours.

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

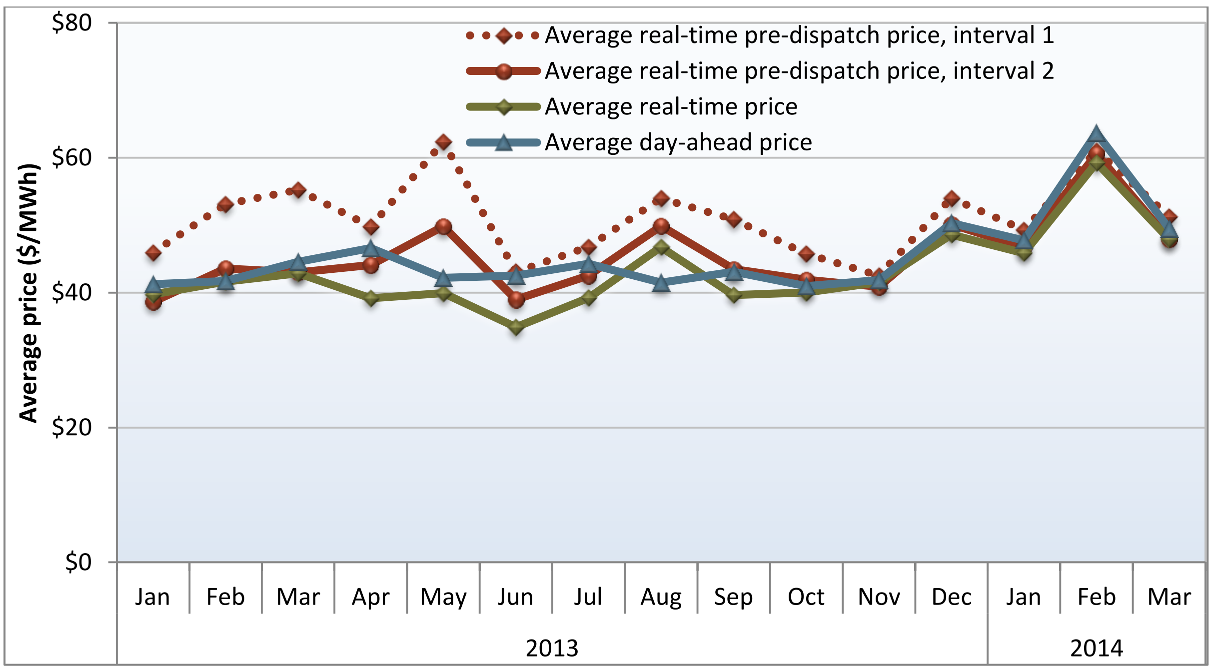
On May 1, 2014, the ISO implemented a new 15-minute market. Specifically, the ISO changed inter-tie scheduling from an hourly to a 15-minute basis, and established a 15-minute settlement for internal resources, inter-ties and convergence bids. The ISO retained the existing 5-minute dispatch to provide real-time balancing.

The ISO's previous 15-minute real-time pre-dispatch market produced energy prices for each 15-minute interval which were 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. DMM provided a comparison of the previous market's 15-minute non-binding prices to day-ahead and 5-minute real-time prices.

[17] These limits are outlined in Operating Procedure 2250: http://www.caiso.com/Documents/2250.pdf.

After implementation of the changes on May 1, the 15-minute market prices are now based on the second 15-minute interval of the 15-minute process, which anticipates several intervals over two and a half hours. As illustrated in Figure 1.13, the average second interval 15-minute system marginal prices (represented by the solid red line) have been consistently lower than the first interval 15-minute prices (dashed red line). However, the figure shows that this difference decreased significantly in the first quarter of 2014. Moreover, the second interval prices of the 15-minute process do not appear to be consistently different than either day-ahead or real-time prices, particularly over the last couple quarters. Prices in this second 15-minute interval have had 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 1.13 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 following implementation of the new 15-minute market 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. In preparation for implementation of the 15-minute market, the ISO lowered the maximum adjustment for the flexible ramping constraint from 900 MW to 600 MW at the end of January, as discussed above. The ISO will continue to monitor and adjust this limit going forward as necessary.

- 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 with implementation of the new 15-minute market.

- Another factor that could 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 performed an analysis indicating that reductions from the current level of $247 to $60 would be appropriate. The ISO intended to make the change on May 1 during the spring release, but postponed the change after participant feedback.[18] The ISO intends to make the change upon further approval. Lowering the penalty price would help improve the efficiency of commitment of flexible ramping resource commitment in the new 15-minute market, which would then improve the efficiency of mitigating ramping shortages. DMM supports the ISO reevaluating and adjusting the penalty factor as needed, but recommends that the ISO track the effectiveness of the new level once changed.

DMM will continue to work closely with the ISO after the implementation of the new 15-minute market to monitor market performance and recommend 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 first quarter remained low, but it increased slightly from the previous quarter. It affected overall prices in the day-ahead and real-time markets less than in the third and second quarters of the previous year.

During the quarter, the ISO replaced multiple nomograms in Southern California with more granular contingencies to better manage congestion. Much of the congestion that did occur was related to contingencies on the Barre-Lewis and Barre-Villa lines, planned outages in the Fresno area 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.

[18] See the following technical bulletin for further details on the proposed change: http://wwwpub.oa.caiso.com:21083/Documents/TechnicalBulletin-FlexibleRampingConstraintPenaltyPrice-FifteenMinuteMarket.pdf. See the following market notice regarding the postponement of the change: http://www.caiso.com/Documents/FlexibleRampingConstraintPenaltyPriceWillRemainatCurrentValueFERCOrderGoLive.htm.

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 first 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 11 percent of hours. During these hours, prices in the PG&E area increased by about $0.36/MWh and prices in the SCE and SDG&E areas decreased by $0.27/MWh. This constraint, located in the Fresno area, is heavily dependent on imports from the 230 kV system through the McCall, Herndon, and Henrietta banks, and local hydro generation. The constraint is adjusted to protect for 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 T-135 VICTVLUGO_DVRB_NG at about 6 percent of hours. This constraint, located in the SCE area, was activated to protect the Lugo-Victorville 500 kV line.

In the SCE area, the Barre-Lewis and the Barre-Villa 230 kV line constraints were binding in the first quarter. The Barre-Lewis 230 kV line was congested in about 7 percent of hours, and Barre-Villa 230 kV line was congested in about 5 percent of hours due to contingencies. When the Barre-Lewis and Barre-Villa lines were binding, prices in the SCE area increased by about $1.80/MWh and $3/MWh, respectively. These constraints increased prices in the SDG&E area by $0.96/MWh and $0.54/MWh, and decreased prices in the PG&E area by about $1.48/MWh and $2.60/MWh, respectively. In previous quarters, the ISO used the Barre-Lewis nomogram instead of applying the Barre-Lewis and Barre-Villa contingencies. Using contingencies is a more granular approach to manage congestion.

The Path 26 branch group constraint was binding in about 1.4 percent of the hours, because of a planned outage on the Midway bus. When congestion occurred on this constraint, prices in the SCE and SDG&E areas increased by $1.69/MWh while the PG&E area prices decreased by $2.18/MWh.

In the SDG&E area, the constraint with the largest impact was SLIC 2157511 LUG0-MIRA LOMA 3. This constraint was binding in over 4 percent of hours and increased prices in the SDG&E and SCE areas by $1.57/MWh and $1.28/MWh, respectively, while decreasing prices in the PG&E area by $1.74/MWh. This constraint was activated because of a planned outage of the Lugo-Mira Loma 500 kV line. Other significant binding constraints in the first quarter included the Doublet Tap-Friars due to contingencies of the Penasquitos-Old Town and Encina-Penasquitos 230 kV lines.

As shown in Table 1.2, with the exception of the SOUTHLUGO_RV_BG and the Path 15 branch group constraints, other internal congestion occurred infrequently and typically had a minimal impact on overall day-ahead energy prices.

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

Area	Constraint	Frequency	Load area		
			PG&E	SCE	SDG&E
PG&E	30880_HENTAP2 _230_30900_GATES _230_BR_2 _1	10.5%	$0.36	-$0.27	-$0.27
	T-135 VICTVLUGO_DVRB_NG	6.1%	$0.62	-$0.48	-$0.78
	33020_MORAGA _115_30550_MORAGA _230_XF_1 _P	2.5%	$0.33	-$0.24	-$0.24
	SLIC 2207662 NGila-HWD PVDV	1.7%	$0.43	-$0.45	$0.26
SCE	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	6.6%	-$1.48	$1.80	$0.96
	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	5.1%	-$2.59	$2.98	$0.54
	PATH26_BG	1.4%	-$2.18	$1.69	$1.69
	25201_LEWIS _230_24137_SERRANO _230_BR_1 _1	0.4%	-$4.54	$4.07	-$1.10
SDG&E	SLIC 2157511 LUG0-MIRA LOMA 3	4.1%	-$1.74	$1.28	$1.57
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	3.2%	-$0.06	-$0.21	$0.87
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	2.2%			$1.90
	SOUTHLUGO_RV_BG	2.1%	-$2.60	$1.80	$2.70
	7820_TL 230S_OVERLOAD_NG	1.6%	-$0.11		$1.89
	PATH15_BG	1.6%	$4.56	-$3.65	-$3.65
	22831_SYCAMORE_138_22117_CARLTHT2_138_BR_1 _1	1.5%			$4.85
	22136_CLAIRMNT_69.0_22140_CLARMTTP_69.0_BR_1 _1	0.5%			$3.52
	SLIC 2196141 MIDWAY SOL1	0.4%	-$1.26	$1.04	$1.04
	24155_VINCENT _230_24126_RIOHONDO_230_BR_1 _1	0.2%	-$4.14	$3.22	$3.57
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	0.2%	-$2.17	$1.69	$1.67

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 first quarter.

Overall, the most frequently congested constraint was PATH15_S-N located in the PG&E area, which was binding about 1.7 percent of the time in the first quarter. This constraint increased prices by about $26/MWh in the PG&E area and decreased prices in the SCE and SDG&E areas by $21/MWh. This constraint was binding due to planned outages of the Gates-McCall and Banos-Westley 230 kV lines.

Congestion on the Barre-Villa and Barre-Lewis 230 kV lines, which occurred in 1.5 and 0.9 percent of intervals, respectively, increased prices in the SCE area by about $8/MWh. Congestion on these constraints increased prices in the SDG&E area by about $4/MWh (Barre-Villa line) and about $9/MWh (Barre-Lewis line). Both constraints decreased prices in the PG&E area by about $11/MWh. This constraint was impacted by the San Onofre retirement as well as other planned outages.

The 7820_TL 230S_OVERLOAD_NG nomogram drove real-time prices in the SDG&E area up by about $26/MWh and decreased PG&E prices by over $3/MWh. The other remaining constraints in the 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 Serrano transformer, the 22831_SYCAMORE_138_22117_CARLTHT2_138_BR_1 _1 line, and the SOUTH_OF_LUGO branch group.

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

Area	Constraint	Frequency	Load area		
			PG&E	SCE	SDG&E
PG&E	PATH15_S-N	1.7%	$25.72	-$20.69	-$20.69
	30880_HENTAP2 _230_30900_GATES _230_BR_2 _1	1.0%	$3.56	-$2.52	-$2.52
	LBN_S-N	0.3%	$16.95	-$14.21	-$14.21
	SLIC 2207662 NGila-HWD PVDV	0.2%	$8.28	-$8.48	$6.67
	TRACY500_BG	0.1%	-$33.94	$26.27	$26.27
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	1.5%	-$11.54	$8.15	$4.06
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	0.9%	-$10.71	$7.84	$8.62
	PATH26_N-S	0.6%	-$98.26	$80.47	$80.47
	T-135 VICTVLUGO_EDLG_NG	0.6%	$5.03	-$3.88	-$6.88
	T-135 VICTVLUGO_DVRB_NG	0.4%	$9.77	-$7.96	-$13.69
	SLIC 2196141 MIDWAY SOL1	0.4%	-$8.95	$7.57	$7.57
	IID-SCE_BG	0.3%			-$18.50
	SLIC 2157511 LUG0-MIRA LOMA 3	0.3%	-$17.63	$13.53	$18.62
	SLIC 2209261 LUGOMOHV_OOS_DVRB	0.1%	$15.38	-$11.26	-$28.88
	24155_VINCENT _230_24126_RIOHONDO_230_BR_1 _1	0.1%	-$42.27	$33.14	$37.48
	22260_ESCNDIDO_230_22844_TALEGA _230_BR_1 _1	0.1%	$7.57	$8.80	-$66.18
SDG&E	7820_TL 230S_OVERLOAD_NG	0.6%	-$3.00		$26.15
	22831_SYCAMORE_138_22117_CARLTHT2_138_BR_1 _1	0.4%			$25.29
	22462_ML60 TAP_138_22772_SOUTHBAY_138_BR_1 _1	0.2%			$27.94
	24138_SERRANO _500_24137_SERRANO _230_XF_3	0.2%	-$29.19		$49.09
	22692_ROSCYNTP_69.0_22696_ROSE CYN_69.0_BR_1 _1	0.2%			$34.63
	SOUTH_OF_LUGO	0.2%	-$33.63	$27.02	$36.66
	22824_SWTWTRTP_69.0_22820_SWEETWTR_69.0_BR_1 _1	0.1%			$63.65
	SOUTHLUGO_RV_BG	0.05%	-$33.58	$26.57	$36.13

Overall, congestion occurred more frequently in the day-ahead market than in the real-time market, as seen by a comparison of Table 1.2 and Table 1.3. In the first 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 1 percent of intervals in the real-time market. While this constraint increased day-ahead prices in the PG&E area by nearly $0.36/MWh, it increased prices by over $3.56/MWh in the real-time market. A similar pattern can also be seen with the 24016_BARRE_230_24154_VILLA PK_230_BR_1 _1 constraint.

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.[19] The price impact of congestion differs across load areas and markets.

In the first quarter, both day-ahead and real-time congestion increased prices in the SCE and SDG&E areas and decreased prices in the PG&E area. Day-ahead congestion had a relatively small impact, separating the load area prices by less than $0.30/MWh.[20]

Day-ahead price impacts

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

The overall impact of congestion on day-ahead prices in the PG&E area was a decrease of about $0.26/MWh from the system average, and an increase in SCE area prices by about $0.29/MWh and in SDG&E area prices by about $0.27/MWh. Compared to the previous quarter, the impact of SDG&E area congestion decreased by about a third, from $0.94/MWh, while congestion in other areas was similar.

The Barre-Villa and Barre-Lewis line constraints had the largest overall impact on prices in the first quarter. These constraints replaced the Barre-Lewis nomogram. In the PG&E area, the PATH15_BG constraint increased prices by $0.07/MWh (0.14 percent) and decreased prices in the SCE and SDG&E areas by $0.06/MWh (0.1 percent). In the SDG&E area, day-ahead prices were driven by multiple smaller constraints. Each of these constraints shifted the SDG&E area prices by less than 10 cents.

Table 1.4 Impact of congestion on overall day-ahead prices

	PG&E		SCE		SDG&E	
Constraint	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.13	-0.25%	$0.15	0.29%	$0.00	0.01%
24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.10	-0.18%	$0.12	0.22%	$0.02	0.04%
SLIC 2157511 LUG0-MIRA LOMA 3	-$0.07	-0.13%	$0.05	0.10%	$0.06	0.12%
PATH15_BG	$0.07	0.14%	-$0.06	-0.11%	-$0.06	-0.11%
SOUTHLUGO_RV_BG	-$0.05	-0.10%	$0.04	0.07%	$0.06	0.10%
T-135 VICTVLUGO_DVRB_NG	$0.04	0.07%	-$0.03	-0.05%	-$0.05	-0.09%
30880_HENTAP2 _230_30900_GATES _230_BR_2 _1	$0.04	0.07%	-$0.03	-0.05%	-$0.03	-0.05%
PATH26_BG	-$0.03	-0.06%	$0.02	0.04%	$0.02	0.04%
22831_SYCAMORE_138_22117_CARLTHT2_138_BR_1 _1					$0.07	0.13%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					$0.04	0.08%
25201_LEWIS _230_24137_SERRANO _230_BR_1 _1	-$0.02	-0.03%	$0.02	0.03%	$0.00	0.00%
7820_TL 230S_OVERLOAD_NG					$0.03	0.06%
24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.00	0.00%	-$0.01	-0.01%	$0.02	0.04%
24155_VINCENT _230_24126_RIOHONDO_230_BR_1 _1	-$0.01	-0.02%	$0.01	0.01%	$0.01	0.02%
33020_MORAGA _115_30550_MORAGA _230_XF_1 _P	$0.01	0.02%	-$0.01	-0.01%	-$0.01	-0.01%
Other	$0.00	0.00%	$0.00	0.01%	$0.04	0.07%
Total	-$0.26	-0.5%	$0.29	0.5%	$0.27	0.5%

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

[20] 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.

Real-time price impacts

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

- Congestion on the Path26_N-S constraint drove prices in the SCE and SDG&E areas up by $0.51/MWh (1 percent). The overall impact of congestion on prices was about $0.40 (0.8 percent) in the SCE area and $0.64 (1.2 percent) in the SDG&E area. In the previous quarter, real-time congestion did not have a significant impact on the Southern California load area prices.
- In the PG&E area, the overall impact of congestion on real-time prices was a decrease of about $0.57/MWh, 1.1 percent below the system energy price. The largest price impact was associated with congestion on Path15_S-N, which increased prices by about $0.44/MWh (0.87 percent).

Table 1.5 Impact of congestion on overall real-time prices

	PG&E		SCE		SDG&E	
Constraint	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
PATH26_N-S	-$0.63	-1.24%	$0.51	1.01%	$0.51	1.00%
PATH15_S-N	$0.44	0.87%	-$0.35	-0.69%	-$0.35	-0.68%
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.18	-0.35%	$0.13	0.25%	$0.02	0.04%
24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.09	-0.19%	$0.07	0.14%	$0.01	0.02%
7820_TL 230S_OVERLOAD_NG	-$0.01	-0.02%			$0.15	0.30%
SLIC 2157511 LUG0-MIRA LOMA 3	-$0.05	-0.11%	$0.04	0.08%	$0.06	0.11%
SOUTH_OF_LUGO	-$0.05	-0.10%	$0.04	0.08%	$0.06	0.11%
24138_SERRANO _500_24137_SERRANO _230_XF_3	-$0.05	-0.10%			$0.09	0.17%
LBN_S-N	$0.05	0.10%	-$0.04	-0.08%	-$0.04	-0.08%
T-135 VICTVLUGO_DVRB_NG	$0.04	0.08%	-$0.03	-0.06%	-$0.06	-0.11%
24155_VINCENT _230_24126_RIOHONDO_230_BR_1 _1	-$0.04	-0.09%	$0.04	0.07%	$0.04	0.08%
T-135 VICTVLUGO_EDLG_NG	$0.03	0.06%	-$0.02	-0.05%	-$0.04	-0.08%
22831_SYCAMORE_138_22117_CARLTHT2_138_BR_1 _1					$0.09	0.17%
30880_HENTAP2 _230_30900_GATES _230_BR_2 _1	$0.04	0.07%	-$0.03	-0.05%	-$0.03	-0.05%
SLIC 2196141 MIDWAY SOL1	-$0.03	-0.06%	$0.03	0.05%	$0.03	0.05%
22824_SWTWTRTP_69.0_22820_SWEETWTR_69.0_BR_1 _1					$0.08	0.15%
30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	-$0.03	-0.05%	$0.02	0.04%	$0.02	0.04%
PATH15_N-S	-$0.03	-0.05%	$0.02	0.04%	$0.02	0.04%
22462_ML60 TAP_138_22772_SOUTHBAY_138_BR_1 _1					$0.07	0.13%
IID-SCE_BG					-$0.06	-0.12%
SLIC 2209261 LUGOMOHV_OOS_DVRB	$0.02	0.03%	-$0.01	-0.02%	-$0.03	-0.06%
SLIC 2207662 NGila-HWD PVDV	$0.02	0.03%	-$0.02	-0.03%	$0.01	0.03%
TRACY500_BG	-$0.02	-0.04%	$0.01	0.03%	$0.01	0.03%
SOUTHLUGO_RV_BG	-$0.02	-0.03%	$0.01	0.02%	$0.02	0.03%
Other	$0.03	0.05%	-$0.03	-0.05%	-$0.06	-0.11%
Total	-$0.57	-1.1%	$0.40	0.8%	$0.64	1.2%

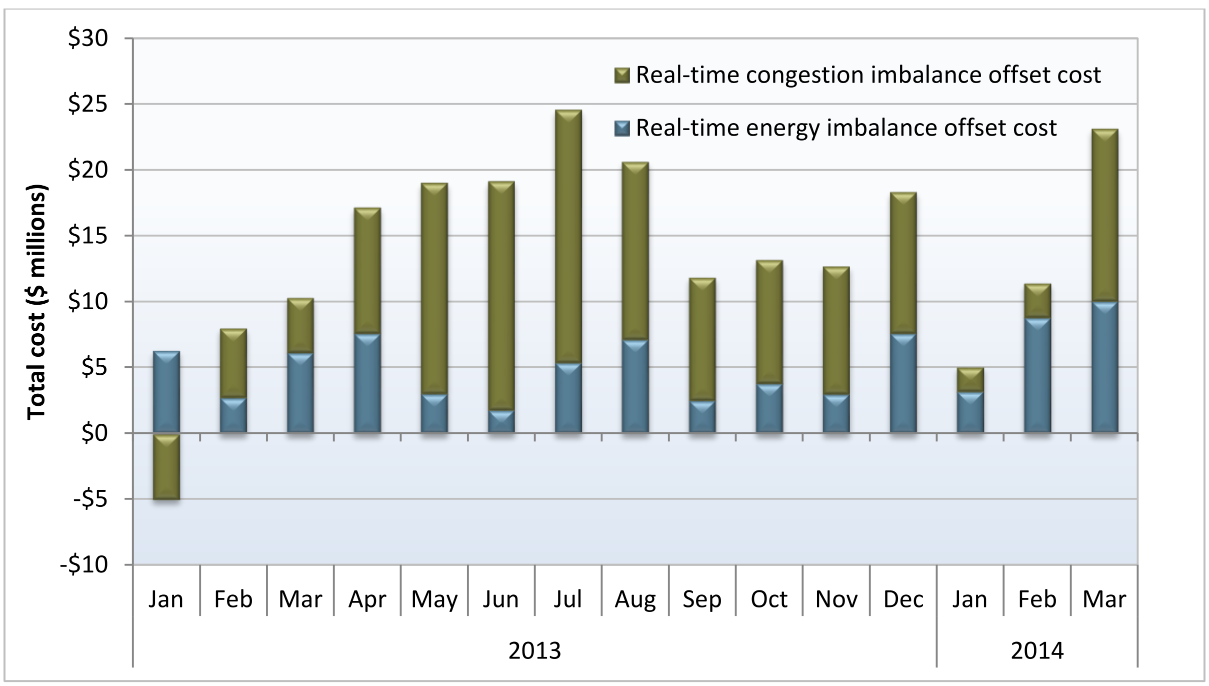
Overall, the frequency of real-time congestion increased slightly from the previous quarter. It had a relatively small impact, decreasing PG&E area prices by about $0.57/MWh, a decrease from -$0.28/MWh in the previous quarter. Congestion in Southern California increased prices by $0.40/MWh in the SCE area and $0.64/MWh in the SDG&E area. Real-time market congestion in these areas was insignificant in the previous quarter. 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.

1.6 Real-time imbalance offset costs

Real-time imbalance offset costs totaled about $40 million in the first quarter of 2014, down from $44 million in the fourth quarter of 2013. This change was the result of substantial reductions in congestion offset costs that were counteracted, in part, by increasing energy offset costs. The first quarter value is slightly below the average quarterly offset cost for 2011 and 2012 of about $50 million, and about equal to the average quarterly cost in 2013 of $44 million.

Congestion offset costs accounted for approximately 44 percent of the total imbalance costs during the first quarter, totaling about $18 million (see Figure 1.14). The remaining $22 million were energy imbalance offset costs. This value was higher than any other quarterly real-time energy imbalance offset cost observed since the second quarter of 2012 ($23 million). The real-time energy imbalance offset costs were primarily driven by differences in settlement between inter-ties and internal resources.

Figure 1.14 Real-time imbalance offset costs



Together, costs incurred on two days accounted for over $8 million, or about 37 percent of the total real-time imbalance energy offset cost. On February 6, imbalance energy costs were $6.6 million. As discussed in further detail in Section 3.1, there were significant electric reliability issues related to gas pipeline concerns. ISO operators adjusted hour-ahead market loads and exceptionally dispatched significant volumes of generation on the inter-ties in order to maintain reliability. The high real-time imbalance energy offset costs on this date were driven by the substantial volume of imports settled at hour-ahead prices which were substantially higher than real-time prices. For instance, hour-ahead prices in hours ending 18 and 19 exceeded real-time average prices by over $800/MWh.

On March 15, real-time imbalance energy offset costs totaled $1.6 million, driven by energy costs due to changes in transmission limitations after the day-ahead market run which resulted in decreased import capacity.

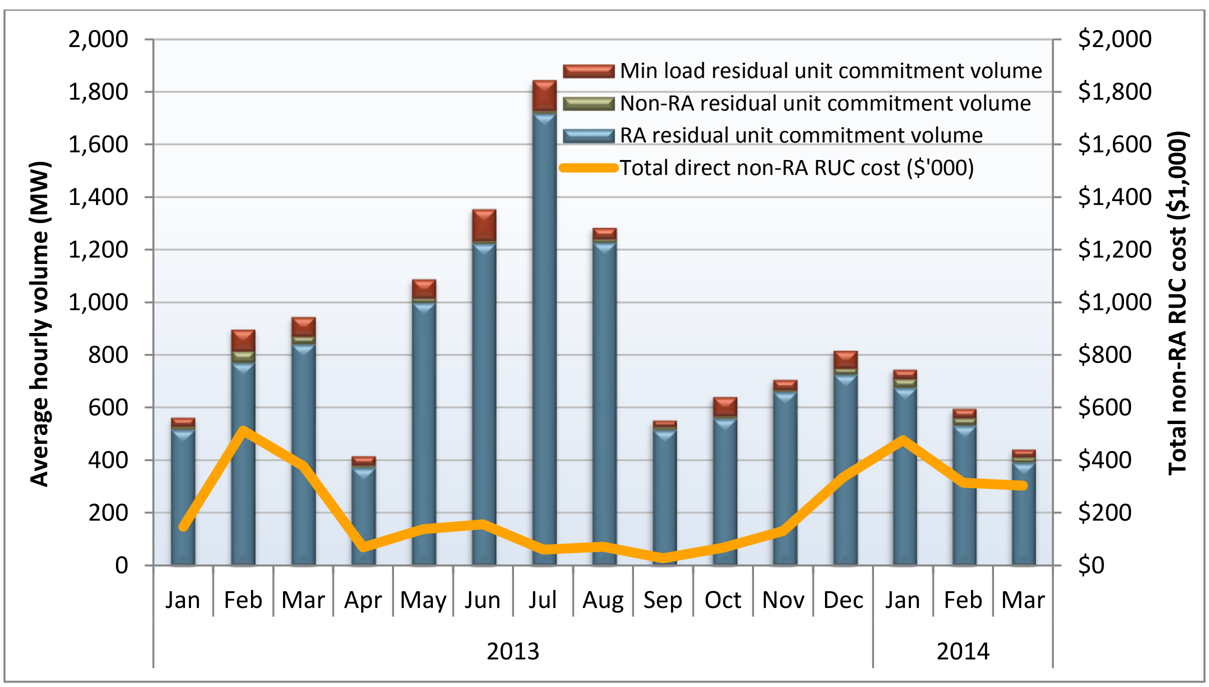
Real-time congestion offset costs dropped substantially in the first quarter to $18 million from $30 million in the fourth quarter of 2013. Real-time congestion offset costs were primarily due to unscheduled flows and market modeling differences. Together, costs incurred on five days in March accounted for more than $5.8 million, about one third of congestion offset costs for the quarter.

1.7 Residual unit commitment

Despite low volumes of residual unit commitment, the direct costs of procuring residual unit commitment capacity rose in the first quarter to $1.1 million from $0.7 million in the fourth quarter of 2013. Even so, the 2014 first quarter costs were similar to the first quarter costs in 2013. As in prior quarters, increased residual unit commitment costs have been driven primarily by an increase in residual unit commitment requirements to replace cleared net virtual supply.

Figure 1.15 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. As in previous quarters, the majority of residual unit commitment capacity is resource adequacy capacity which is procured at no cost.

Figure 1.15 Residual unit commitment costs and volume

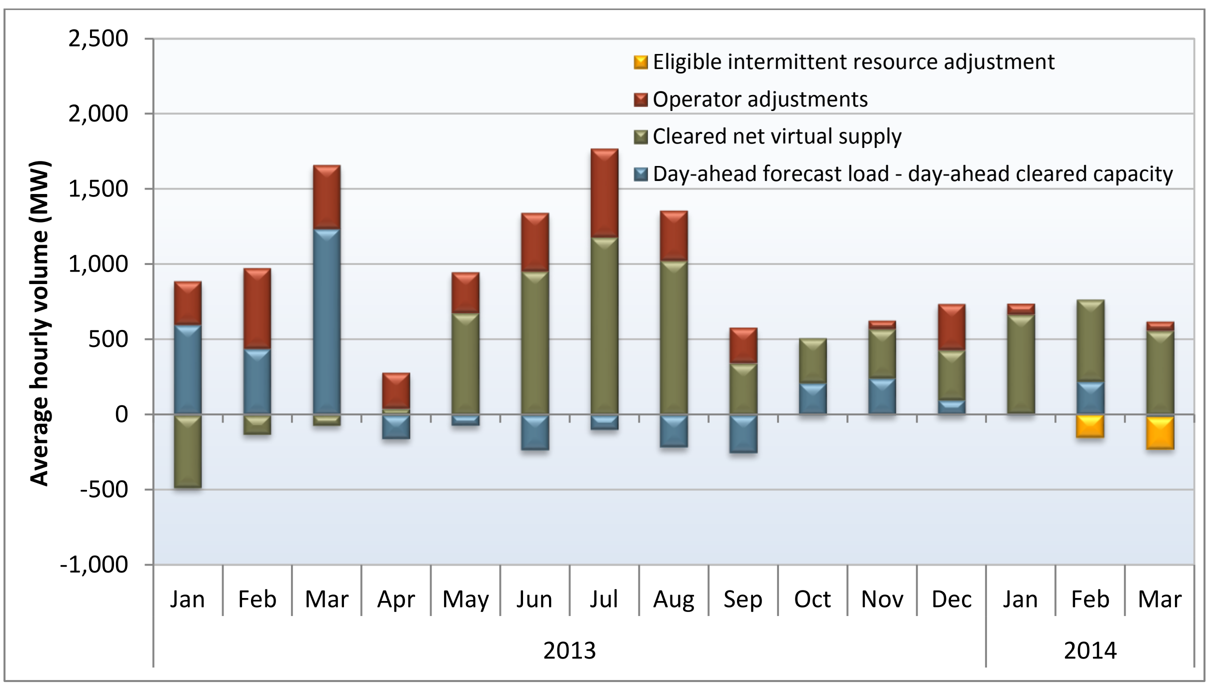


Minimum load capacity committed by the residual unit commitment process accounts for a portion of the bid cost recovery payments.[21] Residual unit commitment bid cost recovery payments were $2.7 million in the first quarter, about 40 percent lower than the $4.7 million in the previous quarter. Virtual bidders accounted for $3 million in residual unit commitment bid cost recovery charges in the quarter (for further detail see Section 2.2).

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. Use of this tool decreased substantially in the first quarter of 2014, compared to the first quarter of 2013.

As illustrated in Figure 1.16, residual unit commitment procurement appears to be driven in large part by the need to replace cleared net virtual supply volumes that do not materialize in the real-time market. On average, cleared net virtual supply (green bar) has had a greater presence in the first quarter of 2014 than it did in the final quarter of 2013. Virtual supply began to play an increasing role in residual unit commitment procurement beginning in the second quarter of 2013.

Figure 1.16 Determinants of residual unit commitment procurement



The ISO introduced an automatic adjustment to residual unit commitment schedules to account for differences between the day-ahead schedules of participating intermittent resource program (PIRP)

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

resources and the forecast output of these renewable resources.[22] This adjustment, called the eligible intermittent resource adjustment, went into effect on February 7, 2014, and is represented by the yellow bar in Figure 1.16. In the future, this adjustment may be expanded to include adjustments for forecasts of participating intermittent resource program renewables without day-ahead schedules. DMM supports this change.

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 increased residual unit commitment in the first quarter, but was not a significant factor in any month except for February. This effect was significantly smaller in the first quarter of 2014 than in the first quarter of 2013. Operator adjustments to the residual unit commitment process (red bar) played a minimal role in the residual unit commitment procurement in the first quarter of 2014 compared to previous periods.

[22] Specifically, the adjustment is only made for PIRP resources that have positive schedules in the day-ahead market. PIRP resources that are not scheduled in the day-ahead market are not adjusted at this time.

2 Convergence bidding

Participants engaging in convergence bidding continued to earn positive returns from participation in ISO markets in the first quarter. The net revenues from the market were about $3.8 million in this quarter, compared to about $9.3 million in the previous quarter. Virtual supply generated net revenues of about $11 million, while virtual demand accounted for losses of around $7.2 million. However, total payment to convergence bidders fell to $0.8 million after taking into account virtual bidding bid cost recovery charges ($3 million).

Most positive convergence bidding revenues resulted from offsetting virtual demand with supply bids at different locations. This is designed to profit from higher anticipated congestion between these locations in real time. This type of offsetting bid represented over 68 percent of all accepted virtual bids in the fourth quarter, a decrease from 75 percent in the previous quarter.

Total hourly trading volumes decreased considerably in the first quarter to 3,010 MW from 4,160 MW in the previous quarter. Virtual supply averaged around 1,800 MW while virtual demand averaged around 1,200 MW during each hour of the quarter. Thus, the average hourly net virtual position in the first quarter was 590 MW of virtual supply, an increase from 320 MW of net virtual supply in the previous quarter.

For the quarter, net revenue for net virtual demand positions was negative due to infrequent real-time price spikes. Net revenue from net virtual supply positions was positive as prices were generally higher in the day-ahead market than the real-time market. The higher volumes of virtual supply in the first quarter may be due to larger separation between the real-time and day-ahead market prices compared to previous quarters (see Section 1.2).

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.[23] 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 considerably in the first quarter to 3,010 MW from 4,160 MW in the previous quarter.

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

- On average, about 61 percent of virtual supply and demand bids offered into the market cleared in the first quarter. This is a slight increase over the previous quarter.
- Cleared hourly volumes of virtual supply outweighed cleared virtual demand by around 590 MW on average, an increase from 320 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 580 MW and 620 MW respectively. On average, in all hours, except for hour ending 18, virtual supply exceeded virtual demand.

[23] 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 Monthly average virtual bids offered and cleared

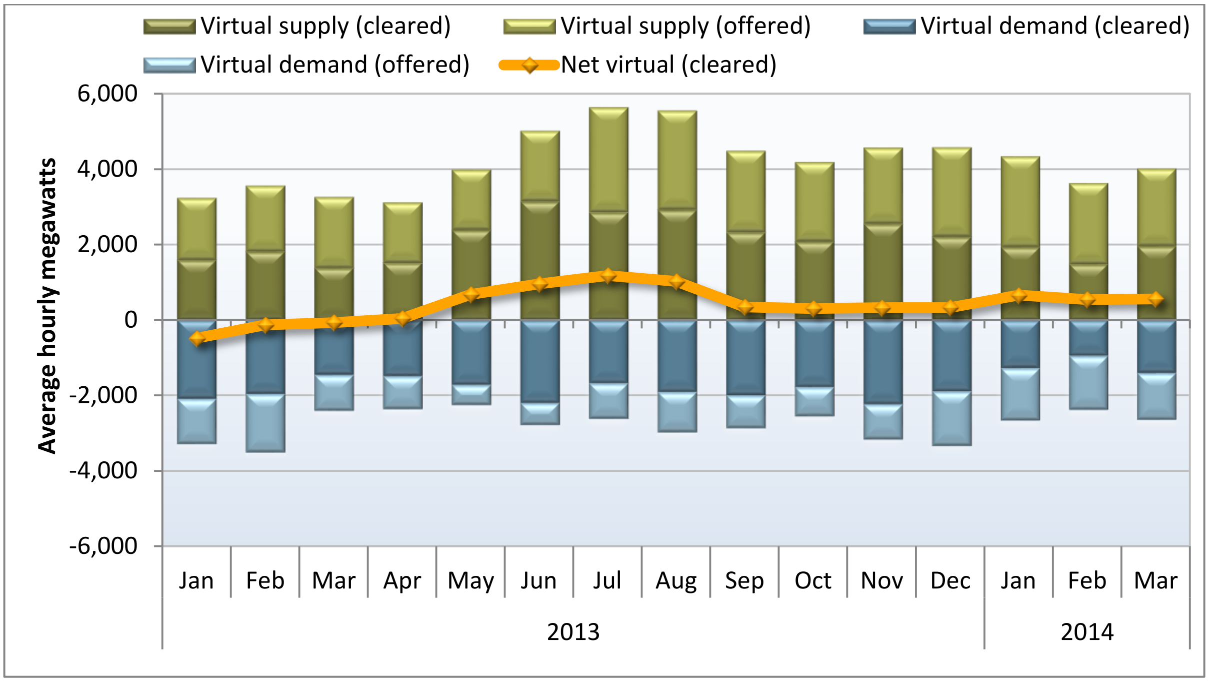
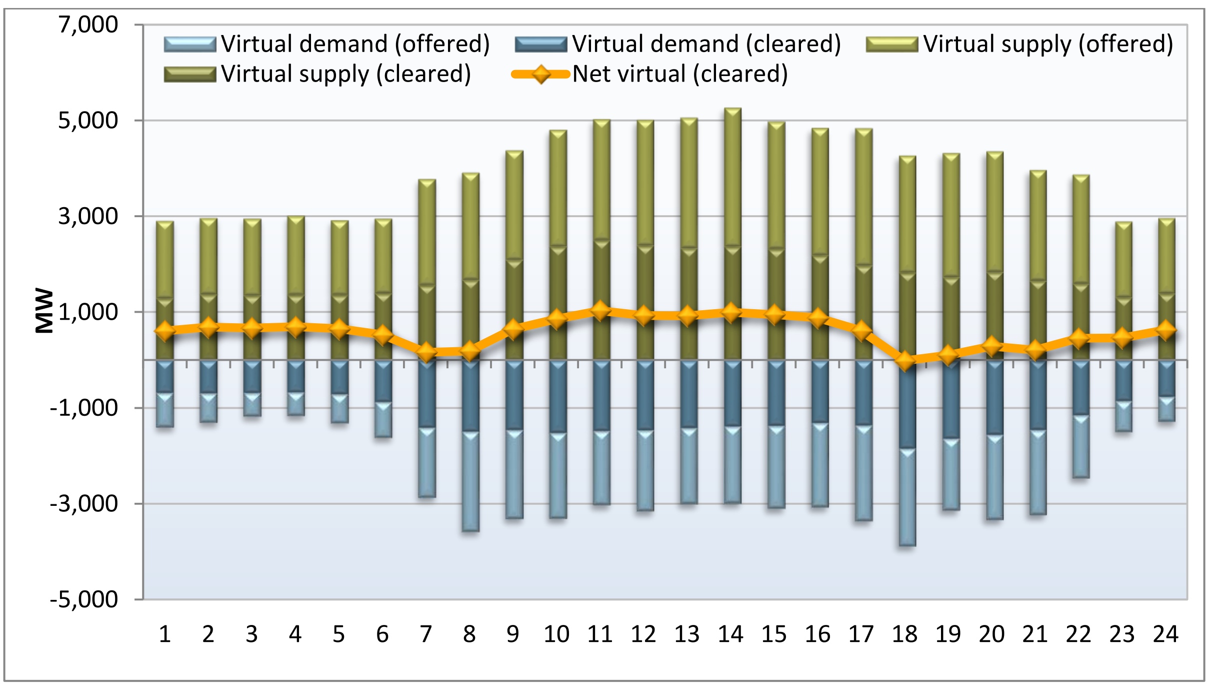


Figure 2.2 Hourly offered and cleared virtual activity (January – March)



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 in 20 hours in February. However, the January and March net convergence bidding volumes were increasingly more inconsistent with price differences between the day-ahead and real-time markets, with 17 hours in January and only 16 hours in March consistent. For the quarter, net convergence bidding volumes were consistent with day-ahead and real-time price differences in 18 hours, as shown in Figure 2.3.

Figure 2.3 Hourly convergence bidding volumes and prices (January through March)

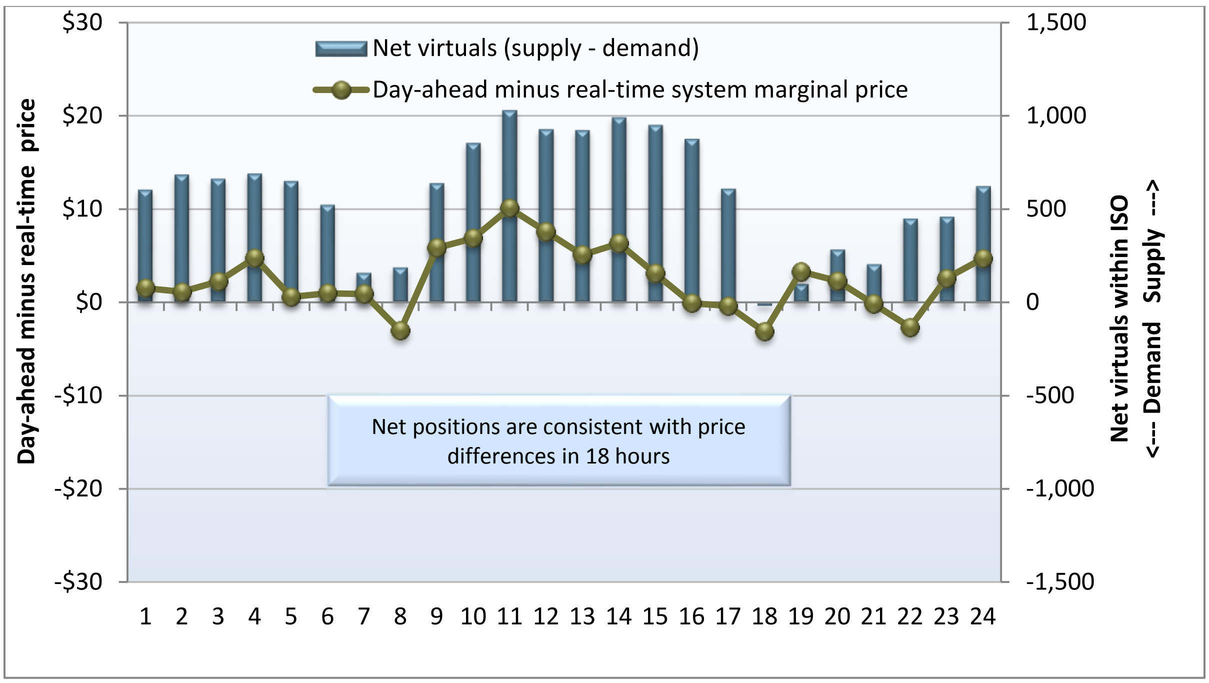


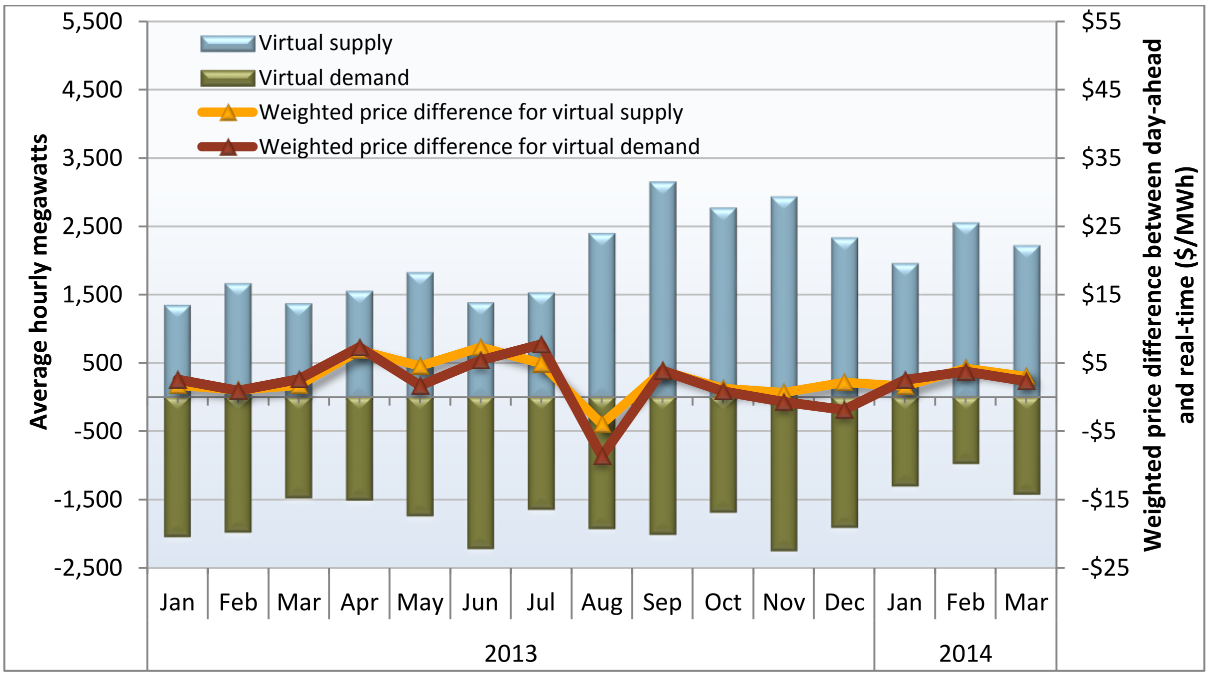
Figure 2.4 compares cleared convergence bidding volumes with the volume-weighted average price difference at which these virtual bids were settled. The difference between day-ahead and real-time prices shown in this figure represents the average price difference weighted by the amount of virtual bids clearing at different locations.

When the red line is positive, it indicates that the weighted average price charged for 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 inconsistent with weighted average price differences for the hours in which virtual demand cleared the market for the entire first quarter. In general, virtual demand positions were not profitable. While there were a few high real-time prices during unseasonably cold weather on a few days in February, overall virtual demand positions were not 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 2.4 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 have been consistently profitable since January 2012, with the exception of August 2013.

Figure 2.4 Convergence bidding volumes and weighted price differences



As noted earlier, a large portion of the virtual supply clearing the market was paired with demand bids at different locations by the same market participants. Such offsetting virtual supply and demand bids are likely used as a way of hedging or arbitraging spatial price differences caused by congestion within the ISO system. Also, offsetting positions are not exposed to bid cost recovery settlement charges.[24] 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. The congestion remained low in this quarter, which reduced the profitability of the offsetting trades in this quarter.

Offsetting virtual supply and demand bids

As described above, market participants can hedge congestion costs or earn revenues associated with differences in congestion between different points within the ISO system by placing virtual demand and supply bids at different 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

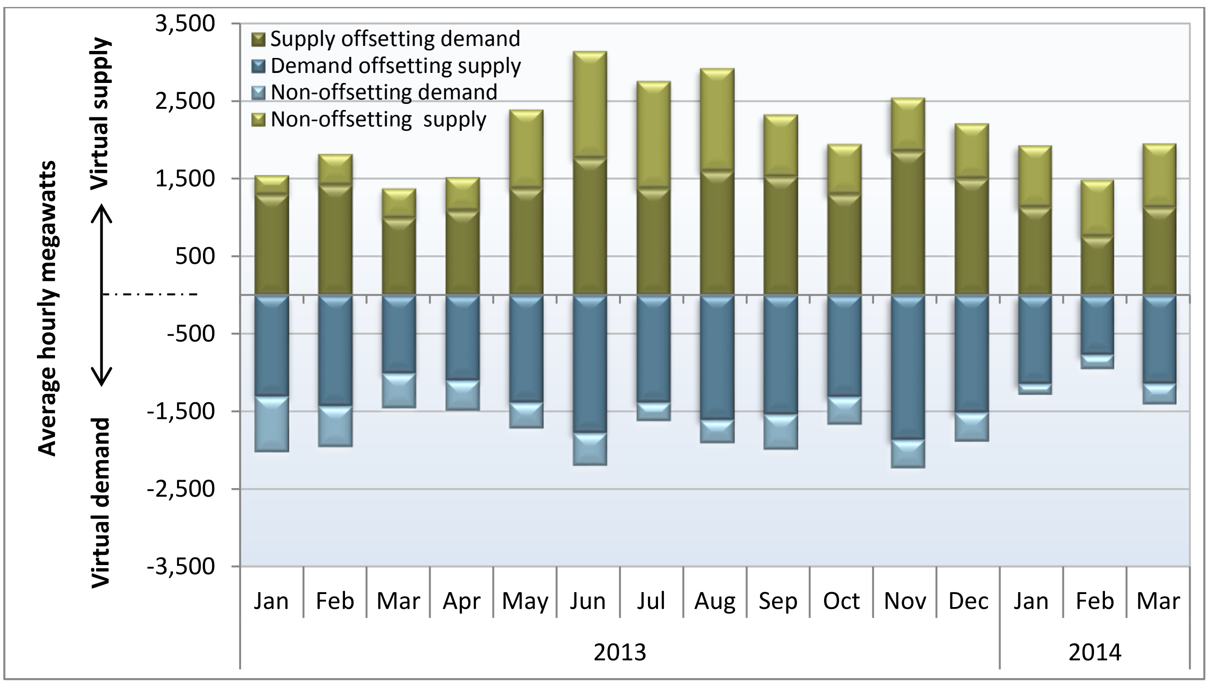
[24] Please refer to the discussion at the end of this section for detailed analysis of bid cost recovery charges to convergence bidders.

profitable if there are differences in price caused by congestion in the day-ahead and real-time markets between these two locations.

In the first quarter, the majority of cleared virtual bids were offsetting bids. The amount of offsetting supply decreased from a relatively high level compared to the same quarter the previous year. Figure 2.5 shows the average hourly volume of offsetting virtual supply and demand positions. The dark blue and dark green bars represent the average hourly overlap between demand and supply by the same participants. The lighter portion of each bar represents the remaining portion of virtual supply (green) and demand (blue) that was not offset by virtual demand or supply by the same participants.

As shown in Figure 2.5, offsetting virtual positions accounted for an average of about 1,020 MW of virtual demand offset by 1,020 MW of virtual supply in each hour of the first quarter. These offsetting bids represent about 68 percent of all cleared virtual bids in the first quarter, a decrease from 75 percent in the previous quarter. This suggests that virtual bidding continues to be used to hedge or profit from congestion, although to a lesser extent.

Figure 2.5 Average hourly offsetting virtual supply and demand positions by same participants



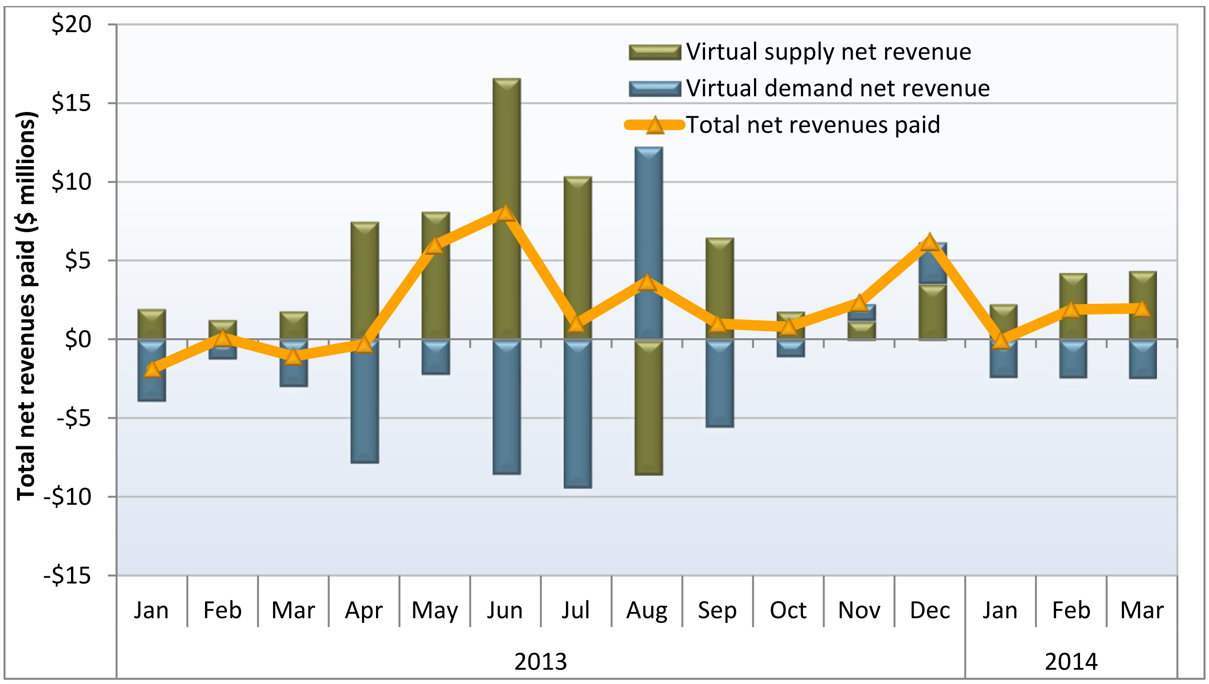
2.2 Convergence bidding revenues

This section highlights sources of net revenues (or payments) received (or paid) by convergence bidders. As in the previous quarter, convergence bidding participants earned positive returns. In the first quarter, net revenues were about $3.8 million from revenue collected on virtual supply positions.

Figure 2.6 shows total monthly net revenues for cleared virtual supply and demand. This figure shows the following:

- The net revenues from the market were about $3.8 million in this quarter, compared to about $9.3 million in the previous quarter.
- Virtual supply revenues were profitable in every month of the first quarter because day-ahead prices were generally higher than real-time prices. In total, virtual supply accounted for net payments of about $11 million for the quarter.
- Virtual demand was not profitable in any month during the quarter. In total, virtual demand accounted for approximately $7.2 million in net payments to the market.
- In the first quarter, convergence bidders were paid about $0.8 million, after subtracting virtual bidding bid cost recovery charges of around $3 million for the quarter.

Figure 2.6 Total monthly net revenues paid from convergence bidding



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 $0.9 million (24 percent) of the total convergence bidding settlements, a dramatic drop from about $8 million or nearly 85 percent of revenue gains in the fourth quarter of 2013. Physical generation and load participants accounted for about 16 percent of volume but around 64 percent of revenues, which were entirely from virtual supply positions.

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 entities represent the largest segment of the virtual market, accounting for about 75 percent of volumes but only about 24 percent of settlement dollars. Marketers represent about 9 percent of the trading volumes and 12 percent of the settlement dollars. Generation owners and load-serving entities represent a small segment of the virtual market in terms of volumes (about 16 percent) but the largest settlements portion (64 percent).

Table 2.1 Convergence bidding volumes and revenues by participant type (January – March)

Trading entities	Average hourly megawatts			Revenues\Losses ($ millions)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	1,072	1,185	2,257	-$6.5	$7.4	$0.9
Marketer	70	208	279	-$0.2	$0.6	$0.5
Physical generation	78	208	286	-$0.6	$1.6	$1.0
Physical load	0	207	207	$0.0	$1.4	$1.4
Total	**1,220**	**1,808**	**3,028**	**-$7.2**	**$11.0**	**$3.8**

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.[25] 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.[26]

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.[27]

- Integrated forward market bid cost recovery tier 1 allocation addresses costs associated with situations when the market clears with positive net virtual demand.[28] In this case, virtual demand leads to increased unit commitment in the day-ahead market, which may not be economic.

[25] 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.

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

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

- Day-ahead residual unit commitment tier 1 allocation relates to situations where the day-ahead market clears with positive net virtual supply.[29] 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 2.7, the day-ahead residual unit commitment tier 1 allocation charge associated with virtual bids exceeded the previous high point in December of the previous quarter, in percentage terms, by reaching a peak of about 23 percent of total bid cost recovery charges in January. This is consistent with an increase in the number of individual net virtual supply hours and associated residual unit commitment costs in January 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. Similar to the previous quarter, the integrated forward market bid cost recovery costs associated with net virtual demand remained low in the first quarter.

Figure 2.8 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 first quarter were close to $3 million. As noted earlier, the total estimated net revenue for convergence bidding was around $3.8 million. Total convergence bidding revenue adjusted for bid cost recovery costs was around $0.8 million.

[28] 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.

[29] 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.

Figure 2.7 Convergence bidding costs associated with bid cost recovery tier 1 and residual unit commitment tier 1 as a percent of total bid cost recovery

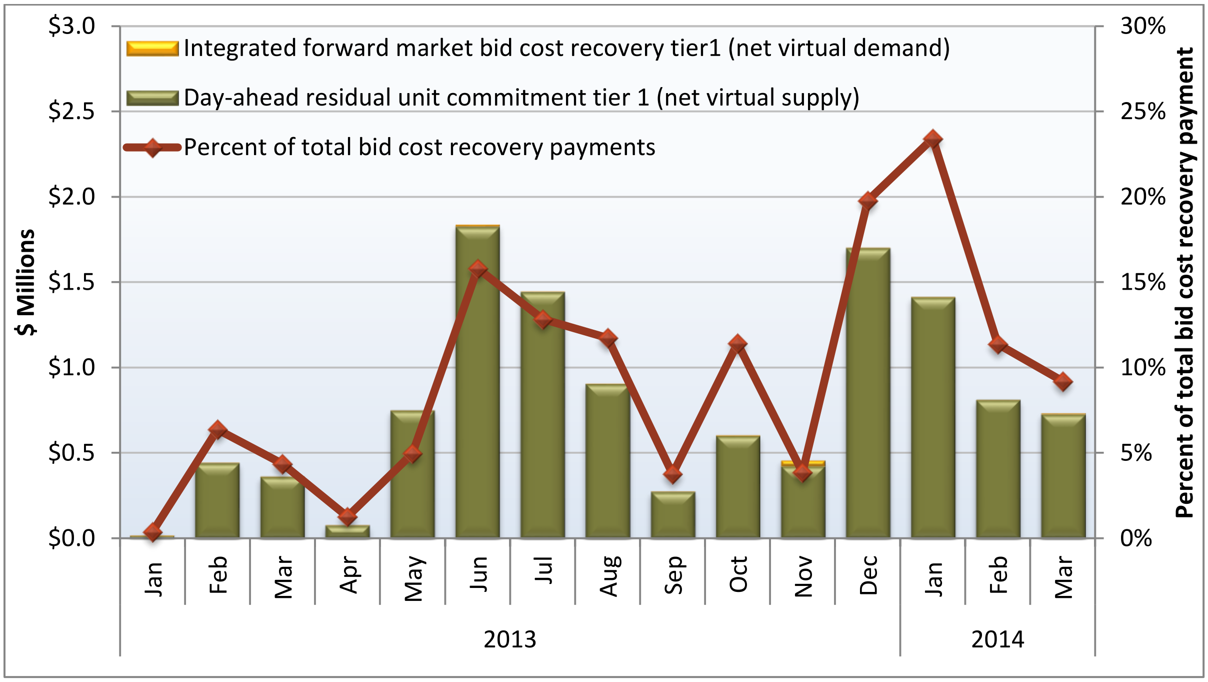
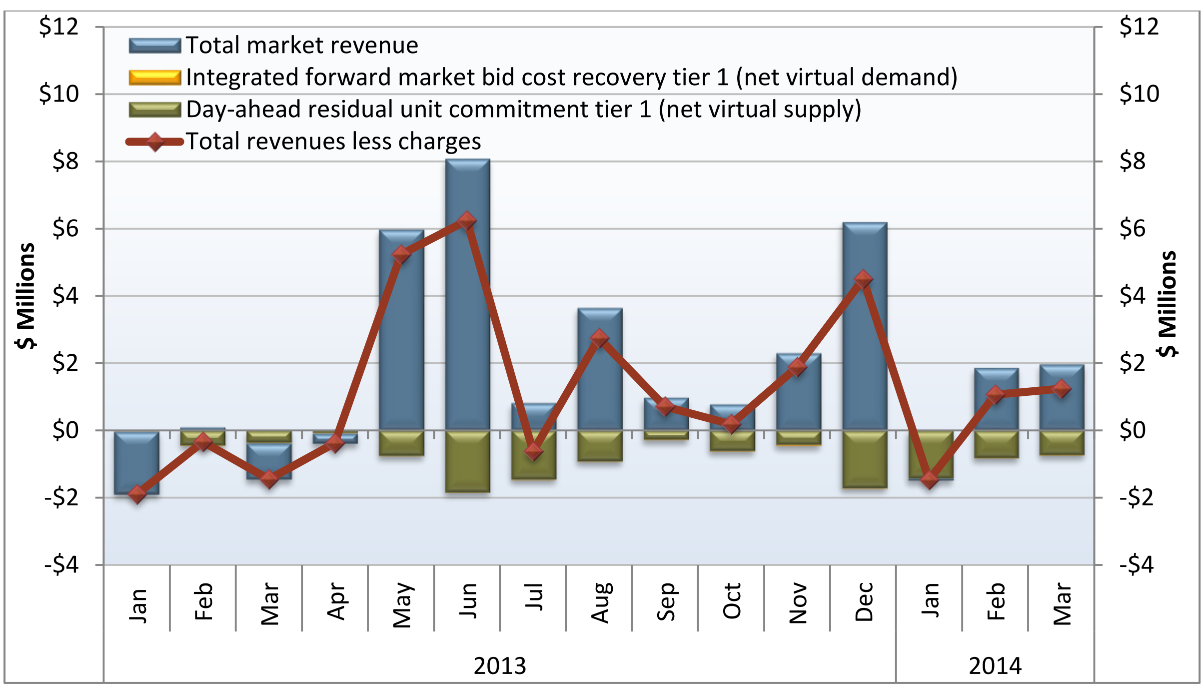


Figure 2.8 Convergence bidding revenues and costs associated with bid cost recovery tier 1 and residual unit commitment tier 1



3 Special Issues

3.1 Gas-electric market events during winter 2013-14

This section provides background and analysis of two events related to gas and electric system coordination and interaction. The first event occurred around December 6 through December 12, 2013. The second event occurred on and around February 6, 2014.

During these periods, the ISO took a variety of manual adjustments and out-of-market actions to help manage gas pipeline limitations and ensure electric system reliability. The ISO has published a technical bulletin providing detailed information about various actions and the market impacts of these actions.[30] DMM's review indicates these actions appear to have been necessary and appropriate, given the extraordinary conditions and uncertainties during these periods.

DMM also agrees with stakeholders and the ISO that incremental steps should be taken to address extreme gas market events. However, DMM cautions that some of the proposed solutions – such as eliminating the cost-based limits currently placed on start-up and minimum load bids for gas-fired units – are not necessary and could have a detrimental impact on overall market competitiveness and efficiency. DMM looks forward to participating further in stakeholder processes addressing these issues this year.

Background

Overall, natural gas demand is highest in the winter months even though natural gas-fired generation is highest in the summer months. This is because natural gas is used to heat homes and businesses in the winter and is also used in many industrial processes. However, unlike natural gas-fired generation, these other customers of natural gas typically have priority over natural gas-fired generation. Thus, in an emergency, natural gas-fired generation is often curtailed first. As a result, natural gas reliability issues can become electric reliability issues and need to be coordinated carefully in an emergency to preserve both natural gas and electric system reliability.

Natural gas markets are not well synchronized with electric markets. For example, spot natural gas markets trade three day weekend packages from Saturday to Monday. The volume of gas purchased is for the three day period and must be managed to cover all three days. These weekend packages trade on Friday morning. This daily spot gas market is fairly liquid. However, in the event that conditions change during the weekend (or during the day), the ability for natural gas power plants to obtain additional gas can be more difficult as intra-day (also known as same day) transactions in gas markets are typically very limited and illiquid.

Natural gas spot market prices are important in the ISO markets because they factor into market participant energy offers. They also feed directly into default energy bids the ISO uses for mitigation

[30] See details at http://www.caiso.com/Documents/TechnicalBulletinGasEvents_MarketResults_Feb6_2014.pdf.

purposes, transition costs for multi-stage generating units, and proxy costs for minimum load and start-up costs.[31]

For the day-ahead market, the ISO uses a daily spot natural gas index price that is lagged due to the timing of gas markets, relative to when the ISO's day-ahead market is run. For example, the ISO's day-ahead market for February 6 used the natural gas price that traded on February 4 for operation day February 5.[32] Part of the reason for the lag is that most of the published natural gas market indices are posted well after the ISO's day-ahead market begins.[33] The ISO uses multiple natural gas indices in its calculations to limit the potential effects of gaming, manipulation or other actions that might significantly distort index prices.

The ISO's real-time market uses natural gas index prices that are mostly consistent with the appropriate gas day.[34] For example, the ISO's real-time market for February 6 used the natural gas price that traded on February 5 for operation day February 6. In the real-time market, the largest source of variation between the gas price index used by the ISO and actual gas prices stems from differences between day-ahead natural gas prices and intra-day transactions and potential charges associated with gas imbalances over multi-day periods.

The ISO's temporary solution to address natural gas and electric coordination addresses the issue of using lagged natural gas prices in the day-ahead market. This is discussed in further detail below.

December 2013

During the first couple weeks of December 2013, the weather was unseasonably cold for much of California, stretching as far south as San Diego. On the morning of Friday, December 6, natural gas trading occurred for Saturday, December 7, through Monday, December 9. The weather conditions grew colder than anticipated after the natural gas spot trading occurred for the weekend. On Saturday, multiple participants with natural gas generation in Southern California informed both the ISO and DMM of tightness of gas supply. They indicated that their ability to get gas was limited and that they may be

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[31] Minimum load and start-up registered costs are based on an average of month-ahead natural gas futures prices, not the daily spot natural gas price. For more information see Attachment C of the ISO's Market Instruments Business Practice Manual: http://bpmcm.caiso.com/BPM%20Document%20Library/Market%20Instruments/BPM_for_Market_Instruments_v32_clean.doc. Participants that select the registered cost option submit a cost that cannot not exceed 150 percent of their calculated proxy costs. These proxy costs use the average of the month-ahead natural gas futures price noted above. One of the reasons for providing this bid-based registered cost option was to provide an alternative for generation unit owners who believed they had significant non-fuel start-up or minimum load costs not covered under the proxy cost option. The trade-off, however, is that once participants elect the registered cost option, their costs will remain fixed for 30 days. The reason for fixing the costs for 30 days is to limit market power in the event that a resource is temporarily selected by the ISO through exceptional dispatch or a minimum online constraint to address reliability concerns.

[32] There is some discussion that the ISO uses a two-day lagged price. This is inaccurate. Much like the ISO's day-ahead market publishes prices for the next day, natural gas markets trade and publish prices for the next day as well. For example, the ISO day-ahead market for February 6 was run on February 5 and published by 1 p.m. The natural gas market traded for February 6 on the morning of February 5. However, the ISO used the natural gas market price index which traded on February 4 for February 5 delivery in its February 5 day-ahead market run for February 6. This is only a one-day lagged price that traded two days earlier.

[33] The InterContinental Exchange (ICE) publishes its daily spot index around 10 a.m. PPT. All other index providers publish at later periods.

[34] It is important to recognize that the natural gas and electric operation periods are not consistent. Electric operation days are from midnight to midnight. Gas operation days in the west are typically from 7 a.m. to 7 a.m. PT. This creates a partial disconnect in real time.

exposed to penalties of up to $100/MMcf. As a result, they noted that they would reflect these conditions in their bidding into the ISO markets.

Meanwhile, ISO operators were also in contact with pipeline operators during this period, including Southern California Gas.[35] By Monday (December 9), Southern California Gas asked ISO operators to adjust power plants to help maintain gas system reliability and to avoid creating an electric reliability issue. The ISO operators used exceptional dispatch on internal generation to help the pipeline address its reliability concerns. ISO operators also adjusted hour-ahead market loads above forecast to pull in more imports on the inter-ties.

The conditions and actions occurred again on December 10 and 11. Southern California Gas pipeline operators again requested assistance from the ISO to help maintain gas reliability and the ISO took actions through exceptional dispatch and through hour-ahead load adjustments to minimize the reliability issue.

During this period energy bids and prices increased in both the day-ahead and real-time markets. Day-ahead market prices reached over $75/MWh in peak hours on December 10, while real-time prices in peak hours increased to over $100/MWh on December 9 and 10. Congestion occurred primarily in the PG&E area and not in Southern California where the gas challenges were most prevalent. This congestion was primarily due to planned outages in the Fresno area that were unrelated to the natural gas situation. There was also some real-time market congestion on Path 26 limiting flows from Northern California to Southern California. This congestion separated prices in the SCE and SDG&E areas from the PG&E area prices due to planned outages on the Vincent transformer bank and the Gates-Midway 500 kV lines.

February 2014

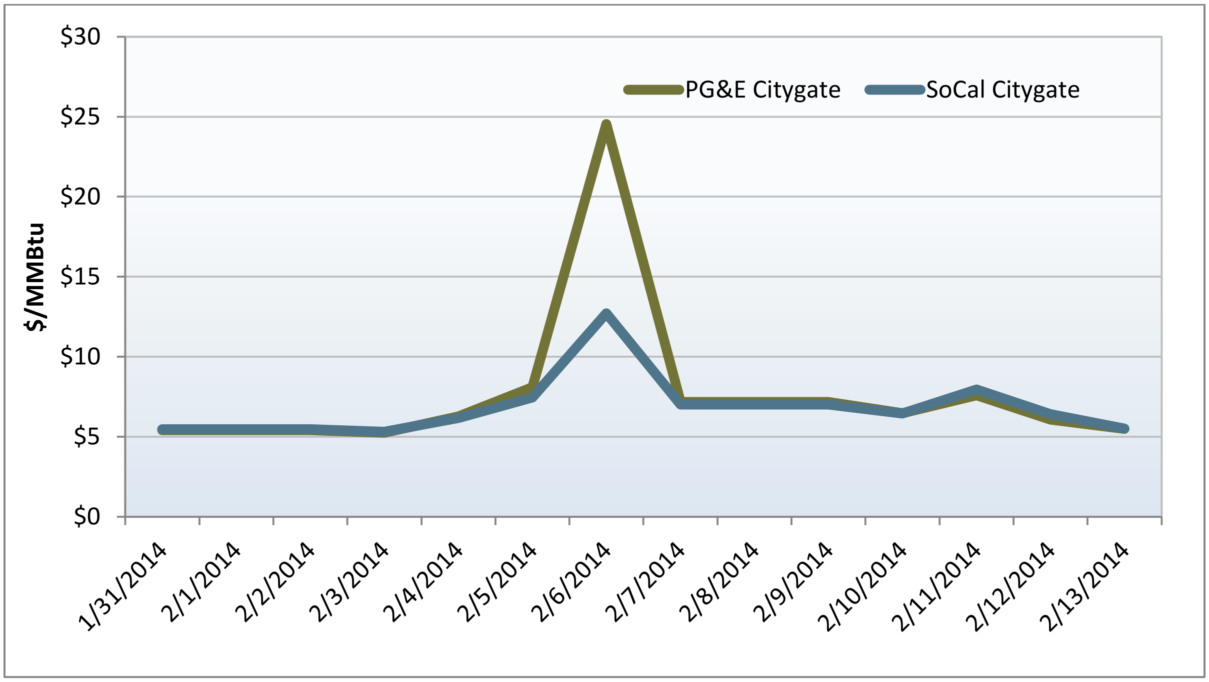
Unlike early December, conditions within California were fairly mild in early February. However, outside of California, much of the country, including the Pacific Northwest, were experiencing severe cold weather conditions. Furthermore, there were natural gas supply limitations in some parts of the country as a result of the cold weather. This created competition for natural gas supplies. In some cases, natural gas was being pulled out of storage in California to offset natural gas demand needs outside of California. In order for resources in California to attract natural gas supply, natural gas prices in California increased. Figure 3.1 shows natural gas prices over this period.

Natural gas prices began the month of February trading a little over $5/MMBtu. On February 4, gas prices increased by about $1/MMBtu and then increased to about $7.50/MMBtu on February 5. The largest increase occurred on February 6. The Southern California Gas Citygate hub price increased to under $13/MMBtu, while the Pacific Gas and Electric Citygate hub price increased to almost $25/MMBtu, which was over 300 percent of the prior day’s price. On February 7, natural gas prices decreased to around $8/MMBtu. Natural gas prices at California trading hubs had not experienced such high levels or volatility in several years.[36]

[35] For further detail on operations coordination during this event, see Brad Bouillon’s prepared statement for the FERC April 1, 2014, conference on *Winter 2013-2014 Operations and Market Performance in Regional Transmission Organizations and Independent System Operators*: http://www.ferc.gov/CalendarFiles/20140401083914-Bouillon,%20California%20ISO.pdf.

[36] In contrast, Northeastern gas market trading hubs typically exhibit this type of behavior during most winters due to limited pipeline capacity and high flows into their region.

Figure 3.1 Natural gas prices at select California trading hubs



As noted above, the ISO day-ahead market used the gas prices from trading on February 4 for gas operating day February 5 as part of its market run for February 6. These natural gas prices were utilized in calculating minimum load and start-up costs for natural gas units that elected proxy costs,[37] as well as transition costs and default energy bids used for mitigation.

Meanwhile, market participants increased their incremental energy bids to reflect the increased price of natural gas. The combination of the high incremental energy bids along with relatively inexpensive minimum load costs increased natural gas unit commitment above prior days.[38]

Overall, bid mitigation for local market power played a limited role in the day-ahead market for February 6. Mitigation of gas-fired units was triggered by congestion on only one constraint in the San Diego area. This resulted in mitigation of energy bids for a total of five units over the course of nine hours.

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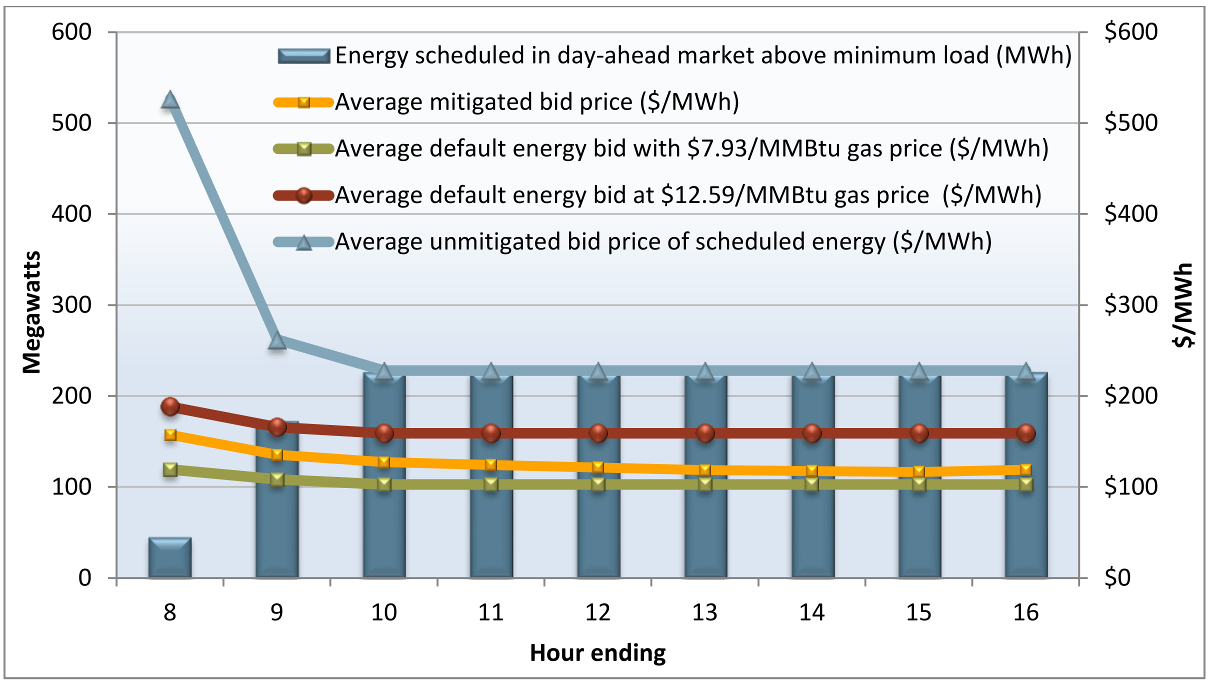
[37] Most participants elected the registered cost option and not the proxy cost option during this period. Moreover, most participants elected registered cost values below the 150 percent cap. Participants have noted that natural gas risk was one of the reasons why they needed the option to elect up to 150 percent of proxy costs (for more information see http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostsRefinement2012.aspx). However, given the level of natural gas price volatility experienced in February 2014, it is interesting to note that participants appear to have underappreciated this risk as they had more tools available to them to protect them from the risk that occurred than what they availed themselves of.

[38] See Brad Bouillon's prepared statement for the FERC April 1, 2014, conference on *Winter 2013-2014 Operations and Market Performance in Regional Transmission Organizations and Independent System Operators,* p. 7: http://www.ferc.gov/CalendarFiles/20140401083914-Bouillon,%20California%20ISO.pdf.

As shown in Figure 3.2, mitigation of these units' bids resulted in an increase of about 226 MW of additional energy during hours ending 10 to 16 (see blue bars). The average bid price of this energy was about $227/MWh (see light blue line). If default energy bids for these units had been calculated using the gas index for February 6 ($12.59/MMBtu), the default energy bid for these units would have been about $159/MWh (red line). However, these default energy bids were calculated using the gas index for gas delivered on February 5 ($7.93/MMBtu), so the average default energy bid for this energy was about $103/MWh (green line). The mitigated bid price used in the day-ahead market averaged about $121/MWh (yellow line). This is because the competitive price (which excludes congestion on uncompetitive constraints that can be relieved by these units) was usually higher than the default energy bids used in the market software. This competitive price is used as a floor in the bid mitigation process.

Figure 3.2 Impact of bid mitigation in day-ahead market on February 6, 2014



In the real-time market, no congestion occurred that required mitigation of these units. If mitigation occurred, the default energy bids would have been based on the higher gas prices for February 6 at $12.59/MMBtu (red line). All five units were shut down in real-time. Only one unit was operating above minimum load for a few hours in the morning before being shut down. All of these units were shut down as a result of gas curtailments issued by Southern California Gas.

In real time on February 6, ISO operators were in communication with pipeline operators. During the morning of February 6, Southern California Gas took action to reduce the output on a set of gas-fired generators in its service territory. Consequently, the ISO took actions to limit natural gas burn, most notably on the Southern California Gas system, to help maintain both gas and electric system reliability. These actions included:

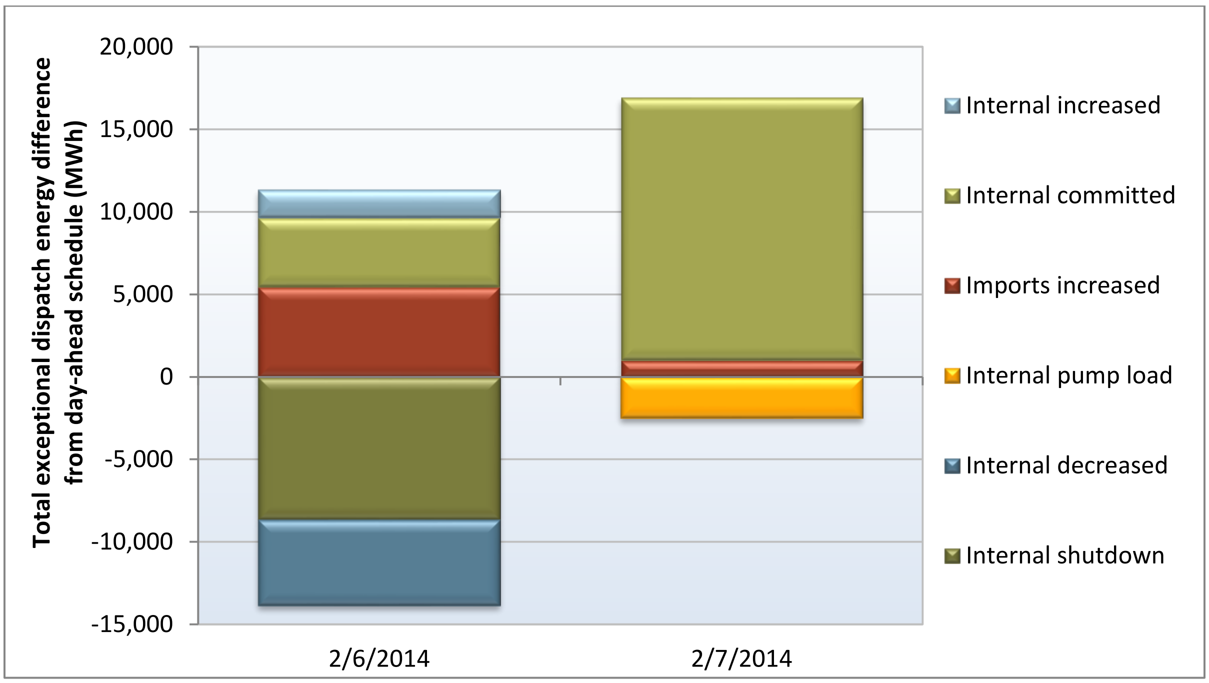
- Issuing exceptional dispatches to limit output from gas-fired generation within gas constrained areas of Southern California;

- Procuring more imports in the hour-ahead market by manually adjusting the load forecast upwards;
- Procuring more imports after the hour-ahead market through exceptional dispatches; and
- Calling upon interruptible load programs operated by the state's major electric utilities.[39]

Figure 3.3 shows the volumes of exceptional dispatch in real time relative to the day-ahead schedules on February 6 and 7. This figure shows that on February 6, the ISO managed the gas situation by shutting down and decreasing schedules on some units, while correspondingly increasing both internal and external generation on other resources to offset the loss of generation.

On February 7, the ISO continued to manage the gas situation through exceptional dispatch commitments of a small number of resources. Additional capacity was made available through the exceptional dispatch of pumped storage resources. Exceptional dispatch shutdowns and decreases from day-ahead schedules were not required on February 7.

Figure 3.3 Difference in volume on exceptional dispatch units between day-ahead and real-time



While the ISO real-time market prices were high on February 6, averaging about $140/MWh during peak hours, the real-time market software could not account for the non-modeled natural gas pipeline contingency. Load adjustments reached 2,200 MW above the load forecast and drove hour-ahead market prices to almost $300/MWh in an attempt to procure more imports to relieve gas use within California.

[39] A more detailed description and analysis of the market impacts of these events is provided in a technical bulletin issued by the ISO on May 19, 2014: http://www.caiso.com/Documents/TechnicalBulletinGasEvents_MarketResults_Feb6_2014.pdf.

Conclusions

In both gas events, DMM finds that the ISO operators took actions to ensure that gas system reliability issues did not become electric system reliability issues. Given the severity of the February 6 event, ISO operators took more actions than in December, calling on interruptible loads and exceptionally dispatching significant volumes of generation on internal resources as well as on the inter-ties in order to maintain reliability.

In early March, the ISO made an emergency filing with FERC to waive tariff provisions to use more updated gas price information as part of the day-ahead market run.[40] Specifically, the ISO asked FERC to allow it to use only one natural gas index in the event that the natural gas markets moved by more than 150 percent of the previous day's price.[41] In addition, the ISO would switch a pre-defined list of participants from registered to proxy costs during the duration of the event. DMM provided guidance and feedback as the ISO developed the emergency tariff waiver that was accepted by FERC on March 14 and was effective through April 30, 2014.[42]

Unlike the February 6 event, the natural gas price that was traded on Friday, December 6, for December 7 through 9, did not reflect the tight natural gas conditions. Prices for December 10 increased from about \$4.70/MMBtu to about \$7.30/MMBtu at the SoCal Citygate trading hub. Had the ISO's emergency tariff waiver been in place at this time, this price movement would have triggered the ISO's emergency tariff provisions for the December 10 day-ahead market.

DMM has supported the ISO efforts to improve gas and electric market coordination. DMM is currently involved in the ISO's stakeholder process on commitment cost changes to address gas market issues. While DMM agrees that some changes to the market are required, DMM cautions that some suggested changes could have significant and unacceptable market power consequences. Our concerns are outlined in the recommendations section below.

Recommendations

Some stakeholders have suggested that the cold weather events of December and February should be addressed by allowing participants to submit their own start-up and minimum load bids without any specific limits, and then only apply mitigation through some form of *ex post* review of costs. DMM strongly opposes this type of fundamental modification in the current process for limiting start-up and minimum load bids for a variety of reasons.

First, it is important to remember that in 2013 the ISO just completed a process to lower the limit on start-up and minimum load bids in order to limit potential gaming or manipulative practices aimed at profiting from high bid cost recovery payments. The ISO has adopted rules to address specific practices

[40] See the following ISO filings: https://www.caiso.com/Documents/Mar6_2014_TariffWaiver_GasPriceIndexRequirement-ExpeditedER14-1440-000.pdf and https://www.caiso.com/Documents/Mar6_2014_TariffWaiver_GasPriceIndexRequirement-Next-DayER14-1442-000.pdf.

[41] Had these provisions been in place at the beginning of the winter, the ISO would have triggered the use of the updated natural gas price on two days, December 10, 2013, for the SoCal Citygate price and February 6, 2014, for both the SoCal Citygate and the PG&E Citygate prices.

[42] For more information see FERC Docket No. ER14-1442-000. The order granting the ISO waiver can be found here: http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13484915.

by one participant aimed at profiting from high minimum load bids under the registered cost option.[43] The lower 150 percent limit implemented in 2013 is seen as an important protective measure against other such practices.[44]

Second, except for the manipulative practices of one participant, the current framework for limiting these bids has worked well under almost all conditions over the five year period since the new nodal market began in 2009. The specific problems occurring due to the very extreme conditions on February 6, 2014, have been addressed in a targeted manner by recent tariff filings. DMM believes that issues which arise under very extreme and infrequent conditions can continue to be addressed effectively in a targeted manner through additional refinements, if necessary.

Finally, DMM notes that if rules are modified to allow participants to submit their own start-up and minimum load bids without any specific limits, some form of mitigation will still be needed. Any *ex post* review of bids would be very administratively burdensome, and would not mitigate the distortion in the market that would have already occurred due to use of the unmitigated bids.

Another option that has been discussed in the past has been to automatically apply mitigation only when it is determined that a unit may have local market power – such as the ISO's automated procedures for energy bid mitigation. In practice, however, units may have market power as a result of various capacity constraints that require units to be committed and operating at least at minimum load. These constraints include the minimum online constraints (MOCs) and new constraints being added through the flexible ramping product and the contingency modeling enhancements. Unlike transmission constraints used to determine if energy bid mitigation should be triggered, these other constraints are much more complex and may not be binding when market power may occur.

3.2 California greenhouse gas allowance market

Generating resources became subject to California's greenhouse gas cap-and-trade program compliance requirements starting in January 2013. This section highlights the impact of these requirements in 2013 and 2014. These highlights include the following:

- The price of greenhouse gas emissions permits rose in the first quarter to an average of \$12.10/mtCO_2e, ending the quarter at \$12.00/mtCO_2e. This is an increase from the \$11.86/mtCO_2e average in the fourth quarter of 2013, but was lower than average prices in the first, second, and third quarters of 2013, which averaged \$14.55/mtCO_2e, \$14.59/mtCO_2e, and \$13.27/mtCO_2e, respectively.[45]

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[43] See the following filings for further information: California Independent System Operator Corporation, "Tariff Revision and Request for Expedited Treatment," March 18, 2011: http://www.caiso.com/2b45/2b45d10069e0.pdf and "Tariff Revision and Request for Waiver of Sixty Day Notice Requirements," June 22, 2011: http://www.caiso.com/Documents/2011-06-22_Amendment_ModBCRrules_EDEnergySettRules_ER11-3856-000.pdf. Also see "Order approving stipulation and consent agreement" in FERC Docket Nos. IN11-8-000 and IN13-5-000, July 30, 2013: http://www.ferc.gov/CalendarFiles/20130730080931-IN11-8-000.pdf.

[44] Part of the reason for this rule change was to protect against any new practices that might become profitable given changes that the ISO made to bid cost recovery rules in 2013. Under these new rules, bid cost recovery payments are now calculated separately for the day-ahead and real-time markets, rather than netting any net revenues from one market against any bid cost recovery shortfall in another market.

[45] mtCO_2e stands for metric tons of carbon dioxide equivalent, a standard emissions measurement.

- DMM estimates that average wholesale energy prices are about $4/MWh higher in the first quarter due to cap-and-trade compliance costs, based on statistical analysis after cap-and-trade implementation. 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 regulations 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.[46]

The cap-and-trade program covers major sources of greenhouse gas emissions including power plants.[47] 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.[48] Effective January 1, 2014, CARB's cap-and-trade program became linked with Quebec.[49] Formal linkage allows entities to use allowances issued in either Quebec or California for compliance in either region. The two regions plan to hold joint auctions this year. Until that occurs, only entities registered in the jurisdiction may participate in auctions, but allowances may be traded in the secondary over-the-counter market.

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 (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).[50]

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46 For more information on this program, please see chapter 5 of the *2013 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2014: http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf.

47 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.

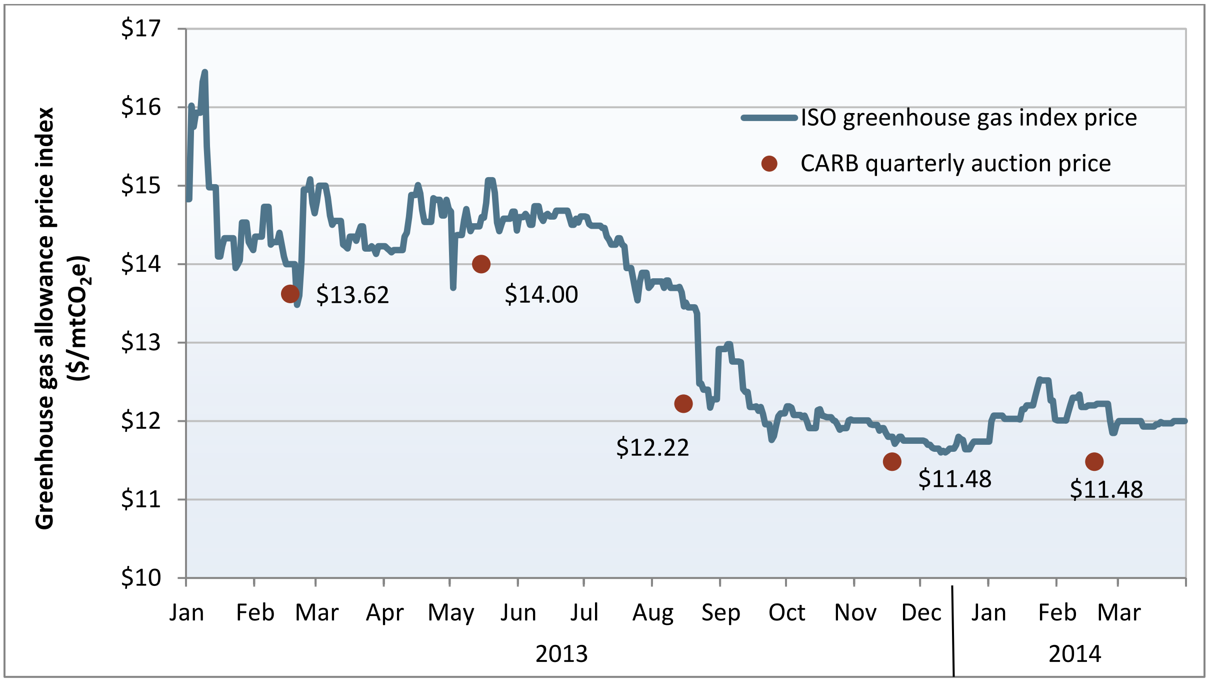
48 Additional background information can be found in the 2013 fourth quarter report at https://www.caiso.com/Documents/2013FourthQuarterReport-MarketIssues_Performance-Feb2014.pdf

49 Further information on linkage with Quebec is available here: http://www.arb.ca.gov/cc/capandtrade/linkage/linkage_fact_sheet.pdf or http://www.arb.ca.gov/newsrel/newsrelease.php?id=508.

50 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 calculates a 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.[51] Daily values of the ISO greenhouse gas allowance index are plotted in Figure 3.4. In the first quarter, allowance costs were fairly stable, beginning the quarter at \$11.74/mtCO_2e and ending at \$12.00/mtCO_2e. The average index value for the quarter was \$12.10/mtCO_2e. The index price rose prior to CARB's quarterly auction held on February 19 as trading volumes increased. 2014 allowances cleared the auction at \$11.48/mtCO_2e and 2017 allowances cleared at \$11.38/mtCO_2e.

Figure 3.4 ISO's greenhouse gas allowance price index



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.[52]

[51] The indices are ICE and ARGUS Air Daily. As the ISO noted in a market notice issued on May 8, 2013, 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 2013. For more information, see the ISO notice: http://www.caiso.com/Documents/GreenhouseGasAllowancePriceSourcesRevisedMay8_2013.htm.

[52] 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.

The first residential climate credit, a semi-annual credit of $35, was announced on the final day of this quarter.[53]

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 period of greenhouse gas compliance. This approach relies on the comparison of market data before cap-and-trade implementation with data from 2013 and 2014.[54] DMM used a similar model in the prior quarters, but removed indicator variables for holidays, Saturday and Sunday for simplicity and several gas price indices due to lack of available data. As in the fourth quarter model, we have included a variable to control for differences in convergence bidding volumes, assumed to be exogenous.[55] 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.[56]

The energy price DMM chose to analyze was the day-ahead system marginal energy cost.[57] DMM decided 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.[58]

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, net virtual supply, scheduled

[53] For more information, see http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K322/89322065.PDF.

[54] 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.

[55] 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 the third quarter 2013: http://www.caiso.com/Documents/2013ThirdQuarterReport-MarketIssues_Performance-Nov2013.pdf.

[56] 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.

[57] 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.

[58] 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.

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).[59]

$$\text{Average Electricity Price} = \beta_0 + \beta_1\text{GHG} + \beta_2\text{Load} + \beta_3\text{Load}^2 + \beta_4\text{Load}^3 + \beta_5\text{Gas}_{\text{Weighted}} + \beta_6\text{NetVS} + \beta_7\text{Wind} + \beta_8\text{Solar} + \beta_9\text{Hydro} + \beta_{10}\text{Nuclear} + \beta_{11}\text{Geothermal} + \beta_{12}\text{Imports\_IV} + \varepsilon$$

Using this model, DMM estimates that, in the first quarter, the average impact of greenhouse gas compliance was about $3.98/MWh or $0.34 per dollar of the allowance price.[60] Quarterly estimates in 2013 range from $2.71/MWh in the fourth quarter to $9.60/MWh in the second quarter. Although rough, our model predicts the average ISO day-ahead system energy prices fairly well, explaining approximately 95 percent of the variation in this measure in both quarterly models.[61] 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

[59] 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/.)

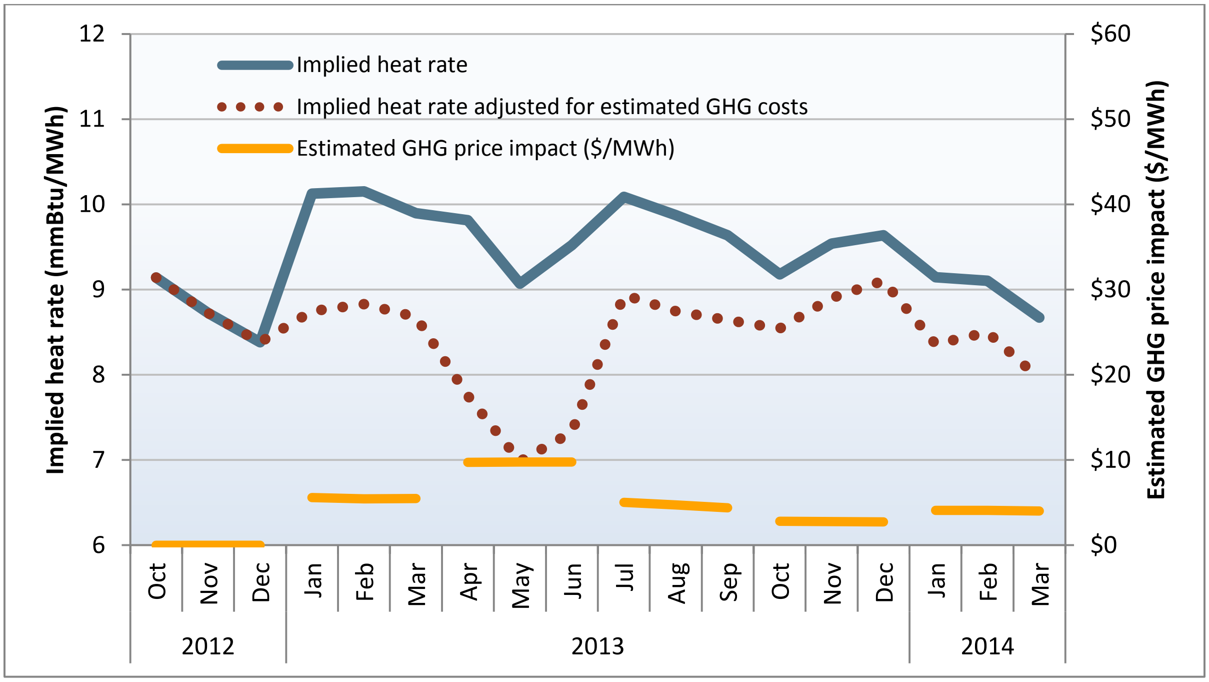
[60] Two alternative greenhouse gas measures are used. The first is an indicator variable equal to 1 in the greenhouse gas compliance period and 0 before that period. In this case, the coefficient estimate (β_1 in the equation above) may be interpreted as the estimated average impact of greenhouse gas 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). Quarterly estimates were generated by using a set of quarterly indicator variables multiplied by the greenhouse gas measure in place of a single greenhouse gas measure. DMM's regression results are based on values from January 2012 through March 2014 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.

[61] In the first case, R^2 = 0.952 and the adjusted R^2 = 0.950. In the second case, R^2 = 0.9519 and the adjusted R^2 = 0.9509.

dollar of greenhouse gas allowance costs. The 34 cents per dollar of the allowance price estimate represents the additional emissions cost of a unit with a heat rate of about 6,300 Btu/kWh.[62]

Figure 3.5 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.[63]

Figure 3.5 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 used quarterly estimates of the greenhouse gas impact: $0.38 per dollar of allowance cost in the first quarter of 2013, $0.67 in the

[62] 0.0530731 $mtCO_2e$ /MMBtu x 8,000 Btu/kWh = $0.425/$ Greenhouse gas allowance price. The emissions factor, 0.0530731 $mtCO_2e$ /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. Default emissions factors are available in tables C1 and C2 of the same source. DMM thanks ARB staff for their assistance with this calculation. $0.33594 divided by an emissions factor of 0.0530731 = 6.32976.

[63] 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.

second quarter, $0.36 in the third quarter, $0.23 in the fourth quarter, and $0.34 in the first quarter of 2014.

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 2014. Average adjusted implied heat rates in the first quarter of 2014 (8,300 Btu/kWh) and the average annual value in 2013 (8,400 Btu/kWh), were both slightly lower than the annual average implied heat rate in 2012 (8,600 Btu/kWh).