California ISO
Shaping a Renewed Future

California Independent System Operator

May 1, 2014

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: RTO/ISO Market Monitoring Unit Reports – California ISO
Docket No. ZZ14-4-000

Dear Secretary Bose:

Attached please find the *"2013 Annual Report on Market Issues and Performance"* prepared by the Department of Market Monitoring of the California Independent System Operator Corporation ("ISO Annual Report").

Pursuant to Section 5.2 of Appendix P of the ISO tariff, the Department of Market Monitoring "shall review and report on market trends and the performance of the wholesale markets to the CAISO, the CAISO Governing Board, FERC staff, the California Public Utilities Commission, Market Participants, and other interested entities, on at least a quarterly basis and submit a more comprehensive annual state of the market report." The ISO Annual Report was prepared pursuant to that tariff provision and provides discussion and analysis of ISO operations in calendar year 2013.

The ISO has also made the ISO Annual Report available to market participants and the general public by posting it on the ISO website at the following link: http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf

Thank you for your attention to this matter.

Sincerely,
/s/ David S. Zlotlow

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2013 ANNUAL REPORT ON MARKET ISSUES & PERFORMANCE

California ISO
Shaping a Renewed Future

Department of Market Monitoring

ACKNOWLEDGEMENT

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Executive summary

The ISO's markets continued to perform efficiently and competitively overall in 2013. Key highlights of market performance in this report by the Department of Market Monitoring (DMM) include the following:

- Total wholesale electric costs increased by 31 percent. This increase was primarily driven by a 30 percent increase in natural gas prices in 2013 compared to 2012.
- After controlling for the gas price increase, wholesale electric costs increased by 5 percent, primarily as a result of implementation of the state's greenhouse gas cap-and-trade program.
- Overall prices in the ISO energy markets over the course of 2013 were highly competitive, averaging very close to what DMM estimates would result under highly competitive conditions.
- About 97 percent of physical system load was scheduled in the day-ahead energy market, which continued to be highly efficient and competitive.
- Average real-time prices were systematically lower than day-ahead market prices throughout the year. Day-ahead prices averaged just over $2/MWh higher than real-time prices for the year, peaking in the second quarter at almost $6/MWh higher.
- This price trend marks a reversal from prior years when average real-time prices tended to be higher than average day-ahead prices. This new trend of lower real-time prices is largely attributable to a decrease in brief but high real-time price spikes caused by limitations in ramping energy. This trend is also partly attributable to additional unscheduled generation in real time, particularly from wind and solar units and from other sources.

Other aspects of the markets performed well and helped keep overall wholesale costs low.

- The ISO implemented new automated local market power mitigation procedures in the real-time software which mitigated local market power more effectively than the previous approach.
- Ancillary service costs totaled $57 million, or about 31 percent less than in 2012. This decrease was driven by a decrease in the quantity of ancillary services procured by the ISO due to lower loads and lower ancillary services prices.
- Bid cost recovery payments totaled $108 million, or about 1 percent of total energy costs in 2013, compared to about $104 million or 1.3 percent of total energy costs in 2012. Payments for units committed by the residual unit commitment process accounted for $23 million of these costs, compared to $8 million in 2012. This increase was driven in large part by the need to schedule physical capacity to meet the portion of the day-ahead load forecast met by net virtual supply in the day-ahead energy market. In 2013, about $9 million or 8 percent of bid cost recovery payments were allocated to virtual bidders with net virtual supply positions.
- Exceptional dispatches, *out-of-market* unit commitments and energy dispatches issued by ISO grid operators to meet constraints not incorporated in the market software, decreased from 2012 and remained relatively low. Total energy from all exceptional dispatches totaled about 0.26 percent of total system energy in 2013 compared to 0.53 percent in 2012. The above-market costs resulting

from these exceptional dispatches decreased almost 50 percent from $34 million in 2012 to $18 million in 2013.

- Congestion within the ISO system decreased in 2013, particularly in the second half of the year. The reduction in real-time congestion can be attributed partly to improved ISO procedures that better align day-ahead constraint limits with real-time limits. This allows for better commitment and scheduling of resources to resolve anticipated congestion in real time.
- Lower real-time congestion drove real-time market revenue imbalance charges allocated to load-serving entities lower. These charges decreased from $187 million in 2012 to $120 million in 2013, or just over 1 percent of total wholesale costs.
- Net revenues paid to convergence bidders (after allocation of bid cost recovery payments) totaled about $17 million in 2013, down from $52 million in 2012. The majority of these profits were associated with virtual supply. Net revenue paid for virtual bids totaled about $26 million, but about $9 million in bid cost recovery payments were allocated to virtual bidders with net virtual supply positions, so that net profits from virtual bidding totaled about $17 million.

This report also highlights key aspects of market performance and issues relating to longer-term resource investment, planning and market design.

- About 2,000 MW of summer peak hour generating capacity from renewable generation was added in 2013, with most of this coming from increased solar generation. Energy from wind and solar resources directly connected to the ISO grid provided about 8 percent of system energy, compared to about 5 percent in 2012.
- Energy from new wind and solar resources is expected to increase at a much higher rate in the next few years as a result of projects under construction to meet the state's renewable portfolio standards. This will increase the need for flexible and fast ramping capacity that can be dispatched by the ISO to integrate increased amounts of variable energy efficiently and reliably.
- Over 3,500 MW of new gas-fired generation was added in 2013. Most of this capacity was added as part of the California Public Utilities Commission's long term procurement process. However, this increase in capacity was mostly offset by over 2,900 MW of thermal generation retirements in 2013, including both units at the San Onofre Nuclear Generating Station (SONGS).

Net operating revenues for many – if not most – older existing gas-fired generation are likely to be lower than the going-forward costs of these units. A substantial portion of this existing capacity is located in transmission constrained areas and is needed to meet local reliability requirements and to ensure enough flexible capacity exists to integrate the influx of new intermittent resources. Most of this capacity will also need to be replaced or repowered to comply with the state's restrictions on use of once-through cooling. This investment is likely to require some form of longer-term capacity payment or contracting.

The state's resource adequacy program continued to work well as a short-term capacity procurement mechanism. However, concerns continue that the state's current one-year ahead resource adequacy process may not be sufficient to ensure that sufficient flexible generation will be kept online or added over the next few years to reliably integrate the increased amount of intermittent renewable energy coming online.

The ISO and the CPUC continued to address these resource adequacy issues through several initiatives in 2013. One initiative involved the development of specific requirements for flexible generating capacity needed to integrate increasing amounts of intermittent renewable generation into the ISO system. The ISO and CPUC are continuing to collaborate on a process to incorporate these flexibility requirements into a multi-year ahead resource adequacy process or centralized capacity market. In early 2014, the ISO Board of Governors approved a proposed tariff filing regarding flexibility requirements and resource adequacy capacity.[1]

DMM is highly supportive of these initiatives as ways of increasing the efficiency of the state's capacity procurement process and addressing key gaps in the state's current market design. More detailed recommendations concerning capacity procurement initiatives are provided in the final section of this executive summary.

Total wholesale market costs

The total estimated wholesale cost of serving load in 2013 was $10.7 billion or over $46/MWh. This represents an increase of about 31 percent from a cost of over $35/MWh in 2012. The increase in electricity prices was due, in large part, to a 30 percent increase in wholesale natural gas prices.[2]

After accounting for higher gas prices, DMM estimates that total wholesale energy costs increased from $42/MWh in 2012 to $44/MWh in 2013, representing an increase of almost 5 percent in gas-normalized prices.[3] This increase can be primarily attributed to implementation of the state's greenhouse gas cap-and-trade program.

Other factors putting upward pressure on prices discussed in this report include the following:

- Decreased energy from hydro-electric resources, particularly during the summer months;
- Decreased imports from the Southwest and, in particular, the Northwest especially in the second half of the year;
- The retirement of over 2,200 MW of generation from the San Onofre Nuclear Generating Station in Southern California.[4]

Other factors that contributed to lowering prices discussed in this report include:

- Additions of new generation capacity, including renewable and also gas-fired generation;
- Decreased regional congestion; and
- Increased net virtual supply, which lowered day-ahead prices and brought them closer to real-time prices.

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[1] For more information on the ISO Board decision, see http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=585EB499-6AEF-4FAA-8656-D9F5C253A63E.

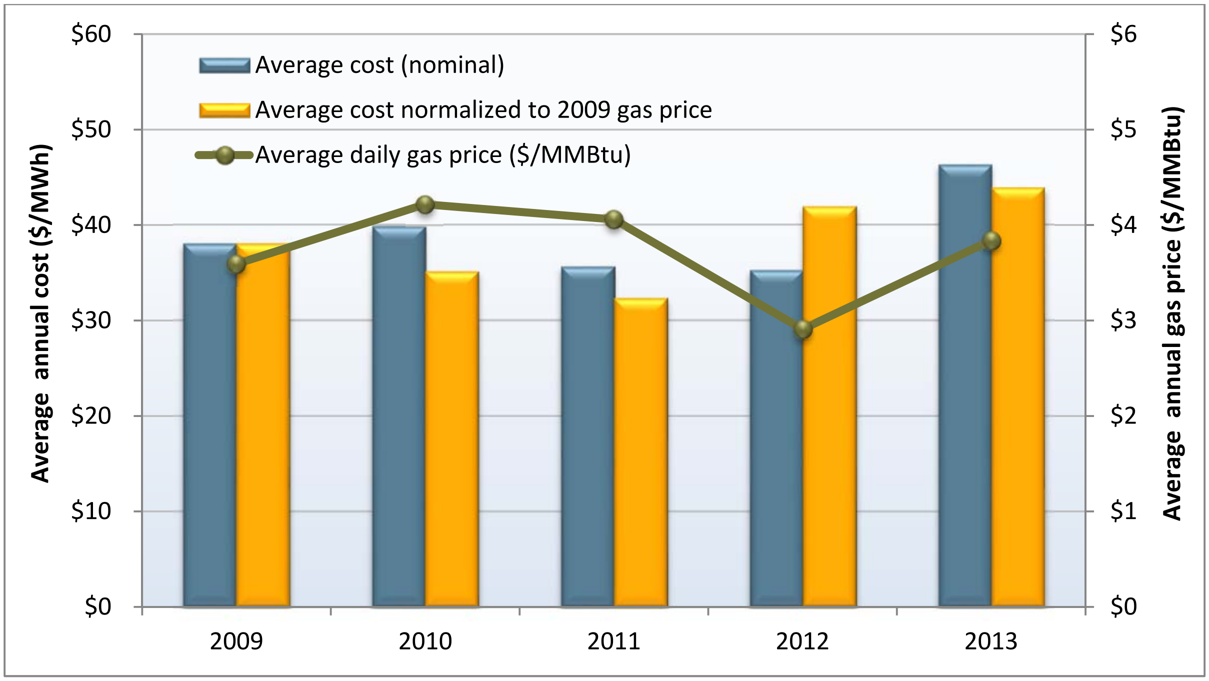
[2] In this report, we calculate average annual gas prices by weighting daily spot market prices by the total ISO system loads. This results in a price that is more heavily weighted based on gas prices during summer months when system loads are higher than winter months, when gas prices are often highest.

[3] Gas prices are normalized to 2009 prices.

[4] This capacity went offline due to outages in early 2012 but was permanently retired in 2013. Thus, while this does not represent a drop in capacity compared to 2012, the retirement of the San Onofre units continued to put upward pressure on prices in 2013.

Figure E.1 shows total estimated wholesale costs per MWh from 2009 to 2013. Wholesale costs are provided in nominal terms (blue bar), as well as after normalization for changes in average spot market prices for natural gas (yellow bar). The green line represents the annual average natural gas price and shows the correlation between the cost of natural gas and the total wholesale costs.

Figure E.1 Total annual wholesale costs per MWh of load (2009-2013)



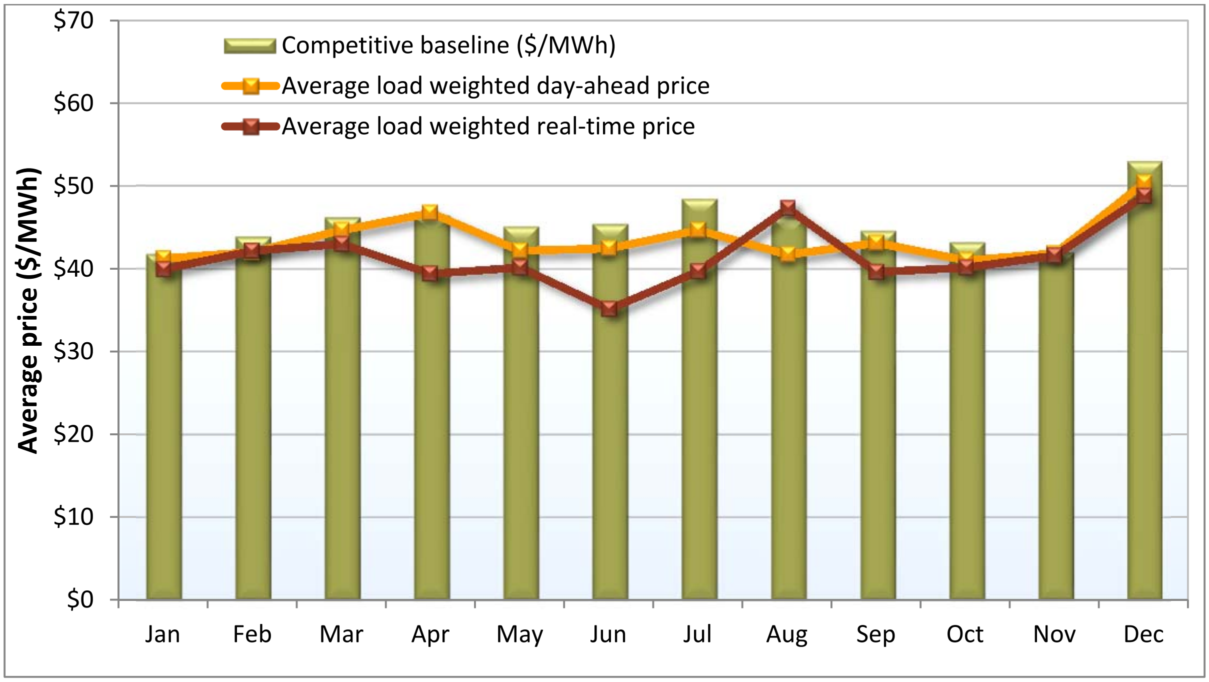
Market competitiveness

Overall wholesale energy prices were about equal to competitive baseline prices DMM estimates would result under perfectly competitive conditions. DMM calculates competitive baseline prices by re-simulating the market using the actual day-ahead market software with bids reflecting the marginal cost of gas-fired units. Figure E.2 compares this price to actual average system-wide 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, which does not reflect all system conditions and limitations that impact real-time prices.

As shown in Figure E.2, prices in the day-ahead market were about equal to the competitive baseline prices in most months in 2013. Day-ahead prices exceeded the competitive benchmark just slightly in April and were lower in all other months.

In the real-time market, average prices were lower than the competitive baseline in 2013 in most months except for August. A major factor contributing to these lower real-time prices was the substantial amount of real-time energy that was not scheduled in the day-ahead market.[5] In August, real-time prices were driven higher than day-ahead prices and slightly over the average competitive baseline price by periods of high loads and wildfire related transmission outages. In the fourth quarter, day-ahead prices and real-time prices were very close to the competitive benchmark.

Figure E.2 Comparison of competitive baseline prices with day-ahead and real-time prices



Energy market prices

Energy market prices were higher in 2013 than 2012, as seen in Figure E.3 and Figure E.4.

- This increase was attributed primarily to a 30 percent increase in gas prices in 2013, compared to 2012. Gas prices were atypically low in 2012 and increased in 2013 to levels consistent with 2011.
- Most of the remaining increase in electricity prices can be attributed to implementation of the state's greenhouse gas cap-and-trade program. DMM estimates that, on average in 2013, day-ahead market prices were about $6/MWh higher with this program.[6]
- Another factor causing upward pressure on electricity prices was a decrease in in-state hydro-electric generation in 2013. In the fourth quarter, hydro-electric generation was down about 40 percent compared to the fourth quarter of the previous year.

[5] This unscheduled energy was the combined result of a variety of factors, rather than being driven by any single source. Various sources of additional real-time energy included minimum load energy from units committed after the day-ahead market through the residual unit commitment process and exceptional dispatches, additional must-take energy from thermal generating resources, and unscheduled energy from variable renewable energy. A detailed analysis of this issue is provided in Section 3.3.

[6] For further detail on the cap-and-trade program, see Chapter 5.

Figure E.3 Comparison of system energy prices (peak hours)

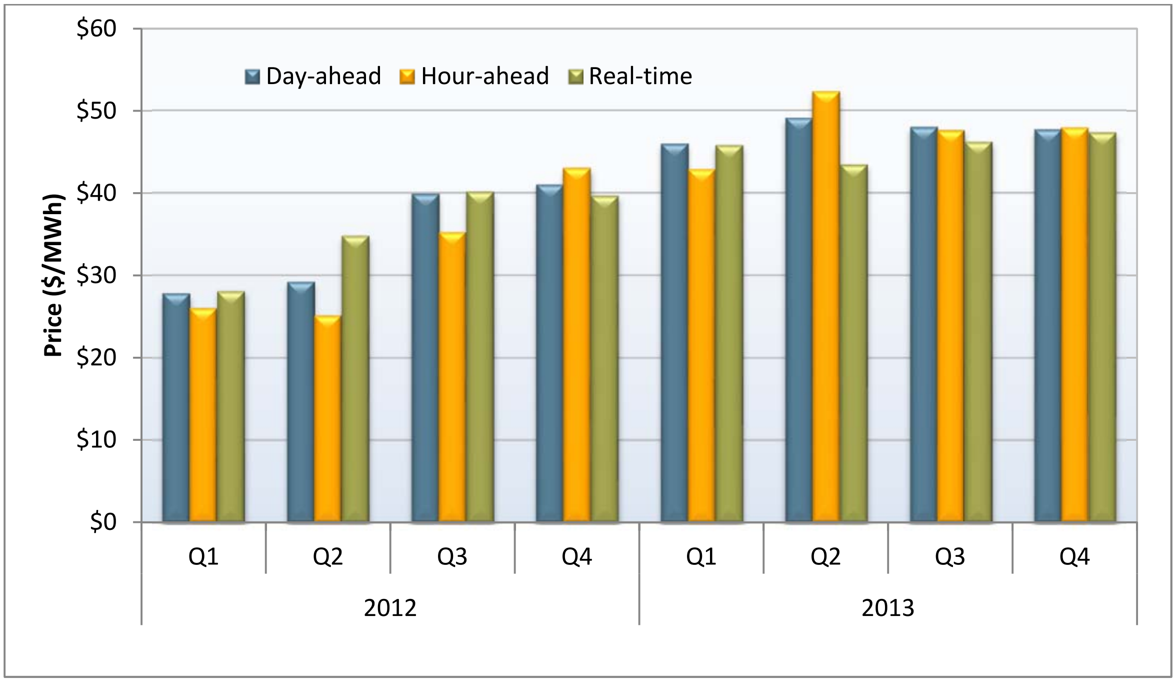
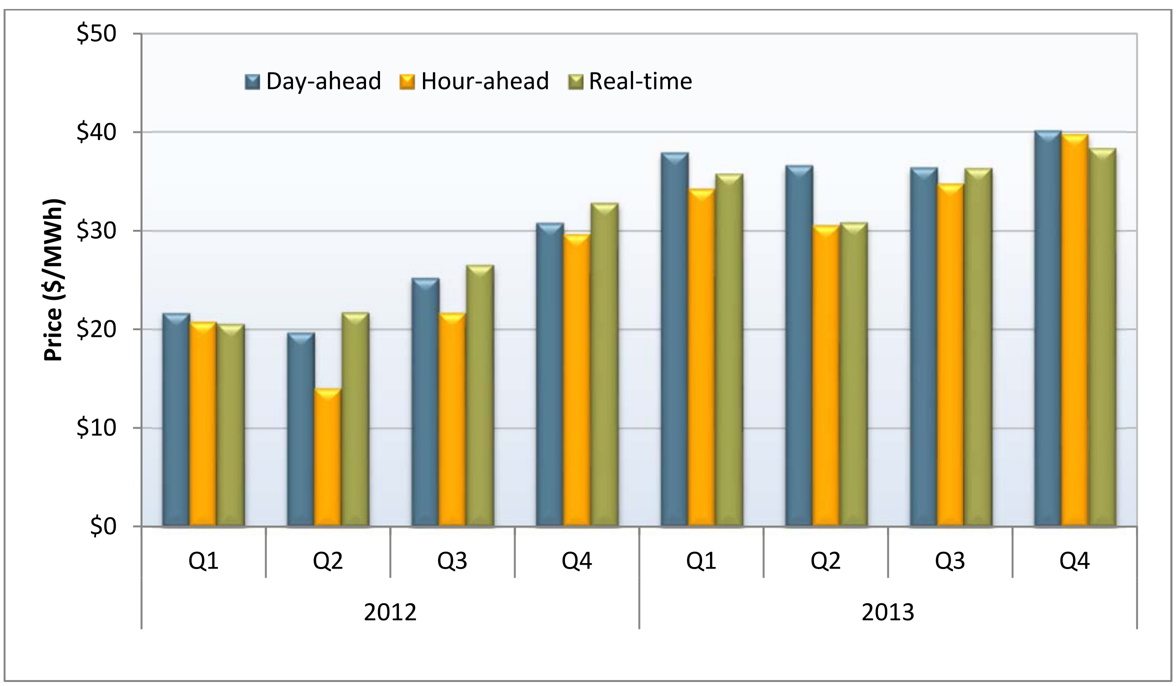


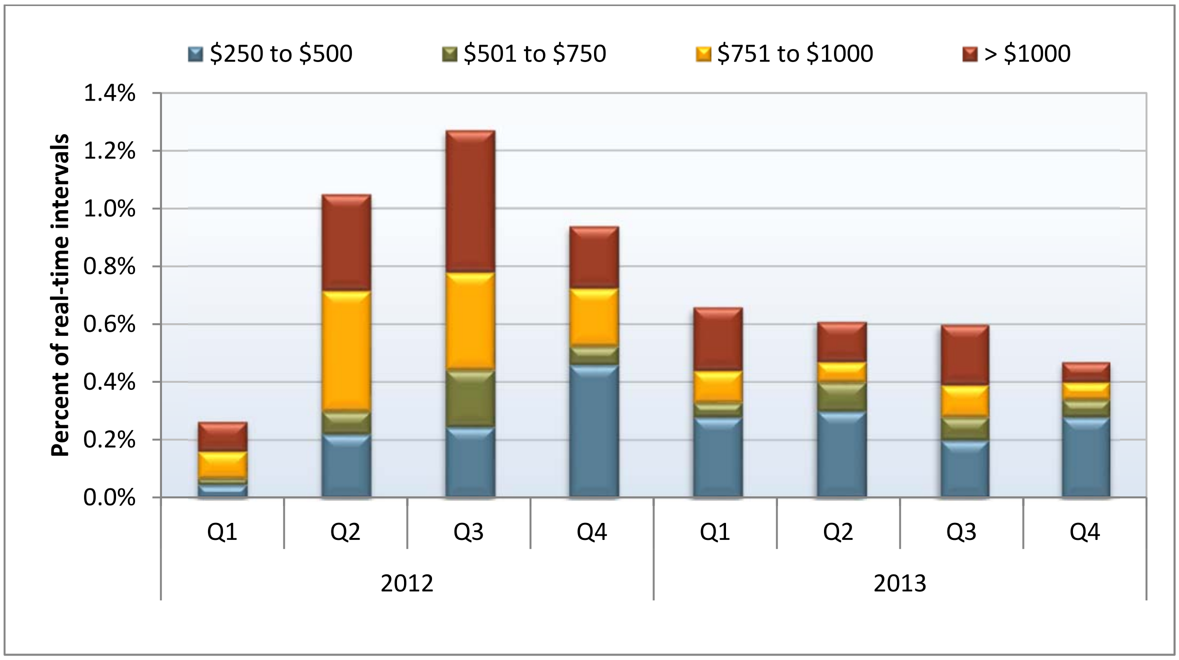
Figure E.4 Comparison of system energy prices (off-peak hours)



Price levels in the real-time market were systematically lower than the day-ahead market for most of the year, particularly in the second quarter. Price convergence between the hour-ahead and real-time markets was mixed in the first half of 2013, and more consistent in the second half of the year.

One of the key factors that historically drove divergence between average prices in the different energy markets has been relatively infrequent but extremely high real-time price spikes. Figure E.5 shows the frequency of different price spike levels in aggregate load area prices by quarter over the past two years. Both the frequency and level of price spikes decreased in 2013 as compared to 2012.

Figure E.5 Price spike frequency by quarter



Convergence bidding

Virtual bidding is a part of the Federal Energy Regulatory Commission's standard market design and is in place at all other ISOs with day-ahead energy markets. In the California ISO market, virtual bidding is formally referred to as *convergence bidding*. The ISO implemented convergence bidding in the day-ahead market in February 2011.

Virtual bidding on inter-ties was temporarily suspended in November 2011. In May 2013, FERC issued an order conditionally accepting elimination of convergence bidding on inter-ties, with the expectation that convergence bidding at the inter-ties would be brought back when a feasible long-term solution exists.[7] Convergence bidding on the inter-ties will be slowly phased in by the ISO one year after implementation of FERC Order No. 764 in the spring of 2014.[8] The delay in implementation and the

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

[8] For more information see the ISO 764 compliance filing: http://www.caiso.com/Documents/Nov27_2013_TariffAmendment-ComplianceFERCOrder764_ER14-495.pdf.

phasing in of convergence bidding were done as precautionary measures “to serve as an additional safety net to prevent unforeseen and unintended market outcomes.”[9]

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

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

Total net revenues paid to entities engaging in convergence bidding totaled around $17 million in 2013, down from over $52 million in 2012. These numbers have been adjusted for bid cost recovery payments. Because virtual bids can result in additional commitment of physical generation in the day-ahead energy market or residual unit commitment process, virtual bids can be charged for bid cost recovery payments resulting from day-ahead unit commitments. In 2013, virtual bidders were allocated about $9 million in bid cost recovery payments, compared to only $3.5 million in 2012. This increase is the result of the trend of increased net virtual supply in the day-ahead market, which can increase unit commitment in the residual unit commitment process.

The majority of convergence bids were designed to hedge or profit from congestion. These positions represented over 70 percent of all accepted virtual bids in 2013, up from 55 percent in 2012. The increase in both the quantity and net revenues of offsetting virtual bids likely stems from the differences in congestion between the day-ahead and real-time markets in the first two quarters of 2013. Congestion in general, and congestion differences between the day-ahead and real-time market, decreased dramatically in the last two quarters of 2013. Revenues from non-offsetting virtual supply bids were higher in the second half of the year.

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 nearly $17 million (almost 65 percent) of the total convergence bidding revenues in 2013.

Table E.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 revenues in millions of dollars.

DMM has defined financial entities as participants who own no physical power and only participate in the convergence bidding and congestion revenue rights markets. 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 markets.

As shown in Table E.1, financial participants represent the largest segment of the virtual market, accounting for about 78 percent of volumes and about 65 percent of revenues. Generation owners and load-serving entities represent about 32 percent of the revenues but only about 10 percent of volumes. Marketers represent about 12 percent of the trading volumes and 3 percent of the revenues.

[9] Ibid, p. 47.

Table E.1 Convergence bidding volumes and revenues by participant type (2013)

Trading entities	Average hourly megawatts			Revenues\Losses ($ millions)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	1,578	1,578	3,156	-$21.7	$38.4	$16.7
Marketer	193	293	486	-$4.9	$5.8	$0.9
Physical generation	67	186	253	$0.1	$4.6	$4.6
Physical load	2	158	160	-$0.2	$3.8	$3.6
Total	**1,840**	**2,216**	**4,056**	**-$26.7**	**$52.5**	**$25.8**

Greenhouse gas cap-and-trade program

Resources in the ISO market became subject to the state's greenhouse gas cap-and-trade program compliance requirements starting in January 2013. California Assembly Bill 32 (AB 32), the Global Warming Solutions Act of 2006, directed 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 action in a suite of regulatory measures adopted by CARB to achieve this goal. Sources with compliance obligations under cap-and-trade are required to surrender allowances. Imports from unspecified sources and electric generation resources emitting more than 25,000 metric tons of greenhouse gas annually, either within California or as imports into California, are covered under the first phase of the cap-and-trade program.

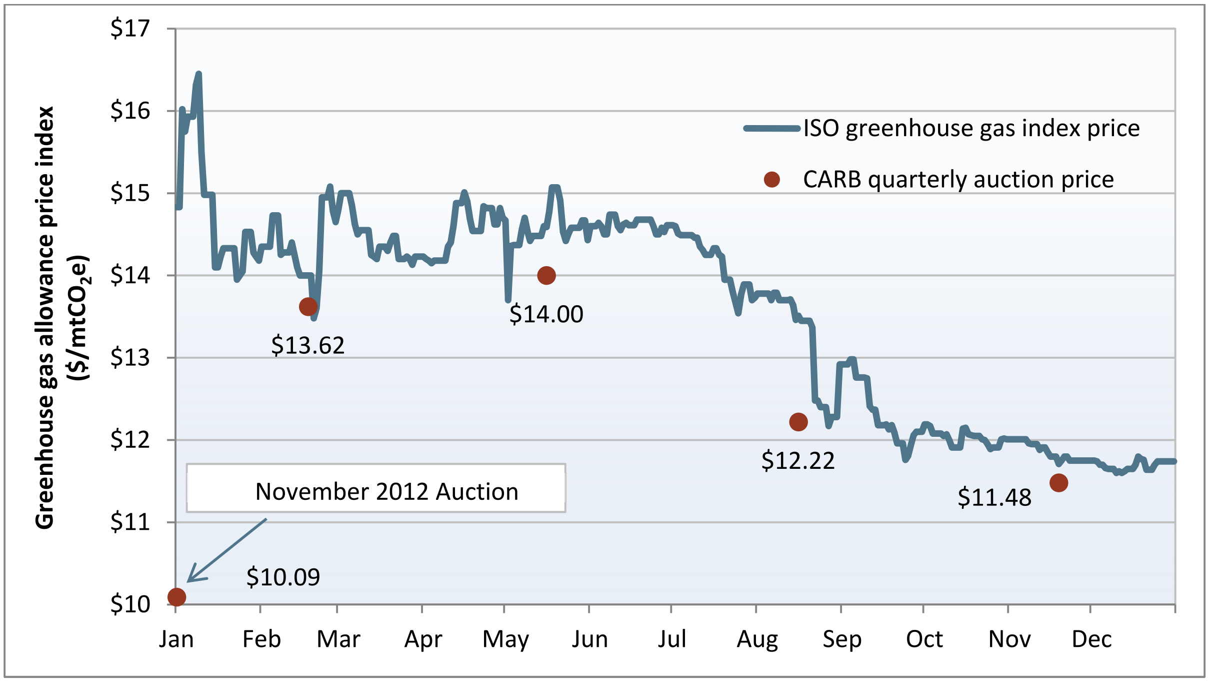
The cost of greenhouse gas allowances in bilateral markets averaged about \$14.50/mtCO_2e for the first half of the year and averaged about \$12.50/mtCO_2e in the second half of the year. By the end of the year, the cost of greenhouse gas allowances was around \$11.75/mtCO_2e (see Figure E.6).

DMM estimates that these greenhouse gas compliance costs have increased the average wholesale electricity price in 2013 by about $6/MWh. This is consistent with the additional emissions costs for gas units typically setting prices in the ISO market. A simple review of bilateral market prices outside of California does not clearly indicate whether or not regional bilateral prices were affected by the cap-and-trade program. Further analysis would be needed to determine the nature of the impact, if any.

Prior to implementation of the greenhouse gas cap-and-trade program, there was concern that the program would adversely affect imports into the ISO market. DMM analysis found that while some participants stopped sending power to California, others increased imports into California. In the first half of the year, DMM found that both offered and cleared imports increased relative to 2012, by 13 percent and 7 percent, respectively.

In the second half of the year, both offered and cleared imports were down relative to 2012, by 10 percent and 18 percent, respectively. However, DMM does not attribute the drop in offered and cleared imports in the second half of 2013 to the cap-and-trade program as other potential factors drove this change. Decreases in offered and cleared import megawatts were larger coming from the north, which may be due to decreases in hydro-electric generation in the Pacific Northwest and increases in power prices at the Mid-Columbia and Palo Verde trading hubs.

Figure E.6 ISO's greenhouse gas allowance price index



Local market power mitigation

In 2013, the ISO implemented the second phase enhancement of the new transmission competitiveness evaluation and mitigation mechanism to address local market power in the real-time market. Together with the first phase implemented in April 2012, this completes the transition to the new procedure in both the day-ahead and real-time markets.

This local market power mitigation procedure requires that each constraint be designated as either *competitive* or *non-competitive* prior to the actual market run. This is determined through a test, known as *dynamic path assessment*, which determines the competitiveness of transmission constraints based on actual system and market conditions for each interval. Generation bids are subject to mitigation if mitigation procedures indicate generators are effective to relieve the congestion on constraints that are structurally uncompetitive.

For these provisions to be effective, it is important that constraints designated as competitive are in fact competitive under actual market conditions. The new dynamic path assessment approach uses actual market conditions and produces a more accurate and less conservative assessment of transmission competitiveness.

The number of units subject to bid mitigation in the day-ahead market was lower in 2013 compared to 2012 as a result of decreased congestion and more competitive bidding. Most resources subject to mitigation submitted competitive offer prices, which meant that their bids were not lowered as a result of the mitigation process. On average, less than one unit per hour actually had their bid price lowered in the day-ahead market as a result of mitigation.

In the day-ahead market, the amount of additional energy that DMM estimates was dispatched from units as a result of bid mitigation was slightly higher in 2012 compared to 2013. This was related to a decreased volume of uncompetitively high energy bids in 2013.

The frequency of bid mitigation in the real-time market in 2013 was lower when compared to 2012. However, the estimated impact of bid mitigation on the amount of additional real-time energy dispatched as a result of bid mitigation was about the same in 2013 as in 2012.

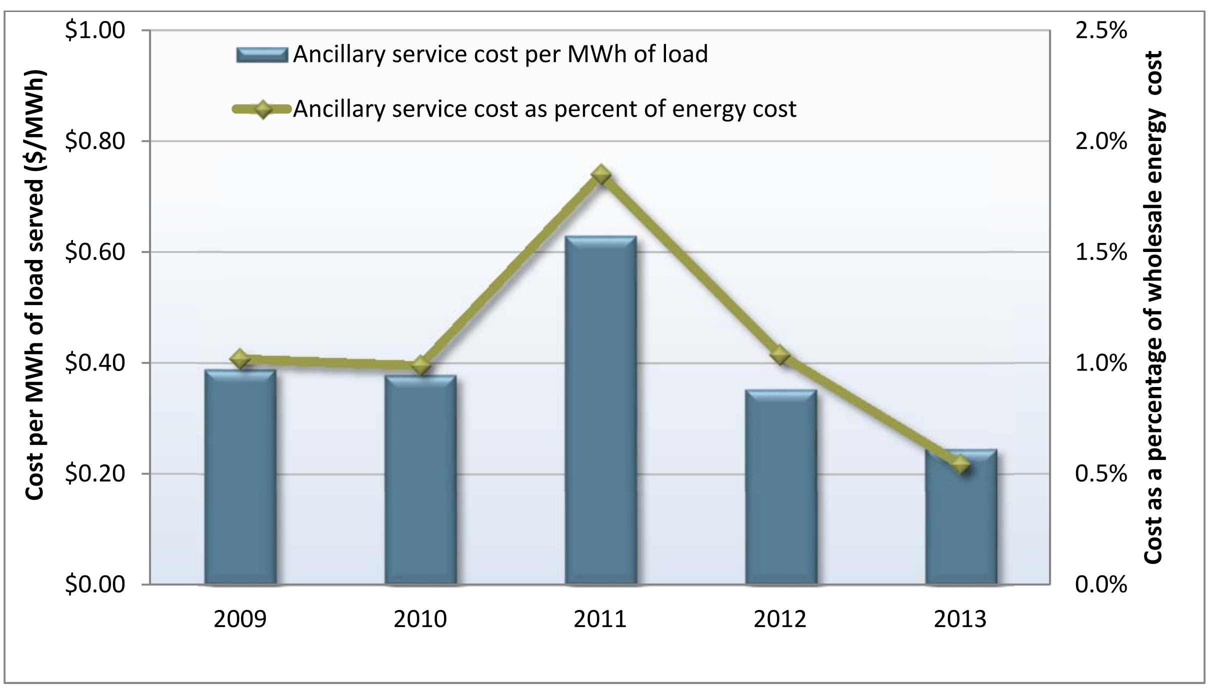
Mitigation provisions that apply to exceptional dispatch for energy above minimum load reduced costs by $450,000 in 2013, reflecting the fact that exceptional dispatches were relatively low and bids mitigated did not significantly exceed competitive levels. The impact of mitigation of exceptional dispatches was extremely high in 2012 ($227 million) due to uncompetitive bidding by several suppliers controlling resources frequently needed to meet special reliability constraints.

Ancillary services

Ancillary service costs decreased to $57 million in 2013, representing a 31 percent decrease from $83 million in 2012. The costs of ancillary services were driven lower primarily by a decrease in ancillary service prices but were also lower due to a decrease in procurement levels. In particular, low cost hydro generation provided more spinning reserves in 2013 due to the poor hydro conditions, and non-spinning reserve costs were lower as a result of fewer peak load days in 2013.

As shown in Figure E.7, ancillary service costs decreased to $0.25/MWh of load served in 2013 from $0.36/MWh in 2012. On a per MWh basis, ancillary service costs in 2013 were lower than in any year since the ISO's nodal market began in 2009. Ancillary service costs represent 0.5 percent of wholesale energy costs, down from 1 percent in 2012.

Figure E.7 Ancillary service cost as a percentage of wholesale energy cost



The ISO implemented the pay-for-performance product, often referred to as mileage, in June 2013. This product complements the regulation markets by adding a performance payment to the existing capacity payment system.

Overall, mileage has been an extremely small part of the market from a settlement standpoint, totaling about $530,000 in seven months. Mileage prices were low for much of the year, averaging $0.10 in either direction. High prices occurred occasionally, reaching as high as $23 in some intervals. These high prices are related to changes in resource dispatch between the day-ahead and real-time markets, and represent a small part of the regulation market in total.

The ISO originally intended to impose a performance standard on regulation resources. The performance standard would disqualify any resource that delivered mileage with less than 50 percent measured accuracy. These resources would no longer be eligible to sell regulation services to the ISO markets.

Once the mileage market was implemented, it quickly became apparent that the proposed standard of performance and measurement of accuracy would disqualify the majority of resources providing regulation and have negative market impacts. The ISO has requested a temporary waiver from FERC allowing it to delay enforcement of this performance standard. During the waiver period, the ISO intends to study the situation in more depth and assess whether a change to the tariff is necessary.

Exceptional dispatches

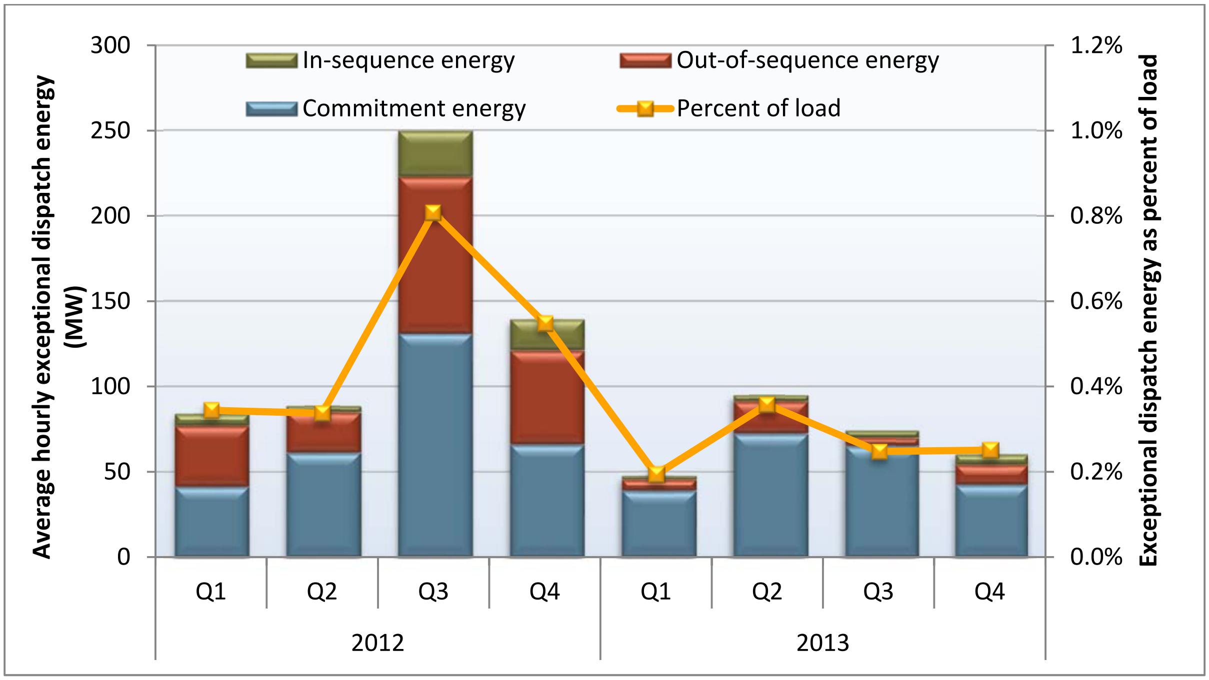
Exceptional dispatches are instructions issued by grid operators when the automated market optimization is not able to address particular reliability requirements or constraints. These dispatches are sometimes referred to as *manual* or *out-of-market* dispatches. The ISO has made an effort to reduce exceptional dispatches by refining operational procedures and incorporating additional constraints into the market model that reflect reliability requirements.

Total energy from all exceptional dispatches decreased in 2013, falling from 0.53 percent in 2012 to 0.26 percent of system load in 2013. The following is shown in Figure E.7:

- Minimum load energy from units committed through exceptional dispatches averaged about 50 MW per hour in 2013, down from about 75 MW in 2012. This represents about 79 percent of energy from exceptional dispatches in 2013.
- Exceptional dispatches resulting in out-of-sequence real-time energy with bid prices higher than the market prices accounted for an average of about 10 MW per hour in 2013, down from 52 MW in 2012. This decrease was primarily the result of fewer exceptional dispatches needed to position units at a level where they could provide more upward ramping capacity.
- About 30 percent of the energy above minimum load from exceptional dispatches cleared in-sequence, meaning that their bid prices were less than the market clearing prices.

The above-market costs of all exceptional dispatches decreased from $34 million in 2012 to $18 million in 2013. Of these costs, approximately $1.4 million was related to exceptional dispatch energy in 2013, compared to about $8 million in 2012.

Figure E.8 Average hourly energy from exceptional dispatches



Out-of-market costs

There are multiple forms of out-of market costs incurred in the ISO markets that are not directly paid to generators or collected from load-serving entities through market clearing prices. Most of these costs are ultimately allocated to load-serving entities through various charges, sometimes referred to as *uplifts*. These costs include the following categories:

- Bid cost recovery payments;
- Real-time imbalance offset costs;
- Real-time exceptional dispatch costs; and
- Other reliability costs including reliability must-run and capacity procurement mechanism costs.

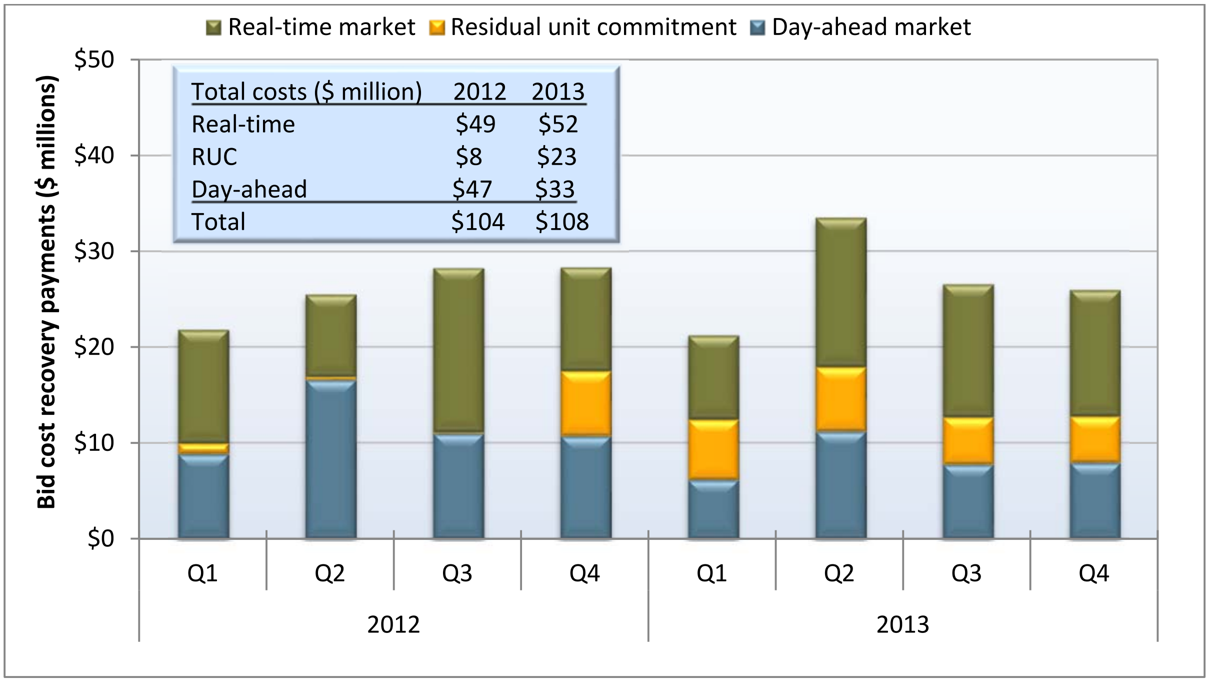
Bid cost recovery payments

Generating units are eligible to receive bid cost recovery payments if total market revenues earned over the course of a day do not cover the sum of all the unit's accepted bids. Excessively high bid cost recovery payments can indicate inefficient unit commitment or dispatch. However, a large portion of bid cost recovery payments in 2013 were incurred to meet special reliability issues in the event of a contingency and to replace energy from liquidated net virtual supply. The latter greatly influenced the residual unit commitment bid cost recovery costs.

Figure E.9 provides a summary of total estimated bid cost recovery payments in 2013. These payments totaled around $108 million or about 1 percent of total energy costs. This compares to a total of

$104 million or about 1.3 percent of total energy costs in 2012, an increase of about 4 percent from 2012 to 2013, but a lower percent of total costs.

Figure E.9 Bid cost recovery payments



DMM estimates that units committed to meet reliability needs, both through minimum online constraints incorporated in the day-ahead energy market and units committed by exceptional dispatches to meet special capacity-based reliability requirements, accounted for about $25 million or about 23 percent of total bid cost recovery payments in 2013.

Approximately $23 million or about 21 percent of bid cost recovery payments in 2013 stemmed from units committed by the residual unit commitment process. The costs increased primarily from a significant increase in net virtual supply in 2013. These costs were also affected by increases in the residual unit commitment procurement levels due to reliability related adjustments made by ISO operators, and differences between forecasted versus bid-in demand in the day-ahead market.

Real-time imbalance offset costs

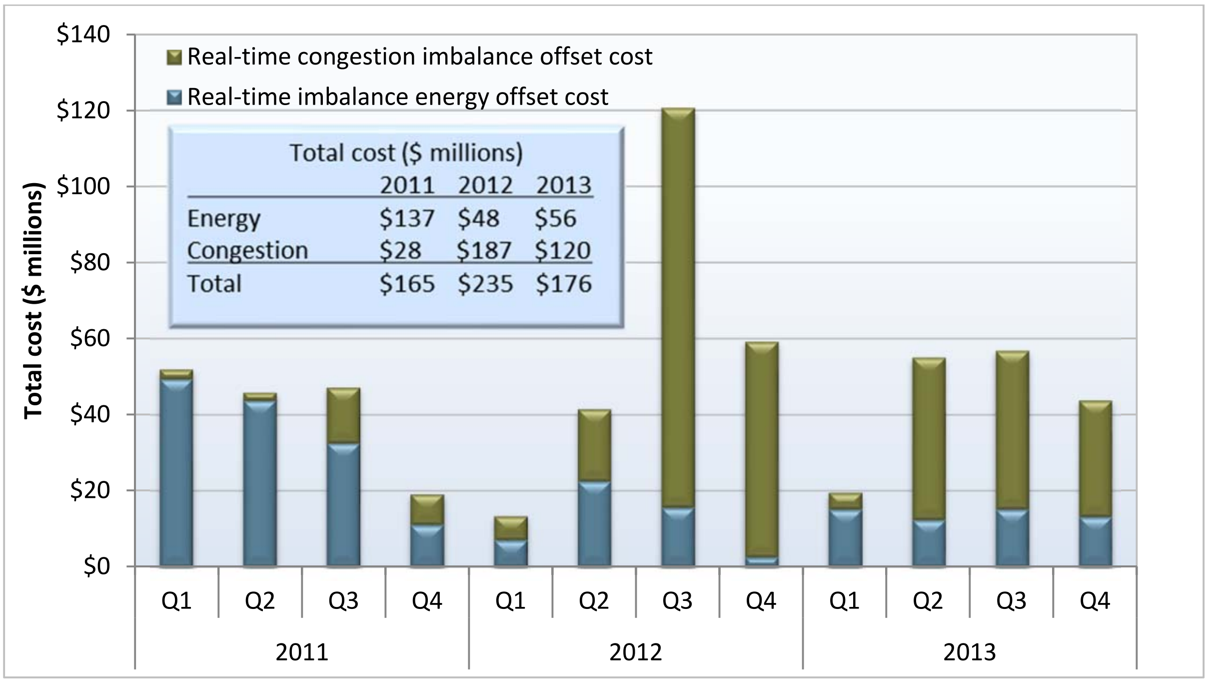
The real-time imbalance offset charge is the difference between the total money paid out by the ISO and the total money collected by the ISO for energy settled at hour-ahead and 5-minute market prices. The charge is allocated as an uplift to load-serving entities and exporters based on measured system demand.

The real-time imbalance offset charge consists of two components. Any revenue imbalance from the energy and loss components of hour-ahead and 5-minute real-time energy settlement prices is collected through the *real-time imbalance energy offset charge* (RTIEO). Any revenue imbalance from just the congestion components of these real-time energy settlement prices is recovered through the *real-time congestion imbalance offset charge* (RTCIO).

Total real-time imbalance costs for energy and congestion were about $176 million in 2013, compared to $235 million in 2012. As shown in Figure E.10 this decline was primarily attributable to decreases in the real-time congestion imbalance offset costs, which fell from $187 million to $120 million. The ISO's efforts to address systematic modeling differences between the day-ahead and real-time markets, including better alignment of day-ahead and real-time transmission limits and modification of the constraint relaxation parameter, contributed to reducing real-time congestion imbalance costs in 2013 compared to the summer of 2012. However, as the 2013 results show, the possibility of high real-time imbalance offset costs continues to exist as random and unexpected events occur.

Real-time imbalance energy offset costs increased from $48 million in 2012 to $56 million in 2013. A substantial portion of these costs occurred on a relatively small number of days due to specific events.

Figure E.10 Real-time imbalance offset costs



Total cost ($ millions)	2011	2012	2013
Energy	$137	$48	$56
Congestion	$28	$187	$120
Total	$165	$235	$176

Real-time exceptional dispatch costs

Real-time exceptional dispatch costs, also known as out-of-sequence costs, decreased from about $8 million in 2012 to around $1.4 million in 2013. This decrease was the result of decreases in overall volumes of exceptional dispatch energy. ISO goals to decrease the frequency and volume of exceptional dispatches and the elimination of uncompetitive bidding by participants in Southern California influenced the drop in out-of-sequence energy costs.

Other reliability costs

Other reliability costs include reliability must-run and capacity procurement mechanism costs. Because load-serving entities procure most local capacity requirements through the resource adequacy program, the amount of capacity and costs associated with reliability must-run contracts have been relatively low over the past few years. However, these costs increased to $21 million in 2013 from $6 million in 2012. Most of this increase was the result of a reliability must-run agreement that placed synchronous condensers at Huntington Beach Units 3 and 4 into service in late June 2013 for the rest of the year. This agreement was put into place due to the outages and retirement of the SONGS units.

While reliability must-run payments increased notably, capacity payments related to the capacity procurement mechanism decreased. Capacity procurement mechanism costs decreased from $26 million in 2012 to only $2.7 million in 2013. 2013 costs were closer to 2011 costs which were only $1.5 million.

The high capacity procurement mechanism payments in 2012 were directly related to the outages of SONGS units 2 and 3, which were offline for almost all of 2012 due to a combination of both planned and forced outages as well as for testing of critical systems. Steps were taken in 2013 to avoid using the capacity procurement mechanism for the SONGS outages and retirement. In total, there were only two capacity procurement contracts in 2013 related to outages and contingency concerns.

Resource adequacy

The CPUC's resource adequacy provisions require load-serving entities to procure adequate generation capacity to meet 115 percent of their monthly forecast peak demand. The capacity amount offered into the market each day depends on the actual availability of resources being used to meet these requirements. For example, thermal generation availability depends on forced and planned outages. Hydro, cogeneration and renewable capacity availability depends on their actual available energy. The amount of capacity from these energy-limited resources that can be used to meet resource adequacy requirements is based on their actual output during peak hours over the previous three years.

Chapter 10 in this report provides an analysis of the amount of resource adequacy capacity actually available in the ISO market during 2013 peak hours. This analysis shows that resource adequacy capacity availability was relatively high during the highest load hours of each month. During the peak summer load hours, about 94 percent of resource adequacy capacity was available to the day-ahead energy market. This is approximately equal to the target availability level incorporated in the resource adequacy program and similar to the results in prior years.

The state's resource adequacy program continued to work well as a short-term capacity procurement mechanism. Capacity made available under the resource adequacy program in 2013 was mostly sufficient to meet system-wide and local area reliability requirements. However, because of the SONGS outages and retirement, and local voltage concerns, the ISO increased reliance on meeting local reliability requirements through reliability must-run contracts.

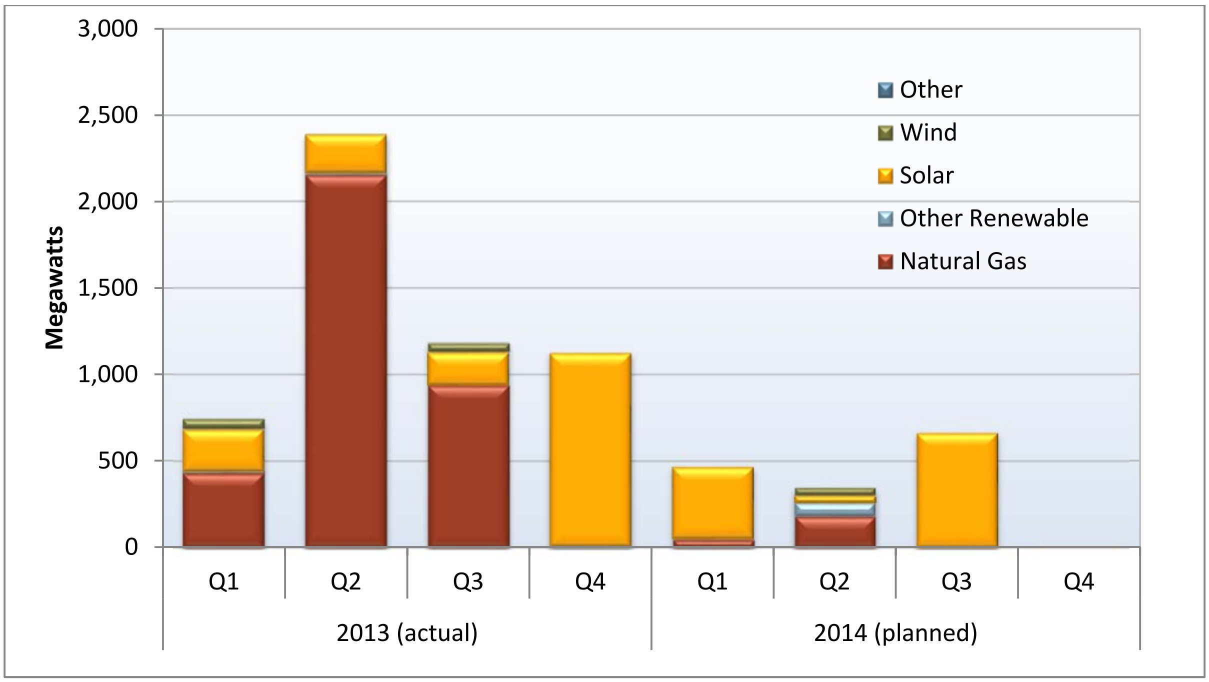
The CPUC, at the urging of the ISO, has adopted requirements for California's investor-owned utilities to procure flexible capacity to help meet the system net load changes. This represents a wider focus of the resource adequacy program from simply meeting peak system and local capacity needs to also include flexible capacity needs during ramping periods when renewable generation drops off. The ISO is developing the necessary protocols to determine requirements for flexible capacity, to count flexible resource adequacy showings, to determine must-offer requirements, and to cure any shortfalls in the showings through backstop procurement.

Generation addition and retirement

California currently relies on long-term procurement planning and resource adequacy requirements placed on load-serving entities by the CPUC to ensure that sufficient capacity is available to meet system and local reliability requirements. Trends in the amount of generation capacity being added and retired each year provide an indication of the effectiveness of the California market and regulatory structure in incenting new generation investment.

Figure E.11 summarizes the quarterly trends in summer capacity additions in 2013 and planned additions in 2014. Over 6,700 MW of new nameplate generation began commercial operation within the ISO system in 2013, contributing to over 5,500 MW of additional summer capacity. This included over 3,500 MW of new gas-fired capacity and about 3,200 MW of nameplate renewable generation, which added about 2,000 MW of summer capacity. The new gas capacity was added as part of the CPUC's long term procurement plan and the new renewable capacity was primarily from solar resources.

Figure E.11 Generation additions by resource type (summer peak capacity)



The ISO anticipates the increase of several thousand megawatts of new nameplate renewable generation in the coming years to meet the state's 33 percent renewable goals. While over 3,500 MW of gas generation came online in 2013, this was offset by over 2,900 MW in thermal generation retirements. Moreover, significant reductions in total gas-fired capacity are possible beyond 2014 due to the state's restrictions on using once-through cooling technology. The ISO has highlighted the need to backup and balance renewable generation with the flexibility of conventional generation resources to maintain reliability as more renewable generation comes online.

Under the ISO market design, annual fixed costs for existing and new units critical for meeting reliability needs can be recovered through a combination of long-term bilateral contracts and spot market revenues. Each year DMM analyzes the extent to which revenues from the spot markets would contribute to the annualized fixed cost of typical new gas-fired generating resources. This represents a market metric tracked by all ISOs and FERC.

Results of this analysis using 2013 prices for gas and electricity show a continued decrease in net operating revenues for hypothetical new combustion turbine gas units and an increase in net operating revenues for hypothetical new combined cycle units, compared to prior years. This is partially attributed to the greenhouse gas allowance program. New combined cycles were more efficient than the prevailing market greenhouse gas cost, whereas new combustion turbines were less efficient.

In both cases, however, the 2013 net revenue estimates for hypothetical combined cycle and combustion turbine units continued to fall substantially below the estimates of the annualized fixed costs for these technologies. For a new combined cycle unit, net operating revenues earned from the markets in 2013 increased to an estimated $60/kW-year in Southern California, compared to potential annualized fixed costs of $176/kW-year.

Under current market conditions, additional new generic gas-fired capacity does not appear to be needed at this time. However, a substantial portion of the state's 15,000 MW of older gas-fired capacity is located in transmission constrained load pockets and is needed to meet local reliability requirements. Much of this existing capacity is also needed to provide the operational flexibility required to integrate the large volume of intermittent renewable resources coming online. However, this capacity must be retrofitted or replaced over the next decade to eliminate use of once-through cooling technology.

Net operating revenues for many – if not most – older existing gas-fired generation are likely to be lower than their going-forward costs. A substantial portion of this existing capacity is located in transmission constrained areas and is needed to meet local reliability requirements and to ensure enough flexible capacity exists to integrate the influx of new intermittent resources. Most of this capacity will also need to be replaced or repowered to comply with the state's restrictions on use of once-through cooling. This investment is likely to require some form of longer-term capacity payment or contracting.

The ISO and the CPUC continued to address these resource adequacy issues through several initiatives in 2013. One initiative involves development of specific requirements for flexible generating capacity needed to integrate increasing amounts of intermittent renewable generation into the ISO system. The ISO and CPUC are continuing to collaborate on a process to incorporate these flexibility requirements into a multi-year ahead resource adequacy process or centralized capacity market. In early 2014, the ISO Board approved a proposed tariff filing regarding flexibility requirements and resource adequacy capacity.[10]

Recommendations

DMM works closely with the ISO to provide recommendations on current market issues and market design initiatives on an ongoing basis. A detailed discussion of DMM's comments and recommendations are provided in Chapter 11 of this report.

[10] For more information on the ISO Board decision, see http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=585EB499-6AEF-4FAA-8656-D9F5C253A63E.

Re-design of the hour-ahead and 5-minute real-time markets

The ISO is scheduled to implement a new real-time market design in May 2014 that centers on dispatch and pricing through a 15-minute market for all internal generation and inter-tie transactions.

Compared to the current hour-ahead market, dispatches and prices produced in the 15-minute process should be much more consistent with 5-minute market results. However, DMM has additional comments and recommendations on several aspects of this market design change.

- **Real-time imbalance offset costs.** The proposed changes should significantly reduce revenue imbalances allocated to load through real-time imbalance offset charges by decreasing the difference in prices used to settle inter-tie transactions and 5-minute prices currently used to settle energy from resources within the ISO system. However, DMM cautions that, despite the proposed market improvements, large real-time revenue imbalances could still occur if transmission limits are adjusted downward after the day-ahead market to account for unscheduled flows when congestion occurs.

- **Virtual bidding.** Under this new real-time market design, virtual bids on inter-ties and internal locations within the ISO would all be settled at 15-minute prices. This eliminates the problem that led to high revenue imbalance costs and the suspension of virtual bidding on inter-ties in late 2011. However, DMM cautions that virtual bidding on inter-ties could inflate real-time revenue imbalances in the event that constraint limits need to be adjusted downward in the 15-minute process to account for unscheduled flows not incorporated in the day-ahead market model. In response to concerns by DMM and other entities, the ISO modified its proposal so that virtual bidding at inter-ties would not be re-implemented until 12 months after the start of the new 15-minute market. DMM recommends that the ISO carefully assess the potential costs and benefits of re-implementing virtual bidding at inter-ties as it gains experience with the new 15-minute market design in 2014.

- **Scheduling of variable energy resources.** Under this new market design, variable energy resources may reserve hourly inter-tie transmission capacity to accommodate fluctuations in these resources' 15-minute schedules. Hourly transmission capacity reserved for variable energy resources will either become financially binding or released for other resources in the 15-minute market. However, this has the potential to displace other inter-tie supply resources with fixed hourly schedules. Consequently, DMM has recommended that the ISO retain the authority to use its own forecast of the output of a variable energy resource if schedules submitted by these resources appear to be systematically inaccurate and create detrimental market impacts. The ISO included this provision in its initial compliance filing for FERC Order 764, but was required under FERC's March 20, 2014 order to either delete the tariff clause granting the ISO this authority or to establish specific criteria for triggering the automatic use of the ISO's forecast for a variable energy resource that has submitted inaccurate forecasts.

  DMM believes that developing specific criteria for triggering the use of the ISO's forecast may alleviate some reliability concerns related to inaccurate variable energy resource forecasts. However, DMM does not believe this approach will effectively address the potential for variable energy resources to profit from strategically inaccurate forecasts intended to profit from systematic differences between the 15-minute and 5-minute markets. Therefore, DMM is recommending the ISO create a new settlement rule to prevent variable energy resources from profiting from inaccurate forecasts. The rule would calculate the net revenues a resource received from inaccuracies in its 15-minute market forecast over an appropriately long period of time (e.g., several weeks or months). If the resource has positive net revenues from its forecast inaccuracies over this period of time, payment of the net revenues would be rescinded.

Flexible ramping product

The ISO is proposing to replace the flexible ramping constraint currently incorporated in the real-time market software with a flexible ramping product to be implemented in 2015. This product would be procured in both the day-ahead and real-time markets and address both upward and downward ramping flexibility. DMM is supportive of this product as a more effective way of ensuring operational ramping flexibility than the current flexible ramp constraint.

The ISO's initial flexible ramping product proposal contains several provisions relating to market power mitigation. The last proposal includes a bid price cap of $250/MW, which is consistent with the existing caps on ancillary services. DMM believes that the best option for ensuring market efficiency and competitiveness would be to eliminate or revise the provision in the ISO's initial proposal allowing bids for flexible capacity up to $250/MW. No specific short-term marginal costs have been demonstrated or described that these bids would be used to cover.

Modeling enhancements to protect against contingencies

The ISO is also proposing to implement an alternative modeling approach aimed at reducing the use of exceptional dispatches and minimum online commitment constraints. The modeling enhancements proposed by the ISO include the modeling of post-contingency preventive-corrective constraints and generation contingencies in the market optimization so the need to position units to meet applicable reliability criteria would be incorporated into the market model.[11]

DMM is highly supportive of this initiative. The initiative directly addresses one of the recommendations in our 2011 annual report, in which we recommended that the ISO monitor and seek to limit exceptional dispatches related to needs for online capacity and ramping capability to meet overall system and south of Path 26 needs.[12] DMM believes one of the main additional benefits of this approach is that it will allow these reliability requirements to be met more efficiently because they will be met by explicit constraints incorporated in the market model. This will allow requirements to be calculated in a more automated manner based on actual system conditions and then met by the least cost mix of resources as determined by the market software optimization.

Separate capacity bids could be used to exercise market power on these local constraints and there has been no demonstrated marginal cost that these bids would represent. Consequently, DMM recommends that no separate capacity bids be allowed as part of the contingency modeling enhancements until such time as marginal costs of providing capacity are demonstrated and appropriate market power mitigation measures developed for these costs.

[11] *Contingency Modeling Enhancements Issue Paper*, March 11, 2013: http://www.caiso.com/Documents/IssuePaper-ContingecyModelingEnhancements.pdf.

[12] *2011 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2012, p. 200: http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.

Procurement of flexible capacity multiple years in advance

DMM supports efforts to modify the state's resource adequacy program to include multi-year capacity procurement that includes flexible capacity requirements.

The ISO is developing several short-term products that may provide additional market revenues for resources providing flexibility in real time. These include the flexible ramping product and the contingency modeling enhancements. However, it is very unclear how often these constraints will be binding and, therefore, provide significant market revenues. Therefore, DMM believes it is prudent to continue developing a market design that includes provisions to ensure sufficient flexible capacity is built or maintained in advance on the timeline needed to bring new flexible capacity online.

DMM believes the ISO's recent flexible capacity proposal is a step in the right direction, but recommends that the ISO and CPUC continue work toward multi-year ahead flexibility requirements that ensure that all operational and market flexibility requirements can be met by capacity procured to meet these requirements. Consequently, DMM urges the ISO and CPUC to work toward a clear and orderly proposal to develop additional provisions and refinements to the flexible capacity procurement process. More detailed recommendations are provided in Chapter 11.

Energy imbalance market

In 2013, the ISO completed its proposed design for the new energy imbalance market (EIM) that is scheduled for implementation in the fall of 2014. The EIM will allow balancing authorities throughout the West to voluntarily participate in a real-time imbalance energy market operated by the ISO. This market will optimally dispatch resources within the ISO and EIM balancing authority areas' footprint to meet the combined real-time imbalance needs of both regions in the most cost effective manner.

DMM worked closely with the ISO and its Market Surveillance Committee to ensure that this new market will offer benefits for both current participants within the ISO system as well as entities outside the ISO that will be participating in this new market as sellers or relying on it to meet their imbalance energy needs. DMM supports the general design outline in the ISO final proposal. DMM will also collaborate with the ISO to develop the appropriate monitoring capabilities and identify actions that may be taken to mitigate any issues that arise following implementation of the energy imbalance market in October 2014.

DMM has noted that the energy imbalance market's local market power mitigation provisions do not protect against market power on an EIM-wide level in cases where there may be one or two major suppliers in the EIM. Consequently, DMM recommended the rules be modified so that bid mitigation tests and procedures be triggered when congestion occurred into an EIM balancing authority area on an EIM scheduling constraint from the ISO or another EIM balancing area.

Expansion of network model to regional level

In early 2014, the ISO completed development of a proposal expanding the topology and inputs used to project actual power flows in the day-ahead and real-time models incorporated in the market software. By expanding the full network model to include other balancing areas, the ISO will also be able to reflect their outages and other reliability parameters and analyze how they may affect the ISO market.

DMM strongly supports the ISO's final proposal to expand its network model. However, creating and testing an expanded network model is likely to be a difficult and complex task. Other ISOs have experienced serious challenges in improving the accuracy of their estimates of unscheduled flows. Consequently, both DMM and the MSC have recommended that the ISO analyze, validate, and benchmark the full network model before and after implementation to ensure this feature provides the intended benefits.

The ISO has committed to performing a variety of studies as part of pre-implementation testing and to report on these results to stakeholders and the Board. DMM supports this approach, but also emphasizes that this pre-implementation testing be viewed as the first step in an ongoing process of monitoring, analysis, refinement and improvement of the full network model. DMM has provided specific recommendations relating to the metrics and analysis for the ISO to use in assessing the expanded modeling functionality impacts, and DMM is continuing to work closely with the ISO to monitor and enhance this new functionality before and after it is implemented in fall 2014.[13]

Compensating injections

In our 2011 annual report, DMM recommended that the ISO capture additional data elements needed to more effectively determine the impacts of compensating injections.[14] DMM believes analysis of the difference between modeled versus actual flows over longer time periods could provide insights into systematic patterns in unscheduled flows that might be incorporated into the day-ahead modeling process, rather than only the 15-minute and 5-minute real-time markets.

DMM reiterates the recommendation that more data and analysis is required to better understand the actual effectiveness of compensating injections in terms of improving estimated flows and congestion management on individual constraints within the ISO. For instance, on multiple occasions the ISO has observed that compensating injections have had the effect of increasing modeled flows on internal constraints above metered flows, triggering congestion in the real-time market when actual flows were below actual constraint limits.

Cost-based bids for gas-fired units

On February 6, 2014, a cold weather event led to a rapid increase in gas prices and highlighted the potential market impacts of the gas prices used by the ISO to calculate bids under the proxy cost option, which are based on gas prices traded two days prior to the operating day. This event also highlighted the potential impact of monthly fixed start-up and minimum load bids under the registered cost option selected by most gas-fired capacity in cases when a rapid increase in gas prices occurs.

To address this issue in the immediate future, the ISO requested, and the FERC granted, temporary waivers of its tariff to allow it to incorporate a more recent gas price forecast into its day-ahead market solution and settlement practices under certain conditions. The ISO plans to undertake a stakeholder process to explore market rule refinements to address this issue on a permanent basis.

Some stakeholders have suggested that the events of February 6, 2014, 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

[13] Memorandum from Eric Hildebrandt to ISO Board of Governors, re: Market Monitoring Report, January 30, 2014: http://www.caiso.com/Documents/DepartmentMarketMonitoringReport-Memo-Feb2014.pdf.

[14] *2011 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2012, pp. 200-201: http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.

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 by one participant aimed at profiting from high minimum load bids under the registered cost option. [15] The lower 150 percent limit implemented in 2013 is seen as an important protective measure against other such practices.
- Second, 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 caused by the very extreme conditions on February 6, 2014, have been addressed in a targeted manner by recent tariff filings. DMM believes that issues that 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 cost-based limits and mitigation will still be needed. Reviewing bids after-the-fact would be very administratively burdensome and would still require establishment of some kind of cost-based standard or limit. If *ex post* review indicated this standard or limit was exceeded, there would be no way to mitigate the distortion in the market that would have already occurred due to use of the unmitigated bids.

Transition cost bids for multi-stage generating units

Under the current tariff, transition cost bids submitted by participants are not required to reflect actual transition costs and are not subject to any cost verification. DMM continues to recommend, as we first noted in our 2011 annual report, that the ISO revise the caps for transition cost bids for multi-stage generating units. As noted in our 2012 annual report, DMM believes this will become increasingly important if the ISO requires additional resources to be modeled as multi-stage generating units. In March 2014, the FERC approved a 2013 filing by the ISO to require most units be modeled as multi-stage generating units. Thus, DMM continues to re-iterate this recommendation.

DMM's experience suggests that by far the main component of transition costs is fuel consumption, which is relatively easy to estimate and verify. DMM suggests that rules be modified so that only the fuel component of transition costs is scaled up or down based on daily spot market fuel prices. Any verified non-fuel component of transition costs would remain fixed from day-to-day.

[15] See citations in Section 11.8, footnote 242.

Organization of report

The remainder of this report is organized as follows:

- **Loads and resources.** Chapter 1 summarizes load and supply conditions impacting market performance in 2013. This chapter includes an analysis of net operating revenues earned by hypothetical new gas-fired generation from the ISO markets.
- **Overall market performance.** Chapter 2 summarizes overall market performance in 2013.
- **Real-time market performance.** Chapter 3 provides an analysis of real-time market performance, including reasons for day-ahead and real-time price divergence.
- **Convergence bidding.** Chapter 4 analyzes the convergence bidding feature that was added in 2011 and its effects on the market.
- **Greenhouse gas cap-and-trade program.** Chapter 5 analyzes the effects of California's implementation of the greenhouse gas cap-and-trade program on the ISO markets in 2013.
- **Ancillary services.** Chapter 6 reviews performance of the ancillary service markets.
- **Market competitiveness and mitigation.** Chapter 7 assesses the competitiveness of the energy market, along with impact and effectiveness of market power and exceptional dispatch mitigation provisions.
- **Congestion.** Chapter 8 reviews congestion and the market for congestion revenue rights.
- **Market adjustments.** Chapter 9 reviews the various types of market adjustments made by the ISO to the inputs and results of standard market models and processes.
- **Resource adequacy.** Chapter 10 assesses the short-term performance of California's resource adequacy program in 2013.
- **Recommendations.** Chapter 11 highlights DMM recommendations on current market issues and new market design initiatives on an ongoing basis as well as follow-up on a variety of specific recommendations for market improvements made in our prior annual and quarterly reports.

Chapter 1 of DMM's 2010 annual report provides a summary of the nodal market design implemented in 2009 and key design enhancements that were added in 2010 and early 2011.[16] This chapter of our 2010 annual report also highlights various state policies and requirements closely linked to the design and performance of the ISO markets.

[16] *2010 Annual Report on Market Issues and Performance*, April 2011, pp. 17-32. http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf.

1 Load and resources

Average and peak loads were down slightly in 2013, driven by relatively mild summer weather conditions. Overall supply conditions also remained relatively stable and favorable. Although hydro-electric generation was down due to poor precipitation, wind and solar generation were up as new generation was added. While both San Onofre Nuclear Generating Station (SONGS) units retired, representing over 2,200 MW of retired capacity, over 3,500 MW of natural gas generation was added. More specific trends highlighted in this chapter include the following:

- The average price of natural gas in the daily spot markets increased 30 percent from 2012.[17] This was the main driver in the 31 percent increase in the nominal annual wholesale energy cost per MWh of load served in 2013.
- Summer loads peaked at 45,097 MW, a 4 percent decrease from 2012 and the lowest peak load observed in several years.
- Hydro-electric generation provided approximately 8 percent of total supply in 2013, a decrease from 9 percent in 2012. The drop in hydro-electric generation was most pronounced in the second half of the year when it was less than 75 percent of the low hydro conditions during the same period in 2012.
- Net imports decreased by 7 percent in 2013 compared to 2012, driven by a 10 percent decrease in imports from the Northwest compared to 2012.
- About 2,000 MW of summer peak generating capacity from renewable generation was added in 2013 with most of this coming from increasing solar generation. Energy from wind and solar provided about 8 percent of system energy, compared to about 5 percent in 2012. While wind produced about two times more generation than solar, the increase in wind and solar generation in 2013 from 2012 in absolute terms was about the same.
- Demand response programs operated by the major utilities continued to meet about 5 percent of the ISO's overall system resource adequacy capacity requirements. Activation of these programs continued to be limited in 2013.
- Price responsive demand response capacity continued to surpass reliability based demand response capacity. Price responsive capacity accounted for 53 percent of demand response in 2013. This capacity can be dispatched during the operating day in response to real-time market conditions or on a day-ahead basis in response to expected market conditions. Reliability-based programs that can only be activated under extreme system conditions made up the remaining 47 percent.
- Over 3,500 MW of new gas-fired generation was added in 2013. Most of this capacity was added as part of the CPUC's long-term procurement plan.

[17] In this report, we calculate average annual gas prices by weighting daily spot market prices by the total ISO system loads. This results in a price that is more heavily weighted based on gas prices during summer months when system loads are higher than winter months, when gas prices are typically highest.

- The estimated net operating revenues for typical new gas-fired generation in 2013 remained substantially below the annualized fixed cost of new generation. This analysis does not include revenues earned from resource adequacy contracts or other bilateral contracts. However, these findings continue to emphasize the critical importance of long-term contracting as the primary means for investment in any new generation or retrofit of existing generation needed under the ISO's current market design.

1.1 Load conditions

1.1.1 System loads

System loads were significantly lower in 2013, despite continued economic recovery and additional load from the Valley Electric Association and the City of Colton, both of which joined the ISO in January 2013. The decrease in load is likely due to relatively mild temperatures in peak demand months. Table 1.1 summarizes annual system peak loads and energy use over the last five years.

Table 1.1 Annual system load: 2009 to 2013

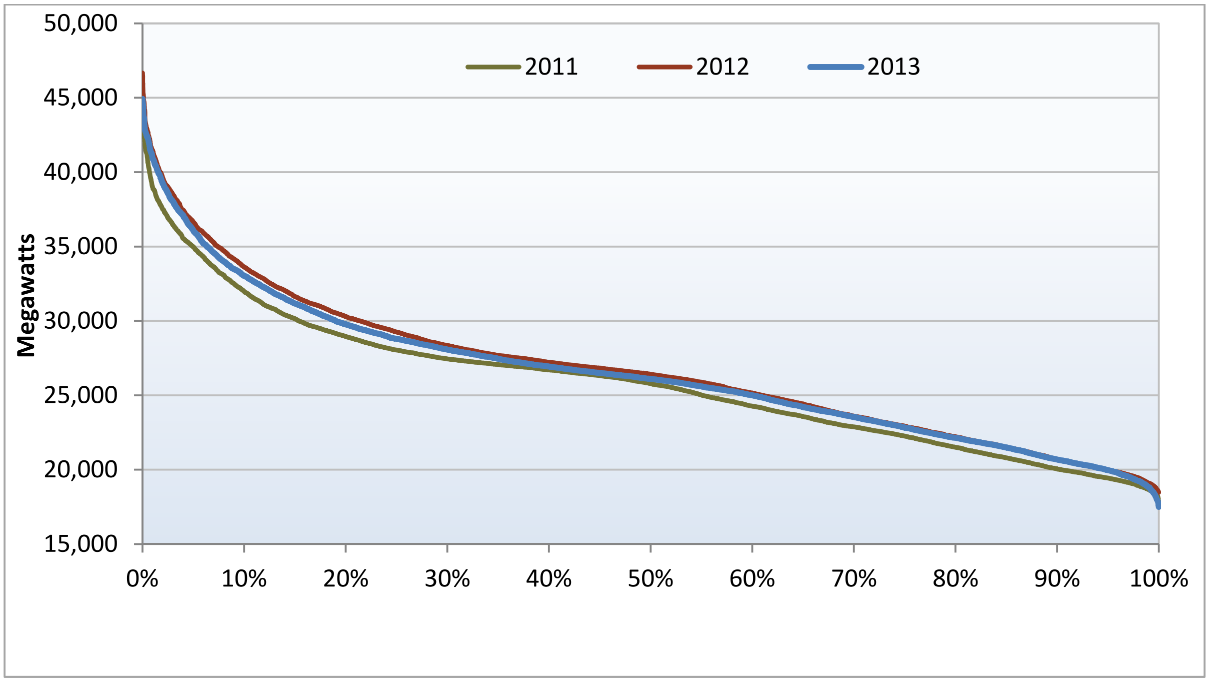
Year	Annual total energy (GWh)	Average load (MW)	% change	Annual peak load (MW)	% change
2009	230,754	26,342	-4.3%	46,042	-3.5%
2010	224,922	25,676	-2.5%	47,350	2.8%
2011	226,087	25,791	0.4%	45,545	-3.8%
2012	234,882	26,740	3.7%	46,847	2.9%
2013	231,800	26,461	-1.0%	45,097	-3.7%

Annual, average and peak load measures all decreased in 2013.

- Annual total energy reached 231,800 GWh, a 1.3 percent decrease over 2012.
- Average loads during all hours decreased by 1.0 percent.
- Summer loads peaked at 45,097 on June 28 at 4:53 p.m., a 3.7 percent drop from 2012 and the lowest peak load observed in the last 5 years.

Demand was relatively low during peak hours compared to highs in 2012 (see Figure 1.1 for load duration curves for 2011 through 2013). System load exceeded 40,000 MW in 134 hours in 2013 compared to 151 hours in 2012, a decrease from 1.7 percent to 1.5 percent of hours.

Figure 1.1 System load duration curves (2011 to 2013)



Other measures of peak load served in 2013 also decreased. System demand during the single highest load hour varies substantially year to year because of summer heat waves. The potential for such heat-related peak loads creates a continued threat of operational reliability problems and drives many of the ISO's reliability planning requirements.

Figure 1.2 summarizes load conditions during summer peak hours.

- Average hourly summer peak load was 32,454 MW, a slight decrease from the record high of 32,603 MW observed in 2012.[18]
- Average daily peak load fell about 0.5 percent to 36,270 MW.
- The single hour peak load fell about 3.7 percent to 44,923 MW.[19]

Peak load was lower than both the ISO's 1-in-2 year and 1-in-10 year forecasts. In coordination with the CPUC and other local regulatory authorities, the ISO sets system level resource adequacy requirements based on the *1-in-2 year*, or median year, forecast of peak demand. Resource adequacy requirements for local areas are based on the *1-in-10 year*, or 90th percentile year, peak forecast for each area.

Summer peak demand in 2013 was well below both the 1-in-2 year and 1-in-10 year forecasts, as demonstrated in Figure 1.3. The instantaneous peak load (45,097 MW) was about 5 percent below the 1-in-2 year forecast (47,413 MW).

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[18] Summer peak hours included in this calculation are from June to August, hours ending 7 to 22.

[19] This value is lower than the instantaneous peak reported earlier because DMM calculates the hourly peak load as the average of twelve 5-minute intervals.

Figure 1.2 Summer load conditions (2003 to 2013)

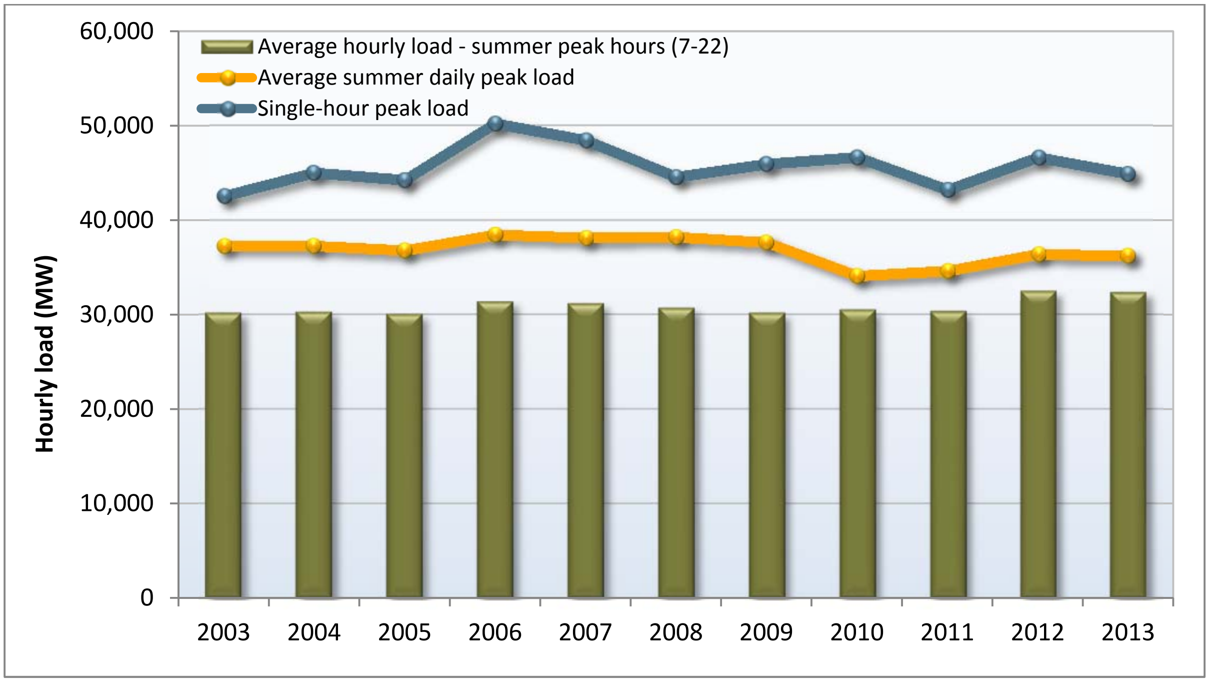
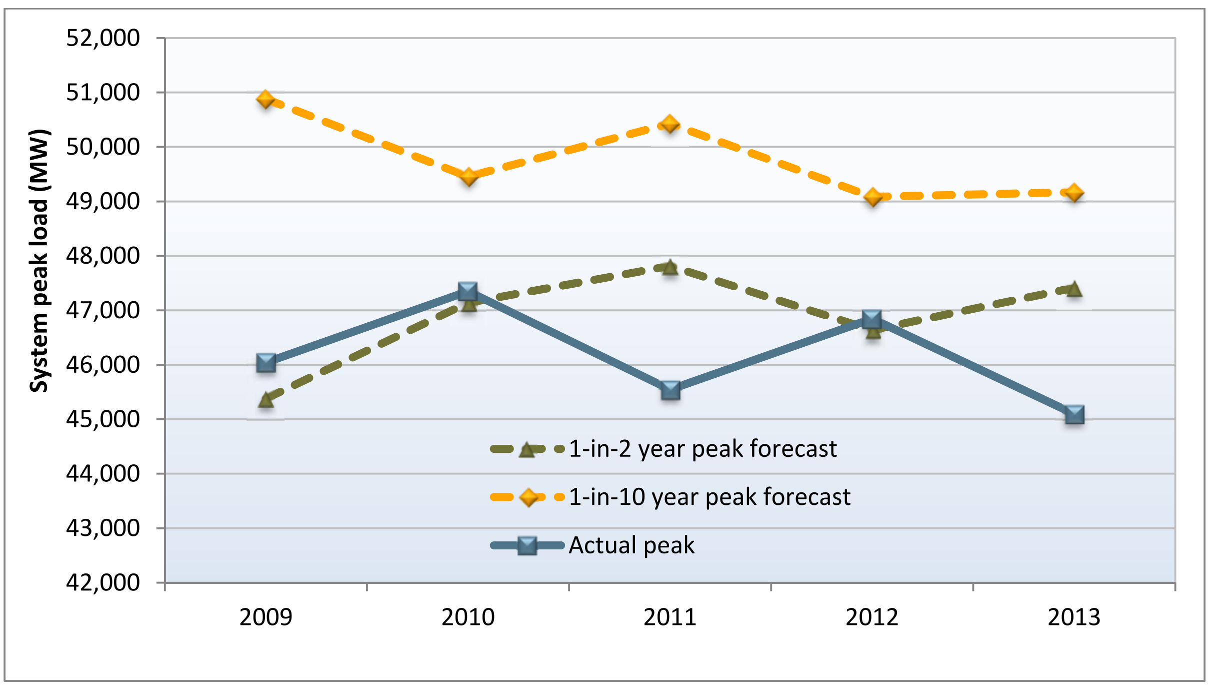


Figure 1.3 Actual load compared to planning forecasts



1.1.2 Local transmission constrained areas

The ISO has defined 10 local capacity areas for use in establishing local reliability requirements for the state's resource adequacy program (see Figure 1.4). Table 1.2 and Figure 1.5 summarize the total amount of load within each of these local areas under the 1-in-10 year forecast used to set local reliability requirements. Most of the total peak system demand is located within two areas: the Los Angeles Basin (40 percent) and the Greater Bay Area (21 percent).

The three investor-owned utility (IOU) areas may be characterized as follows:

- The Southern California Edison area accounts for 50 percent of total local capacity area loads under the 1-in-10 year forecast. Loads in the Los Angeles Basin account for 81 percent of the potential peak load in this area.
- The Pacific Gas and Electric area accounts for 40 percent of total local capacity area loads under the 1-in-10 year forecast. Loads in the Greater Bay Area account for 53 percent of the potential peak load in the PG&E area.
- The San Diego Gas and Electric area is comprised of a single local capacity area, which accounts for 11 percent of the total local capacity area load forecast.

In the following chapters of this report, we summarize a variety of market results for each of these three main load areas – also known as *load aggregation points* or LAPs. In some cases, we provide results for specific local capacity areas. These results provide insight into key locational trends under the nodal market design. The proportion of load and generation located within the areas shown in Table 1.2 and Figure 1.5 is an indication of the relative importance of results for different aggregate load and local capacity areas on overall market results.

In addition to local capacity area load forecasts, Table 1.2 shows the total amount of generation in each local capacity area and the proportion of that capacity required to meet local reliability requirements established in the state resource adequacy program. In most areas, a very high proportion of the available capacity is needed to meet peak reliability planning requirements. One or two entities own the bulk of generation in each of these areas. As a result, the potential for locational market power in these load pockets is significant. This issue is examined in Chapter 7 of this report.

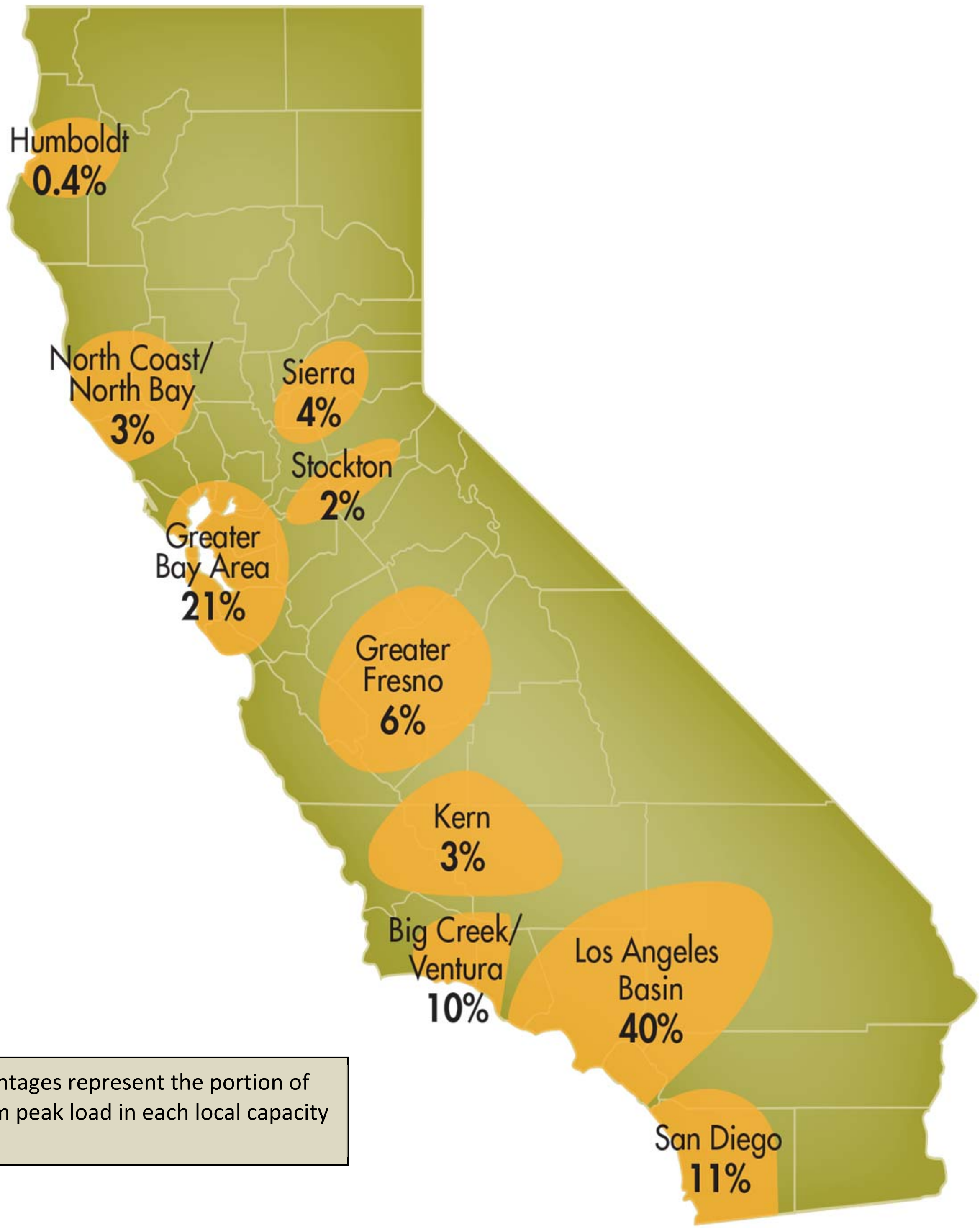
The available supply in Table 1.2 for the Los Angeles Basin includes over 2,200 MW of generation from the San Onofre nuclear plant which has been retired. As shown in Table 1.2, without this generation, almost all of the available supply within the Los Angeles Basin is needed to meet local capacity requirements.[20]

In addition, California's once-through cooling (OTC) regulations affect a significant proportion of capacity needed to meet local capacity requirements in four local capacity areas: Greater Bay Area, Los Angeles Basin, Big Creek/Ventura and San Diego. Further discussion of this issue is available in DMM's 2011 annual report.[21]

[20] Without the 2,246 MW dependable generation provided by the San Onofre nuclear plant, total dependable generation in the LA Basin falls to 10,881, 95 percent of which would be required to meet the local capacity requirement.

[21] *2011 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2012, p. 27: http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.

Figure 1.4 Local capacity areas



Percentages represent the portion of system peak load in each local capacity area.

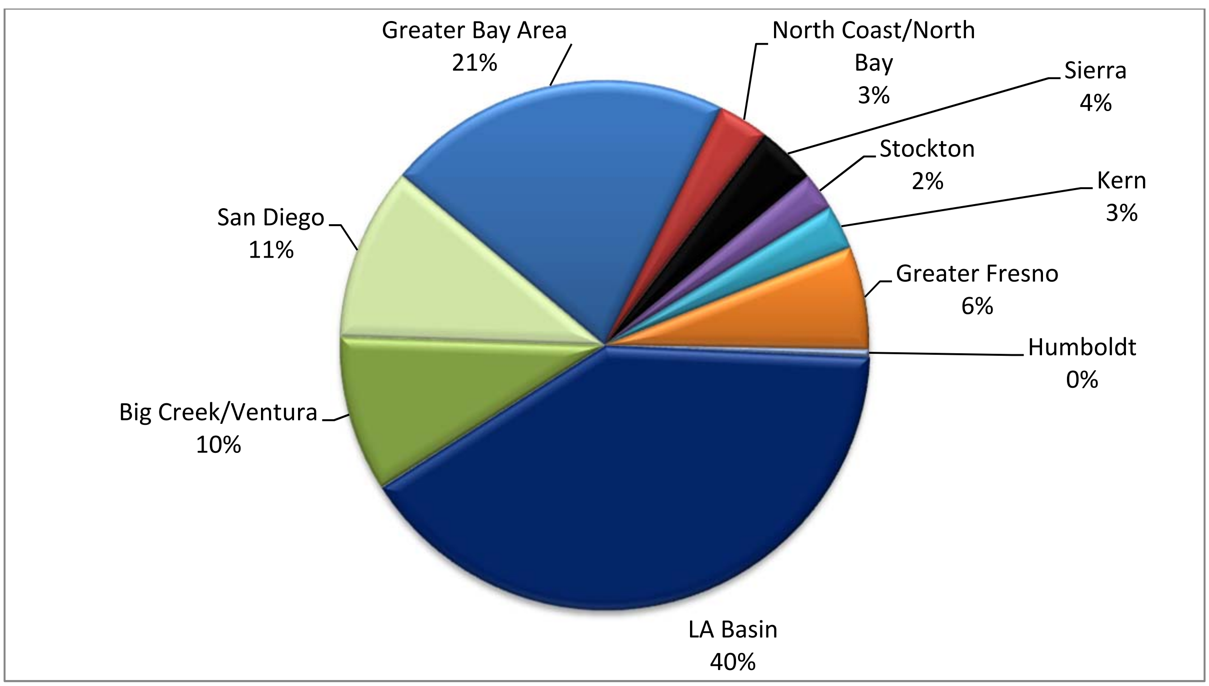
Table 1.2 Load and supply within local capacity areas in 2013

Local Capacity Area	LAP	Peak Load (1-in-10 year) MW	%	Dependable Generation (MW)	Local Capacity Requirement (MW)	Requirement as Percent of Generation
Greater Bay Area	PG&E	10,233	21%	7,664	4,502	59%
Greater Fresno	PG&E	3,032	6%	2,817	1,786	63%
Sierra	PG&E	1,738	4%	2,039	1,930	95%*
North Coast/North Bay	PG&E	1,479	3%	869	629	72%
Stockton	PG&E	1,109	2%	620	567	91%*
Kern	PG&E	1,311	3%	584	525	90%*
Humboldt	PG&E	210	0.4%	217	212	98%*
LA Basin	SCE	19,460	40%	13,127	10,295	78%
Big Creek/Ventura	SCE	4,596	10%	5,276	2,241	42%
San Diego	SDG&E	5,114	11%	4,149	3,082	74%*
Total		**48,282**		**37,362**	**25,769**	**69%**

Source: *2014 Local Capacity Technical Analysis: Final Report and Study Analysis*, April 30, 2013. See Table 6 on page 22. http://www.caiso.com/Documents/Final2014LocalCapacityTechnicalStudyReportApr30_2013.pdf

* Generation deficient LCA (or with sub-area that is deficient). Deficient area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.

Figure 1.5 Peak loads by local capacity area (based on 1-in-10 year forecast)



1.1.3 Demand response

Overview

Demand response continues to play an important role in meeting California's capacity planning requirements for peak summer demand. These programs are operated by the state's three investor-owned utilities and meet about 5 percent of total ISO system resource adequacy capacity requirements.

Demand response is a resource that allows consumers to reduce electricity use in response to forecast or actual market conditions, including high prices and reliability signals. By providing capacity to help meet demand on extremely high load days, demand response could decrease demand in high use periods enough to lower market prices for energy and ancillary services and increase transmission reliability.

Demand response programs are generally dispatched and administered by the utilities that sponsor these programs, rather than by the ISO. These programs are overseen by the CPUC. Independent curtailment service providers offer demand response by participating in utility sponsored programs, as do other non-utility entities. Currently, demand response provided directly to the ISO is primarily limited to water pumping loads.[22]

In August 2010, the ISO implemented a proxy demand resource product. This market enhancement allows aggregators of end-use loads to bid directly into the energy and ancillary service markets. This product was implemented to increase direct participation in the energy and ancillary service markets by utility demand response programs, as well as aggregated end-use or independent demand response providers. However, less than 6 MW of proxy demand resource capacity was registered when load peaked in 2013, about the same as in 2012. These resources provided no energy in 2013, very similar to the negligible amount of energy they provided to the market in 2012.

In addition to the utility demand response programs, the ISO issues flex alerts when system conditions are expected to be particularly high. Flex alerts urge consumers to voluntarily reduce demand through broadcast press releases, text messages and other means. The program is funded by the utilities under the authority of the CPUC. The ISO issued two flex alerts in 2013. The first was a flex alert on April 16 in the San Jose area in response to the Metcalf transformer being damaged by gunfire; the second was a two day state-wide flex alert issued for July 1 and July 2 in response to projected record demand due to heat waves.

Utility demand response programs

Almost all of California's current demand response consists of load management programs operated by the state's three investor-owned utilities. These programs are triggered by criteria set by the utilities and are not necessarily tied to market prices. Notification times required by the retail programs are also not well coordinated with ISO market operations, which limited the programs' use and usefulness in the ISO system.

[22] The ISO does not release information on the amount of participating loads since virtually all this capacity is operated by one market participant – the California Department of Water Resources.

Utility-managed demand response programs can be grouped into three categories:

- ***Reliability-based programs.*** These programs consist primarily of large retail customers under interruptible tariffs and air conditioning cycling programs. These demand resources are primarily triggered only when the ISO declares a system reliability threat or for a local transmission emergency.[23]
- ***Day-ahead price-responsive programs***. These programs are triggered on a day-ahead basis in response to market or system conditions that indicate relatively high market prices. Specific indicators used by utilities to trigger these programs include forecasts of temperatures or unit heat rates that may be scheduled given projected real-time prices. This category also includes *critical peak pricing* programs under which participating customers are alerted that they will pay a significantly higher rate for energy during peak hours of the following operating day.
- ***Day-of price-responsive programs***. These programs are referred to as *day-of* demand response programs since they can be dispatched during the same operating day for which the load reduction is needed. These resources include capacity from air-conditioning cycling programs dispatched directly by the utilities and much of the load reduction capacity procured through curtailment service providers. These programs can also be triggered on a day-ahead basis in response to market or system conditions.

From the perspective of overall market performance and system reliability, day-of price responsive demand programs are significantly more valuable than price-responsive programs that can only be triggered on a day-ahead basis. These programs provide capacity that is able to respond to rapidly changing market conditions without being reserved a day in advance.

Table 1.3 summarizes total demand response capacity for each of the three major utilities during the peak summer month of August, as reported to the CPUC since 2009.[24] As shown in Table 1.3, there is a notable drop in reported demand response capacity from 2009 to 2010. This was due to a change in the way that demand response capacity is assessed and reported.

Through 2009, demand response capacity was reported based on total controllable load enrolled in each program. Protocols in effect since 2010 require utilities to report two measures of demand response capacity: *ex ante* and *ex post*.[25] *Ex post* values are calculated by multiplying total program enrollment by the average customer impact for customers enrolled in the previous year. *Ex ante* values are calculated by multiplying total program enrollment by the estimated average load impact that would occur under expected weather and load conditions on the peak day of the month between 1:00 p.m. and 6:00 p.m. The *ex ante* values form the basis for the remaining discussion in this section because they are most representative of actual available demand response capacity during 2013.

Each investor-owned utility uses demand response capacity to meet resource adequacy requirements. As shown in the bottom two rows of Table 1.3, demand response capacity used to meet resource

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[23] In early 2014, FERC accepted the ISO's modification to the reliability demand response program. The change will allow reliability demand response to be dispatched as part of the market optimization during a system emergency. Bid prices will range between $950 and $1,000/MWh. The change will be effective May 2014. For more information see: http://www.caiso.com/Documents/Mar28_2014_OrderAcceptingTariffRevisions-ReliabilityDemandResponse_ER11-3616_ER13-2192.pdf.

[24] The monthly reports are available at http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Monthly+Reports/index.htm.

[25] *Load Impact Estimation for Demand Response: Protocols and Regulatory Guidance*, California Public Utilities Commission Energy Division, April 2008.

adequacy requirements from 2010 to 2012 has tracked closely with estimates of actual demand response capacity reported in these years under the more advanced reporting protocols.

In 2013, the gap between ex ante reported demand response capacity and demand response capacity used to meet resource adequacy requirements widened as ex ante reported demand response capacity fell. The ex ante reported capacity offered in SCE and SDG&E fell by 30 percent despite an increase in the number of enrolled accounts. The decline was driven by reduced ex ante estimates of capacity enrolled in specific programs.[26] Ex ante reported capacity in PG&E increased by almost 20 percent. The amount of this capacity used to meet resource adequacy requirements is determined by the CPUC, based on its estimate of demand response capacity that can be expected under peak summer conditions.

In 2013, ex ante estimates of demand response capacity available in August equaled approximately 84 percent of the resource adequacy requirements that the CPUC allowed these resources to meet. The decrease in demand response used to meet resource capacity requirements since 2010 reflects the use of the more stringent protocol for measuring and reporting demand response programs that took effect in 2010. The CPUC allows a 15 percent adder to be applied to demand response capacity used to meet resource adequacy requirements. This accounts for the fact that demand response reduces the amount of load used to calculate the 15 percent supply margin used in setting resource adequacy requirements.

Table 1.3 Utility operated demand response programs (2009-2013)

Utility/type	2009 Enrolled MW	2010 Estimated* MW	2011 Estimated* MW	2012 Estimated* MW	2013 Estimated* MW
Price-responsive					
SCE	498	214	287	962	706
PG&E	508	304	469	340	404
SDG&E	89	72	58	118	54
Sub-total	1,095	589	814	1,420	1,164
Reliability-based					
SCE	1,577	1,245	1,167	727	684
PG&E	533	291	253	282	332
SDG&E	62	9	8	2	0
Sub-total	2,172	1,544	1,428	1,010	1,016
Total	3,267	2,134	2,270	2,430	2,180
Resource adequacy allocation	2,637	2,221	2,421	2,598	2,582
With 15 percent adder	3,033	2,554	2,784	2,987	2,970

* Capacity for 2009 based on planning projections of program enrollment and impacts.
Capacity for 2010-2013 based on *ex ante* assessment of program enrollment and impacts.

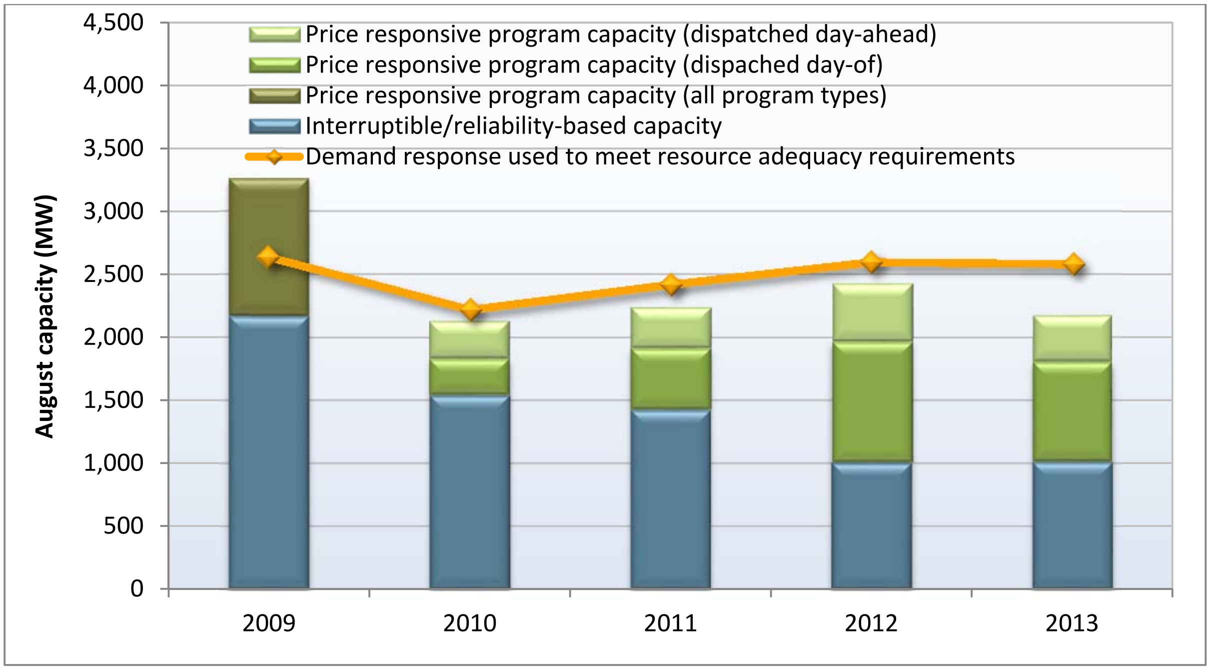
Figure 1.6 summarizes data in Table 1.3, but provides a further breakdown of the portion of price-responsive capacity that can be dispatched on a day-ahead and day-of basis since 2010.[27] The following is shown in Figure 1.6:

[26] These programs include SCE's Summer Discount Plan and PTR (Peak Time Rebate / Save Power Day program).

[27] Prior to 2010, data provided in the monthly reports are not sufficient to differentiate between price-responsive demand response that can be dispatched on a day-ahead and day-of basis.

- Price-responsive programs accounted for 53 percent of this capacity in 2013, which is a major increase from 2009 to 2011 levels, but slightly less than the 2012 value (58 percent).
- Reliability-based programs accounted for 47 percent of the capacity from utility-managed demand response resources in 2013. Historically, reliability programs have been a larger component of demand response capacity.
- In 2013, price-responsive programs that can be dispatched on a day-of basis fell to 36 percent of all demand response capacity, down slightly from about 39 percent in 2012.

Figure 1.6 Utility operated demand response programs (2009-2013)



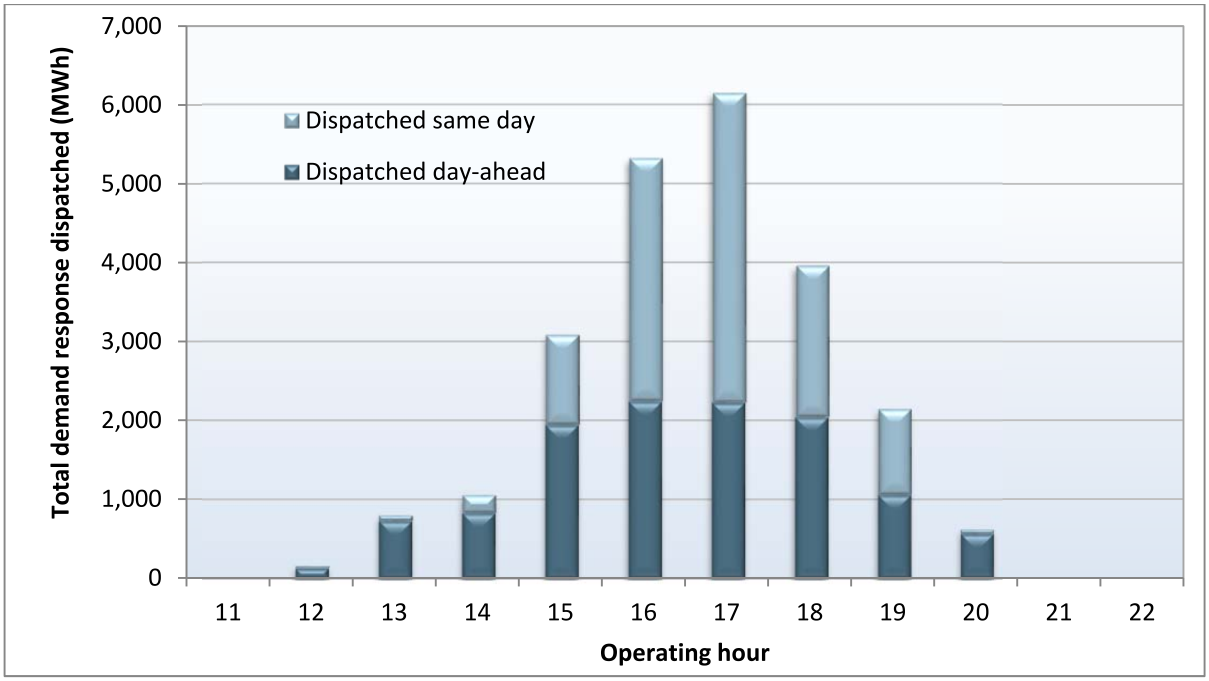
From the perspective of overall market performance and system reliability, price-responsive demand response, which can be dispatched on the same day that high market prices or critical system conditions occur, are significantly more valuable than programs that can only be triggered on a day-ahead basis or in response to a system reliability emergency.

Use of demand response programs

Demand response resources continue to be dispatched by utilities on a limited basis. These programs were dispatched at a slightly higher volume in 2013 than in 2012, as measured by post event estimates provided 7 days after the event and then re-estimated at year end. However, the total estimated impact of these demand response events represents a very small portion of total energy in the market – approximately 0.01 percent.

While demand response dispatch volume was small in 2013, these resources were dispatched during the peak hours of the months that have historically seen the highest levels of demand, when they are likely to have the most impact. Figure 1.7 shows the annual total amount of demand response activated by the three largest utilities in 2013 by operating hour. Dispatch was concentrated in the hours between 2:00 p.m. and 6:00 p.m., often the peak ramping hours in the day. As demonstrated in Figure 1.7, about 50 percent of demand response was dispatched on a day-ahead basis. The remaining half was dispatched on a day-of or emergency basis.

Figure 1.7 Total amount of demand response programs dispatched in 2013 by hour



In 2013, most demand response was dispatched in response to market or system conditions, rather than to evaluate or measure the demand response program itself. Dispatch for measurement or evaluation accounted for approximately 1 percent of dispatch for day-ahead programs and 30 percent of dispatch for day-of programs in 2013. In 2012, dispatch for measurement and evaluation was similar to 2013 for day-ahead dispatch (1 percent) and slightly less than same day dispatch in 2013 at about 22 percent. In 2011, dispatch for measurement and evaluation accounted for a much higher portion – 5 percent of day-ahead dispatch and about 80 percent of same day dispatch.

Demand response issues

While use of demand response increased in 2012 and remained at similar levels in 2013, several challenges remain before this capacity is well integrated into the market and ISO operational decisions. These challenges include limited use of the ISO's proxy demand resource program, the timing and quality of demand response data, and limited integration of available demand response data into ISO operations.

While the ISO implemented a proxy demand resource product in 2010, few bids from these resources were dispatched in 2012 and none were dispatched in 2013. Although proxy demand resource product participation in the ISO markets has been approved by FERC, the CPUC has limited bundled utility customer participation in this program to pilot programs.[28] Thus, while the utilities' programs were triggered more by price than for reliability purposes, the integration of these programs with the ISO markets is still poor as commitment and dispatch decisions continue to occur outside the market optimization.

Daily forecasts of scheduled demand response sent to the ISO by the major investor-owned utilities are the only source of information directly available to the ISO on utility operated demand response resources. However, these forecasts are not well integrated with market operations for several reasons.

First, the timing and form of the forecast reports makes it difficult for these to be included in actual ISO resource commitment decisions. The three major utilities provide the ISO with a daily forecast schedule for demand response programs. This hourly forecast is updated by 8:00 a.m. of the day on which the demand response programs are dispatched and then updated again by the end of day on which the demand response event occurred. Thus, the ISO receives the updated forecast information shortly before or sometimes after the activation of the event, thus making it difficult to incorporate demand response expectations into actual market operations.

Second, measuring the impact of dispatched demand response in a timely fashion remains a challenge. As noted earlier, the utilities provide forecast estimates the day before and the day of operation. Seven days after a demand response event, the utilities provide the ISO with post event estimates of dispatched demand response capacity. Under the CPUC monitoring and evaluation protocols, the actual performance of demand response is re-assessed on an annual basis using final metered data and sophisticated econometric estimates of load without demand response. However, these results are not available until the spring of the following year.[29]

Finally, demand response forecast schedules have also been difficult to integrate into ISO operations because they can differ substantially from actual load reductions achieved. The performance of demand response programs – as measured by the difference between forecasted impacts and after the fact estimates of actual impacts – has been the subject of concern for both the ISO and CPUC. This may be particularly true of new programs without a long history of measured performance which rely heavily on consumer behavior and price responsiveness.[30]

The ISO has developed explicit procedures to incorporate forecasted demand response into the day-ahead market. These procedures were updated in May 2012 to include the day-ahead demand response schedules in manual operator adjustments of the load forecast used in the day-ahead market. While operators reviewed this information and included these numbers in their evaluation of the residual unit commitment procurement target, this rarely resulted in reductions. Although the ISO received more timely notice of demand response than in prior years, forecast demand response was

[28] For further detail see CPUC Decision 10-06-002, issued in Proceeding R.07-01-041. More information on this decision can be found here: http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/118962.htm. A broader discussion of regulatory issues is available in the ISO's 5th Annual Demand Response report in docket no. ER06-615-000: http://www.caiso.com/Documents/2012-01-17_ER06-615_5thAnnualDR_Report_CY2011.pdf.

[29] Values summarized above are based on post event summaries provided by the utilities to the ISO. Because measuring the quantity of demand response dispatched requires estimating what load would have been in the absence of these programs, data used for this report may differ from values submitted to the CPUC.

[30] For further detail on demand response measurement see the CPUC staff report on 2012 demand response evaluation in southern California, *Commission Staff Report: Lessons Learned From Summer 2012, Southern California Investor Owned Utilities' Demand Response Programs,* May 1, 2013: http://www.cpuc.ca.gov/NR/rdonlyres/523B9D94-ABC4-4AF6-AA09-DD9ED8C81AAD/0/StaffReport_2012DRLessonsLearned.pdf.

often low relative to total system load and an inconsistent predictor of final estimated demand response values. As a result, the full benefits of demand response in terms of unit commitment decisions may not be realized in the market at this time given current procedures and quality of information.

Under the current market design, the ISO does not have the data or responsibility for assessing the performance of these utility programs. When these programs are bid and dispatched directly in the ISO market as proxy demand resources, the ISO will play a role in assessing the impact of these resources based on metering data as part of the settlement process.

1.2 Supply conditions

1.2.1 Generation mix

In 2013, natural gas and imports continued to be the largest sources of energy to meet ISO loads. Hydro-electric generation was lower in 2013 due to levels of precipitation and snowpack that fell below low levels in 2012. A growing share was produced by renewable energy resources including wind and solar.

Figure 1.8 provides a profile of average hourly generation by month and fuel type. Figure 1.9 illustrates the same data on a percentage basis. Figure 1.10 shows an hourly average profile of energy supply by fuel type for the peak summer months, July through September. This information is illustrated on a percentage basis in Figure 1.11. These figures show the following:

- Nuclear generation was 5 percent below the reduced levels reached in 2012. This was a result of the extended outages, followed by the permanent retirement of, the San Onofre Nuclear Generating Station units 2 and 3. Overall, nuclear generation provided less than 8 percent of supply in 2013.
- Hydro-electric generation provided approximately 8 percent of supply in 2013, a decrease from 9 percent in 2012. The drop in hydro-electric generation was most pronounced in the second half of the year when it was less than 75 percent of the low hydro conditions during the same period in 2012.
- The gap in supply created by falling hydro-electric and nuclear generation was filled, in large part, by natural gas. Natural gas generators provided approximately 40 percent of supply in 2013, up from 39 percent in 2012 and 28 percent in 2011.
- Combined, natural gas and hydro-electric generation produced the most during the higher load months (August and September) of the year and in the higher load hours of the day (7 through 22). These resources were most often marginal and price setting in the ISO system.
- Imports represented approximately 28 percent of capacity, a slight decrease in percentage terms from 2012 (30 percent). Overall, energy from imports decreased by 7 percent. These values do not net out exports. Net import values do remove exports and are discussed in further detail later in this section.

Figure 1.8 Average hourly generation by month and fuel type in 2013

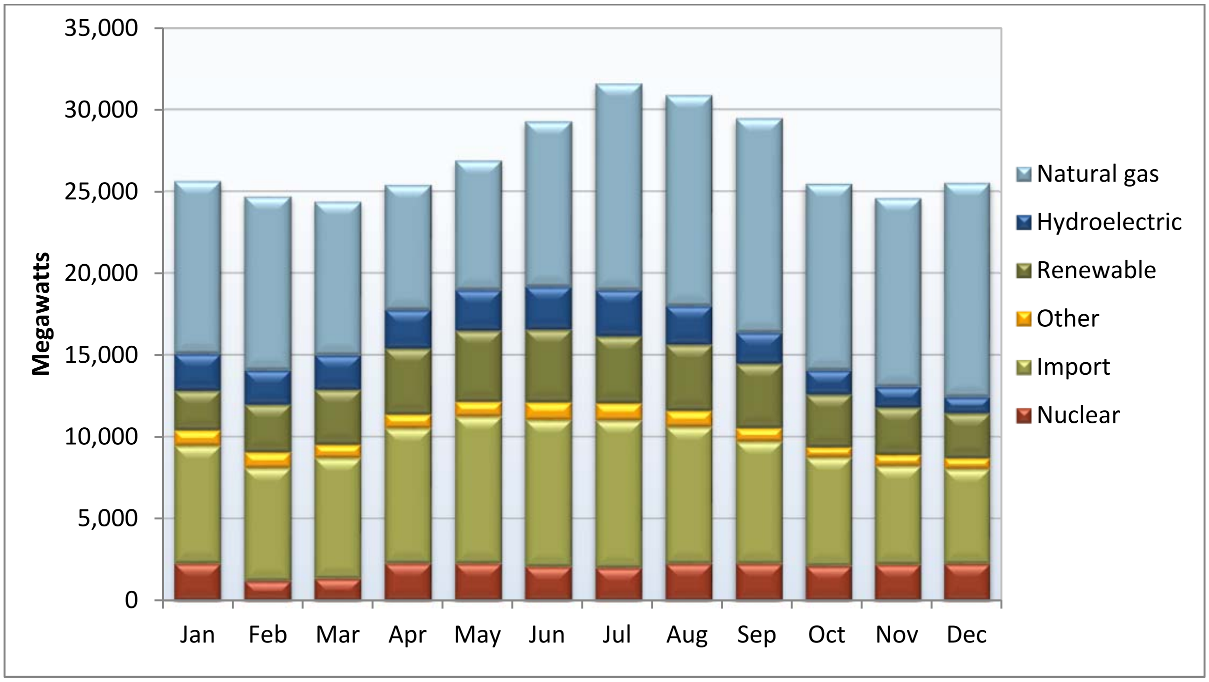


Figure 1.9 Average hourly generation by month and fuel type in 2013 (percentage)

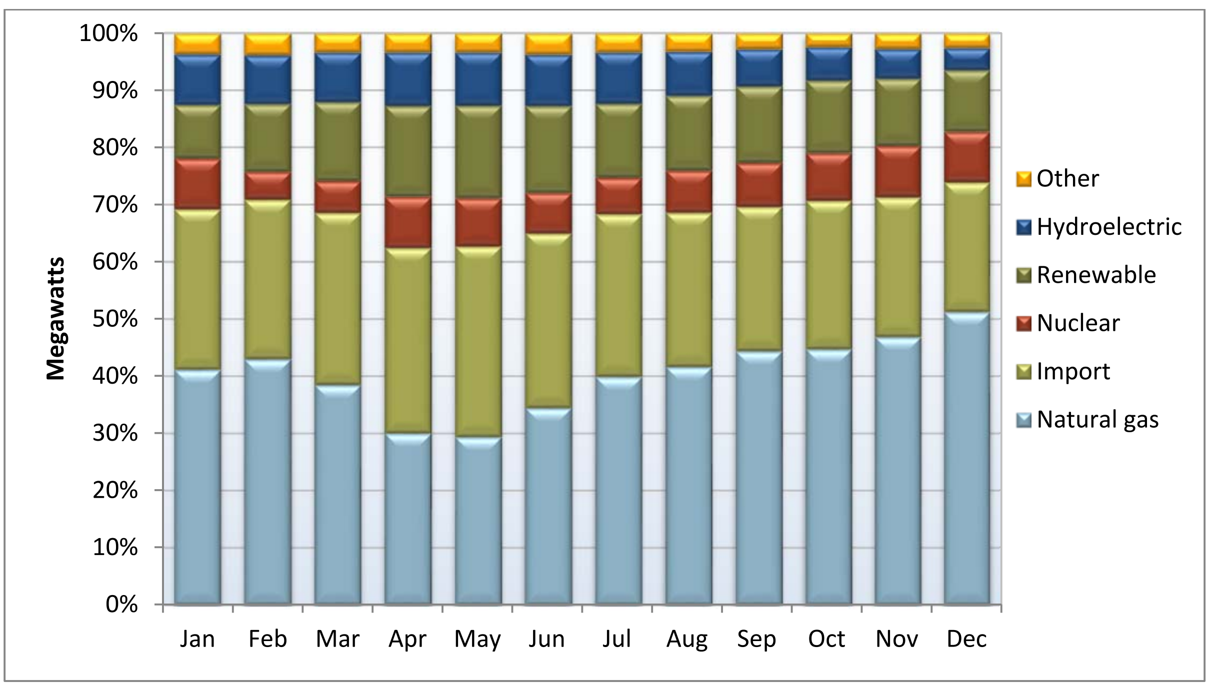


Figure 1.10 Average hourly generation by fuel type in Q3 2013

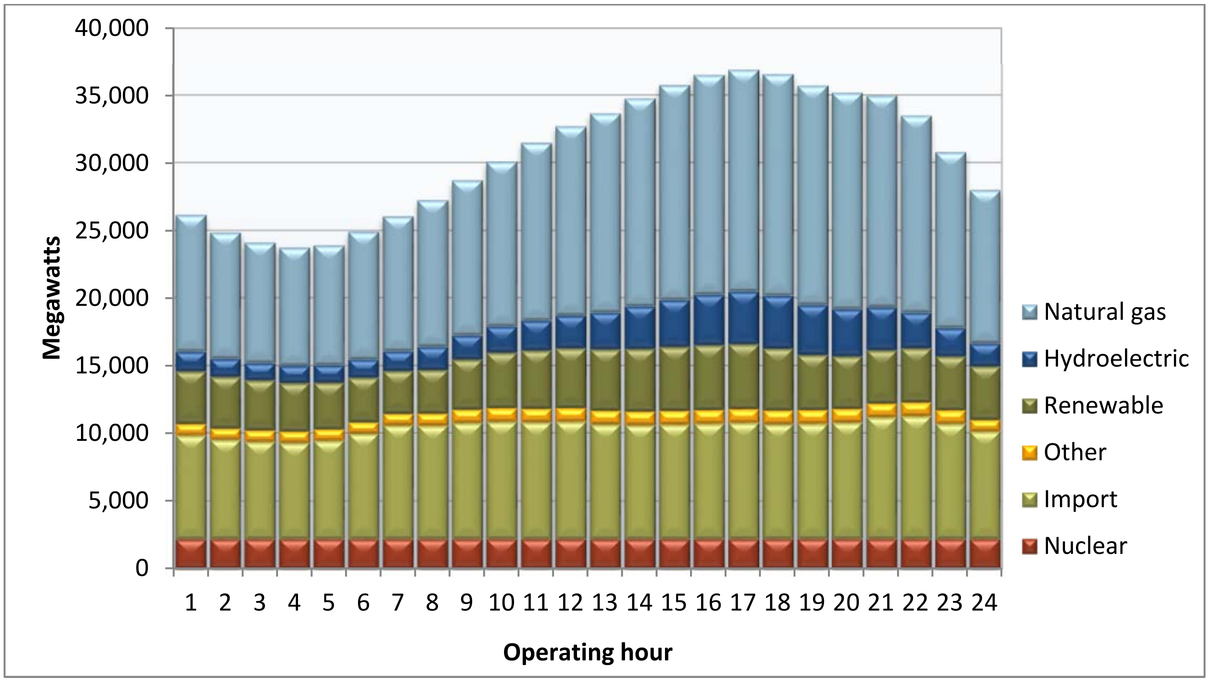
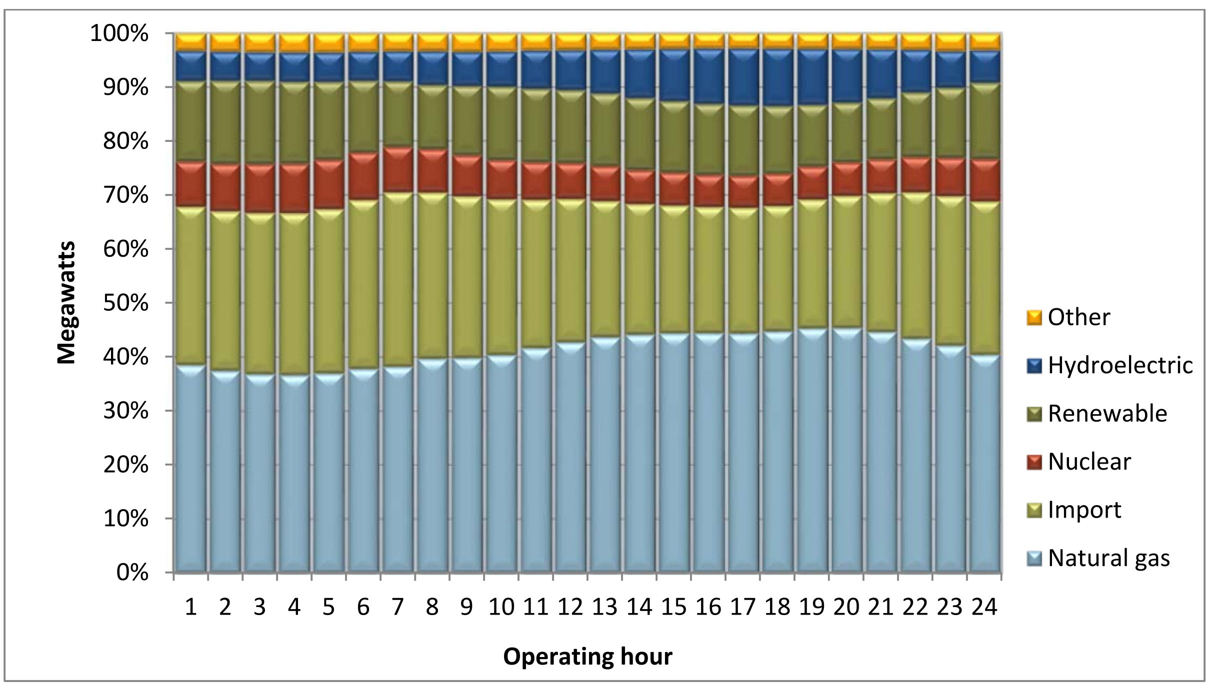


Figure 1.11 Average hourly generation by fuel type in Q3 2013 (percentage)

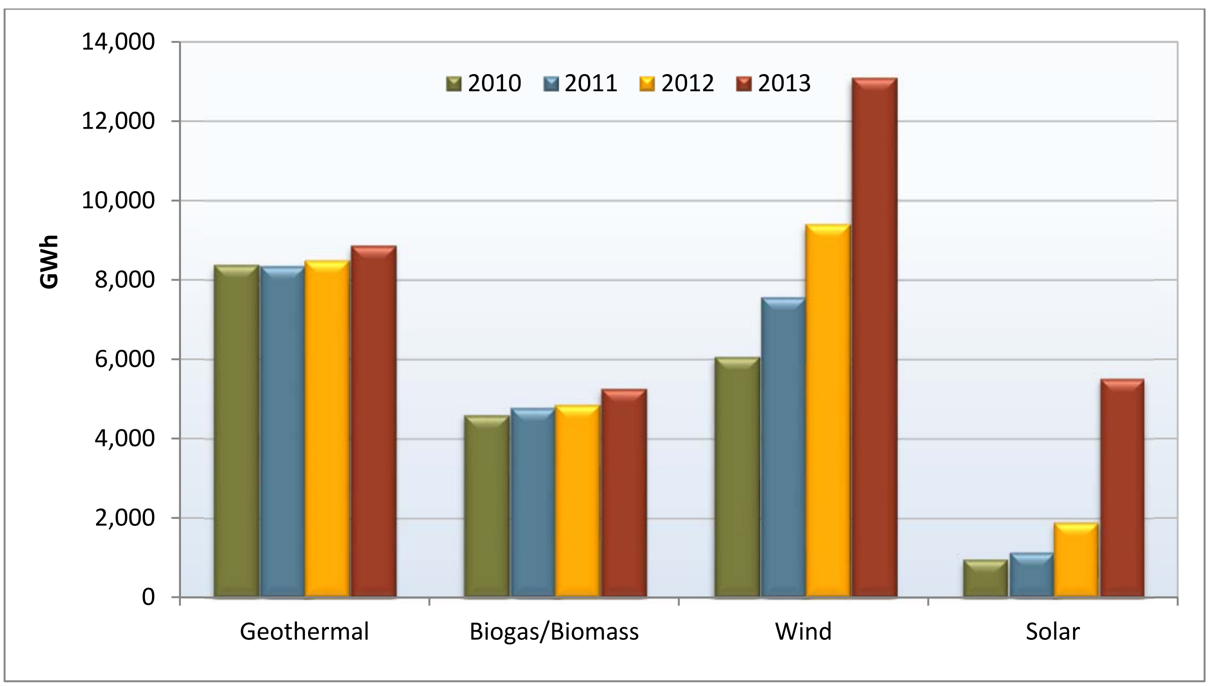


- Non-hydro renewable generation directly connected to the ISO system accounted for 13 percent of total supply.[31] Total renewable generation was up 26 percent from 2012. This increase was due to growth in energy from wind and, to a larger extent, solar resources.

Increased non-hydro renewable generation within the ISO system came predominately from a significant increase of both wind and solar generation in 2013. Figure 1.12 provides a detailed breakdown of non-hydro renewable generation from 2010 through 2013.

- Generation from wind resources directly connected to the ISO grid far exceeded that from geo-thermal, further distancing itself as the largest source of renewable generation inside California.
- Wind resources provided 40 percent of renewable energy, up from 38 percent in 2012. Wind provided 5.5 percent of overall system energy in 2013.
- Solar power from resources directly connected to the ISO system increased dramatically both overall (5,500 GWh from 1,900 GWh), and as a percentage of total renewable energy: from 8 percent in 2012 to 17 percent in 2013. Furthermore, solar surpassed biogas and biomass in total renewable generation for the first time.
- Geothermal provided approximately 27 percent of renewable energy in 2013, or about 4 percent of overall system energy.
- Biogas, biomass, and waste generation contributed 16 percent of renewable energy, or about 2 percent of total system energy.

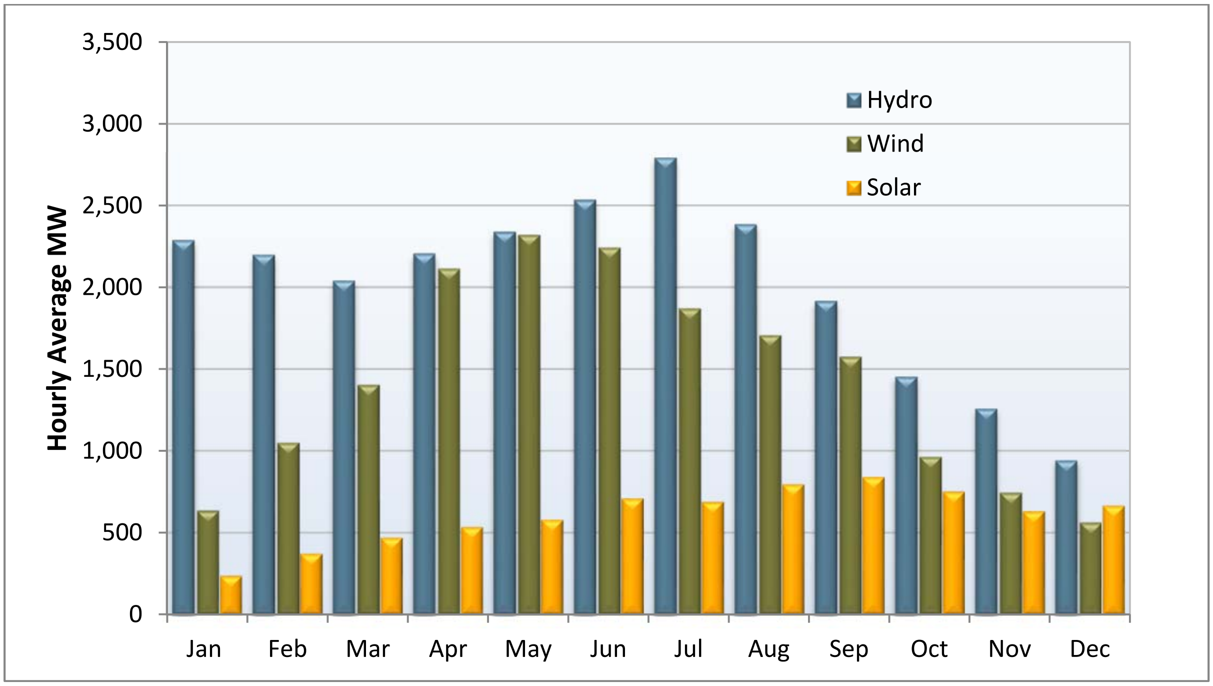
Figure 1.12 Total renewable generation by type (2010-2013)



[31] In this analysis, non-hydro renewables do not include imports or behind the meter generation such as rooftop solar. DMM has very limited access to this information. Thus, this analysis may differ from other reports of total renewable generation.

Wind production peaked in May, when system loads are moderate, hydro-electric generation is more abundant, and the supply portfolio is limited due to outages. The combination of these conditions contributes to the potential for negative price spikes due to over-generation during this period. Figure 1.13 compares average monthly generation from hydro, wind and solar resources. While the share of solar was low in previous years, solar generation increased significantly in 2013. On a monthly basis, solar generation exceeded wind generation in December. Continuing forward, solar is expected to provide an increasing portion of supply from new renewable resources.

Figure 1.13 Monthly comparison of hydro, wind and solar generation (2013)



Hydro-electric supplies

Year-to-year variation in hydro-electric power supply in California has a major impact on prices and the performance of the wholesale energy market. More abundant supplies of run-of-river hydro-electric power generally reduce the need for baseload generation and imports. Hydro conditions also impact the amount of hydro-electric power and ancillary services available during peak hours from units with reservoir storage. Almost all hydro-electric resources in the ISO are owned by load-serving entities that are net buyers of electricity. They therefore seek to manage these resources in a way that moderates overall energy and ancillary service prices.

Overall hydro-electric production in 2013 was relatively low, falling more than 12 percent below production in 2008 – the year with the lowest hydro-electric production in the past decade. Snowpack in the Sierra Nevada Mountains, as measured on May 1, 2013, was only 17 percent of the long-term average, indicating much lower than average hydro conditions.[32] Figure 1.14 illustrates overall production over the last decade.

[32] For snowpack information, please see: California Cooperative Snow Surveys' Snow Water Equivalents (inches), California Department of Water Resources: http://cdec.water.ca.gov/cdecapp/snowapp/sweq.action.

Figure 1.14 Annual hydroelectric production (2004-2013)

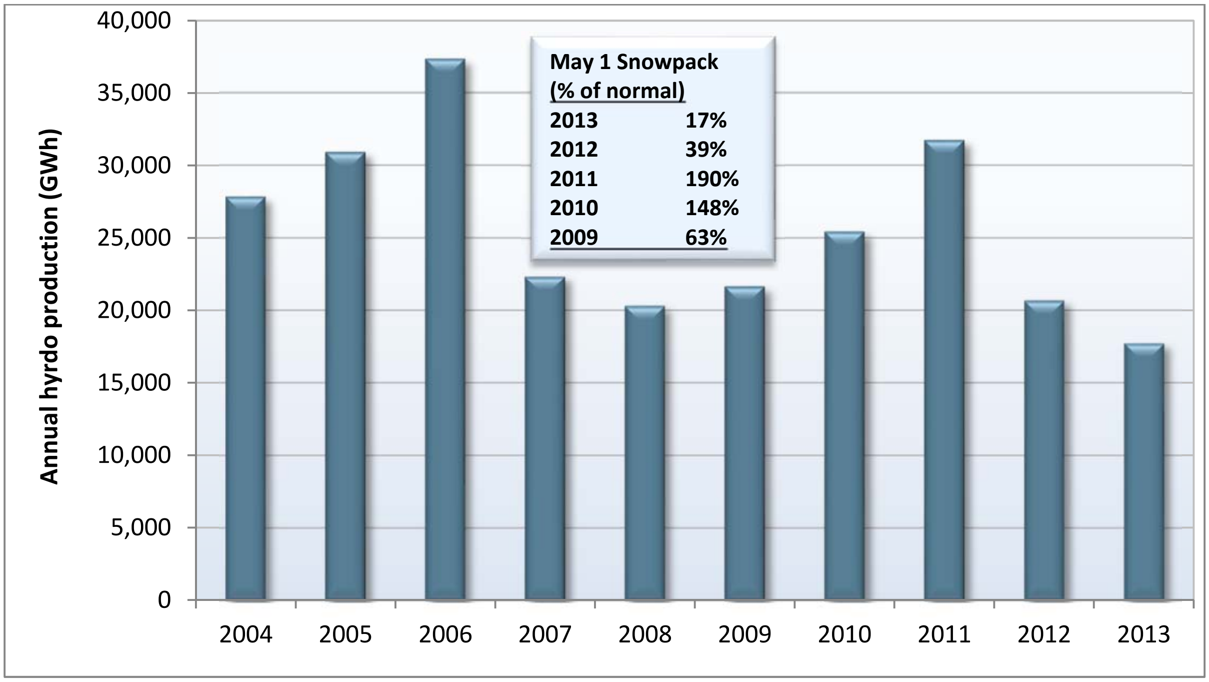


Figure 1.15 Average hourly hydroelectric production by month (2011-2013)

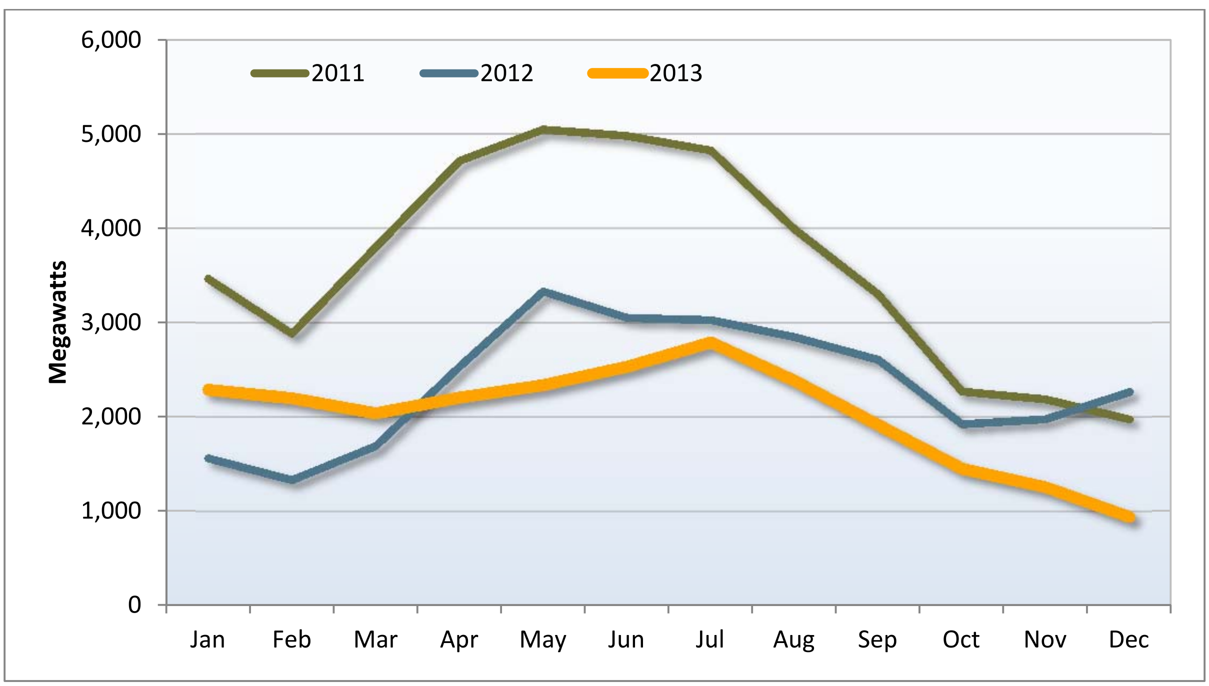


Figure 1.15 compares monthly hydro-electric output from resources within the ISO system for each of the last three years. Hydro production in 2013 was about 86 percent of production in 2012 and 56 percent of production in 2011. During the summer months of June to August, hydro production was only 86 percent of production during the same period of 2012 and 56 percent of the same period in 2011. In the final quarter of the year, hydro production was less than 60 percent of the same period in 2012.

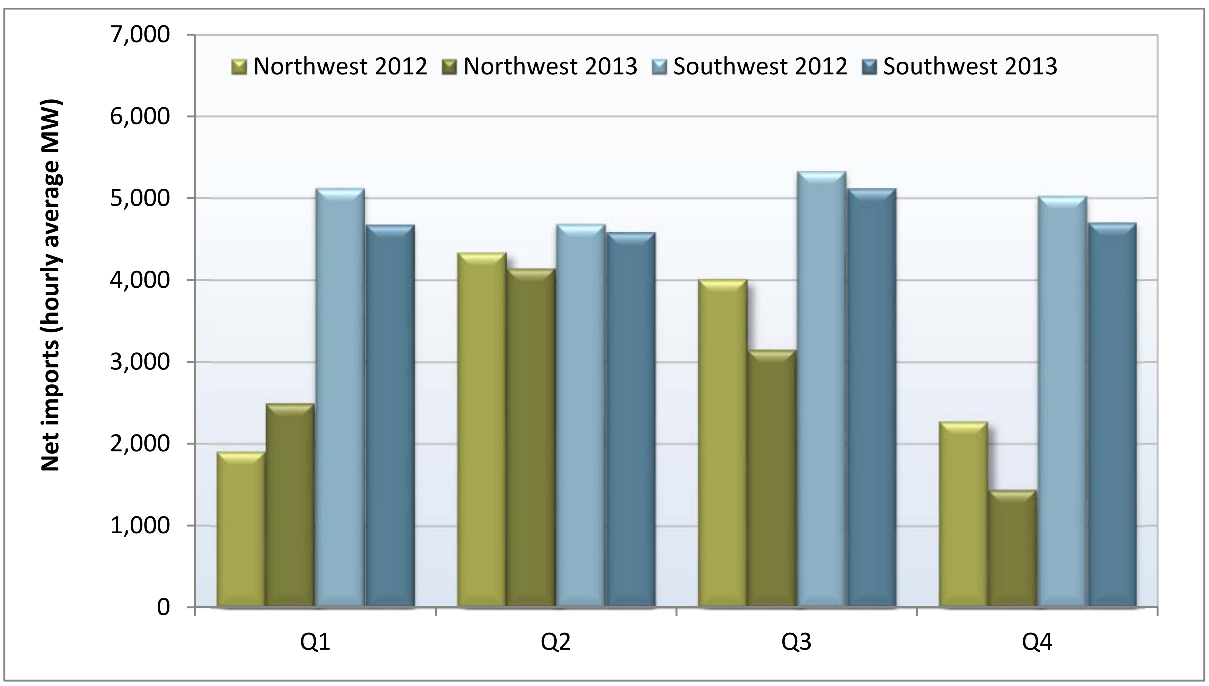
Net imports

Net imports decreased by more than 7 percent in 2013 over 2012 and are comparable to 2011 net import levels.[33] Total net imports from the Northwest decreased by more than 10 percent, while net imports from the Southwest decreased by more than 5 percent.

Figure 1.16 compares net imports by region for each quarter of 2012 and 2013. Net imports from the Southwest were lower than the previous year in each quarter of 2013. Net imports from the Northwest were lower than the previous year in all but the first quarter of 2013. Net imports from the Northwest fell by more than one-quarter in the final half of the year alone.

This decrease in imports was driven by decreases in hydro generation in the Pacific Northwest and increases in power prices at the Mid-Columbia trading hub relative to prices in NP15 in the latter half of the year. The relationship between SP15 and Palo Verde prices is discussed in more detail in Chapter 5. The decline of net imports into the ISO system reflects changes in the relative price of electricity both within and outside of the ISO system.

Figure 1.16 Net imports by region (2012-2013)



[33] Net imports are equal to scheduled imports minus scheduled exports in any period. The import values discussed in the previous section are total import values. Scheduled and cleared import values discussed in Chapter 5 exclude both exports and generation from tie resources which are included in this section.

1.2.2 Generation outages

Generation outage levels, including partial unit derates, fell by 10 percent in 2013, due primarily to the retirement of San Onofre Nuclear Generating Station (SONGS) units 2 and 3 in June. Before their retirement, the capacity of these units — totaling over 2,200 MW — was reflected in outage data throughout 2012.[34]

The ISO groups generation outages into four categories:

- ***Planned outages*** — Reductions in available capacity for scheduled maintenance that are submitted by October 15 of the preceding year and are updated quarterly.
- ***Forced outages*** — Unplanned reductions in capacity due to equipment failure, unforeseen required maintenance or other exigent circumstances.
- ***Ambient outages*** — Reductions in available capacity due to external conditions such as temperature or air quality restrictions.
- ***Normal outages*** — Reductions in available capacity where a planned, forced, or ambient designation is not appropriate, such as the inability to respond to dispatch instructions due to other physical limitations.[35]

Figure 1.17 shows the quarterly averages of maximum daily outages broken out by type during peak hours.[36] Overall generation outages follow a seasonal pattern with the majority taking place in the non-summer months. This pattern is primarily driven by planned outages, as maintenance is performed outside the higher summer load period. Total outages averaged about 12,200 MW in 2013 down from 13,500 MW in 2012. The removal of SONGS outages following the retirement of both units 2 and 3 was the primary driver of decreased outage levels.

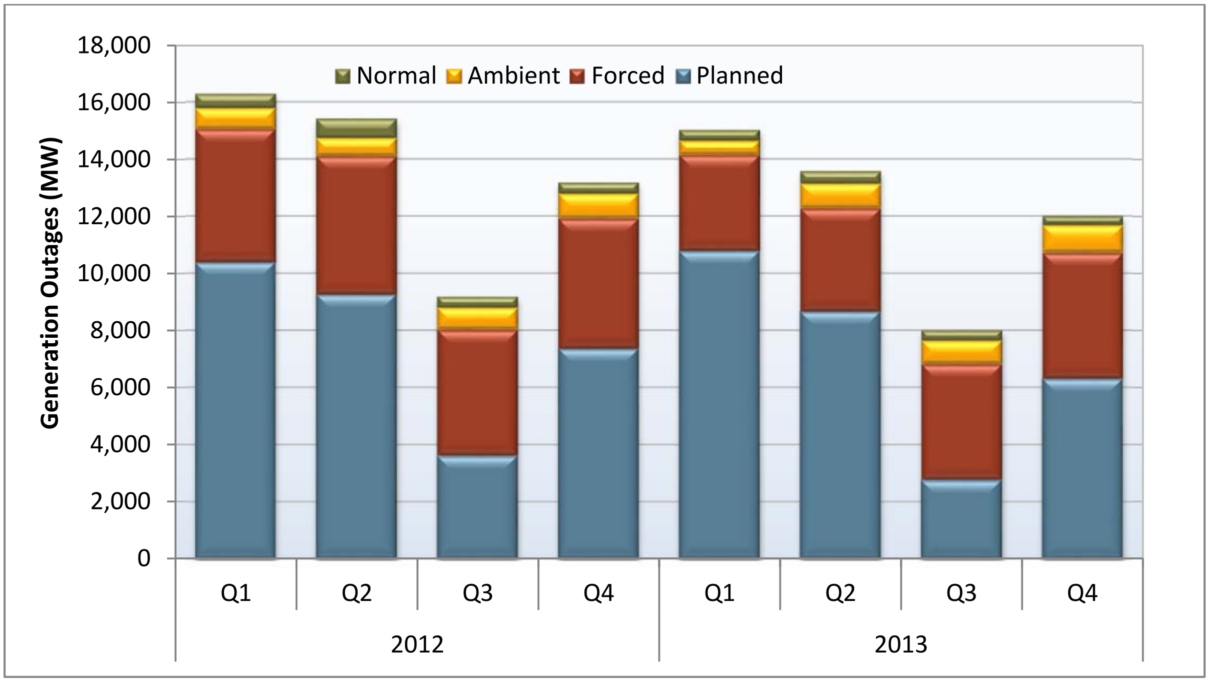
Forced outages averaged about 3,900 MW in 2013, down from 4,600 MW in 2012. SONGS unit 3 accounted for the majority of this decrease. Planned outages also decreased to 7,200 MW in 2013 from 7,700 MW in 2012. The retirement of SONGS unit 2 contributed to a decrease over the year although planned outages were similar to 2012 levels in the first half of 2013. Ambient outages rose to 780 MW in 2013 from 750 MW in 2012 and normal outages fell to 380 MW in 2013 from 490 MW in 2012.

[34] Although the SONGS units were not retired until June 2013, the capacity of these units was removed from outage reporting data at the end of 2012.

[35] These are referred to as normal outages because they are submitted to the ISO using a normal card in the ISO's outage management system, SLIC.

[36] Data are estimated from outage data in the outage management system.

Figure 1.17 Average of maximum daily generation outages by type – peak hours



1.2.3 Natural gas prices

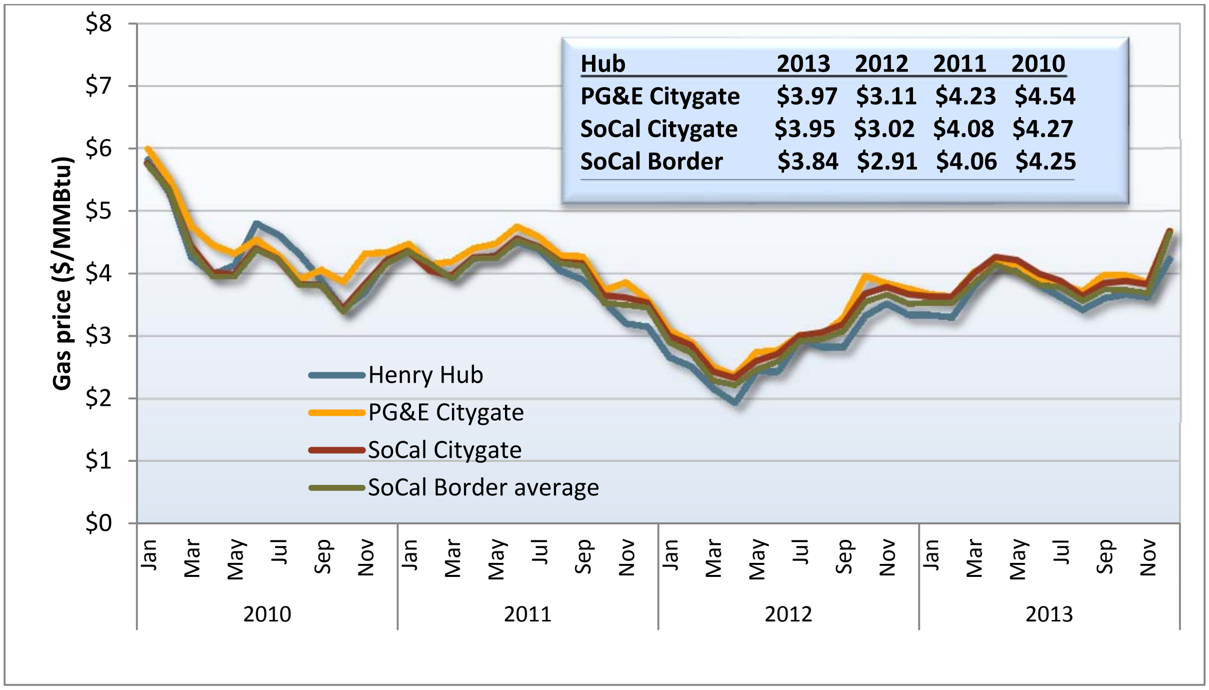
Electric prices in western states typically follow natural gas price trends because natural gas units are usually the marginal source of generation in the ISO and other regional markets. In 2013, the average weighted price of natural gas in the daily spot markets increased by about 30 percent from 2012 levels in each of the main trading hubs in California. While these price increases were significant, average natural gas prices in 2013 remained slightly below 2011 levels.[37] The increase in natural gas prices was the main driver causing the annual wholesale energy cost per MWh of load served in 2013 to increase relative to 2012.

Natural gas prices at California trading hubs followed the increase in prices at the national level, tracking changes at Henry Hub fairly closely. Overall, prices rose in 2013 from low price levels in 2012 as natural gas storage conditions reflected more normal conditions. Natural gas storage levels reached historic highs at the end of the mild 2012 winter. In 2013, storage levels were at more normal levels at the end of the winter heating season.

[37] Average weighted natural gas prices at PG&E Citygate were 28 percent higher than 2012 and 6 percent lower than 2011. Prices at the SoCal Border were 32 percent higher than 2012 and 5 percent lower than 2011. Prices at SoCal Citygate were 31 percent higher than 2012 and 3 percent lower than 2011.

At the end of 2013, prices increased as demand for natural gas increased in response to severe winter conditions both regionally and nationally.[38] Figure 1.18 shows monthly average natural gas prices for 2010 through 2013 at key delivery points in Northern California (PG&E Citygate) and in Southern California (SoCal Citygate and SoCal Border) as well as for the Henry Hub trading point, which acts as a point of reference for the national market for natural gas.

Figure 1.18 Monthly weighted average natural gas prices (2010-2013)



While natural gas prices in California tend to follow national trends, differences can occur that reflect gas pipeline congestion. Because Northern and Southern California are served by different gas producing regions and transportation systems, natural gas prices within California periodically diverge, with prices in Northern California tending to be higher than in Southern California.

In 2013, the load weighted average price at the PG&E Citygate was only one cent higher than the price at the SoCal Citygate. The SoCal Citygate price, which had historically been closer to the SoCal Border price, was closer to the PG&E Citygate price in 2013, following a trend that began in the fourth quarter of 2011. On average in 2013, SoCal Border prices were 3 percent lower than both SoCal Citygate and

[38] Gas prices rose substantially in December of 2013. Day-ahead natural gas prices spiked on December 10, ending the day at over $7/MMBtu at the SoCal Citygate hub, almost doubling in price from the first of the month. The price spike occurred as a result of a cold snap and tight natural gas supply conditions, especially in the San Diego area, over the weekend leading up to December 10. The ISO restricted maintenance and, in coordination with natural gas pipeline operators, issued out-of-market instructions to generators to reduce demand for natural gas in areas with tight gas supply conditions. Participants adjusted their bids in the ISO day-ahead and real-time markets, accordingly, to reflect fuel supply conditions. As the cold snap abated and gas supply conditions improved, gas prices fell. Even so, gas prices settled at a higher level than before the spike. This was consistent with an increase in national natural gas prices driven by weather conditions, and relatively high demand within the ISO system.

PG&E Citygate prices. This price gap narrowed from 2012 when SoCal Border prices were 4 percent below SoCal Citygate and 6 percent below PG&E Citygate prices.

While relatively small price differences remain between northern and southern gas hubs, the overall stabilization of price differences between Northern and Southern California prices was a result of structural changes in the gas markets. These changes include increased production and transportation capacity and lower costs from sources in the northern Rocky Mountain area and Canada to Northern California. The effects of the Ruby Pipeline coming into service in late July 2011 also had a significant effect on reducing the overall price differences. The pipeline takes low cost natural gas from the Rockies to the Northwest.

1.2.4 Generation addition and retirement

California currently relies on long-term procurement planning and resource adequacy requirements placed on load-serving entities to ensure that sufficient capacity is available to meet reliability planning requirements on a system-wide basis and within local areas. Trends in the amount of generation capacity being added and retired in the ISO system each year provide important insight into the effectiveness of the California market and regulatory structure in incenting new generation investment.

Figure 1.19 summarizes trends in the addition and retirement of generation from 2004 through 2013. It also includes planned capacity additions and retirements in 2014.[39] Table 1.4 also shows generation additions and retirements since 2004. It includes projected 2014 changes and totals across the 11-year period (2004 through 2014).[40]

Figure 1.20 and Figure 1.21 show additional generation capacity by generator type. As the figures indicate, most of the additional generation capacity is from solar, natural gas and wind generation. The vast majority of the new renewable capacity is expected to come from solar resources.

Generation additions and retirements in 2013

Almost 5,500 MW of new summer peak capacity began commercial operation within the ISO system in 2013. About 2,400 MW of this capacity was installed in the PG&E area and over 3,000 MW came online in the SCE and SDG&E areas. Major natural gas units were added, totaling over 3,500 MW of combined capacity.[41] In 2013, on a nameplate basis, more than 500 MW of wind capacity and more than 2,750 MW of additional solar capacity also came online. A more detailed listing of units added in 2013 is provided in Table 1.5.

Overall, SCE and SDG&E capacity ended 2013 with about 800 MW of additional capacity. The retirement of the San Onofre nuclear units accounted for over 2,200 MW of retired generation. Some of the new

[39] Capacity values in 2011, 2012, 2013, and 2014 are calculated summer peak capacity values. The values in 2010 and before are nominal capacity values. For 2012 through 2014, DMM used capacity factors calculated by the ISO for generation of each fuel type on the basis of actual performance over the prior three year period. These factors may change year to year.

[40] Figure 1.19 and Table 1.4 are based on analysis performed by the ISO's planning department. Their analysis treats the retired San Onofre unit capacity as the product of the units' total capacity, 2,250 MW, and the capacity factor for nuclear units (84 percent). As a result, these figures show retirement of about 1,900 MW with respect to SONGS. However, throughout the body of this report, DMM accounts for the retirement of the nameplate capacity of SONGS. Thus, there can be a slight difference in some of the numbers presented in the text relative to these two charts.

[41] Much of the natural gas-fired generation was added as part of the CPUC's long-term procurement plan. Please see the following for more information: http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm.

gas capacity in the PG&E area was offset by retirement of gas capacity at the same facility. The net capacity increase in PG&E in 2013 was 1,737 MW. Overall, the net change in capacity in the ISO was an increase of almost 2,500 MW.

Anticipated additions and retirements in 2014

The ISO anticipates almost 1,500 MW of new generation in 2014.[42] Around 1,200 MW of this capacity is anticipated to come from renewable resources. Table 1.6 provides more detailed information on these projects. The ISO expects about half of this new capacity, over 800 MW, to be commercially available before the anticipated summer peak season. Natural gas capacity at Morro Bay, totaling 650 MW, retired in February 2014. The ISO does not anticipate further retirements this year.

Over the past two years, much of the new gas-fired generation has been offset by the retirement of older gas-fired and nuclear generation. As a result, non-renewable generation capacity has not grown significantly in the last few years, while renewable generation continued to increase to meet the state's renewable requirements. Beyond 2014, significant reductions in total gas-fired capacity are possible due to the state's restrictions on use of once-through cooling technology.[43]

Meanwhile, the amount of new renewable generation has begun to increase dramatically. As more renewable generation comes online, the ISO has highlighted the need to backup and balance renewable generation with the flexibility of conventional generation resources to maintain reliability.

The state's resource adequacy program continued to work well as a short-term capacity procurement mechanism. However, as DMM has noted in previous annual reports, it has become increasingly apparent that the state's current process for longer-term procurement may not ensure the investment and revenues needed to support sufficient new or existing gas-fired capacity to integrate the increased amount of intermittent renewable energy coming online. The ISO, CPUC and stakeholders have been working through this issue as a part of several initiatives continuing into 2013.[44] This represents a major market design challenge facing the ISO and state policy makers.

[42] Capacity values reported in this section are estimated summer capacity, unless otherwise noted. Values reported here are based on additions that the ISO's interconnection department deems to be very likely and thus offer a conservative estimate.

[43] California's once-through cooling (OTC) regulations affect a significant proportion of capacity needed to meet local capacity requirements in four local capacity areas: Greater Bay Area, Los Angeles Basin, Big Creek/Ventura and San Diego. Further discussion of this issue is available in DMM's 2011 annual report: *2011 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2012, p. 27: http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.

[44] See Section 10.8 for more information.

Figure 1.19 Generation additions and retirements (2004-2014)

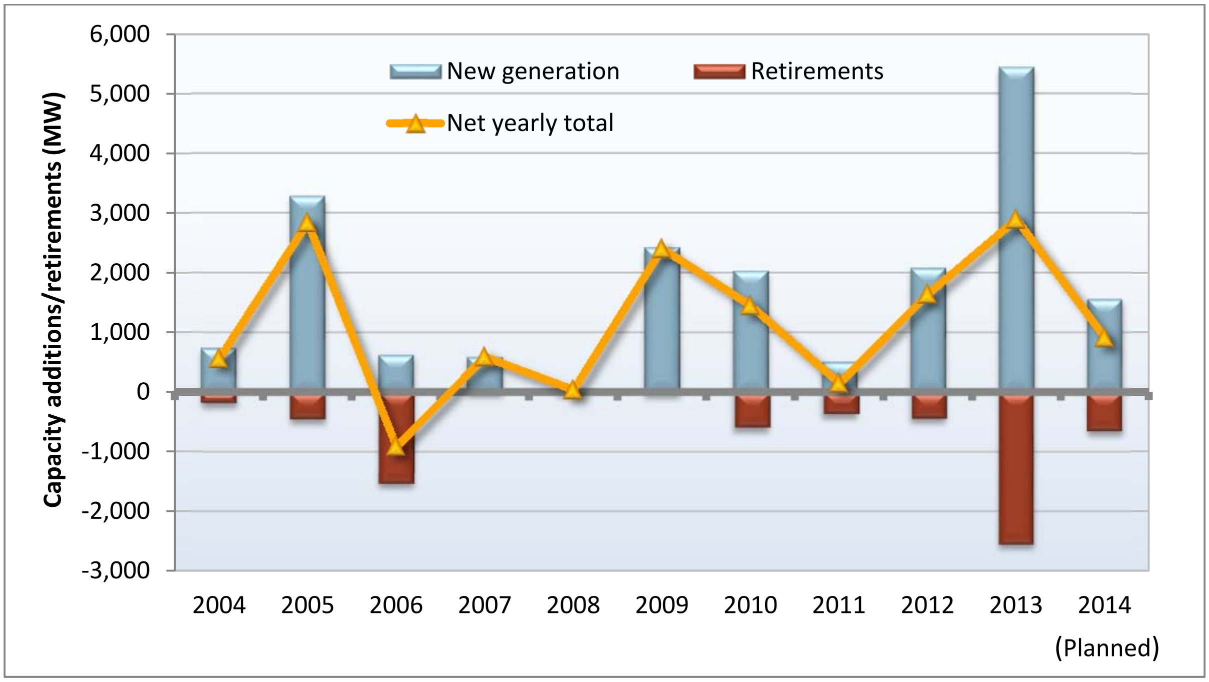


Table 1.4 Changes in generation capacity since 2004

	2004-2008	2009	2010	2011	2012	2013	Projected 2014	Total through 2014
SCE and SDG&E								
New Generation	4,085	1,107	1,042	401	1,054	3,045	1,441	12,176
Retirements	(1,946)	0	(414)	0	(440)	(1,883)	0	(4,683)
Net Change	**2,139**	**1,107**	**628**	**401**	**614**	**1,163**	**1,441**	**7,494**
PG&E								
New Generation	1,233	1,329	1,002	115	1,033	2,411	126	7,249
Retirements	(219)	(26)	(175)	(362)	0	(674)	(650)	(2,106)
Net Change	**1,014**	**1,303**	**827**	**(247)**	**1,033**	**1,737**	**(524)**	**5,143**
ISO System								
New Generation	5,319	2,436	2,044	516	2,087	5,456	1,567	19,425
Retirements	(2,165)	(26)	(589)	(362)	(440)	(2,557)	(650)	(6,789)
Net Change	**3,154**	**2,410**	**1,455**	**154**	**1,647**	**2,899**	**917**	**12,637**

Figure 1.20 Generation additions by resource type (nameplate capacity)

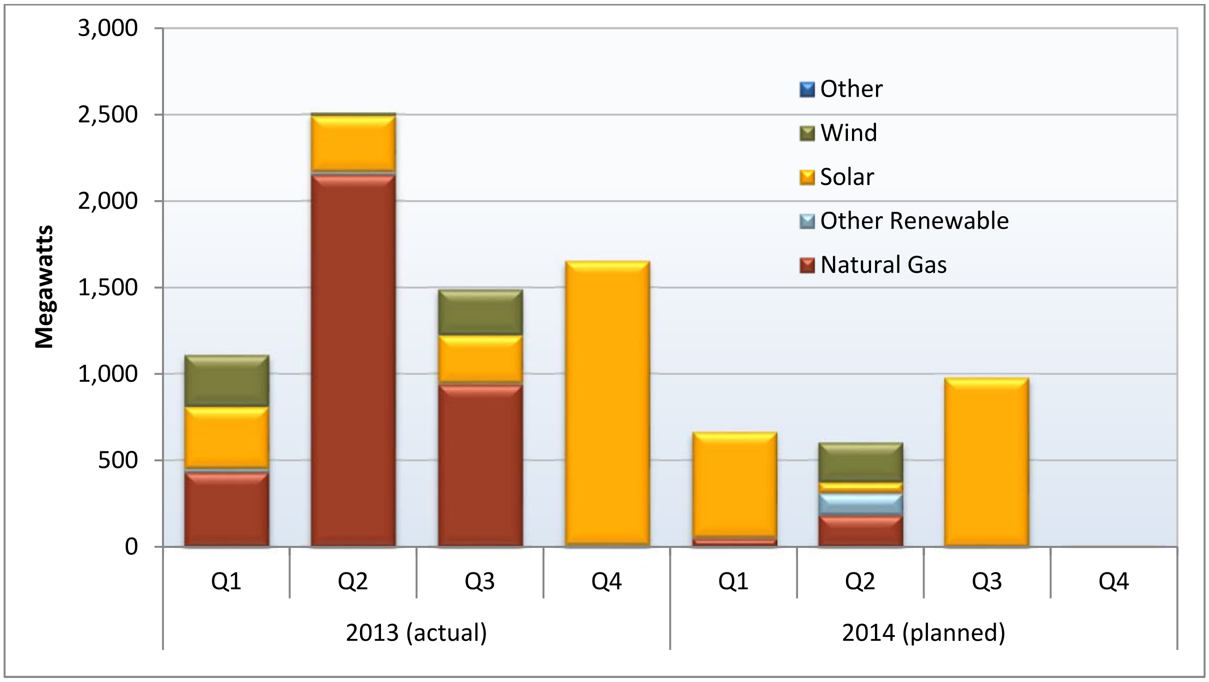


Figure 1.21 Generation additions by resource type (summer peak capacity)

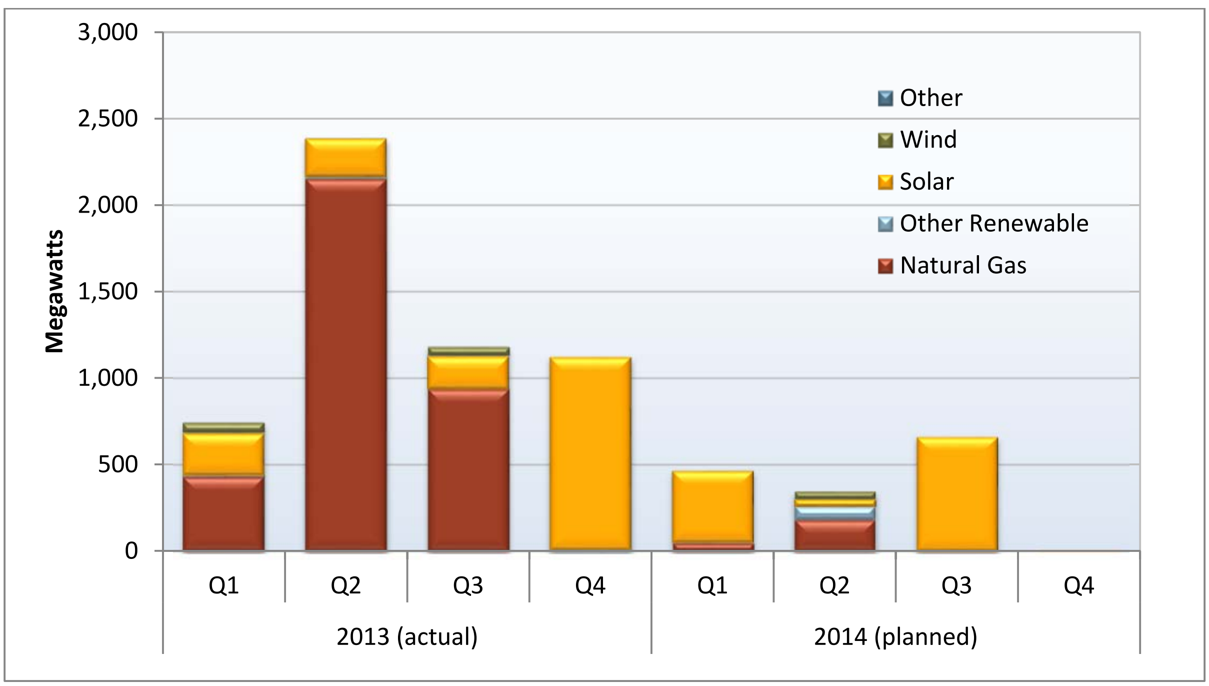


Table 1.5 New generation facilities in 2013

Generating unit	Unit type	Resource capacity (MW)	Summer capacity (MW)	Commercial operation date	Area
Alta 2012 Alta Wind 7*	Wind	168	32	1-Jan-13	SCE
CPC East Alta Wind IX*	Wind	132	25	1-Jan-13	SCE
SPVP010 Fontana RT Solar*	Solar	2	1	8-Jan-13	SCE
SPVP015 Fontana RT Solar*	Solar	3	2	15-Jan-13	SCE
Wellhead Power Delano	Gas Unit	49	49	16-Jan-13	SCE
SPVP023 Fontana RT Solar*	Solar	3	2	16-Jan-13	SCE
Alpine Solar*	Solar	66	45	18-Jan-13	SCE
NRG Borrego Solar One*	Solar	26	18	12-Feb-13	SDG&E
Catalina Solar - Phases 1 and 2*	Solar	110	75	15-Feb-13	SCE
Walnut Creek Energy Park Units 1-3	Gas Units	288	288	21-Mar-13	SCE
Antelope Power Plant*	Solar	20	14	25-Mar-13	SCE
Walnut Creek Energy Park Unit 4	Gas Unit	96	96	29-Mar-13	SCE
AV Solar Ranch 1*	Solar	230	157	1-Apr-13	SCE
Mammoth Unit G3*	Geothermal	14	10	1-Apr-13	SCE
SunEdison - Corona*	Solar	1	1	24-Apr-13	SCE
Walnut Creek Energy Park Unit 5	Gas Unit	100	100	30-Apr-13	SCE
CPV Sentinel	Gas Unit	728	728	6-May-13	SCE
Wind Resource II*	Wind	20	4	20-May-13	SCE
SEPV8 & SEPV9*	Solar	21	14	1-Jun-13	SCE
El Segundo Energy Center 7/8	Gas Units	264	264	29-Jun-13	SCE
El Segundo Energy Center 5/6	Gas Units	263	263	9-Jul-13	SCE
Ocotillo Wind Energy Facility*	Wind	265	50	29-Jul-13	SDG&E
CSU, San Bernardino Fuel Cell*	Biomass	1	1	13-Sep-13	SCE
Imperial Valley (Csolar IV)*	Solar	130	89	11-Oct-13	SDG&E
Centinela Solar Energy Facility (Phase I)*	Solar	51	35	16-Oct-13	SDG&E
Campo Verde Solar*	Solar	150	103	22-Oct-13	SDG&E
Solar Project (Partial COD)*	Solar	220	150	22-Oct-13	SCE
Arlington Valley Solar Energy II*	Solar	127	87	5-Nov-13	SDG&E
Rio Grande*	Solar	5	3	18-Nov-13	SCE
Victor Phelan Solar One*	Solar	18	12	6-Dec-13	SCE
Columbia 3*	Solar	10	7	10-Dec-13	SCE
Champagne*	Solar	1	1	20-Dec-13	SCE
Jurupa*	Solar	2	1	20-Dec-13	SCE
Nautilus Solar Energy*	Solar	2	1	20-Dec-13	SCE
Rosamond 1 and 2*	Solar	40	27	20-Dec-13	SCE
Cascade Solar*	Solar	19	13	24-Dec-13	SCE
Valley Center 1 & 2*	Solar	8	5	30-Dec-13	SDG&E
Ivanpah 1, 2, & 3*	Solar	392	268	30-Dec-13	SCE
Ramona 1*	Solar	2	1	30-Dec-13	SCE
Ramona 2*	Solar	5	3	31-Dec-13	SCE
SCE and SDG&E Actual New Generation in 2013		**4,049**	**3,045**		

Table continues on next page.

Generating unit	Unit type	Resource capacity (MW)	Summer capacity (MW)	Commercial operation date	Area
Buena Vista Biomass*	Biomass	18	11	3-Jan-13	PG&E
California Valley Solar Ranch-Phase B*	Solar	40	27	8-Jan-13	PG&E
Atwell Island PV Solar*	Solar	20	14	8-Mar-13	PG&E
Alpaugh 50*	Solar	50	34	8-Mar-13	PG&E
Alpaugh North*	Solar	20	14	8-Mar-13	PG&E
Gridley Main Two*	Solar	3	2	1-Apr-13	PG&E
Genon Marsh Landing Units 1-4	Gas Units	800	800	1-May-13	PG&E
RE Kansas South*	Solar	20	14	6-Jun-13	PG&E
Oakley Solar Project*	Solar	2	1	12-Jun-13	PG&E
White River Solar*	Solar	20	14	22-Jun-13	PG&E
Gates Solar Station*	Solar	20	14	24-Jun-13	PG&E
West Gates Solar Station*	Solar	10	7	24-Jun-13	PG&E
Grasslands 3*	Solar	1	1	1-Jul-13	PG&E
Johnson Canyon Landfill*	Biogas	1	1	8-Jul-13	PG&E
G2 Energy Hay Road Power Plant*	Biogas	2	1	9-Jul-13	PG&E
Cold Canyon*	Biogas	2	1	21-Jul-13	PG&E
Los Esteros Energy Facility	Gas Unit	315	315	31-Jul-13	PG&E
Grasslands 4*	Solar	1	1	5-Aug-13	PG&E
Russell City Energy Center	Gas Unit	625	625	8-Aug-13	PG&E
Corcoran Solar*	Solar	20	14	14-Aug-13	PG&E
Vaca Dixon Battery NAS	Battery	2	2	6-Sep-13	PG&E
Topaz Solar Farms*	Solar	237	162	9-Sep-13	PG&E
Gurensey Solar Station*	Solar	20	14	18-Sep-13	PG&E
California Valley Solar Ranch-Phase B*	Solar	210	144	1-Nov-13	PG&E
Genesis Station Units 1 and 2*	Solar	250	171	27-Nov-13	PG&E
Mammoth G3*	Geothermal	10	7	20-Dec-13	PG&E
Sonora 1*	Solar	2	1	30-Dec-13	PG&E
Kingsburg 1 & 2*	Solar	3	2	30-Dec-13	PG&E
PG&E Actual New Generation in 2012		**2,722**	**2,411**		
Total Actual New Generation in 2013		**6,771**	**5,456**		
Total Renewable Generation in 2013*		**3,241**	**1,927**		

Source: California ISO Interconnection Resources Department

Table 1.6 Planned generation additions in 2014

Generating unit	Number of projects	Resource capacity (MW)	Summer capacity (MW)	Commercial operation date	Area
Biogas-Biomass Project *	1	50	30	Feb-14	PG&E
Solar Project *	2	20	13	Feb-14	PG&E
Biogas-Biomass Project *	2	3	2	Mar-14	PG&E
Solar Project *	4	6	4	Mar-14	PG&E
Solar Project *	2	22	15	Apr-14	PG&E
Biogas-Biomass Project *	2	4	2	May-14	PG&E
Gas Project	3	13	13	May-14	PG&E
Solar Project *	6	69	47	May-14	PG&E
PG&E Total New Generation in 2014		**185**	**126**		
Solar Project *	1	165	113	Jan-14	SCE
Gas Project	1	50	50	Jan-14	SDG&E
Biogas-Biomass Project *	2	3	2	Mar-14	SDG&E
Solar Project *	2	219	150	Mar-14	SCE
Solar Project *	1	200	137	Mar-14	SDG&E
Wind Project *	2	228	43	Mar-14	SDG&E
Solar Project *	4	11	7	Apr-14	SCE
Biogas-Biomass Project *	6	120	73	May-14	SCE
Gas Project	1	171	171	May-14	SCE
Solar Project *	4	6	4	May-14	SCE
Solar Project *	1	7	4	May-14	SDG&E
Wind Project *	1	4	1	May-14	SCE
Solar Project *	12	18	12	Jun-14	SCE
Solar Project *	5	802	548	Jul-14	SCE
Solar Project *	2	173	118	Aug-14	SCE
Solar Project *	3	5	3	Sep-14	SCE
Solar Project *	4	6	4	Oct-14	SCE
SCE and SDG&E Total New Generation in 2014		**2,187**	**1,441**		
Total Planned New Generation in 2014		**2,371**	**1,567**		
Total New Renewable Generation in 2014*		**2,138**	**1,334**		

1.3 Net market revenues of new gas-fired generation

Every wholesale electric market must have an adequate market and regulatory framework for facilitating investment in needed levels of new capacity. The CPUC's long-term procurement process and resource adequacy program is currently the primary mechanism to ensure investment in new capacity when and where it is needed. Given this regulatory framework, annual fixed costs for existing and new units critical for meeting reliability needs should be recoverable through a combination of long-term bilateral contracts and spot market revenues.

Each year, DMM examines the extent to which revenues from the spot markets would contribute to the annualized fixed cost of typical new gas-fired generating resources. This represents an important market metric tracked by all ISOs.[45] Costs used in the analysis are based on a study by the California Energy Commission (CEC).

The California greenhouse gas cap-and-trade program was implemented in 2013. The cap-and-trade program contributes to increases in both costs and gross revenues for generating units. The net revenue analysis reflects both of these two factors. The findings show that for a hypothetical new combined cycle net revenues increased and that net revenues for a hypothetical new combustion turbine decreased. This is because the greenhouse gas costs of a new combined cycle are less than the increase in market prices associated with greenhouse gas costs, whereas the greenhouse gas costs for a new combustion turbine are higher.[46]

Hypothetical combined cycle unit

Key assumptions used in this analysis for a typical new combined cycle unit are shown in Table 1.7. Results for a typical new combined cycle unit are shown in Table 1.8 and Figure 1.22. The 2013 net revenue results show an increase in net revenues compared to 2012. However, while there was an increase in net revenues from 2012 levels, the 2013 net revenue estimates for a hypothetical combined cycle unit in NP15 and SP15 both fall substantially below the $176/kW-year estimate of annualized fixed costs based on the CEC data.

Table 1.7 Assumptions for typical new combined cycle unit[47]

Technical Parameters	
Maximum Capacity	500 MW
Minimum Operating Level	150 MW
Startup Gas Consumption	1,850 MMBtu/start
Heat Rates	
Maximum Capacity	7,100 MBTU/MW
Minimum Operating Level	7,700 MBTU/MW
Financial Parameters	
Financing Costs	$96.7 /kW-yr
Insurance	$7.3 /kW-yr
Ad Valorem	$9.6 /kW-yr
Fixed Annual O&M	$43.7 /kW-yr
Taxes	$18.5 /kW-yr
Total Fixed Cost Revenue Requirement	**$175.8/kW-yr**

45 A more detailed description of the methodology and results of the analysis presented in this section are provided in Appendix A.1 of DMM's *2009 Annual Report on Market Issues & Performance,* April 2010, which can be found at http://www.caiso.com/2777/27778a322d0f0.pdf.

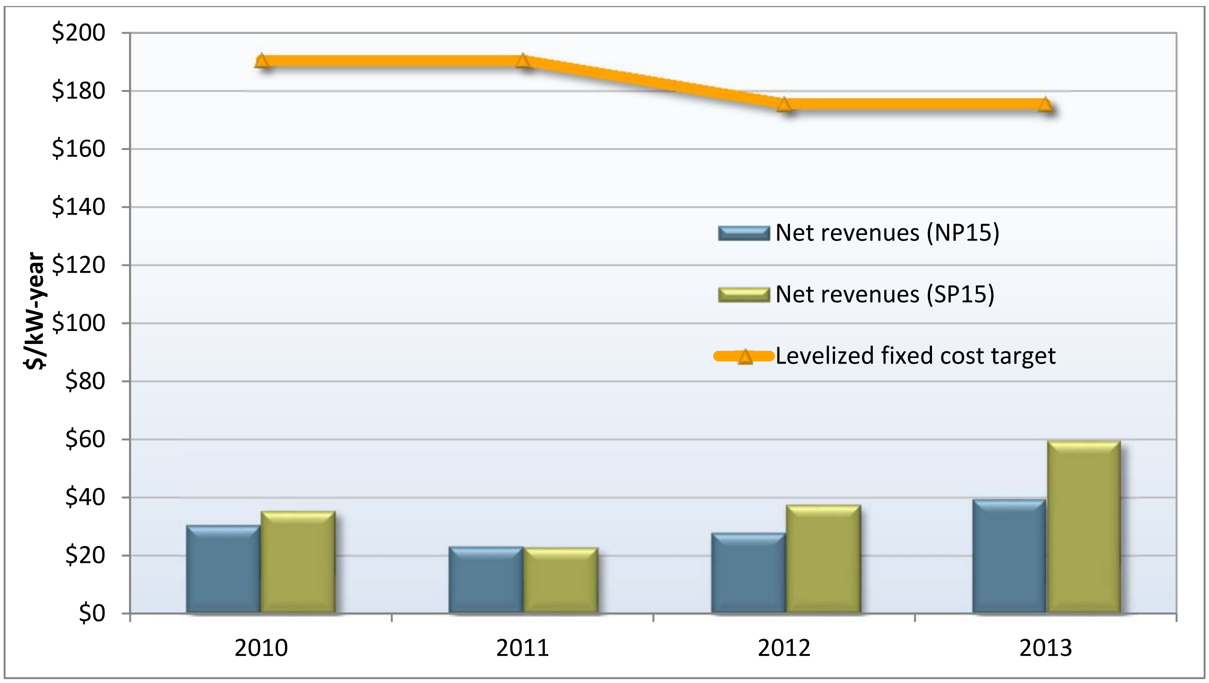
46 The increase in ISO market prices associated with the greenhouse gas cap-and-trade program are outlined in Chapter 5.

47 The financing costs, insurance, ad valorem, fixed annual O&M and tax costs for a typical unit in this table were derived directly from the data presented in the March 2013 CEC Workshop on the Cost of New Renewable and Fossil-Fueled Generation in California: http://www.energy.ca.gov/2013_energypolicy/documents/index.html#03072013. The numbers reported in the workshop are preliminary numbers. The cost of actual new generators varies significantly due to factors such as ownership, location and environmental constraints. More detailed information can be found in the CEC documents.

Table 1.8 Financial analysis of new combined cycle unit (2010-2013)

Components	2010		2011		2012		2013	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	67%	74%	53%	66%	70%	75%	84%	83%
DA Energy Revenue ($/kW - yr)	$137.95	$142.65	$101.62	$94.27	$118.95	$134.59	$286.19	$315.53
RT Energy Revenue ($/kW - yr)	$34.89	$37.31	$28.62	$30.84	$11.70	$11.62	$10.17	$10.14
A/S Revenue ($/kW – yr)	$1.01	$1.25	$1.71	$2.29	$0.37	$0.39	$0.03	$0.06
Operating Cost ($/kW - yr)	$143.25	$145.69	$108.65	$104.41	$103.01	$108.96	$256.78	$266.00
Net Revenue ($/kW – yr)	$30.60	$35.52	$23.30	$22.99	$28.02	$37.64	$39.62	$59.73
5-yr Average ($/kW – yr)	*$30.38*	*$38.97*						

Figure 1.22 Estimated net revenue of hypothetical combined cycle unit



Hypothetical combustion turbine unit

Key assumptions used in this analysis for a typical new combustion turbine are shown in Table 1.9. Table 1.10 and Figure 1.23 show estimated net revenues that a hypothetical combustion turbine unit would have earned by participating in the real-time energy and non-spinning reserve markets. These results show a decrease in the net revenues in the SP15 and NP15 areas in 2013 compared to prior years. Estimated net revenues for a hypothetical combustion turbine also fell well short of the $190/kW-year estimate of annualized fixed costs in the CEC study.

Table 1.9 Assumptions for typical new combustion turbine[48]

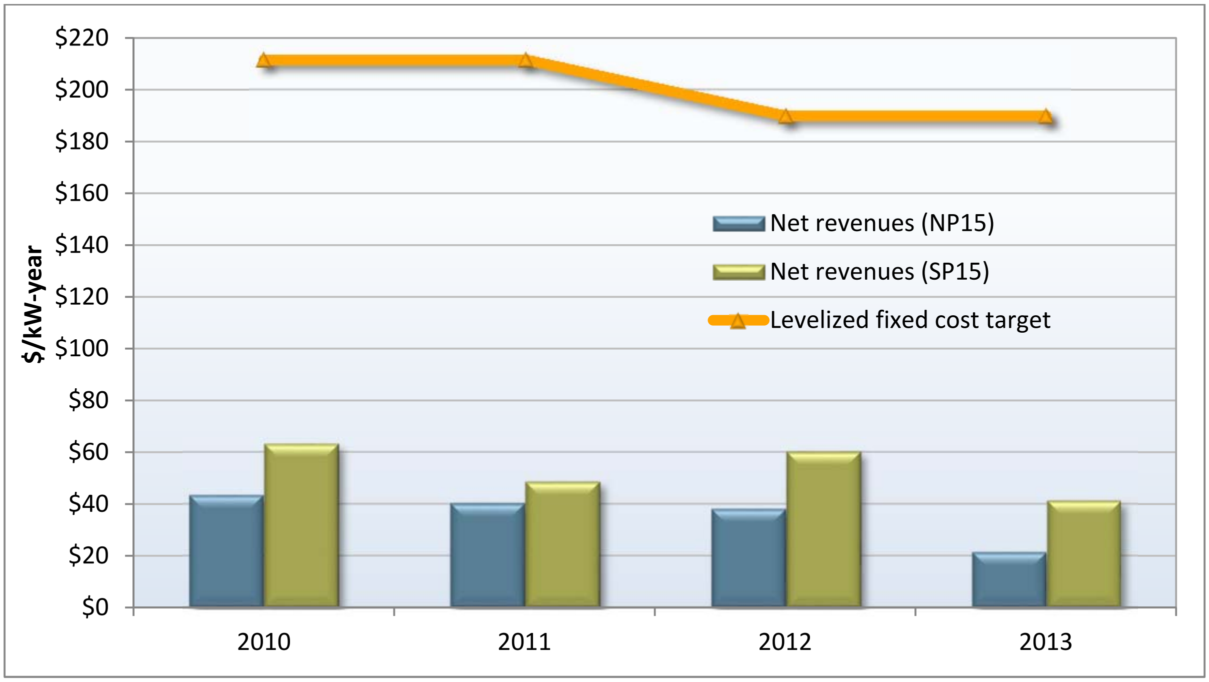
Technical Parameters	
Maximum Capacity	100 MW
Minimum Operating Level	40 MW
Startup Gas Consumption	180 MMBtu/start
Heat Rates (MBTU/MW)	
Maximum Capacity	9,300
Minimum Operating Level	9,700
Financial Parameters	
Financing Costs	$116.2 /kW-yr
Insurance	$8.8 /kW-yr
Ad Valorem	$11.6 /kW-yr
Fixed Annual O&M	$34.7 /kW-yr
Taxes	$18.8 /kW-yr
Total Fixed Cost Revenue Requirement	**$190.1/kW-yr**

Table 1.10 Financial analysis of new combustion turbine (2010-2013)

Components	2010		2011		2012		2013	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	7%	10%	6%	7%	5%	8%	8%	9%
Energy Revenue ($/kW - yr)	$64.97	$95.94	$57.60	$69.57	$48.78	$78.89	$58.48	$82.95
A/S Revenue ($/kW - yr)	$3.36	$2.97	$6.06	$5.98	$4.29	$5.04	$1.14	$1.34
Operating Cost ($/kW - yr)	$24.80	$35.60	$23.23	$26.88	$14.82	$23.62	$38.03	$42.85
Net Revenue ($/kW - yr)	$43.54	$63.32	$40.43	$48.67	$38.26	$60.32	$21.59	$41.45
5-yr Average ($/kW - yr)	*$35.96*	*$53.44*						

48 The financing costs, insurance, ad valorem, fixed annual O&M and tax costs for a typical unit in this table were derived directly from the data presented in the March 2013 CEC Workshop on the Cost of New Renewable and Fossil-Fueled Generation in California: http://www.energy.ca.gov/2013_energypolicy/documents/index.html#03072013. The numbers reported in the workshop are preliminary numbers. The cost of actual new generators varies significantly due to factors such as ownership, location and environmental constraints. More detailed information can be found in the CEC documents.

Figure 1.23 Estimated net revenues of new combustion turbine



Effect of greenhouse gas cap-and-trade program on net revenues

Further analysis shows that greenhouse gas costs added about $5.30/MWh to costs in both the NP15 and SP15 areas for combined cycle units and about $6.90/MWh to costs in the NP15 area and $7.10/MWh to costs in the SP15 area for combustion turbine units. A new combined cycle unit has a more efficient heat rate, and thus less natural gas is burned to produce a megawatt-hour of electricity. This results in fewer greenhouse gases emitted and ultimately lower greenhouse gas compliance costs per megawatt hour of generation.

Compared with about $6/MWh, the estimated average system price impact from the cap-and-trade program shown in Chapter 5, the net revenue of a new efficient combined cycle unit improved slightly with the cap-and-trade program while the net revenue of a less efficient hypothetical combustion turbine unit decreased. While a combustion turbine would not run unless its costs could be recovered, the greenhouse gas costs could reduce the unit's profit margin when it was running.[49] This would in turn reduce its net revenue.

Over the course of the year, greenhouse gas costs increased hypothetical combined cycle net revenue by about $5/kW-yr in both the NP15 and SP15 areas. This explains about 40 percent of the net revenue increase in the NP15 area from 2012 to 2013. The greenhouse gas costs can explain about 20 percent of the SP15 area net revenue increase. The increase in the SP15 area net revenues was more a result of congestion in Southern California, particularly in the first half of the year (see Chapter 8).

[49] The $6/MWh estimate of the effect of the greenhouse gas cap-and-trade program on ISO market prices is an average effect. This effect can differ by hour.

Conclusion

Overall, the findings in this section continue to underscore the critical importance of long-term contracting as the primary means for facilitating new generation investment. Local requirements for new generation investment should be addressed through long-term bilateral contracting under the CPUC resource adequacy and long-term procurement framework. Under California's current market design, these programs can provide additional revenue for new generation and cover the gap between annualized capital cost and the simulated net spot market revenues provided in the previous section.

A more detailed discussion of issues relating to capacity procurement, investment in new and existing generating capacity, and longer-term resource adequacy is provided in Chapter 10 of this report.

2 Overview of market performance

The ISO markets continued to perform efficiently and competitively overall in 2013.

- Total wholesale electric costs increased by 31 percent. This increase was primarily driven by a 30 percent increase in natural gas prices in 2013 compared to 2012. After controlling for the gas price increase, wholesale electric costs increased by 5 percent, primarily as a result of implementation of the state's greenhouse gas cap-and-trade program.
- Overall prices in the ISO energy markets over the course of 2013 were highly competitive, averaging very close to what DMM estimates would result under highly competitive conditions.
- About 97 percent of physical system load was scheduled in the day-ahead energy market, which continued to be highly efficient and competitive.
- Average real-time prices were systematically lower than day-ahead market prices throughout the year. Day-ahead prices averaged just over $2/MWh higher than real-time prices for the year, peaking in the second quarter at almost $6/MWh higher.

Other aspects of the ISO markets performed well and helped keep overall wholesale costs low.

- The ISO implemented new automated local market power mitigation procedures in the real-time software which mitigated local market power more effectively than the previous approach.
- Ancillary service costs totaled $57 million, or about 30 percent less than in 2012. This decrease was driven by a decrease in the quantity of ancillary services procured by the ISO and lower ancillary services prices.
- Bid cost recovery payments totaled $108 million, or about 1 percent of total energy costs in 2013, compared to about $104 million or 1.3 percent of total energy costs in 2012. Payments for units scheduled by the residual unit commitment process accounted for $23 million of these costs, compared to $8 million in 2012. This increase was driven in large part by the need to schedule physical capacity to meet the portion of the day-ahead load forecast met by net virtual supply in the day-ahead energy market as well as operator adjustments. A portion of these costs are ultimately allocated to virtual bidders with net virtual supply positions.
- Exceptional dispatches, out-of-market unit commitments and energy dispatches issued by ISO grid operators to meet constraints not incorporated in the market software, decreased from 2012 and remained relatively low. Total energy from all exceptional dispatches totaled about 0.26 percent of total system energy in 2013 compared to 0.53 percent in 2012. The above-market costs resulting from these exceptional dispatches decreased almost 50 percent from $34 million in 2012 to $18 million in 2013.
- Congestion within the ISO system decreased in 2013, most notably in the second half of the year. The reduction in real-time congestion can be attributed partly to improved ISO procedures that better align day-ahead line limits with real-time limits. This allows for better commitment of resources to resolve anticipated congestion in real time.

- Lower real-time congestion drove real-time market revenue imbalance charges allocated to load-serving entities lower. These charges decreased from $187 million in 2012 to $120 million in 2013, or just over 1 percent of total wholesale costs. Most of the $26 million in net profits received by convergence (or virtual) bidders resulted from either virtual supply bids or offsetting virtual demand and supply bids at different internal locations designed to profit from higher congestion between these locations in real-time.

2.1 Total wholesale market costs

The total estimated wholesale cost of serving load in 2013 was $10.7 billion or over $46/MWh. This represents an increase of about 31 percent from a cost of over $35/MWh in 2012. The increase in electricity prices was due, in large part, to a 30 percent increase in wholesale natural gas prices.[50] After accounting for higher gas prices, DMM estimates that total wholesale energy costs increased from $42/MWh in 2012 to $44/MWh in 2013, representing an increase of almost 5 percent in gas-normalized prices.[51]

A variety of factors contributed to the increase in gas-normalized total wholesale costs in 2013. As highlighted elsewhere in this report, conditions that contributed to higher prices include the following:

- Compliance costs associated with the state's cap-and-trade program;
- Lower in-state hydro-electric generation; and
- Decreased imports from the Southwest and, in particular, the Northwest especially in the second half of the year.

Other factors had the effect of lowering prices. These factors are discussed in the following sections and chapters of this report and include the following:

- Additions of new generation capacity, including renewables and new gas-fired generation;
- Decreased regional congestion; and
- Increased net virtual supply, which lowered day-ahead prices and brought them closer to real-time prices.

Figure 2.1 shows total estimated wholesale costs per MWh of system load from 2009 to 2013. Wholesale costs are provided in nominal terms (blue bar), as well as after normalization for changes in average spot market prices for natural gas (gold bar). The green line, representing the annual average of daily natural gas prices, is included to illustrate the correlation between the cost of natural gas and the total wholesale cost estimate.

[50] In this report, we calculate average annual gas prices by weighting daily spot market prices by the total ISO system loads. This results in a price that is more heavily weighted based on gas prices during summer months when system loads are higher than winter months, when gas prices are often highest.

[51] Gas prices are normalized to 2009 prices.

Figure 2.1 Total annual wholesale costs per MWh of load (2009-2013)

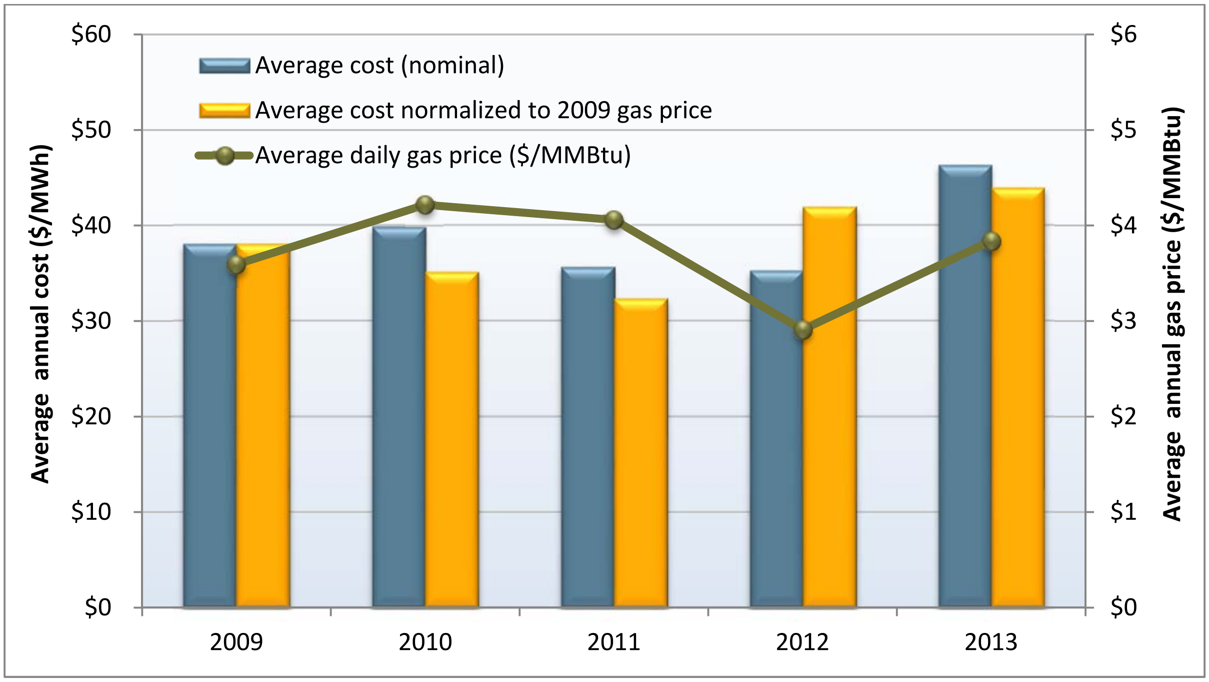


Table 2.1 provides annual summaries of nominal total wholesale costs by category from 2009, when the current nodal market design was implemented, through 2013. Total wholesale market costs are estimated based on prices and quantities cleared in each of the three energy markets: day-ahead, hour-ahead and 5-minute real-time markets. This estimate also includes costs associated with ancillary services, convergence bidding, residual unit commitment, bid cost recovery, reliability must-run contracts, the capacity procurement mechanism, the flexible ramping constraint and grid management charges.[52]

As seen in Table 2.1, the increase in cost in 2013 was due to the increase of day-ahead energy costs, which represents by far the largest component of wholesale energy costs. The increase was offset in part by a decrease in real-time energy costs, as well as decreases in reliability costs and in reserve costs in 2013 relative to 2012. Ancillary service costs decreased, compared to 2012, due to decreases in ancillary service prices and procurement levels, as well as increased usage of limited hydro-electric supplies to provide spinning reserves. Reliability costs decreased as there was less use of the capacity procurement mechanism to address local reliability concerns with the outages of the SONGS units. These reliability needs were addressed through other mechanisms including grid enhancements and synchronous condensers.

[52] A description of the basic methodology used to calculate the wholesale costs is provided in Appendix A of DMM's *2009 Annual Report on Market Issues and Performance*, April 2010, http://www.caiso.com/2777/27778a322d0f0.pdf. This methodology was modified to include costs associated with the flexible ramping constraint and convergence bidding. Flexible ramping costs are added to the real-time energy costs. We've modified the real-time energy cost methodology slightly from the one used in 2012. This has resulted in a slight change in the 2011 and 2012 numbers.

Table 2.1 Estimated average wholesale energy costs per MWh (2009-2013)

	2009	2010	2011	2012	2013	Change '12-'13
Day-ahead energy costs (excl. GMC)	$ 35.57	$ 37.37	$ 32.88	$ 32.57	$ 44.14	$ 11.57
Real-time energy costs (incl. flex ramp)	$ 0.81	$ 0.73	$ 0.80	$ 0.99	$ 0.57	$ (0.42)
Grid management charge	$ 0.78	$ 0.79	$ 0.79	$ 0.80	$ 0.80	$ (0.00)
Bid cost recovery costs	$ 0.29	$ 0.37	$ 0.56	$ 0.45	$ 0.47	$ 0.02
Reliability costs (RMR and CPM)	$ 0.25	$ 0.27	$ 0.03	$ 0.14	$ 0.10	$ (0.04)
Average total energy costs	**$ 37.70**	**$ 39.53**	**$ 35.06**	**$ 34.96**	**$ 46.08**	**$ 11.12**
Reserve costs (AS and RUC)	$ 0.39	$ 0.38	$ 0.62	$ 0.37	$ 0.26	$ (0.11)
Average total costs of energy and reserve	**$ 38.09**	**$ 39.91**	**$ 35.68**	**$ 35.33**	**$ 46.34**	**$ 11.01**

2.2 Overall market competitiveness

To assess the competitiveness of the ISO energy markets, DMM compares actual market prices to competitive benchmark prices we estimate would result under highly competitive conditions. DMM estimates competitive baseline prices by re-simulating the market using the day-ahead market software with bids reflecting the actual marginal cost of gas-fired units, no convergence bids, and actual load.[53]

Figure 2.2 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 2.2, prices in the day-ahead market were similar to competitive baseline prices in most months in 2013. Day-ahead prices exceeded the competitive benchmark in April by about $0.27/MWh and were lower in all other months.

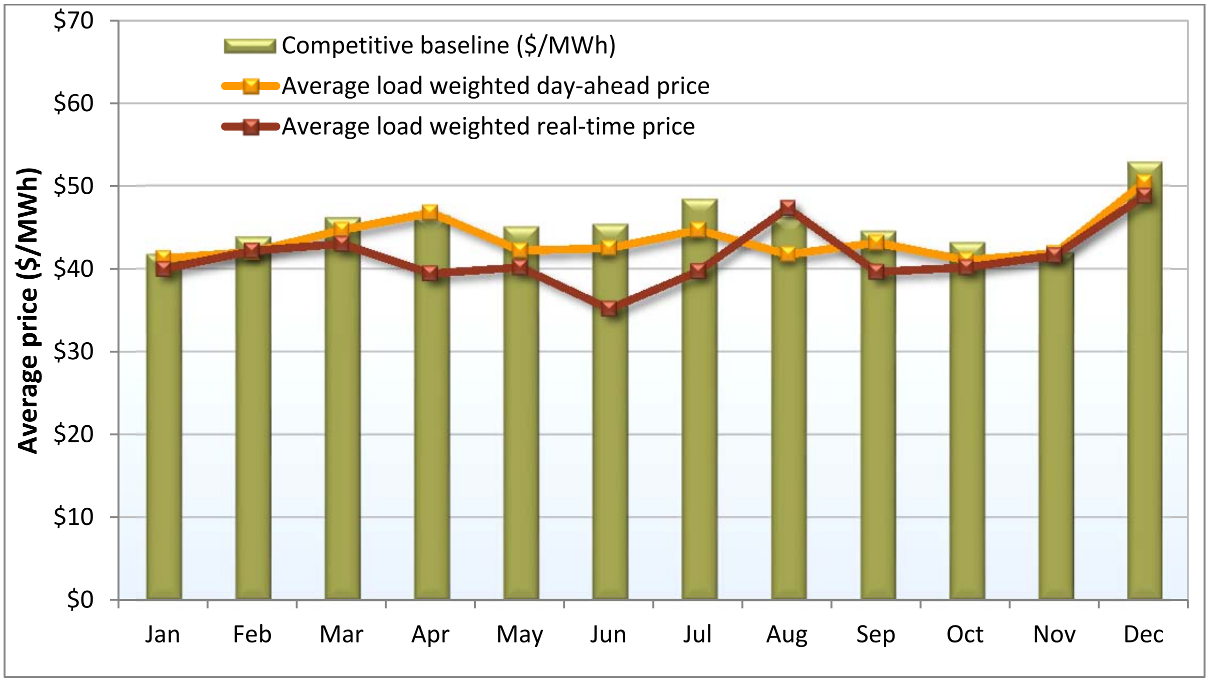
In the real-time market, average prices were lower than the competitive baseline in 2013 in most months except for August. A major factor contributing to these lower real-time prices was the substantial amount of real-time energy that was not scheduled in the day-ahead market.[54] In August, real-time prices were driven higher than day-ahead prices and slightly over the average competitive

[53] 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 to actual system load. This scenario represents the combination of perfect load forecast along with physical and competitive bidding of price-setting resources. For January through April, DMM used PROBE to re-simulate the day-ahead market. While the PROBE simulator can produce a reasonably accurate solution when compared to the original market solution, it has limitations in modeling multi-stage generators and congestion. For the rest of the year, DMM calculated the competitive baseline using its version of the actual market software.

[54] 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 variable renewable energy. A detailed analysis of this issue is provided in Section 3.3.

baseline price by periods of high loads and wildfire related transmission outages. In the fourth quarter, day-ahead prices and real-time prices were very close to the competitive benchmark.

Figure 2.2 Comparison of competitive baseline price with day-ahead and real-time prices



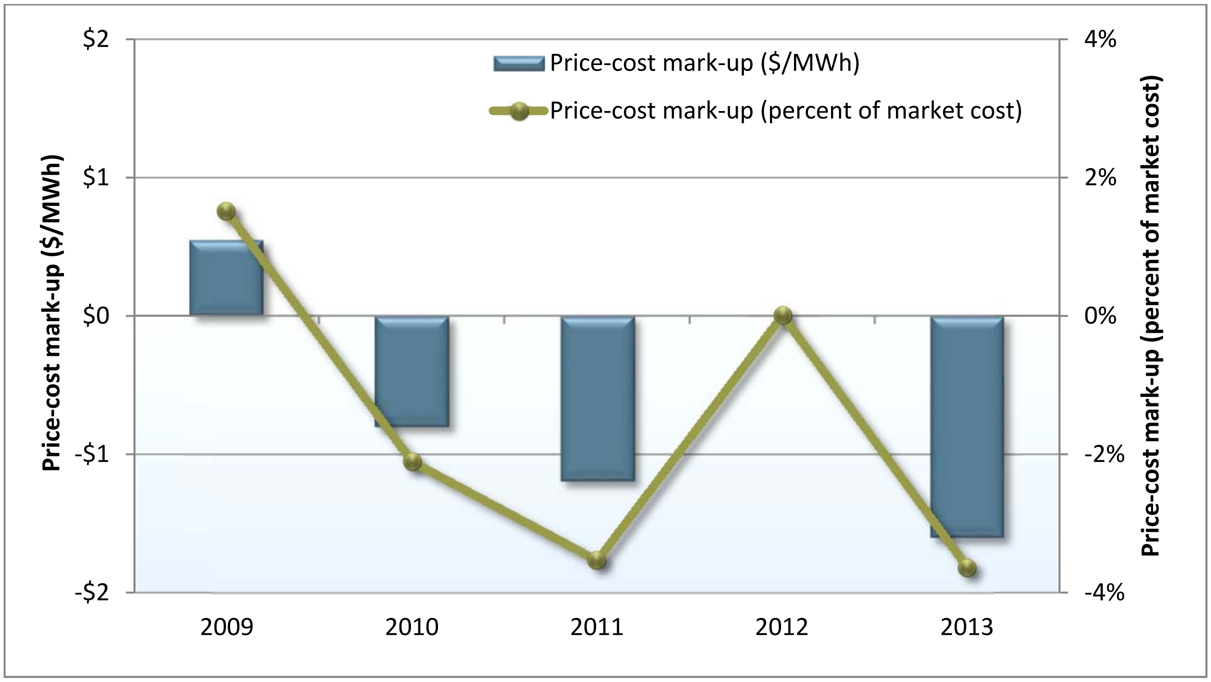
DMM also calculates an overall *price-cost mark-up* by comparing competitive baseline prices to total average wholesale energy costs.[55] Total costs used in this analysis represent a load-weighted average price of all energy transactions in the day-ahead, hour-ahead and real-time markets.[56] Thus, 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 2.3, the overall combined average of day-ahead market and real-time prices was about $1.50/MWh or about 3.8 percent lower than the competitive baseline price. This represents a slight drop in the price-cost markup in 2013 compared to 2012 and is consistent with the slightly negative price-cost markups observed in 2010 and 2011. Slightly negative price-cost mark-ups can reflect the fact that some suppliers bid somewhat lower than their default energy bids – which include a 10 percent adder above estimated marginal costs. In 2012, the overall price-cost mark-up was slightly positive (0.01 percent).

[55] 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 markup of 10 percent.

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

Figure 2.3 Price-cost mark-up (2009-2013)



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

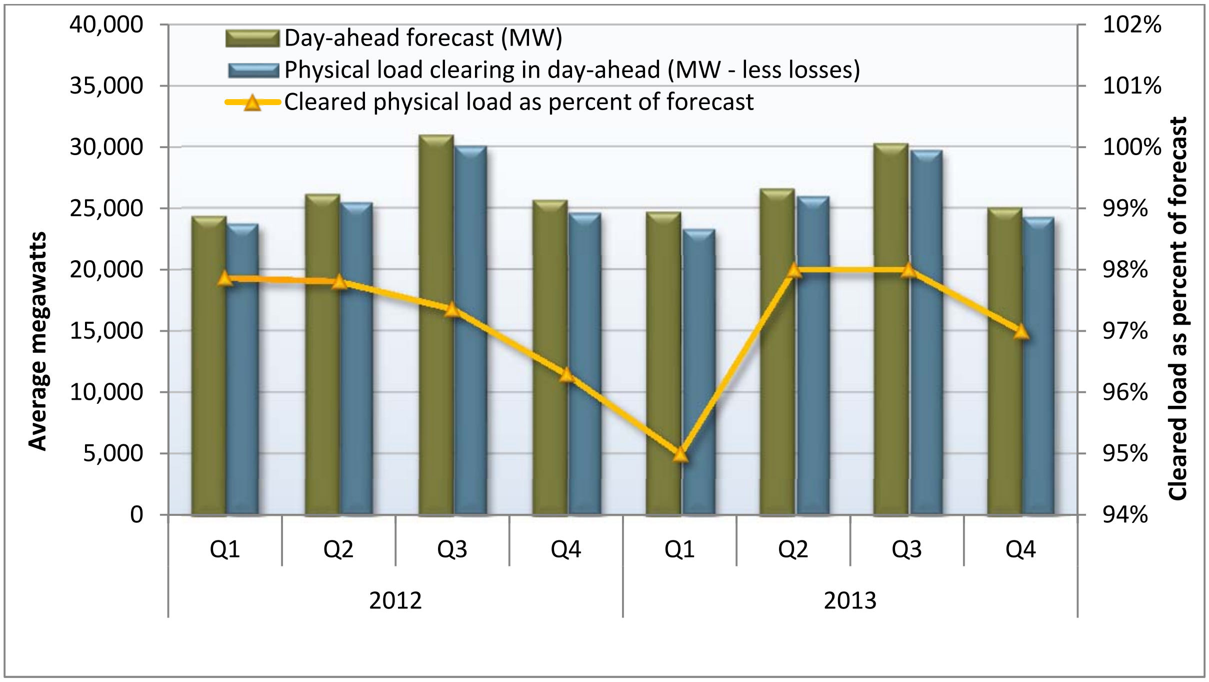
2.3 Day-ahead scheduling

The level of physical load bids clearing the day-ahead market continued to be high in 2013, averaging about 97 percent of total forecast demand and actual loads. For the last two years physical load scheduled in the day-ahead market has averaged about 97 percent, which is slightly lower than the historical average of around 99 percent.

In 2012, virtual demand tended to exceed virtual supply most hours, making the sum of physical load plus net virtual demand clearing the day-ahead very close to forecasted load levels. In 2013, however, virtual supply tended to exceed virtual demand (see Chapter 4). Net virtual supply can be thought of as negative net virtual demand. As a result, when cleared virtual bids are added to physical load, this pushed the combined physical plus virtual demand slightly lower as a percentage of forecasted load levels. This change in convergence bidding from net virtual demand to net virtual supply was consistent with systematically lower prices in the real-time market compared to the day-ahead market in 2013 (see Section 2.4 for further detail on prices).

Figure 2.4 compares the average level of physical load clearing in the day-ahead market to the forecast of demand. The lowest level of physical load bids clearing the day-ahead market in over two years occurred in the first quarter of 2013 (95 percent). While the ISO's load forecast tended to match the actual load for most of the day, physical load clearing the day-ahead market was often lower than the day-ahead forecast load during the peak hours.

Figure 2.4 Physical load clearing day-ahead market compared to load forecast



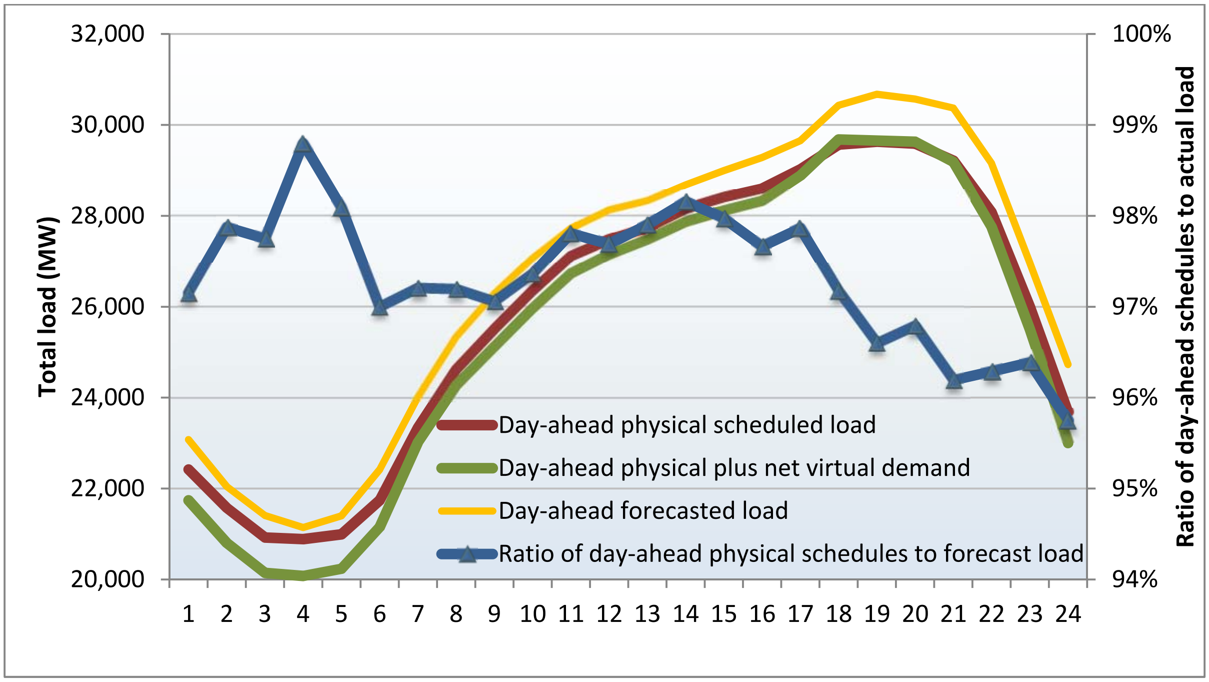
As shown in Figure 2.5, average physical load clearing the day-ahead market over the course of 2013 (red line) was less than the load forecast (yellow line) during all hours of the day, with the greatest differences falling in the evening peak hours. Physical load schedules were about 1,000 MW below forecast loads throughout the day. Overall, this pattern was similar to 2012, as average physical load scheduled in the day-ahead market equaled about 97 percent of forecast load and the difference was slightly more pronounced in the peak hours versus the off-peak hours.

The average total amount of demand, shown in Figure 2.5, including net convergence bids clearing the day-ahead market (green line), did not match the day-ahead forecast load (yellow line) very closely in any hour of the day. This reflects an average net virtual bidding position of net supply in most hours. This reflects the fact that average day-ahead prices were higher than average real-time prices in 2013.[57]

During many peak hours of the summer months virtual supply pushed total demand clearing the day-ahead market about 1,500 MW below actual and forecasted loads. This pattern was most pronounced in the early morning hours and occurred when average real-time prices were below average day-ahead prices.

[57] Virtual bidding trends are discussed in more detail in Chapter 4 of this report.

Figure 2.5 Day-ahead schedules, forecast and actual load (2013)



Self-scheduling of loads and generation

The high level of scheduling in the day-ahead market is due largely to a very high level of self-scheduling of loads and, to a lesser extent, self-scheduling of generation.

Figure 2.6 shows the portion of load clearing the day-ahead market comprised of self-schedules and price-taking demand bids, as opposed to price-sensitive demand bids.[58] Self-scheduled and price-taking demand bids accounted for an average of 96 to 97 percent of load clearing the day-ahead market in 2013, up just slightly from 2011 and 2012. This self-scheduled or price-taking load equaled about 96 percent of the forecast of actual load in both 2011 and 2012. This indicates that load-serving entities continue to be price takers for a very high level of their actual load, while submitting price sensitive bids for the relatively small portion of remaining demand bids.

Figure 2.7 shows the portion of supply clearing the day-ahead market comprised of self-scheduling and price-taking bids.[59] Extremely high levels of self-scheduled supply can decrease market efficiency by reducing the degree to which the market software is free to optimize supply resources based on their bid costs. High levels of self-scheduling can also hinder the ability to manage congestion in the most cost-effective manner. The total amount of self-scheduled and price-taking supply has shown a decreasing trend each quarter since the second quarter of 2011. The trend continued in 2013 as the percent of generation self-supplied in 2013 was 56 percent, compared to 62 percent in 2012 and 75 percent in 2011.

[58] In this analysis, DMM classified load bids within $5/MWh of the maximum bid cap as price-taking because these bids are virtually certain to clear the day-ahead market. The energy bid cap has been $1,000/MWh since April 2011.

[59] In this analysis, DMM classified supply bids between the energy bid floor and $0/MWh as price-taking supply because these bids are virtually certain to clear the day-ahead market. The energy bid floor is currently -$30/MWh and scheduled to change to -$150/MWh in the spring of 2014.

Figure 2.6 Average self-scheduled load as a percent of total load cleared in day-ahead market

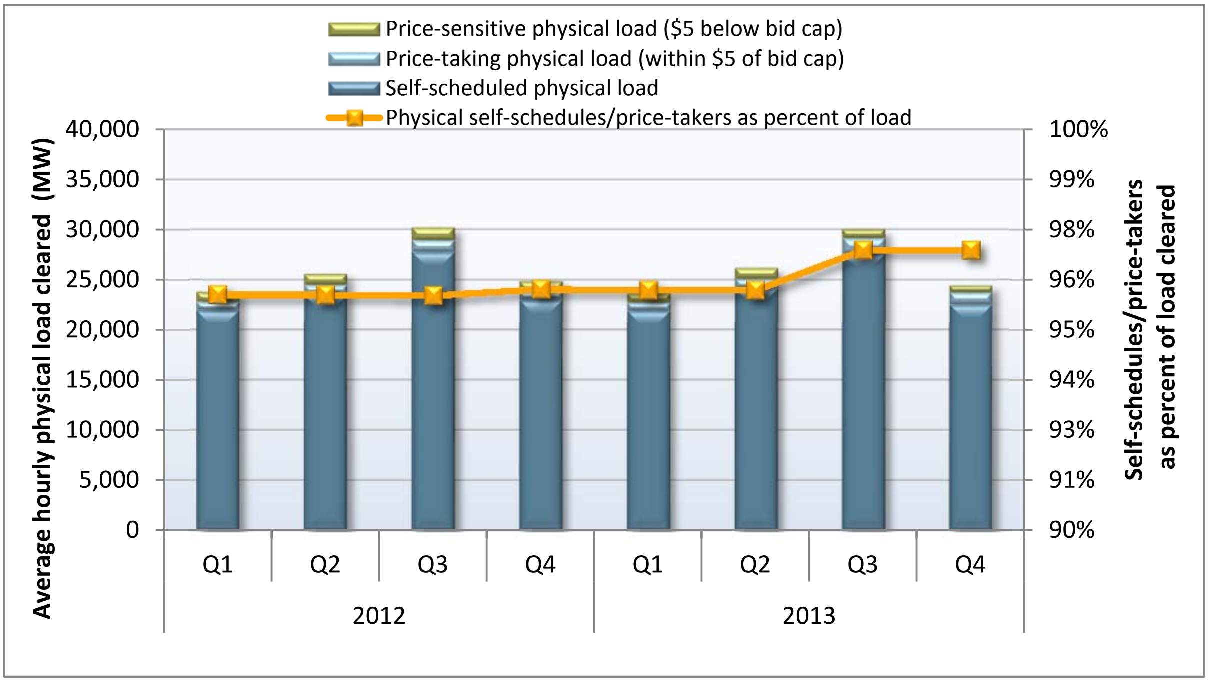
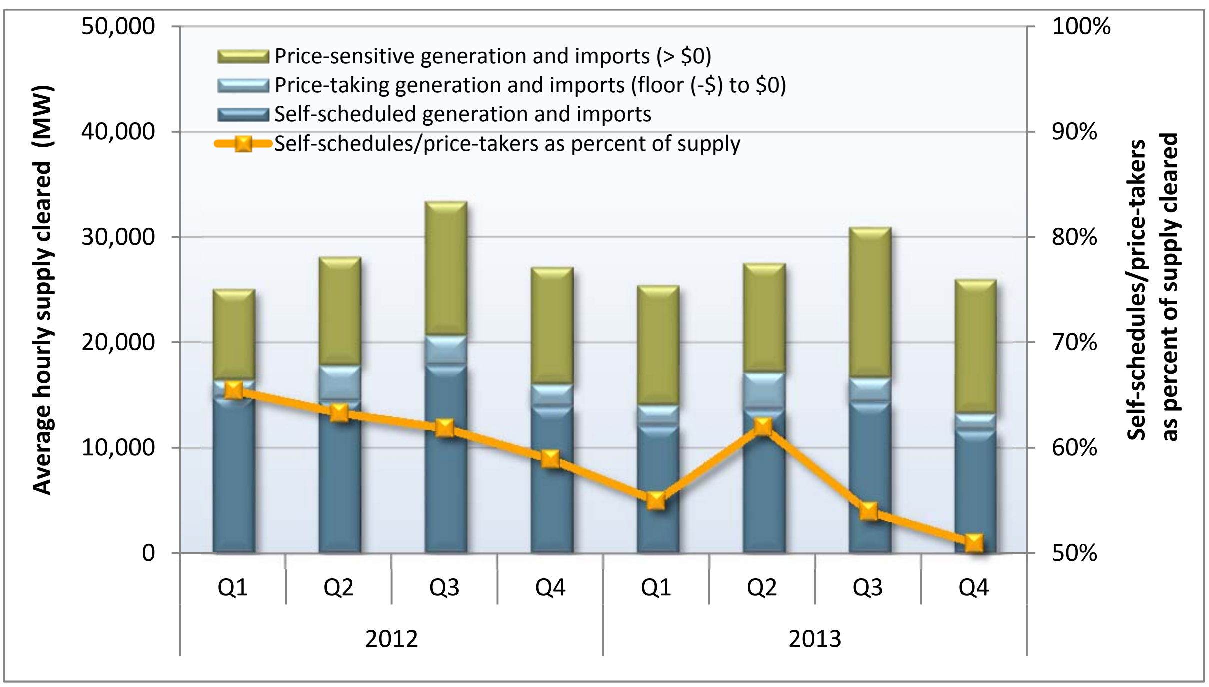


Figure 2.7 Average self-scheduled supply as a percent of total supply cleared in day-ahead market



At the quarterly level, self-scheduled and price-taking supply bids have accounted for an average of about 51 to 62 percent of supply clearing the day-ahead market in 2013. With the exception of the second quarter, self-scheduling of supply has trended downward in all quarters of 2013. When compared to 2012, self-scheduled hydro-electric generation was down by 19 percent. This may be a result of the reduction in hydro-electric availability due to low precipitation. Decreases in the availability of hydro-electric generation in the Pacific Northwest also appeared to have reduced the amount of self-scheduled imports.

Hour-ahead market

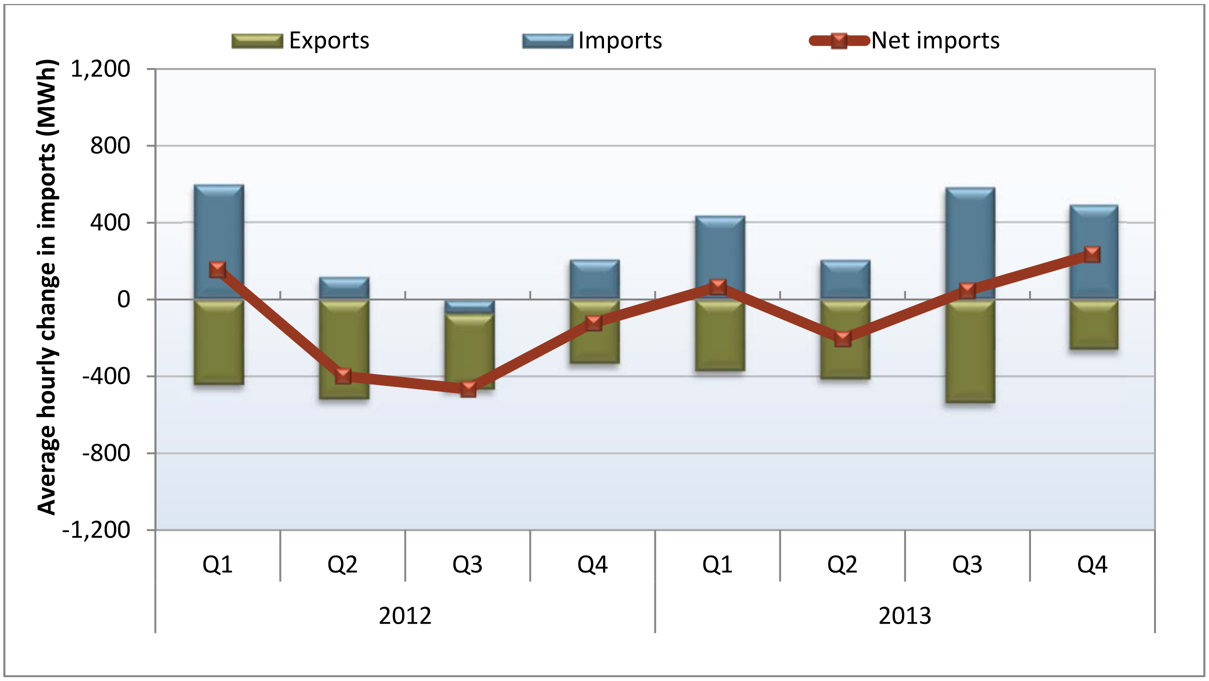
The hour-ahead market allows day-ahead inter-tie schedules to be modified through a re-optimization of the entire market.[60] Market participants with accepted day-ahead imports or export bids can either self-schedule their energy in the hour-ahead market, or re-bid day-ahead scheduled quantities at the same or different prices. If an import scheduled in the day-ahead market does not clear in the hour-ahead market, the market participant buys back the import at the hour-ahead price. Exports scheduled in the day-ahead market that do not clear in the hour-ahead market are sold back at the hour-ahead price.[61]

As seen in Figure 2.8, net import schedules clearing the hour-ahead market were systematically higher than net imports clearing the day-ahead market in 2013, except for the second quarter. This was a change from 2012 when net imports were lower in the hour-ahead market in the last three quarters. In 2013, net imports in off-peak were higher than peak hours.

[60] Implementation of FERC Order No. 764 will substantially change the bidding and scheduling of real-time imports. For further information, please see the ISO's compliance filing: https://www.caiso.com/Documents/Nov27_2013_TariffAmendment-ComplianceFERCOrder764_ER14-495.pdf.

[61] In order to receive positive buy back revenues for imports or positive sell back revenues for exports, participants must have submitted a valid e-tag before the hour-ahead market. Otherwise, any positive revenues received by buying or selling back the transaction in the hour-ahead market will be rescinded per the ISO tariff Section 11.32.

Figure 2.8 Change in net day-ahead imports resulting from hour-ahead market (hour-ahead minus day-ahead schedules)



2.4 Energy market prices

This section reviews energy market prices by focusing on a few key elements: price levels and convergence, congestion, and real-time price volatility. Key points highlighted in this section include the following:

- Energy market prices were higher in 2013 than 2012, on average.
- Day-ahead market prices were systematically higher than real-time market prices in 2013.
- Price convergence, by mid-year, improved between the hour-ahead and real-time markets.
- Congestion decreased significantly in 2013 compared to 2012, particularly in the second half of the year.
- Real-time price spikes occurred less frequently in 2013 compared to 2012.

Price levels and convergence

Energy market prices were higher in 2013 than 2012, as seen in Figure 2.9 and Figure 2.10.

- This increase was attributed primarily to a 30 percent increase in gas prices in 2013, compared to 2012. Gas prices were atypically low in 2012 and increased in 2013 to gas price levels consistent with 2011.

- Most of the remaining increase in electricity prices can be attributed to implementation of the state's greenhouse gas cap-and-trade program. DMM estimates that, on average in 2013, day-ahead market prices were about $6/MWh higher with implementation of this program.[62]

- Another factor causing upward pressure on electricity prices was a decrease in hydro-electric generation in 2013. In the fourth quarter, hydro-electric generation was down about 40 percent compared to the fourth quarter of the previous year.

Figure 2.9 and Figure 2.10 also show that price levels in the day-ahead market were systematically higher than the real-time market particularly in the second quarter. Price convergence between the hour-ahead and real-time markets was mixed in the first half of 2013, and more consistent in the second half of the year. As shown in these figures:

- Day-ahead market price levels were systematically higher than real-time price levels, averaging more than $2/MWh higher for the year. The greatest difference was experienced in the second quarter with day-ahead market prices exceeding the real-time prices by almost $6/MWh on average. This can be primarily attributed to additional generation in real-time that is not included in the day-ahead market, primarily from renewable resources (see Section 3.3 for further detail).

- Hour-ahead market prices were, in general, lower than day-ahead prices and much more consistent with real-time market prices in 2013 compared to 2012. Price convergence improved between hour-ahead and real-time markets in 2013 relative to 2012. Hour-ahead and real-time prices converged within about $0.50/MWh, on average, in 2013. This compares to a difference of $2/MWh, on average, between the hour-ahead and real-time markets in 2012.

Average prices in 2013 indicate price convergence between the day-ahead and real-time markets has shifted as compared to 2012. Specifically, the direction of the price divergence switched to day-ahead prices being higher than real-time prices in 2013 (see Figure 2.11). In addition, hour-ahead market prices were higher than the real-time market prices. Figure 2.12 shows average hour-ahead and real-time prices by quarter trending downward and ending negative in the last quarter of 2013.

When the absolute value of price differences are taken into account, price convergence between the day-ahead and real-time markets remained relatively similar overall in 2013 compared to 2012 (see Figure 2.11).[63] The absolute value of price differences between the hour-ahead and real-time markets in 2013 followed a similar pattern compared to the differences between the day-ahead and real-time market (see Figure 2.12). The absolute price divergence between the day-ahead and real-time and the hour-ahead and real-time markets was most pronounced in the second quarter of 2013. This can be primarily attributed to scheduling differences between renewable resources in the day-ahead and real-time markets and seasonal increases in hydro-electric generation.

[62] For further detail on the cap-and-trade program, see Chapter 5.

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

Figure 2.9 Comparison of quarterly prices – system energy (peak hours)

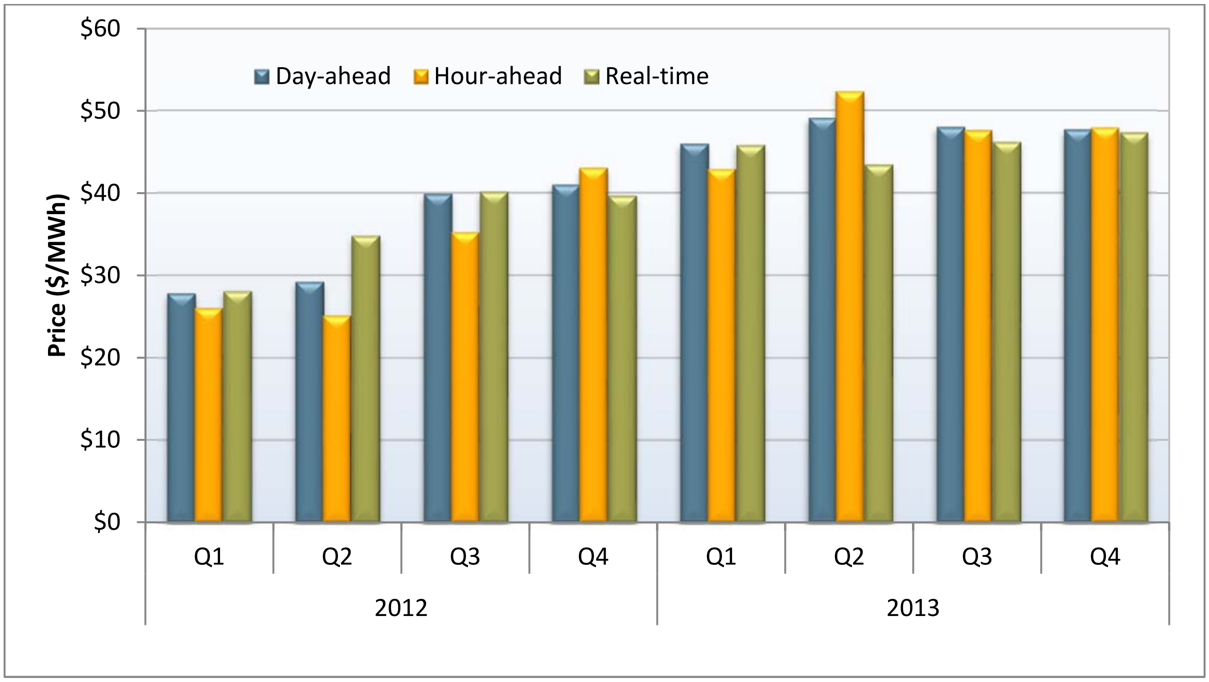


Figure 2.10 Comparison of quarterly prices – system energy (off-peak hours)

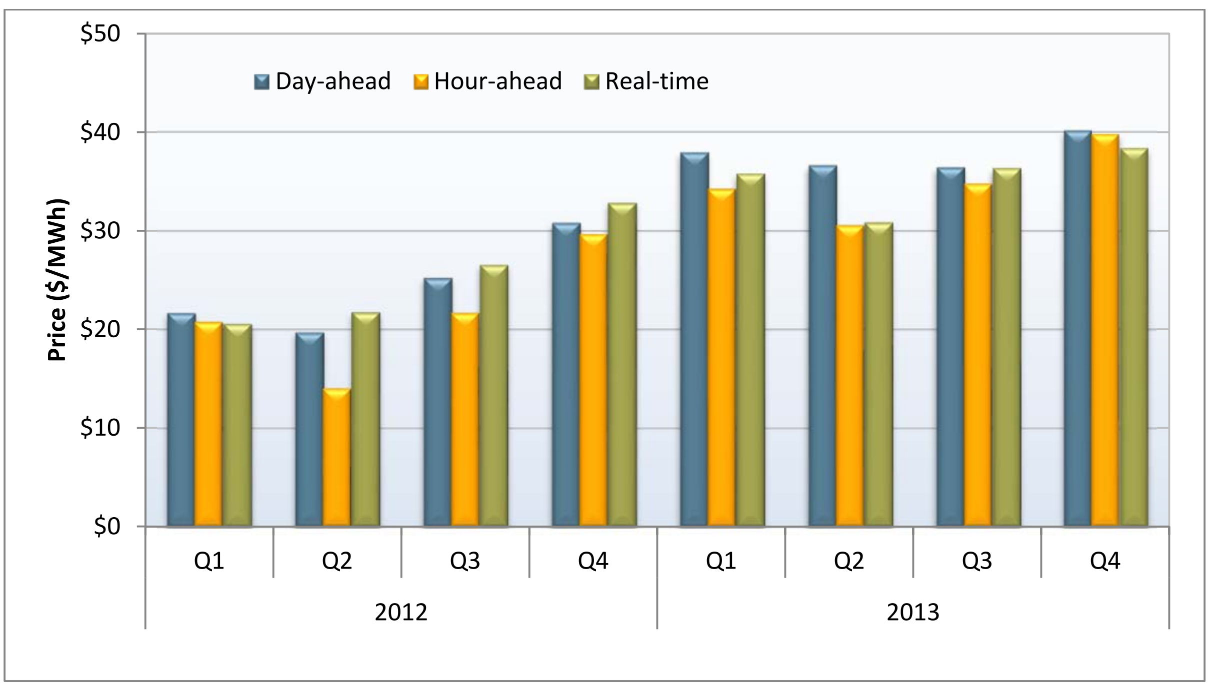


Figure 2.11 Difference in day-ahead and real-time prices – system energy (all hours)

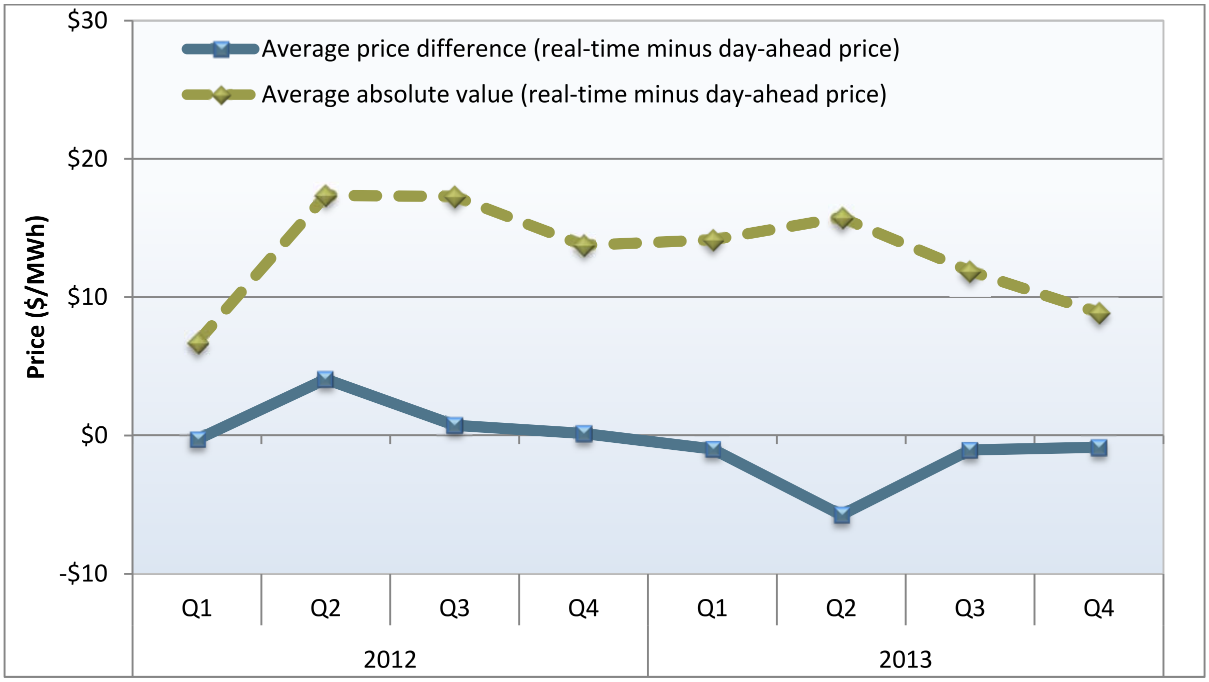
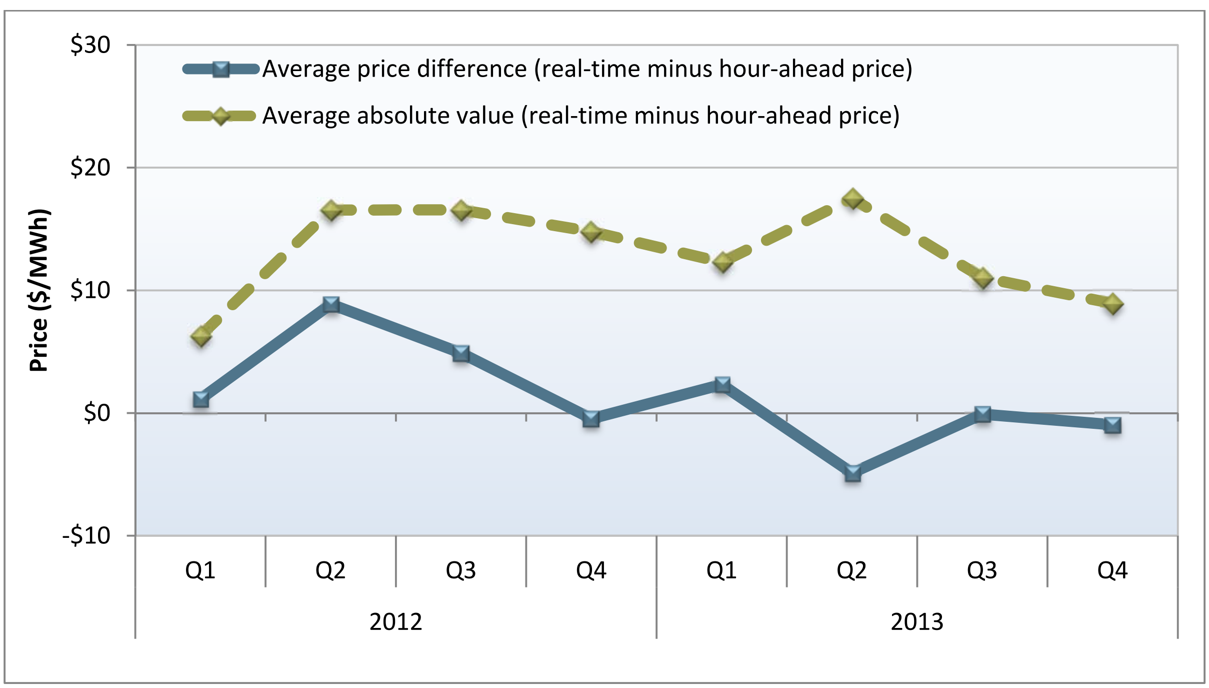


Figure 2.12 Difference in hour-ahead and real-time prices – system energy (all hours)



Congestion

This section compares the difference in congestion prices between the day-ahead, hour-ahead and real-time markets as both a simple and absolute average over time. These metrics show that congestion decreased in 2013 compared to 2012 between the day-ahead and real-time markets, and increased between the day-ahead and hour-ahead markets in the SCE and PG&E areas.

Figure 2.13 shows the quarterly average and absolute congestion price differences between the day-ahead and real-time markets since 2011 for each load area. Figure 2.14 shows the quarterly average and absolute congestion price difference between the day-ahead and hour-ahead markets by load area for the same period.

The simple average (dashed line) and absolute average (solid line) measures of price divergence between the day-ahead and the other markets increased starting in the second quarter of 2012. This trend continued throughout 2012 and into 2013. However, in the second half of 2013 congestion differences decreased between the day-ahead and real-time markets as both a simple average and, to an even greater degree, as an absolute average. For example, in the first quarter of 2013, the absolute difference between the day-ahead and the real-time prices in the SDG&E area was about $8/MWh, while the simple average difference was negative $1.25/MWh. In the fourth quarter, this difference dropped to $3.63/MWh and negative $1/MWh in 2013 for absolute and simple averages, respectively.

The differences in congestion between the day-ahead and hour-ahead markets increased in 2013 compared to 2012 for the SCE and PG&E areas and decreased for the SDG&E area. For instance, the average absolute difference between hour-ahead and day-ahead markets fell from $8.10/MWh in 2012 to $6.25/MWh in 2013 in the SDG&E area, whereas absolute differences in the SCE area increased from $3.80/MWh to $4.80/MWh for the same period. A similar trend existed for simple average price differences between the day-ahead and hour-ahead markets in 2012 and 2013.

Figure 2.13 Average differences in congestion prices between day-ahead and real-time markets

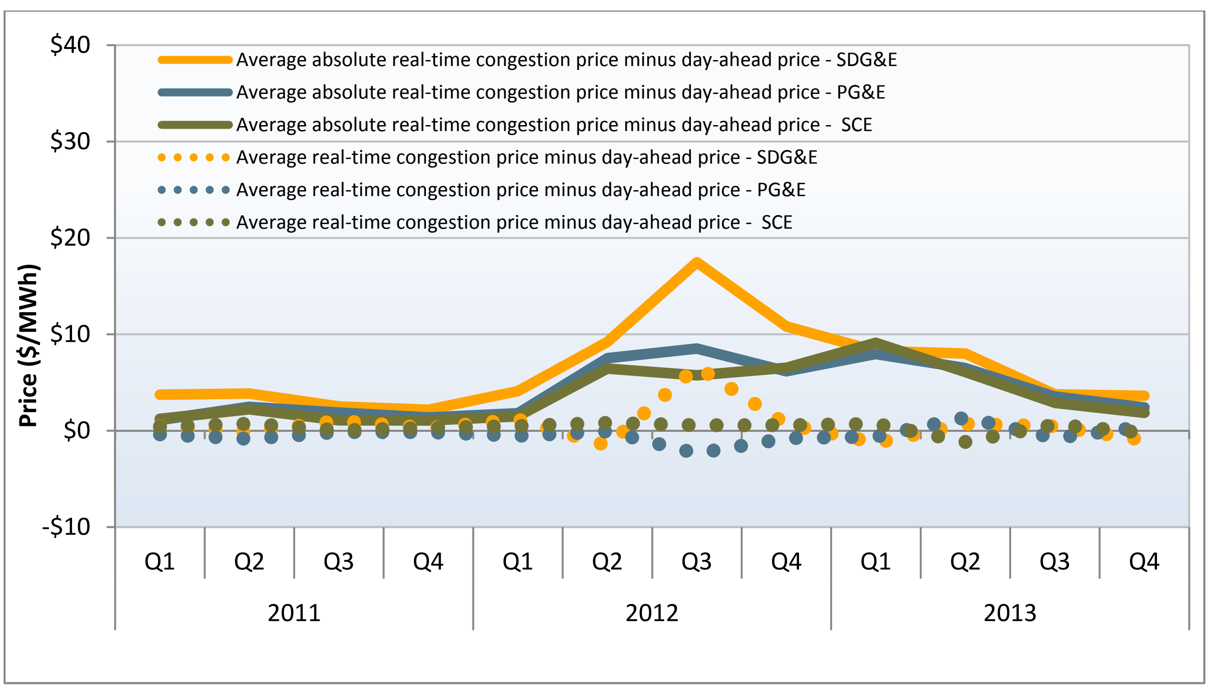
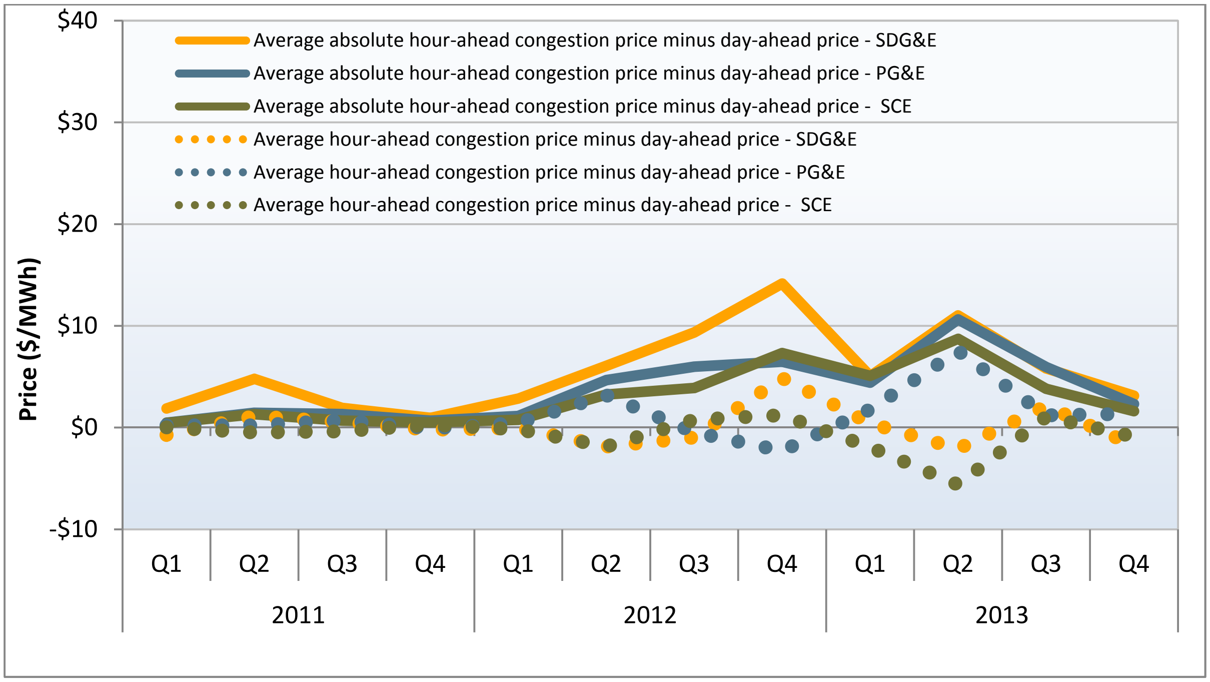


Figure 2.14 Average differences in congestion prices between day-ahead and hour-ahead markets



Convergence bidders can profit from the congestion price differences between the day-ahead and real-time markets. Furthermore, real-time imbalance congestion costs can occur as a result of these congestion differences.[64] However, as seen in Section 2.7, real-time imbalance congestion offset costs were significantly lower in 2013 compared to 2012. This drop can be partly attributed to reductions in congestion differences between the markets and the ISO's efforts to better align constraint limits between the day-ahead and real-time markets.

Price spikes

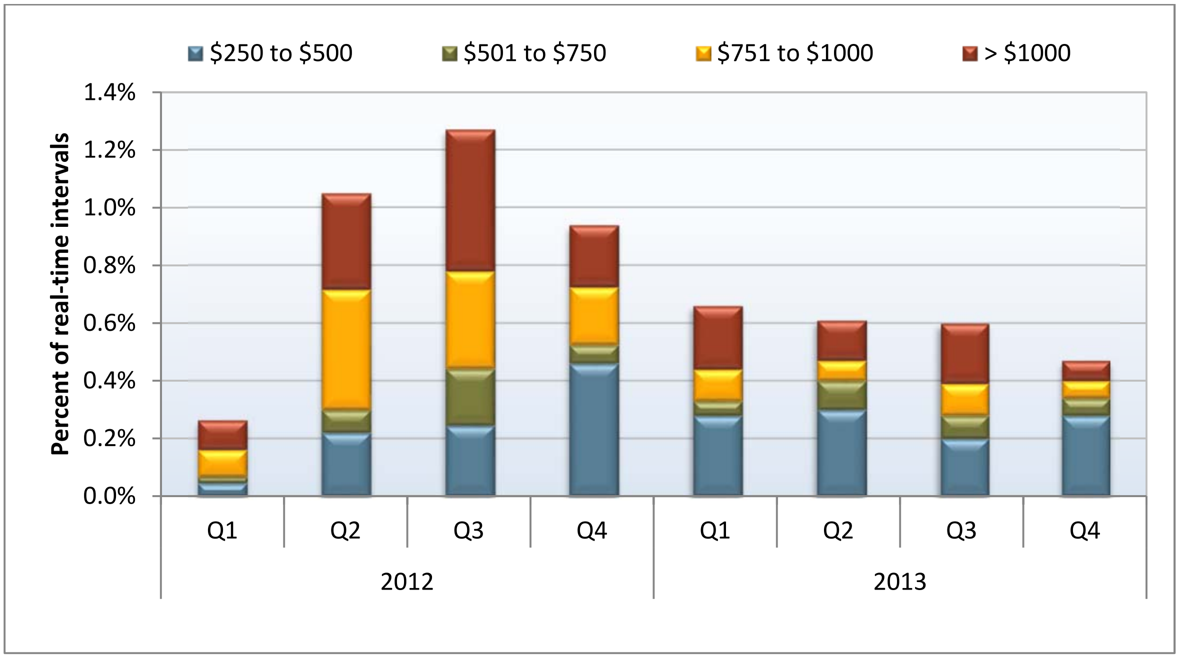
One of the key factors that historically drove price divergence was the small frequency of extreme real-time price spikes. Figure 2.15 shows the frequency of different levels of price spikes on a quarterly basis over the past two years for aggregate load prices. The frequencies shown in Figure 2.15 can be affected by spikes in the system-wide price of energy or price spikes caused by high congestion.

The frequency of real-time price spikes was relatively consistent throughout 2013, with less than 0.6 percent of real-time prices being extremely high. This represents a decrease in the frequency of real-time price spikes from 1 percent in 2012. Reductions in price spikes began in the last quarter of 2012 and continued through 2013.

This change can likely be attributed to several factors. First, ISO operators increased the flexible ramping requirement during the peak hours, and most notably during the ramping hours. Second, the ISO better aligned transmission limits between the day-ahead and real-time markets which contributed to less extreme congestion. Third, there was more competitive bidding in the real-time market in 2013.

[64] *2012 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2013, Section 3.4: pp. 90-99: http://www.caiso.com/Documents/2012AnnualReport-MarketIssue-Performance.pdf.

Figure 2.15 Real-time price spike frequency by quarter



2.5 Residual unit commitment

The purpose of the residual unit commitment market is to ensure that there is sufficient capacity online or reserved to meet actual load in real-time. The residual unit commitment market is run right after the day-ahead market and procures capacity sufficient to bridge the gap between the amount of physical supply cleared in the day-ahead market and the day-ahead forecast load. Capacity procured in the residual unit commitment must be bid into the real-time market.

ISO operators are able to increase the amount of residual unit commitment requirements for reliability purposes and used this tool frequently in 2013.[65] In addition, when the market clears with net virtual supply, residual unit commitment capacity is needed to replace the net virtual supply with physical supply.

Total residual unit commitment volume increased dramatically in the fourth quarter of 2012 and continued at relatively high levels through 2013. Figure 2.16 shows quarterly average hourly residual unit commitment procurement, categorized as either non-resource adequacy or resource adequacy and minimum load. Total residual unit commitment procurement rose from an average of 515 MW per hour in 2012 to 932 MW per hour in 2013.

While capacity procured in residual unit commitment must be bid into the real-time market, only a fraction of the total residual unit commitment capacity is committed to be online by the residual unit commitment process.[66] Most of the capacity procured in the residual unit commitment process is from

[65] See Section 9.8 for further discussion on operator adjustments in the residual unit commitment process.

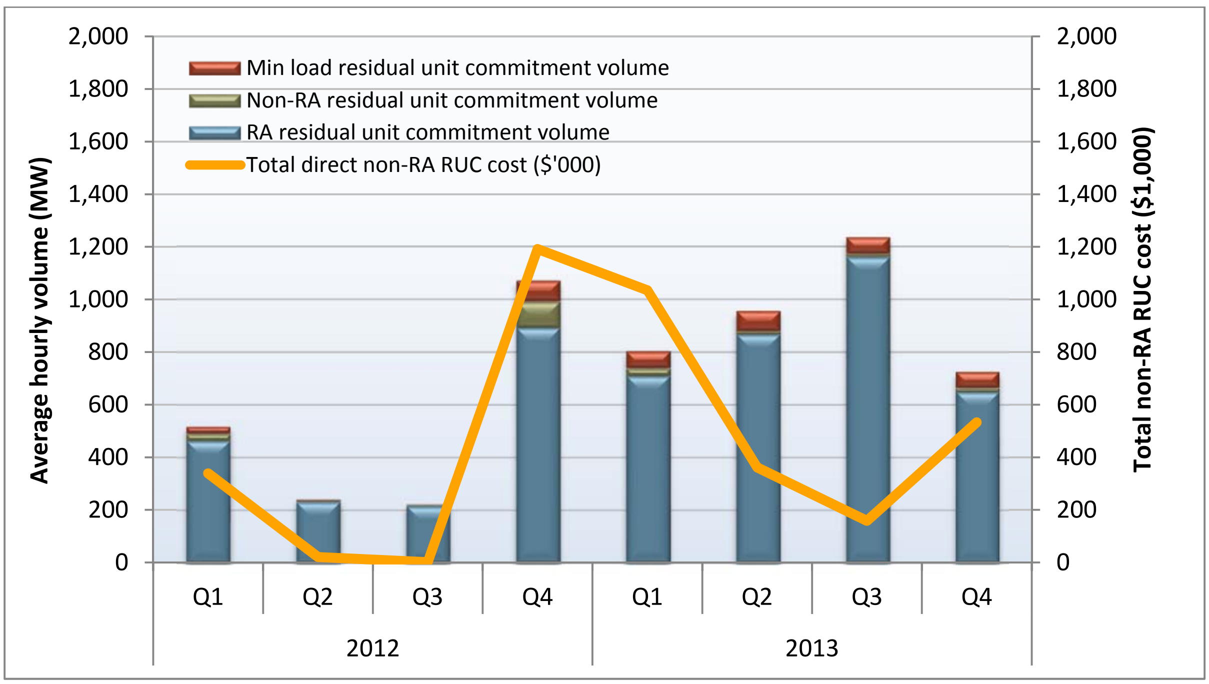
[66] Only the small portion of minimum load capacity from *long-start units*, units with start-up times greater than or equal to five hours, is committed to be online in real-time by the residual unit commitment process.

units which are already scheduled to be online through the day-ahead market or from short-start units that do not need to be started up unless actually needed in real time. Although the total volume of residual unit commitment capacity was over 700 MW in each quarter of 2013, the capacity committed to start up and operate at minimum load averaged just over 65 MW each hour. Moreover, only a small fraction of this capacity (13 MW on average) was from long-start units which are committed to be online by the residual unit commitment process.[67]

Much of the capacity procured in the residual unit commitment market does not incur direct costs but does account for a portion of the bid cost recovery payments discussed in detail in Section 2.6. Only non-resource adequacy units committed in the residual unit commitment receive capacity payments.[68]

Represented by the green segment of each bar in Figure 2.16, the non-resource adequacy residual unit commitment was low in 2013, averaging only 17 MW per hour. The total direct cost of residual unit commitment, represented by the gold line in Figure 2.16, was about $2.1 million in 2013, an almost 35 percent increase over the direct cost of $1.6 million in 2012.

Figure 2.16 Residual unit commitment costs and volume



In 2013, units committed in the residual unit commitment process accounted for around $23 million in bid cost recovery payments, or about 21 percent of total bid cost recovery payments. In 2012, these costs were $8 million or about 8 percent of total bid cost recovery payments. Units committed by the residual unit commitment can be either long- or short-start units. Long-start unit commitment

67 Long-start commitments are resources that require 300 or more minutes to start up. These resources receive binding commitment instructions from the residual unit commitment process. Short-start units receive an advisory commitment instruction in the residual unit commitment process, whereas the actual unit commitment decision for these units occurs in real time.

68 Resource adequacy units receive bid cost recovery payments as well as payments through the resource adequacy process.

accounted for $8 million or just over one-third of the residual unit commitment bid cost recovery payments, whereas short-start unit commitment accounted for about $15 million or almost two-thirds of the residual unit commitment bid cost recovery.

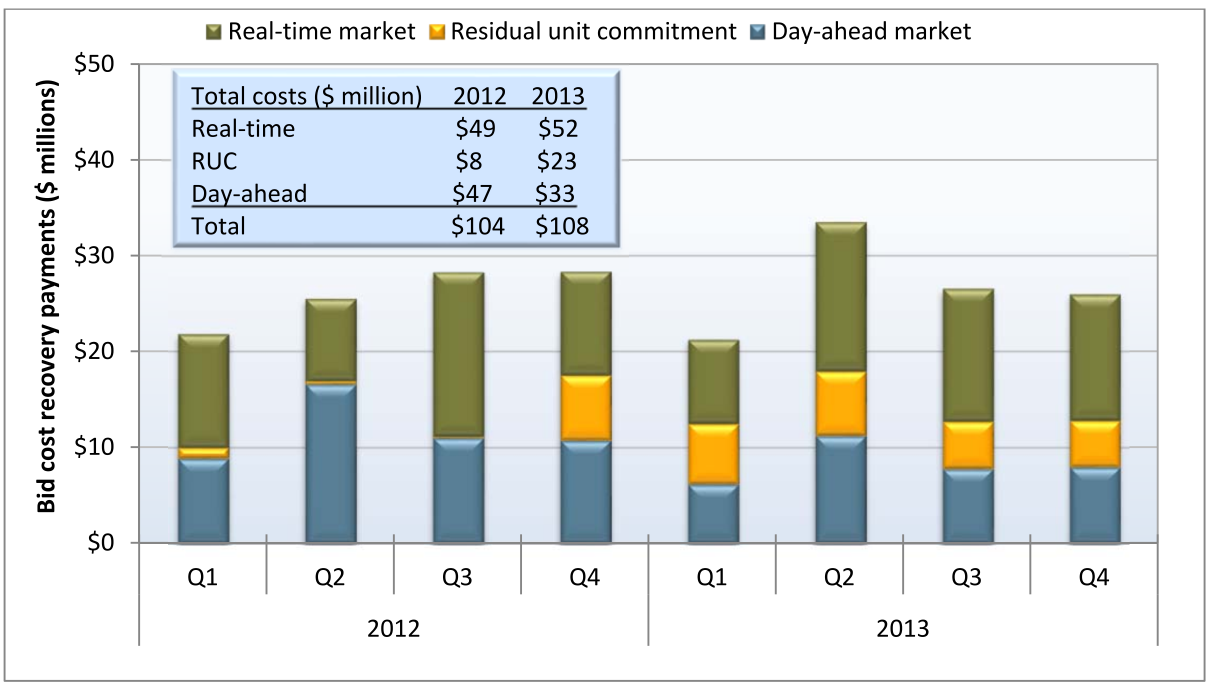
The increase in residual unit commitment bid cost recovery payments is primarily because of the increase in residual unit commitment driven by net virtual supply and operator adjustments to residual unit commitment requirements. The next section explains bid cost recovery in further detail.

2.6 Bid cost recovery payments

Generating units are eligible to receive bid cost recovery payments if total market revenues earned over the course of a day do not cover the sum of all the unit's accepted bids. This calculation includes bids for start-up, minimum load, ancillary services, residual unit commitment availability and day-ahead and real-time energy. Excessively high bid cost recovery payments can indicate inefficient unit commitment or dispatch. However, as described below, a large portion of bid cost recovery payments in 2013 were incurred to meet special reliability issues in the event of a contingency event as well as to replace energy from liquidated net virtual supply. The latter greatly influenced the residual unit commitment bid cost recovery costs.

Figure 2.17 provides a summary of total estimated bid cost recovery payments in 2013 by quarter and by market. Bid cost recovery payments totaled around $108 million or about 1 percent of total energy costs. This compares to a total of $104 million or about 1.3 percent of total energy costs in 2012, an increase of about 4 percent from 2012 to 2013.

Figure 2.17 Bid cost recovery payments



Total costs ($ million)	2012	2013
Real-time	$49	$52
RUC	$8	$23
Day-ahead	$47	$33
Total	$104	$108

Bid cost recovery payments for units committed in the day-ahead energy market totaled $33 million in 2013. DMM estimates that units committed due to minimum online constraints incorporated in the day-ahead energy market accounted for about $9 million or over 8 percent of total bid cost recovery payments in 2013. These constraints are used to meet special reliability issues that require having units online to meet voltage requirements and in the event of a contingency.[69]

Bid cost recovery payments associated with real-time market dispatches accounted for $52 million or almost half of all bid cost recovery payments in 2013. As shown in Figure 2.17, these payments increased notably in the second quarter, reaching around $16 million, and slightly tapering off to $13 million in the fourth quarter.

Bid cost recovery payments resulting from units committed though exceptional dispatches also played a significant role in real-time bid cost recovery payments. These payments are driven primarily by minimum load bid costs, which could equal up to 200 percent of units' actual cost of operating at minimum load.[70] DMM estimates that approximately $16 million of the real-time bid cost recovery payments in 2013 was for units committed through exceptional dispatches.

Bid cost recovery payments associated with units committed through the residual unit commitment process totaled about $23 million in 2013, an increase from $8 million in 2012. This can be attributed to a combination of factors including increases in the residual unit commitment procurement levels driven by reliability related adjustments made by ISO operators, a significant increase in net virtual supply in 2013, and differences between forecasted versus bid-in demand in the day-ahead market (see Section 9.8 for further detail).

ISO operators made adjustments to the system or regional residual unit commitment requirements to mitigate potential contingencies. These changes were concentrated primarily in the peak hours. Occasionally, units were committed in the residual unit commitment process to meet these system needs. However, these units were at times uneconomic in real time requiring recovery of their bid costs through bid cost recovery payments.

2.7 Real-time imbalance offset costs

The real-time imbalance offset charge is the difference between the total money paid out by the ISO and the total money collected by the ISO for energy settled at hour-ahead and 5-minute market prices. The charge is allocated as an uplift to measured demand (i.e., physical load plus exports).

The real-time imbalance offset charge consists of two components. Any revenue imbalance from the energy and loss components of hour-ahead and 5-minute real-time energy settlement prices is collected through the *real-time imbalance energy offset charge* (RTIEO). Any revenue imbalance from the

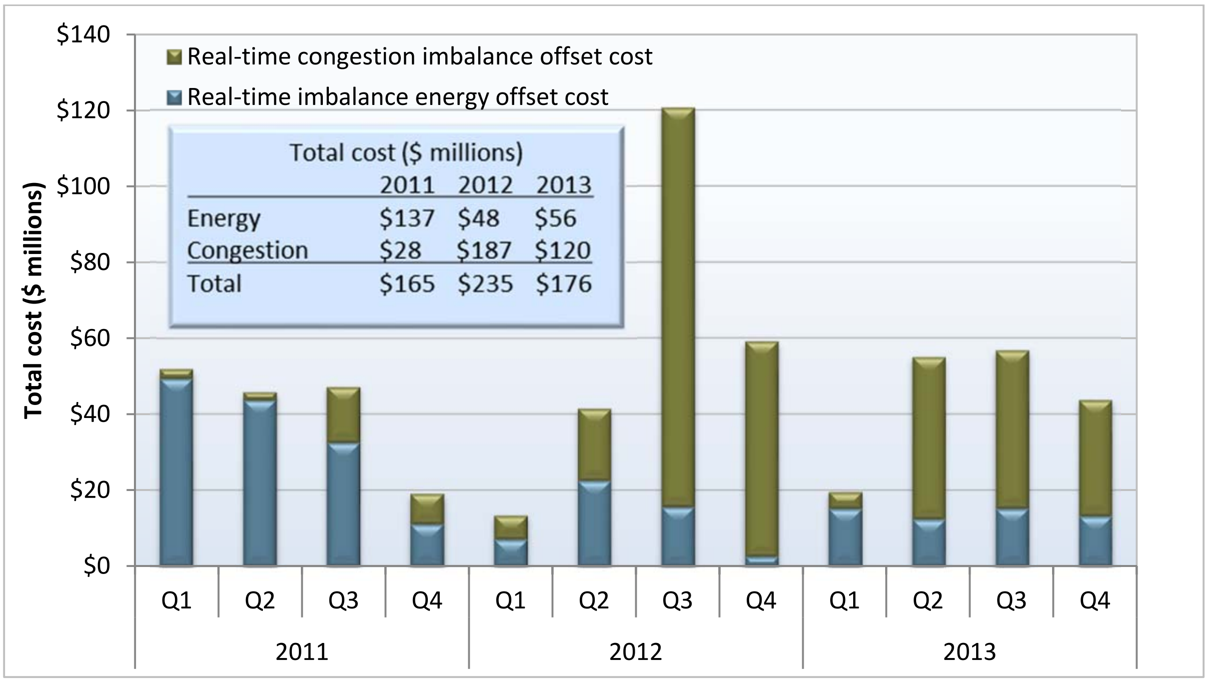
[69] Minimum online constraints are based on existing operating procedures that require a minimum quantity of online capacity from a specific group of resources in a defined area. These constraints make sure that the system has enough longer-start capacity online to meet locational voltage requirements and respond to contingencies that cannot be directly modeled.

[70] The 200 percent registered cost cap changed effective November 1, 2013. The registered cost cap decreased from 200 percent to 150 percent of a unit's projected proxy costs for start-up and minimum load costs, while increasing the types of cost adders allowed in the proxy cost at the same time. Two additional cost categories were included in the calculation: (1) grid management charges and (2) major maintenance costs. For more information, see: http://www.caiso.com/Documents/CommitmentCostsRefinementProject_RegisteredCostCapChangeEffective%2011-1-13.htm.

congestion component of these real-time energy settlement prices is recovered through the *real-time congestion imbalance offset charge* (RTCIO).

Real-time imbalance costs for energy and congestion totaled about $176 million in 2013, compared to $235 million in 2012. As seen in Figure 2.18, the decrease in total imbalance offset costs was primarily attributable to a reduction in the real-time congestion imbalance offset costs, which fell from $187 million in 2012 to $120 million in 2013. Real-time imbalance energy offset costs rose to $56 million in 2013 from a record low of $48 million in 2012.

Figure 2.18 Real-time imbalance offset costs



Real-time congestion offset costs

In 2013, real-time congestion offset costs were primarily due to unpredictable real-time conditions rather than the systematic and predictable congestion patterns stemming from unscheduled flows and market modeling differences that drove congestion offset costs in prior periods.[71] Congestion offset costs incurred on 8 days accounted for over $30 million, more than one-quarter of the annual total costs. Costs on these days were due to:

- The Metcalf transformer outage (April 22, May 2, and May 3);
- The Powerhouse fire under the Midway-Vincent transmission line (May 30);
- Unscheduled flows which resulted in substantial deviations between hour-ahead and 5-minute market congestion (June 8 and July 4);

[71] For further details, see *2012 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2013, Section 3.4: pp. 90-99: http://www.caiso.com/Documents/2012AnnualReport-MarketIssue-Performance.pdf.

- Substantial increase in actual load from day-ahead forecasts (August 30);[72] and
- Congestion cost differences due to the real-time conformance of the SCIT branch group constraint (November 13).

The ISO's efforts to address systematic modeling differences between the day-ahead and real-time markets, including better alignment of day-ahead and real-time transmission limits and modification of the constraint relaxation parameter, contributed to reducing real-time congestion imbalance costs in 2013 compared to the summer of 2012. However, as the 2013 results show, the possibility of high real-time imbalance offset costs continues to exist as random and unexpected events occur.

Real-time imbalance energy offset costs

In 2013, real-time energy offset costs were $56 million and accounted for less than one-third of total real-time imbalance offset costs.[73] A substantial portion of these costs occurred on a relatively small number of days due to specific events.

Real-time energy offset costs incurred on December 9 and 10 totaled over $3.2 million. On these days, natural gas pipeline issues caused internal generation to be backed down in order to help maintain pipeline reliability in Southern California. This generation was replaced, in part, by imports on the inter-ties. The imports settled against hour-ahead prices, whereas the internal generation settled against 5-minute real-time prices. The difference in these prices, combined with virtual demand positions which benefited from higher real-time prices, resulted in the high real-time imbalance energy offset costs.

Real-time energy offset costs incurred on 6 additional days accounted for over 10 percent of the annual total. These days include May 30, the date of the Powerhouse fire under the Midway-Vincent line, and August 30 when actual load was substantially higher than the day-ahead forecast.

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

[73] Real-time imbalance energy offset charges are primarily a function of two factors: the quantity of net import and export energy which the ISO buys (or sells) in the hour-ahead market in a given hour; and the difference between system energy prices in the hour-ahead and 5-minute real-time markets. The quantity of net inter-tie energy bought (or sold) by the ISO at the hour-ahead market price must be subsequently offset by the ISO at the 5-minute market prices. When the ISO sells net exports (including liquidated inter-tie virtual supply) in the hour-ahead market and then purchases additional supply in the 5-minute market at a higher price, this creates a revenue shortfall that is recovered through the imbalance energy offset charge. The ISO can therefore reduce the magnitude of the uplift (positive or negative) in any given hour by either (1) reducing the quantity of net inter-tie energy it acquires that hour, or (2) reducing the system energy price difference between the hour-ahead and 5-minute markets.

3 Real-time market issues

As noted in Chapter 2, real-time prices were systematically below day-ahead prices for much of 2013. This was a change from prior years when real-time prices were typically higher than day-ahead prices. This chapter discusses reasons for the change in systematic price differences in 2013, as well as upcoming changes in the real-time market in 2014 that could potentially promote price convergence between the day-ahead and real-time markets.

Historically, real-time market prices have been affected by brief but extreme price spikes related to short-term ramping limitations. These price spikes are frequently driven by ramping infeasibilities that set price levels to the offer cap and floor. Section 3.1 of this chapter outlines the factors for these price spikes and shows that the frequency of these price spikes declined in 2013. Specifically, the frequency of upward ramping infeasibilities decreased from 0.6 percent of intervals in 2012 to 0.4 percent of intervals in 2013. After the first quarter, the frequency was around 0.2 percent.

DMM attributes this decrease to changes to the flexible ramping constraint, which is outlined in Section 3.2, as well as decreases in congestion, as outlined in Chapter 8. The flexible ramping constraint was added to the model in late 2011. The flexible ramping constraint reserves capacity in the 15-minute real-time market run to address unanticipated changes in load and supply. In 2013, the ISO steadily increased the requirement, particularly during morning and evening ramping hours. The increased requirement led to fewer infeasible market outcomes, and thus fewer price spikes.

When excluding ramping infeasibilities over the past few years, DMM analysis shows that real-time prices have historically been below day-ahead prices, particularly in peak hours. DMM attributes this difference to additional supply showing up in the real-time market that was not scheduled in the day-ahead market. The additional supply is primarily from unscheduled wind and solar resources and, to a lesser extent, minimum load energy from units committed by the ISO for reliability purposes through the residual unit commitment process and exceptional dispatch after the day-ahead energy market was concluded.

Convergence bids, which are intended to converge prices between the day-ahead and real-time markets, offset a portion of this unscheduled energy by adding net virtual supply to the day-ahead energy market. This was particularly the case during off-peak hours, when the trend of lower real-time prices was most pronounced and predictable. However, only a small portion of unscheduled energy was offset by net virtual supply in peak hours. This likely reflects the fact that extremely high real-time prices continued to occur during peak hours as a result of ramping limitations and other events.

In early 2014, the ISO implemented changes to help account for unscheduled renewable capacity in the residual unit commitment market. This change automatically increases scheduled resources up to the forecast level in the residual unit commitment process if they are scheduled below the forecast in the day-ahead market. This change can help reduce the overall amount of residual unit commitment capacity.

In addition, modeling changes related to the ISO's spring 2014 release may help promote price convergence between the day-ahead and real-time markets. Convergence bids will settle against 15-minute market prices which are less volatile than 5-minute market prices. Furthermore, the bid floor will drop to -$150/MWh from -$30/MWh, which may lower overall average prices. This may provide further incentives for virtual supply to bid into the market in the event that the trend of low real-time prices relative to day-ahead prices continues.

3.1 System power balance constraint

Background

The ISO market includes an energy bid cap and bid floor to limit the effect that short-term constraints, modeling issues or market power may have on market outcomes. Currently, the bid cap is set at $1,000/MWh; the bid floor is set at -$30/MWh.[74] The bid cap and floor affect prices directly and indirectly:

- Dispatching a generator with a bid at or near the bid cap or floor will directly impact the system energy cost and prices.
- Penalty prices for relaxing various energy and transmission constraints incorporated in the market software are also set based relative to the bid cap and floor. When one of these constraints is relaxed, prices can reach the energy bid cap or floor, as described below.

Prices have seldom reached the bid cap or floor directly because of the market dispatching energy bids at these bid limits. Most prices hitting these bid limits are caused by relaxing the power balance or transmission capacity constraints.

When energy that can be dispatched in the real-time market is insufficient to meet estimated demand during any 5-minute interval, the system-wide power balance constraint of the market software is relaxed. This constraint requires dispatched supply to meet estimated load on a system-wide level during all 5-minute intervals. The power balance constraint is relaxed under two different conditions:

- When insufficient incremental energy is available for 5-minute dispatch, this constraint is relaxed in the scheduling run of the real-time software. In the scheduling run, the software assigns a penalty price of $1,100/MW for the first 350 MW that this constraint is relaxed.[75] After this, load and export schedules may be reduced at a penalty price of $6,500/MW in the scheduling run. In the pricing run, a penalty price of $1,000/MW is used. This causes prices to spike to the $1,000/MWh bid cap or above.
- When insufficient decremental energy is available for 5-minute dispatch, the software relaxes this constraint in the scheduling run using a penalty price of -$35/MW for the first 350 MW. After this, self-scheduled energy may be curtailed at a penalty price of -$1,800/MW. In the pricing run, a penalty price of -$35/MW is used. This causes prices to drop down to or below the -$30/MWh floor for energy bids.

[74] The -$30/MWh bid floor is really a "soft floor." Bids below -$30/MWh can be submitted, but do not set the market price. Also, bids below -$30/MWh are subject to cost justification if the participant seeks to be paid more than -$30/MWh. The ISO anticipates lowering the bid floor to -$150/MWh, in the spring of 2014. The new bid floor will be a hard cap, with no bids allowed below -$150/MWh for any reason. The lowering of the bid floor is intended to encourage variable energy resources to submit economic decremental bids in real time.

[75] The scheduling run parameter was increased in 2012 from $1,000/MW to ensure that all economic bids were exhausted before the penalty was imposed.

When brief insufficiencies of energy bids that can be dispatched to meet the power balance software constraint occur, the actual physical balance of system loads and generation is not impacted significantly nor does it necessarily pose a reliability problem. This is because the real-time market software is not a perfect representation of actual 5-minute conditions. To the extent power balance relaxations occur more frequently or last for longer periods of time, an imbalance in loads and generation actually does exist during these intervals, resulting in units providing regulation service to provide additional energy needed to balance loads and generation. To the extent that regulation service and spinning reserve capacity are exhausted, the ISO may begin relying on the rest of the interconnection to balance the system, which may affect the reliability performance of the ISO system.

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 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 the ramping limitation in the congested portion of the ISO system.[76]

Power balance constraint relaxations

The frequency of power balance constraint relaxations due to insufficient upward or downward ramping capacity decreased in 2013 compared to previous years. Additionally, congestion contributing to power balance constraint infeasibilities in 2013 also decreased. This played a larger role in previous years.

Figure 3.1 and Figure 3.2 show the frequency with which the power balance constraint was relaxed in the 5-minute real-time market software in each quarter since 2012. The power balance constraint has never been relaxed in the day-ahead or the hour-ahead markets as self-schedules are cut first.

As shown in Figure 3.1, the constraint was relaxed because of insufficient incremental energy in about 0.4 percent of the 5-minute intervals in 2013. When the first quarter is excluded, insufficiencies occurred in about 0.2 percent of intervals in 2013. In 2012, the power balance constraint was relaxed in about 0.6 percent of the 5-minute intervals. Both the total frequency and power balance relaxations as a result of congestion were down in 2013 compared to 2012. In 2013, around 37 percent of the upward ramping capacity relaxations (shown in Figure 3.1) resulted from extreme congestion compared to about 54 percent in 2012.

[76] 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 constraint. Thus, the regional constraint is relaxed instead of the power balance constraint.

Figure 3.1 Relaxation of power balance constraint due to insufficient upward ramping capacity

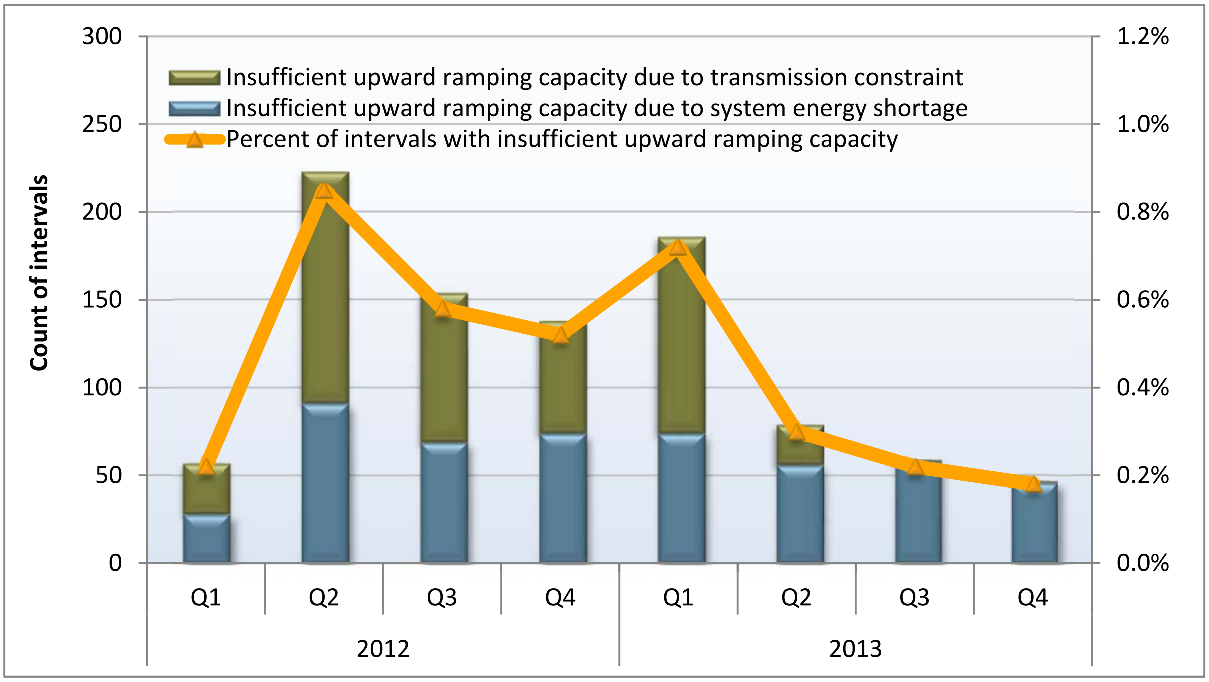
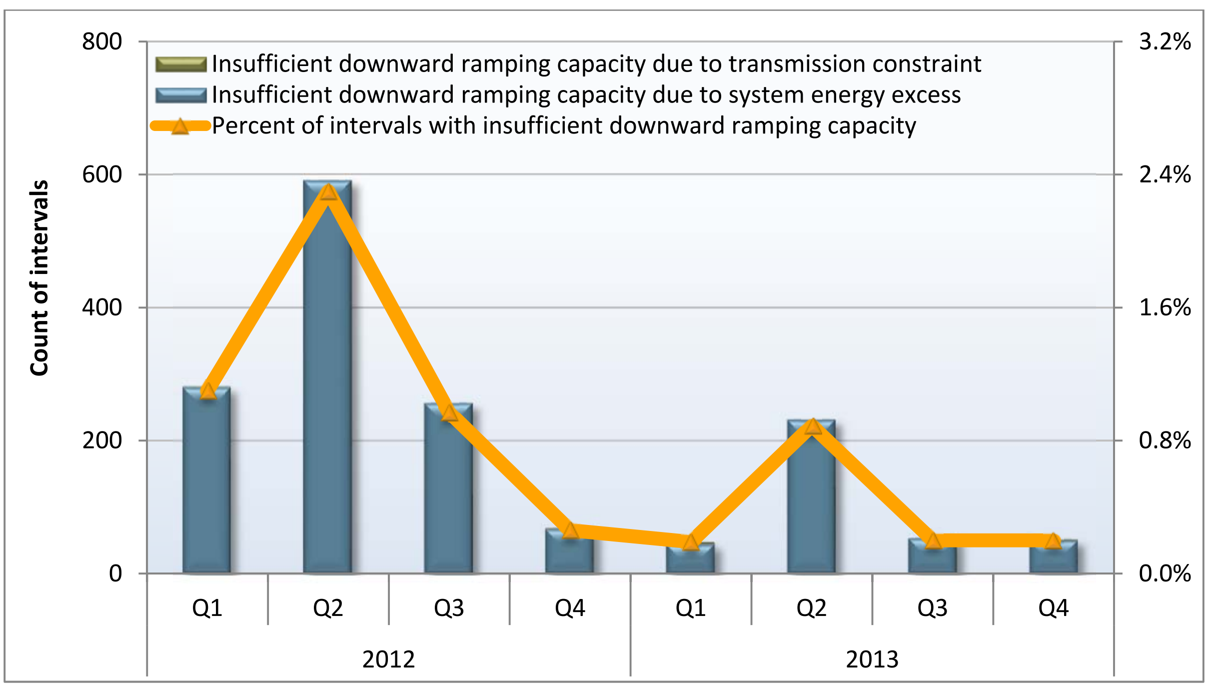


Figure 3.2 Relaxation of power balance constraint due to insufficient downward ramping capacity



There was a significant decrease in the frequency of relaxations due to insufficient downward ramping capability in 2013. In a typical year, power balance constraint relaxations occur more frequently due to insufficient downward decremental capacity rather than insufficient upward capacity. Unlike previous years, power balance constraint relaxations due to insufficient downward decremental capacity occurred with about the same frequency of upward insufficiencies in 2013. As shown in Figure 3.2, the constraint was relaxed due to insufficient decremental capacity in just under 0.4 percent of intervals in 2013. This was a decrease in frequency compared to 2012, where the power balance was relaxed as a result of downward ramping insufficiencies during about 1 percent of intervals.

This is likely a result of decreased scheduling of inflexible hydro-electric generation in 2013 due to poor hydro-electric conditions. When the constraint is relaxed under these conditions, the downward impact on average prices is also less significant because prices only drop towards or to the bid floor of -$30/MWh. As in previous years, congestion was not a driving factor causing downward ramping infeasibilities.

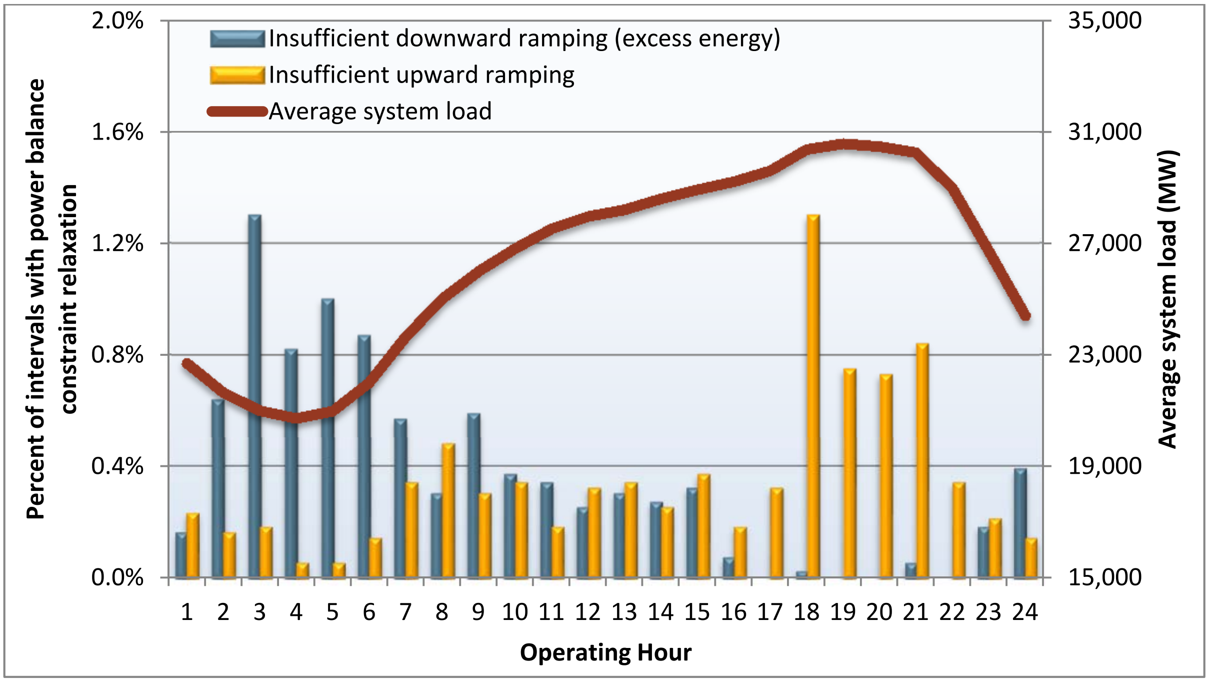
Figure 3.3 shows the percentage of intervals that the power balance constraint was relaxed during each operating hour in 2013. This figure highlights the following:

- Shortages of upward ramping capacity (yellow bar) caused the system power balance constraint to be relaxed most frequently during the highest load hours (18 through 21) of the day. During these hours on average, prices spiked because of shortages of upward ramping in around 0.9 percent of intervals, down from about 1.2 percent in 2012. This was more than three times more frequent than all other hours.

- The system power balance constraint was relaxed due to shortages of downward ramping capacity (blue bar) primarily during off-peak hours, especially during the early morning hours, when periods of excess energy tend to occur. About 64 percent of these intervals occurred in hours ending 1 through 8, during which the constraint was relaxed about 0.7 percent of the time. This is a decrease from 2012 when about 76 percent of downward infeasibilities occurred during the same hours, during which the constraint was relaxed about 2.5 percent of the time. Excess energy often occurs in these hours as generation from wind units reaches higher levels and as loads are at their lowest levels.

Similar to last year, most of these shortages were very short-lived. In 2013, about 87 percent of shortages of upward ramping capacity persisted for only one to three 5-minute intervals (or 5 to 15 minutes). About 95 percent of shortages of downward ramping capacity lasted for only one to three 5-minute intervals. This was an increase from about 72 percent in 2012.

Figure 3.3 Relaxation of power balance constraint by hour (2013)



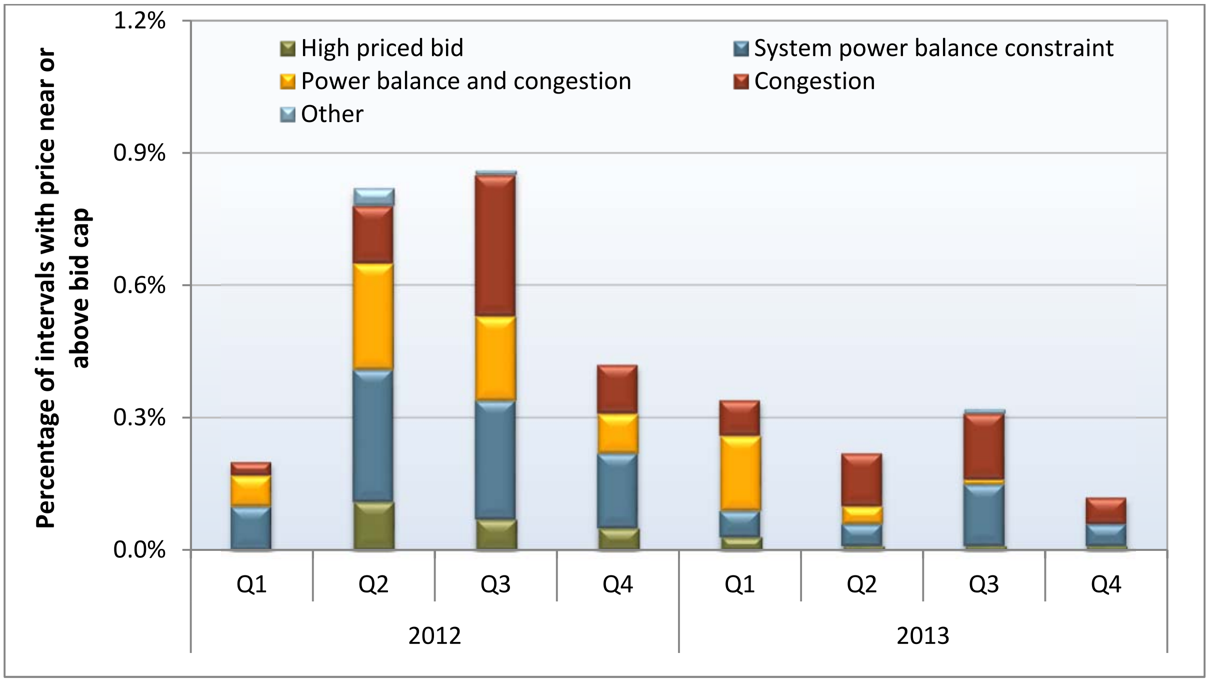
Causes of extremely high prices

Congestion continued to play a role in high prices in the real-time market in 2013. Figure 3.4 shows the approximate frequency of different factors driving high real-time prices for each load aggregation point. For purposes of this analysis, high prices are defined as including all intervals in which the real-time price for a load aggregation point was approaching the bid cap.[77] Reasons for high prices are identified based on the following categories:

- **System power balance constraint** – During these intervals the power balance constraint was relaxed and the congestion component was less than $200/MWh.
- **Power balance constraint and congestion** – These prices occurred in intervals when the power balance constraint was relaxed and the congestion component was greater than $200/MWh.
- **Congestion** – These prices occurred in intervals when the power balance constraint was not relaxed and the congestion component was greater than $200/MWh.
- **High priced bid** – These prices occurred when the power balance constraint was not relaxed and the congestion component was less than $200/MWh, but a high priced bid was dispatched during the interval.
- **Other** – The high price was not included in any of the above categories.

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

Figure 3.4 Factors causing high real-time prices



Results of this analysis show that the main factor causing extremely high prices in the real-time market was congestion either by itself or in combination with the power balance constraint. This is a change from previous years when high prices were caused primarily by the power balance constraint, either by itself or with congestion. As shown in Figure 3.4:

- Congestion played the largest role in causing high load aggregation point prices. In 2013, about 41 percent of all high price events were due to pure congestion, compared to 27 percent in 2012. About 21 percent of the high price events were due to a combination of congestion and the system power balance constraint in 2013, compared to 26 percent in 2013.
- Around 30 percent of all high prices at load aggregation points in 2013 were due to relaxing the power balance constraint during an interval when congestion did not have a significant impact on price. This is slightly down from 34 percent of the high prices in 2012.
- There were relatively few instances where the dispatch of high priced bids could have caused a high load aggregation point price. Overall, these intervals represented about 7 percent of all high price events during the year, compared to 10 percent in 2012.

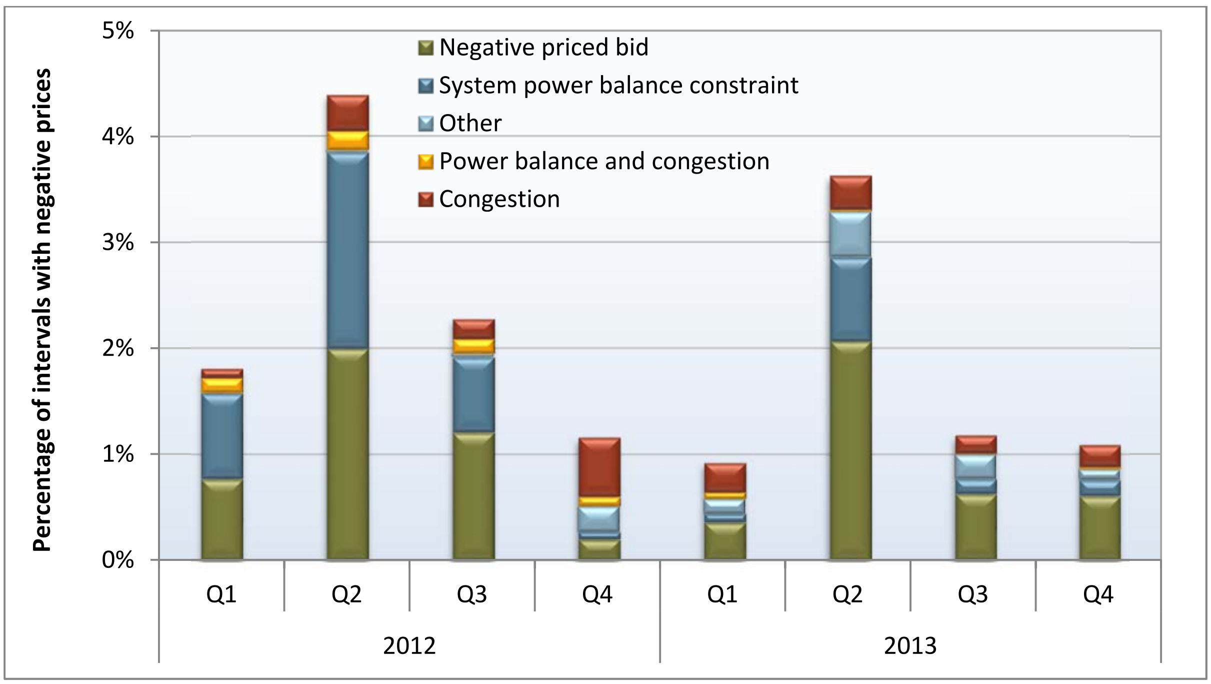
Causes of negative prices

The frequency of negative prices decreased notably in 2013 compared to 2012. This is likely due to decreases in hydro-electric generation. Real-time energy prices become negative for various reasons. Figure 3.5 summarizes an analysis of the causes of real-time prices less than $0/MWh at load aggregation points. The causes for low prices are categorized as follows:

- **Power balance constraint** – During these intervals the power balance constraint was relaxed and the congestion component was less than 50 percent of the price.

- **Power balance constraint and congestion** – These prices occurred when the power balance constraint was relaxed and the congestion component was more than 50 percent of the price. In these cases, the congestion component was negative.
- **Congestion** – These negative prices occurred when the power balance constraint was not relaxed and the negative congestion component accounted for more than half the negative price.
- **Low priced bid** – During these intervals, the energy component was between -$30/MWh and $0/MWh, the congestion component accounted for less than 50 percent of the negative price, and a negatively priced bid was dispatched.
- **Other** – The negative price was not caused by any of the conditions described above.

Figure 3.5 Factors causing negative real-time prices



Results of this analysis show that negatively priced bids play a relatively large role in determining the negative prices in 2013, similar to 2012. As seen in Figure 3.5:

- In 2013, around 54 percent of negative prices were due to the dispatch of negatively priced bids, compared to 43 percent of the negative prices in 2012.
- About 17 percent of negative prices in 2013 occurred when the power balance constraint was relaxed, down from about 36 percent in 2012.
- About 13 percent of negative prices were due to other model parameters. Most of these negative prices had energy components between -$30/MWh and -$35/MWh, but the power balance constraint was not relaxed.
- Congestion continued to play a role in negative prices in 2013. It caused about 14 percent of negative prices for load aggregation points which is slightly more than the 12 percent in 2012.

3.2 Real-time flexible-ramping constraint

This section provides background of the flexible ramping constraint and highlights key performance measures. While it is difficult to benchmark the performance of this constraint with other products, DMM highlights several performance factors. Key highlights include the following:

- Flexible ramping payments were about $26 million for the year, compared to about $20 million in 2012. For the sake of comparison, spinning reserve costs were about $28 million in 2013.
- A little over 40 percent of flexible ramping constraint payments in 2013 were during intervals when the system was unable to procure enough flexible ramping capacity to meet the requirement. In 2012, almost 50 percent of flexible ramping constraint payments were during intervals with flexible ramping procurement shortfalls.
- The ISO operators began to increase the flexible ramping requirement during on-peak periods beginning in February.
- The majority of the ramping capacity was in the northern part of the ISO system. When congestion occurs in the southern part of the system, this capacity can be *stranded* or unavailable for dispatch to help relieve congestion and meet system energy requirements in Southern California. This scenario was more likely in the beginning of the year due to the prevailing congestion patterns, but less likely in the second half of the year as congestion decreased.

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.[78] The constraint is only applied to internal generation and proxy demand response resources and not to external resources. Application of the constraint in the 15-minute real-time pre-dispatch market is intended to ensure that enough capacity is procured to meet the flexible ramping requirement.

The default requirement is currently set to 300 MW, but was frequently adjusted up to 900 MW, typically in the morning and evening ramping hours. The ISO operators have the ability to adjust the requirement depending on system conditions. Over the course of the year, the ISO operators frequently adjusted the requirement to different levels to better prepare for potential ramping shortages, particularly during the steep morning and evening ramping periods.[79]

If there is sufficient capacity already online, the constraint 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. Otherwise, additional flexible ramping capacity is increased to supplement the existing non-contingent spinning reserves in the system in managing these variations.

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

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

[79] On January 31, 2014, the ISO lowered the recommended maximum adjustment of the flexible ramping requirement from 900 MW to 600 MW. For further detail, see the following market notice: http://www.caiso.com/Documents/Notification-RevisedCaliforniaISO_OperatingProcedures2250-2330-2540-4410-5730.htm.

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.

Since December 2011, the penalty price associated with procurement shortfalls was set to $247/MW. This penalty price remained through 2013. However, as part of its analysis of upcoming market changes in the spring of 2014, the ISO has determined that $60/MW is a more appropriate penalty price. Accordingly, the ISO will lower the penalty price on May 1, 2014.[80]

Performance of the flexible ramping constraint

Total payments for flexible ramping resources in 2013 were around $26 million, compared to about $20 million in 2012. For the sake of comparison, costs for spinning reserves totaled about $28 million in 2013. 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 are complex and beyond the scope of this analysis.

Table 3.1 provides a summary of the monthly flexible ramping constraint activity in the 15-minute real-time market in 2013. The table highlights the following:

- For the year, the flexible ramping constraint was binding in 14 percent of 15-minute intervals. The frequency that the flexible ramping constraint was binding varied over the year, being highest in February and March (19 percent) and lowest in September (7 percent).
- The portion of intervals during which the ISO was unable to procure the targeted level of flexible ramping capacity was 1.3 percent of all 15-minute intervals in 2013, compared to 1.6 percent of intervals in 2012.
- The average shadow price when binding varied between $17/MWh and $73/MWh.

Table 3.1 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

[80] For more information see: http://caiso.com/Documents/TechnicalBulletin-FlexibleRampingConstraintPenaltyPrice-FifteenMinuteMarket.pdf.

Figure 3.6 Monthly flexible ramping constraint payments to generators

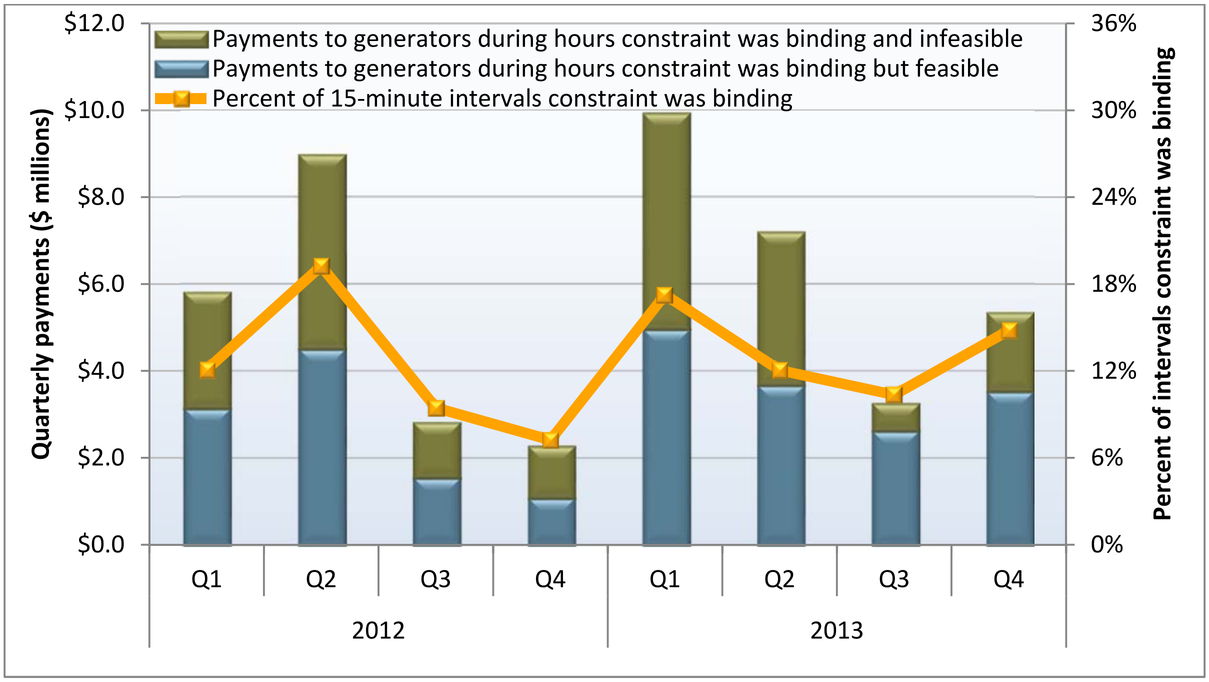
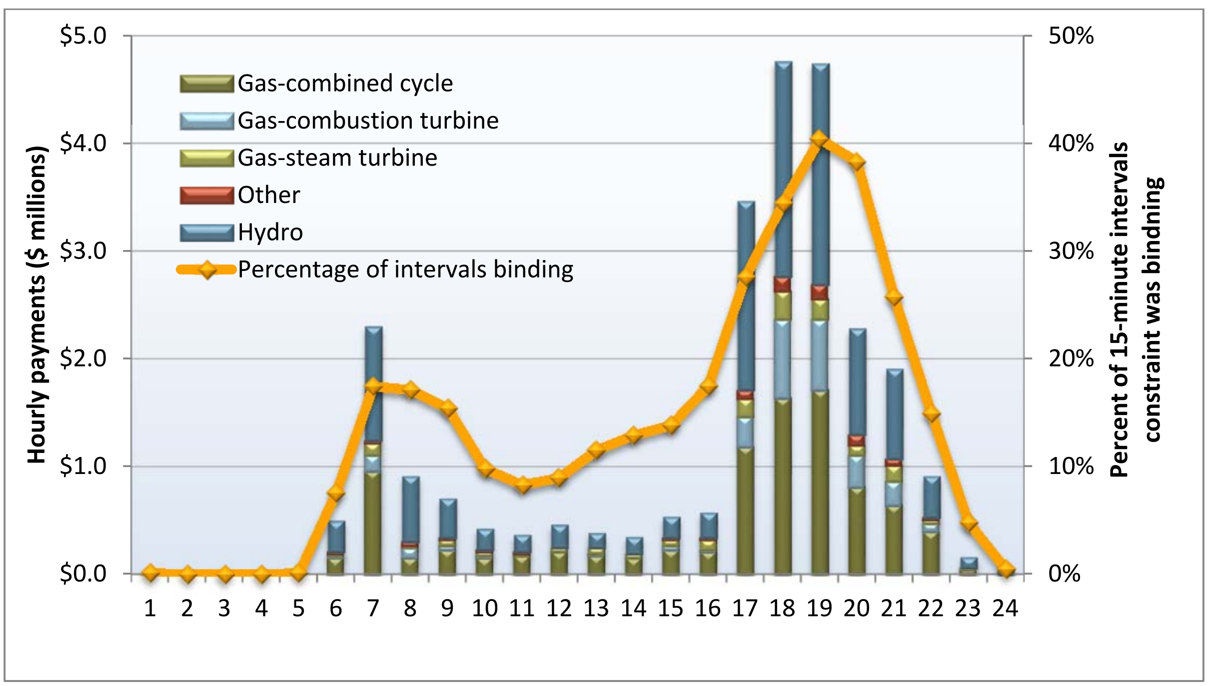


Figure 3.7 Hourly flexible ramping constraint payments to generators (January – December)



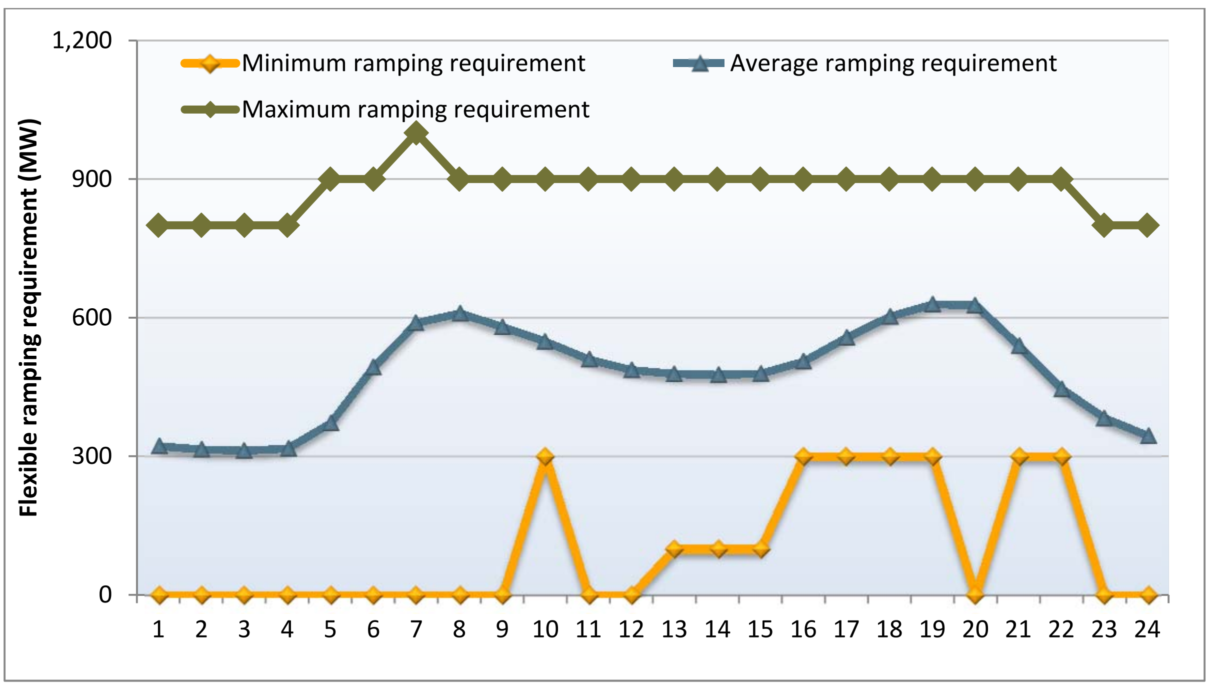
About 40 percent of flexible ramping payments to generators in 2013 occurred during intervals when the system was unable to procure enough flexible ramping capacity to meet the requirement. Figure 3.6 shows the monthly flexible ramping payments to generators. The green bar shows the payments made during intervals with procurement shortfalls and the blue bar shows the payments in all other periods.

On an hourly basis, DMM estimates that most payments for ramping capacity occurred during the evening peak hours and that most payments were for natural gas-fired resources. Figure 3.7 shows the hourly flexible ramping payment distribution during the entire year broken down by technology type. As shown in the graph, the highest payment periods were during hours ending 7 and 17 through 21. Natural gas-fired capacity accounted for about 52 percent of these payments with hydro-electric capacity accounting for 46 percent.

Procurement of flexible ramping capacity

The ISO continues its efforts to decrease the frequency and volume of exceptional dispatch. As a result, ISO operators use market tools such as the flexible ramping constraint to deal with reliability concerns. Figure 3.8 shows the hourly average flexible ramping requirement values in 2013. The hourly ramping requirement ranged from a minimum of 0 MW to a maximum of 900 MW.[81] On average, the requirement was set to around 330 MW in the late evening and early morning hours and over 600 MW in the morning and evening load-ramping hours.

Figure 3.8 Hourly average flexible ramping requirement values (January – December)



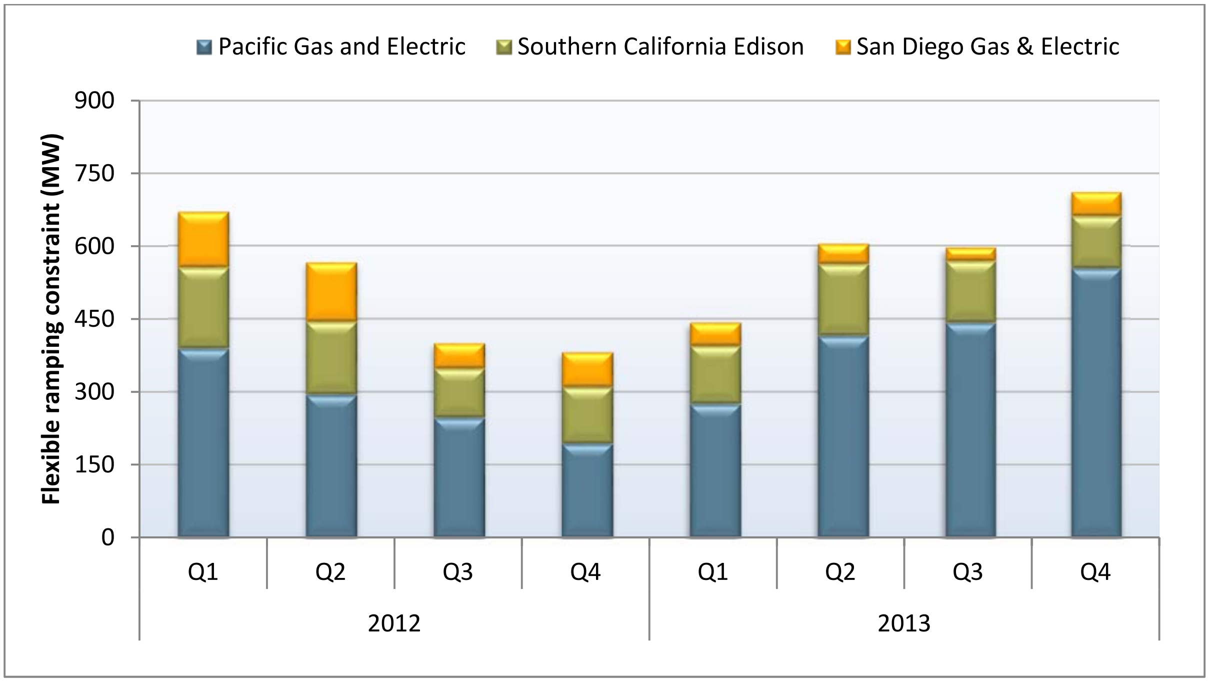
The level of procurement increased over the course of 2013. This was a change from much of 2012, when the requirement fell as the default levels decreased over the year. While the default level

[81] A single hour with 1,000 MW of flexible ramping requirement occurred on December 6, 2013.

remained constant in 2013 at 300 MW, the ISO operators adjusted the flexible ramping requirements by increasing them during peak hours. Figure 3.9 shows that the total procurement grew in 2013 from an average of 440 MW in the first quarter to almost 715 MW in the fourth quarter.

Figure 3.9 also shows the total procurement of flexible ramping capacity by investor-owned utility area. During the year, around 72 percent of the capacity procured for the flexible ramping constraint was in the Pacific Gas and Electric area, which can be stranded when congestion occurs in the southern part of the state. This type of congestion occurred more frequently in the first half of 2013 and less so in the second half of the year.

Figure 3.9 Flexible ramping constraint by investor-owned utility area



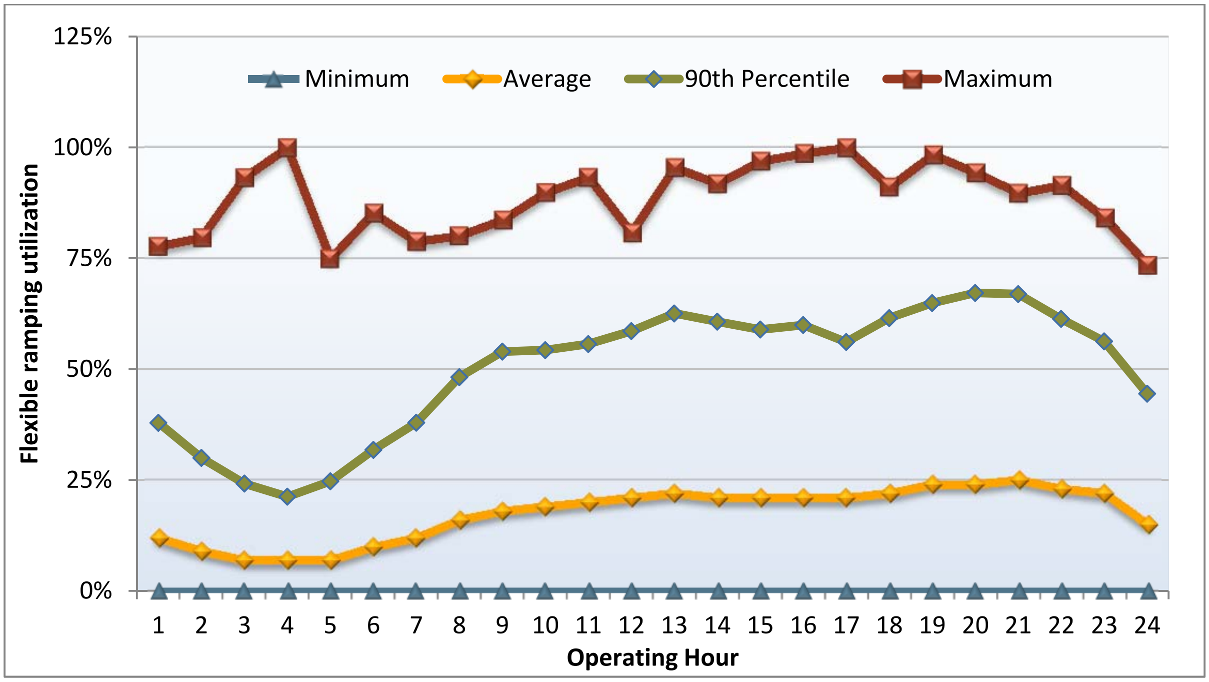
Real-time utilization of flexible ramping capacity

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 hourly utilization was around 17 percent, ranging from 7 percent in the early mornings to 25 percent in the late evening hours. This is a significant decline compared to 2012, which ranged from 15 percent in the early morning hours to 45 percent in the evening hours. The decline in utilization in 2013 compared to 2012 is likely a result of the increase in procurement levels in 2013.

Figure 3.8 shows the minimum, average, 90th percentile and maximum hourly utilization of procured flexible ramping capacity in the 5-minute real-time dispatch in 2013. Utilization at the 90th percentile ranged from 21 percent in the early morning hours to 67 percent in the evening peak hour. Utilization reached 100 percent at some individual 5-minute intervals during hour ending 4 and during the evening ramping hours.

Figure 3.10 Flexible ramping utilization by hour (January – December)



3.3 Day-ahead and real-time price divergence

Average day-ahead prices were systematically higher than real-time prices by an average of about $2/MWh in 2013 (see Section 2.4). These price differences were most pronounced in the second quarter (almost $6/MWh) in both peak and off-peak periods.

This section illustrates that the price relationship changed as a result of increases in the flexible ramping constraint and less congestion, which had historically masked the price differences. Moreover, additional supply in the real-time market, which was not scheduled or committed in the day-ahead market, caused real-time prices to be lower than day-ahead prices. This supply was primarily unscheduled renewable generation, but also included post day-ahead reliability-related generator commitments. While convergence bidding was primarily virtual supply in 2013, which worked to help converge prices between the day-ahead market and real-time market, the volume of virtual supply was not high enough to offset the additional supply in real time.

Historically, real-time prices have been influenced by short but extreme price spikes related to ramping limitations. In late 2011, as noted in Section 3.2, the ISO implemented the flexible ramping constraint, which was added to allow the market software to better resolve infeasibilities in generator ramping in the real-time market related to changes in supply and demand. Beginning at the end of 2012 and continuing through 2013, ISO operators increased the amount of flexible ramping capacity procured during ramping periods (see Figure 3.8). This contributed to reducing the incidence of ramping infeasibilities, which helped reduce the frequency of real-time price spikes.

Figure 3.11 shows the monthly average flexible ramping requirements and the percent of insufficient ramp, both in peak and off-peak hours. The green bars represent the flexible ramping requirements during off-peak hours, while the blue bars represent the flexible ramping requirements during peak hours. The frequency of shortages during peak and off-peak hours are represented by the red and yellow lines, respectively.

Starting in February 2013, the ISO operators increased the flexible ramping requirements for peak hours to an average of about 550 MW and the off-peak requirements to about 400 MW, from an average of 300 MW in earlier months. Corresponding to this increase, the frequency of insufficient upward ramping infeasibilities decreased as the requirement increased. Thus, more ramping availability in real-time contributed to fewer price spikes. As a result, average real-time prices began to fall below day-ahead prices.

This relationship has existed between these markets for some time, but was masked by the infrequent but extreme prices that regularly occurred in the real-time market due to ramping limitations. When these limitations are controlled for, day-ahead peak prices have exceeded real-time peak prices in every month over the past three years, with the exception of August 2013 (see Figure 3.12). Overall, these limitations had very little impact in off-peak hours in most months, except during the first and second quarters of 2013 (see Figure 3.13).

Figure 3.11 Flexible ramping requirements and frequency of insufficient ramp intervals

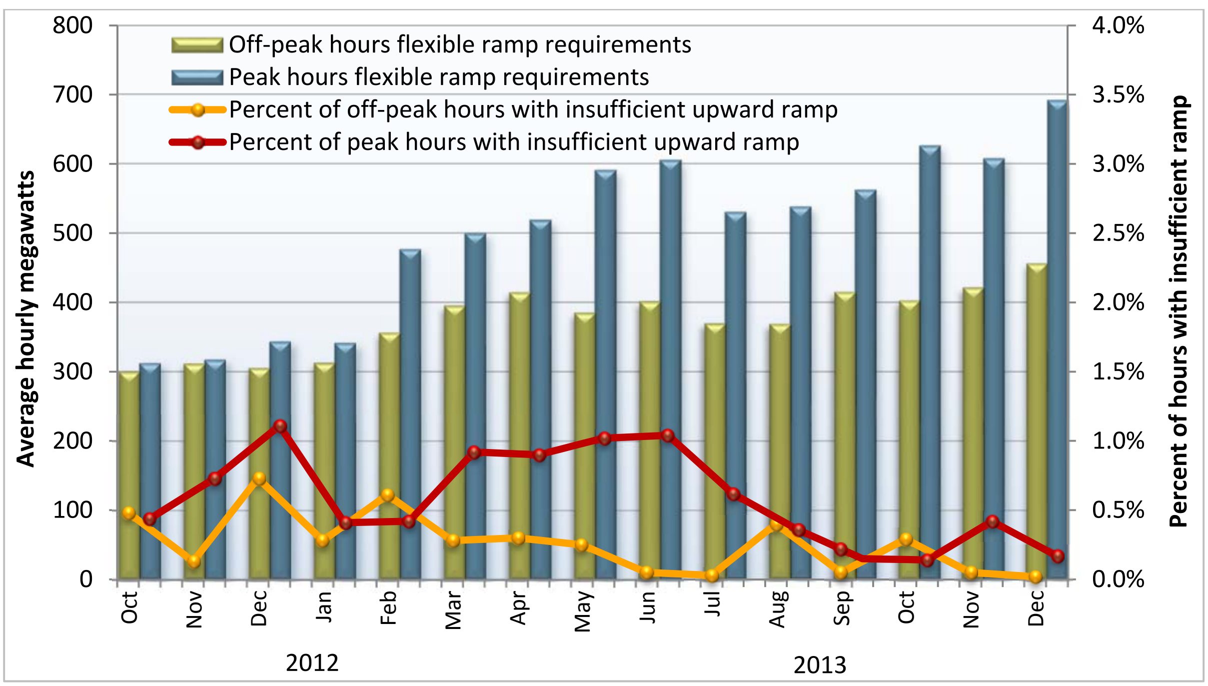


Figure 3.12 Peak average system marginal energy prices excluding power balance constraint limitations

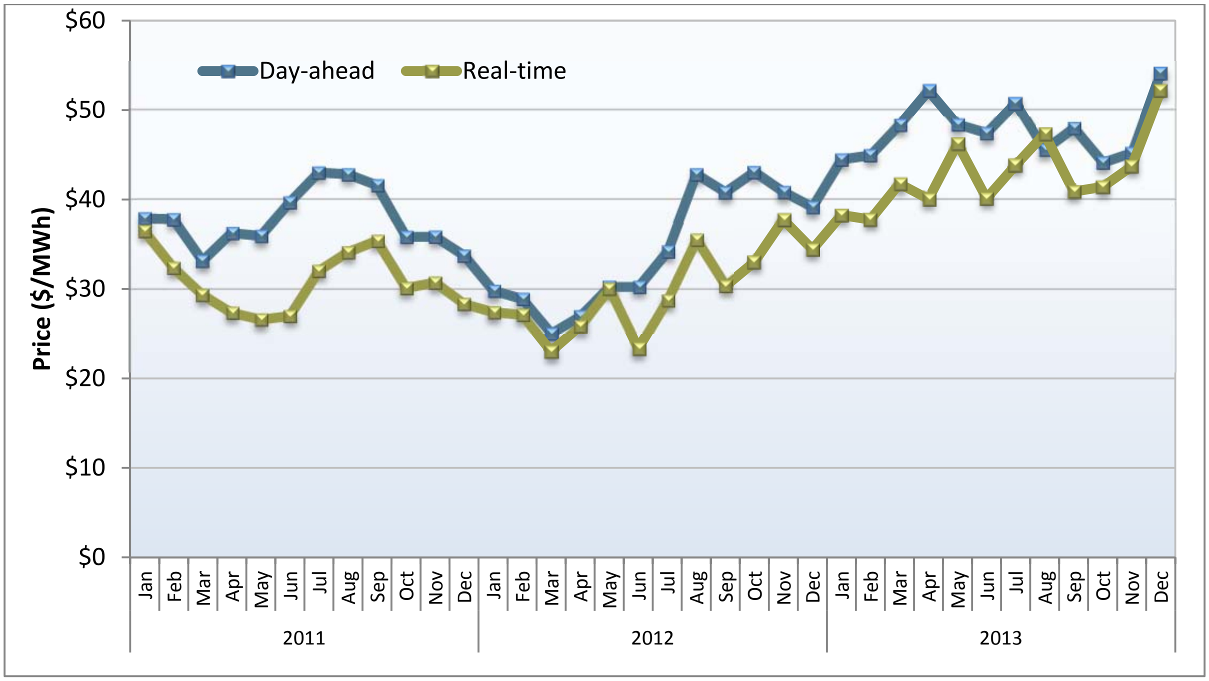


Figure 3.13 Off-peak average system marginal energy prices excluding power balance constraint limitations

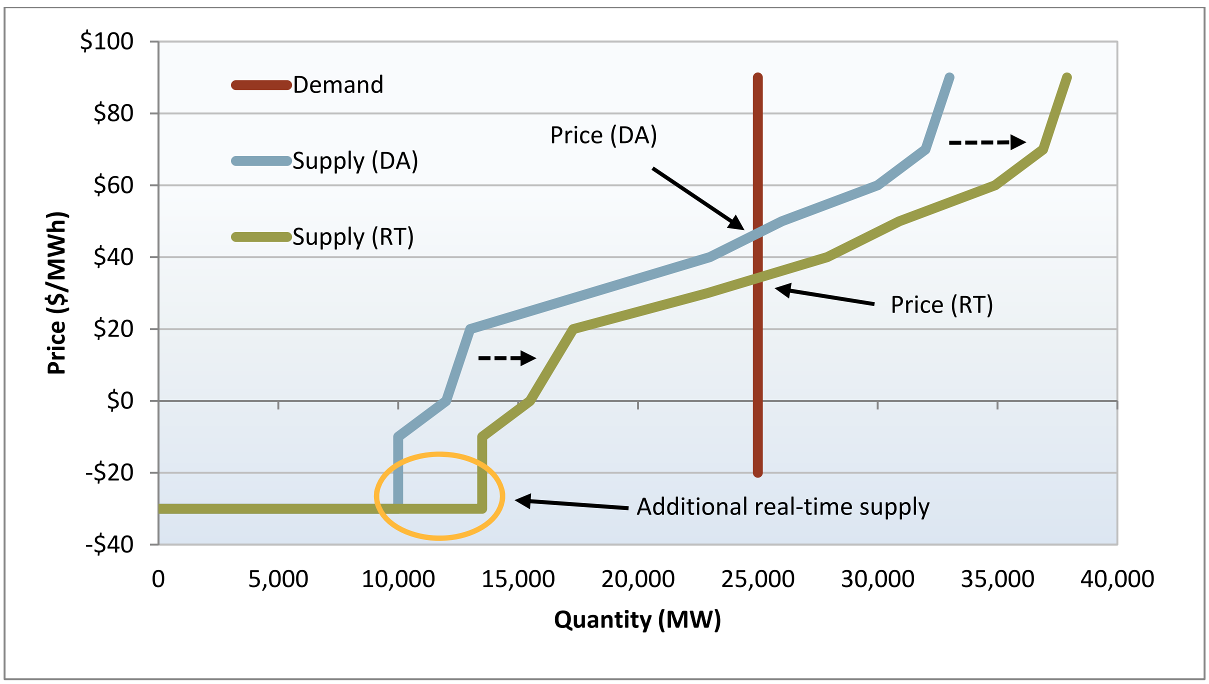
Driving factors

The factors driving real-time prices lower than day-ahead prices include:

- Increased unscheduled generation in real time from wind and solar units;
- Additional generation commitments after the day-ahead market for reliability from the residual unit commitment process and through exceptional dispatch;
- Additional must-take generation due to self-supply and operational parameters (including minimum runtime); and
- Incremental energy bids clearing the real-time market but not the day-ahead market.

These effects mostly shift the supply curve outward, while the last factor changes the shape of the supply curve. As a result, when the supply curve and demand curve meet, they do so at a lower price in the real-time market than in the day-ahead market. Figure 3.14 illustrates this effect.[82]

Figure 3.14 Illustration of supply curve changes from the day-ahead to real time markets



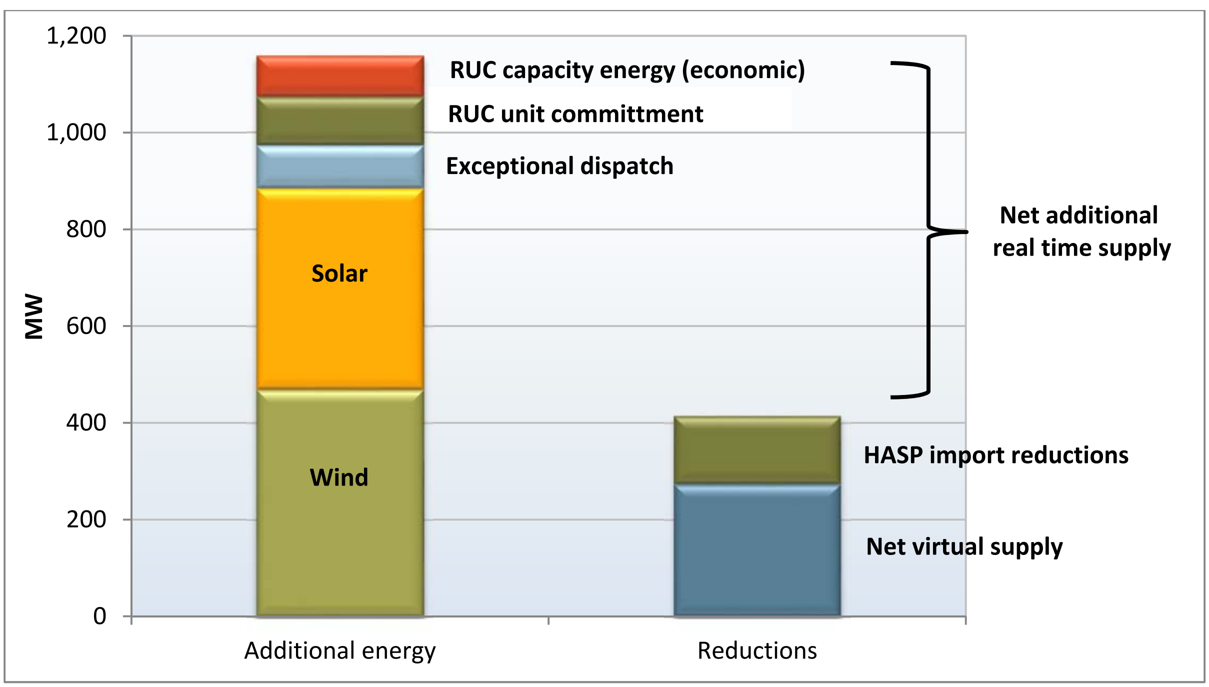
DMM has quantified the average effects of the various factors that cause the real-time supply curve to be different in real time. As seen in Table 3.2 and Figure 3.15, renewable resources were the largest contributor of additional real-time generation. Reliability commitments, through the residual unit commitment and through exceptional dispatch, played a smaller role, while scheduling and bidding decisions also played a role.

82 While bid-in demand in the day-ahead market and actual demand in the real-time market are typically not the same, they are often similar. Thus, for illustrative purposes, we have kept demand the same.

Table 3.2 Average hourly changes in supply in the real-time market relative to the day-ahead market (2013)

Hour	HASP net imports	Wind	Solar	Exceptional dispatch commitment	Exceptional dispatch OOS	RUC long-start unit commitment	RUC capacity RT must-take	RUC capacity economic RT dispatch	Net virtual supply	Total additional RT supply
1	69	593	4	27	2	4	76	81	(678)	178
2	90	588	4	28	3	3	56	74	(770)	75
3	107	564	4	30	2	3	55	67	(781)	51
4	42	529	4	30	3	2	46	51	(812)	(105)
5	134	504	4	33	3	3	49	66	(758)	37
6	364	488	(4)	36	3	4	63	91	(588)	457
7	312	466	(47)	41	3	5	61	68	(320)	588
8	223	419	(56)	44	4	7	78	75	(345)	450
9	246	388	74	48	8	8	80	80	(384)	548
10	153	386	213	53	9	8	74	85	(388)	595
11	1	384	333	59	10	9	63	82	(383)	558
12	(82)	382	400	60	14	12	69	83	(324)	615
13	(129)	381	429	61	15	14	61	65	(258)	638
14	(155)	400	442	65	16	14	67	62	(291)	619
15	(142)	427	447	68	18	16	78	74	(298)	688
16	(141)	469	416	68	21	17	83	85	(274)	744
17	(183)	534	337	67	20	17	77	77	(138)	809
18	(136)	572	251	66	16	17	94	86	109	1,076
19	(78)	582	125	65	18	20	133	102	24	992
20	(19)	580	14	66	18	20	121	81	41	921
21	85	580	(0)	64	14	21	143	99	(28)	979
22	84	579	4	63	15	25	158	92	(319)	699
23	(50)	577	4	57	8	32	168	92	(493)	395
24	(16)	591	4	58	5	35	210	98	(676)	308
Average	**32**	**498**	**142**	**52**	**10**	**13**	**90**	**80**	**(381)**	**538**

Figure 3.15 Average hour ending 16 changes in supply in the real-time market relative to the day-ahead market (2013)



When virtual bids are accounted for, the average difference in supply between the real-time market and the day-ahead market was about 540 MW. The difference was larger in peak hours (over 700 MW) than during off-peak hours (about 175 MW). In hour ending 16, total increases in supply were over 1,150 MW on average, whereas decreases in supply were about 400 MW on average for a net of about 750 MW.

Renewable schedules

Wind and solar generation were systematically higher in the real-time market than in the day-ahead market. This is partly due to the fact that significant portions of renewable generation, particularly solar, came online in 2013. This new generation required testing, which is currently not scheduled in the day-ahead market. Moreover, some participants bid these resources conservatively into the day-ahead market, avoiding the risk of underperformance in real time, or in a manner consistent with contractual terms.

Wind was, on average, about 500 MW higher in real time compared to the day-ahead market in 2013 with a maximum difference of over 2,300 MW. In 2012, wind was about 400 MW higher in real time with an hourly maximum difference of about 2,050 MW. In hours ending 10 through 19, solar generation was about 350 MW higher in the real-time market than in the day-ahead market in 2013 with a maximum difference of over 1,050 MW in a single hour. In 2012, solar averaged only about 50 MW higher in the real-time market than the day-ahead market for the same hours, with a maximum hourly difference of about 450 MW. Thus, the change in solar from 2012 to 2013 highlights the growth in additional real-time supply that was not scheduled day-ahead as new solar resources came online.

Residual unit commitment

DMM has observed that there may be confusion or misunderstanding by numerous stakeholders about the meaning of capacity schedules in the residual unit commitment process. This process is a reliability run that occurs after the completion of the day-ahead market. It ensures that there is enough physical supply available to meet forecasted load and any adjustments made by ISO operators. In most cases, it does not create additional generation in real time. It mainly requires that participants provide bids or self-schedules in the real-time market consistent with their residual unit commitment schedules.

Load-serving entities are not required to fully schedule their load in the day-ahead market, and, occasionally, they schedule less load than what the ISO forecasts. Convergence bidders can also place virtual supply bids in the day-ahead market. These bids can displace physical supply. Finally, operators can adjust the residual unit commitment requirement, increasing the residual unit commitment procurement. All of these factors influence the amount of capacity needed to be procured in the residual unit commitment process on top of the energy schedules from the day-ahead market (discussed further in Section 9.8).

The residual unit commitment process schedules capacity to offset these differences and meet these requirements to ensure that sufficient capacity is available in real time. The only capacity scheduled in the residual unit commitment process that is required to provide energy in real time are units that:

- have a 0 MW schedule in the day-ahead market;
- are scheduled in the residual unit commitment process to generate at their minimum load level; and
- take five or more hours to start up.

Most units with schedules in the residual unit commitment process are not required to provide energy in real time. In 2013, total hourly residual unit commitment schedules averaged about 930 MW.[83] In contrast, the average energy from long-start units committed in the residual unit commitment process was only 13 MW (almost 1.5 percent of total residual unit commitment schedules) with a maximum hourly value of 450 MW.

Units with residual unit commitment schedules are required to submit a bid into the real-time market. However, there is no requirement on how market participants bid this capacity into the real-time market other than to do so within the bounds of the existing offer cap and floor. For instance, market participants may self-schedule this capacity in the real-time market, may bid at levels that are lower than the day-ahead price, or may bid at prices higher than the day-ahead price. However, if a residual unit commitment resource is committed in the real-time market, the ISO software honors operational parameters, such as minimum run-time.[84] This, along with self-scheduling of generation by participants, can result in generation that must be taken in real time.

Must-take capacity procured in 2013 in the residual unit commitment process and not related to long-start commitment accounted for about 90 MW of generation in real time. This generation includes any self-scheduled generation by participants as well as any unit commitment made in the real-time market. Moreover, capacity procured in the residual unit commitment process was economically dispatched by about 80 MW, on average, in the real-time market in 2013. In many instances, this dispatched capacity was on resources that had day-ahead schedules, in addition to capacity that was added by the residual unit commitment process.[85]

Exceptional dispatch

The ISO commits capacity after the residual unit commitment process by exceptional dispatch to meet reliability needs.[86] Units that are committed through exceptional dispatch are set to minimum load and are eligible to receive bid cost recovery payments. On average, ISO operators exceptionally dispatched for commitment a little over 50 MW in 2013, with the maximum commitment in any hour at about 875 MW. This was down from an average of about 75 MW in 2012 and a maximum hourly commitment of just under 900 MW.

In addition to committing units to meet reliability needs, ISO operators can exceptionally dispatch incremental generation uneconomically above minimum load. On average, the ISO exceptionally dispatched about 1 MW of uneconomic generation in 2013, down from just over 5 MW in 2012.

Convergence bidding

The intent of convergence bidding in ISO markets is to help improve price convergence by influencing day-ahead market commitment. However, since prices systematically diverged in 2013, convergence bidding was not as effective at converging prices as intended. This may be the result of the risk and

[83] For more information on residual unit commitment schedules, see Section 2.5.

[84] As highlighted in DMM's *Quarterly Report on Market Issues and Performance*, November 14, 2013, pp. 22-23: http://www.caiso.com/Documents/2013ThirdQuarterReport-MarketIssues_Performance-Nov2013.pdf, the 15-minute market price was systematically higher than the 5-minute market prices in 2013. This can create situations where quick-start generation may be committed by the 15-minute market and not be economic at 5-minute market prices. However, after the commitment has been made, the minimum run-time and other operational parameters would need to be honored.

[85] Resources that had schedules in the day-ahead market had lower bids in the real-time market.

[86] For further discussion, see Section 9.1.

costs associated with bidding virtual supply. Virtual supply is paid the day-ahead price and pays the real-time price.

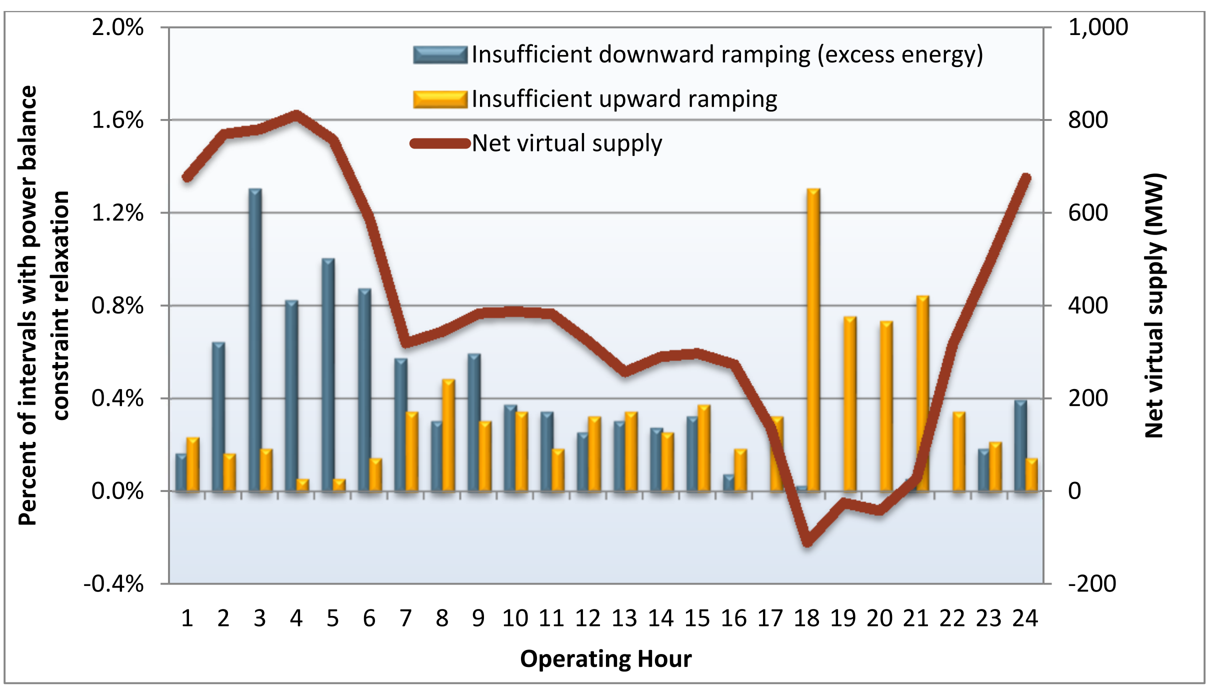
For the year, the net convergence bidding position was, on average, 380 MW of net virtual supply for all hours. In off-peak hours, net virtual supply averaged 695 MW, and in peak hours net virtual supply averaged only 225 MW. Thus, the overall net virtual supply position in 2013 was consistent with the systematic price differences between the day-ahead and real-time market that occurred in 2013.

However, when compared to the total volume of additional supply in the real-time market, the net virtual supply was substantially lower than the average increase in real-time supply relative to the day-ahead market. This was particularly true in peak hours. Moreover, the net virtual position switched from net virtual supply to net virtual demand in hours ending 18 through 20. This may be a result of the asymmetry of risk of virtual supply and demand positions, and the nature of real-time price spikes.

Real-time prices can be negative, but do not typically fall below the bid floor of -$30/MWh. This diminishes the risk of market participants losing substantial money by bidding virtual demand. However, real-time prices occasionally reach or exceed the offer cap of $1,000/MWh. If a participant bids virtual supply, the possibility exists that a brief but extreme price spike will occur and expose the participant to significant losses.

As shown in Figure 3.16, the highest frequency of upward ramping limitations was concentrated in hours 18 through 21. As noted previously, these ramping limitations lead to extreme price spikes. The change in convergence bidding patterns in these hours is consistent with this pattern. Historically, virtual demand bidders have made most of their net revenues during these periods of brief but extreme prices (see Section 4.2 for further detail). Moreover, the net virtual supply positions were highest in the off-peak hours, consistent with the highest frequencies of negative power balance relaxations.

Figure 3.16 Relaxation of power balance constraint and net convergence bids by hour (2013)



In addition to risk, convergence bidders with net virtual supply positions are required to pay bid cost recovery charges.[87] These charges have grown from $2.4 million in 2012 to about $8.9 million in 2013 and may also act as a barrier to bidding virtual supply.

Other considerations

Other factors that may influence the real-time market that were not explicitly studied include multi-stage generators that transition to a higher configuration and other generation including additional must-take hydro-electric output. Multi-stage generation units have different configuration levels that can not only increase their total generation, but also have their own incremental energy bid curves. To the extent that a multi-stage generation unit transitions to a higher configuration, this may add additional supply at minimum load.[88]

Furthermore, hydro-electric generation, particularly during the spring months, had additional must-take generation in real time that was not scheduled in the day-ahead market. This is potentially related to run-of-river hydro-electric facilities and could have a larger effect on increasing real-time generation relative to day-ahead in years with higher precipitation and snowpack.

Conclusions

Average real-time prices were systematically lower than day-ahead prices in 2013. These differences were driven primarily by differences in scheduling of wind and solar generation in the day-ahead and real-time markets, and, to a lesser extent, commitments ISO operators made after the day-ahead market for reliability.

DMM anticipates that several changes in 2014 may help to improve day-ahead and real-time price divergence. These include changes to the residual unit commitment process and model changes related to the ISO's spring 2014 release.

The ISO implemented a change in early 2014 to the residual unit commitment process to better help account for expected renewable generation. Specifically, for renewable resources with day-ahead schedules,[89] the ISO automatically adjusts these schedules upward in the residual unit commitment process to their forecast levels, if their day-ahead schedules are below the forecast. DMM has already observed changes in the residual unit commitment process as a result of this change. While the ISO does not currently adjust renewable resources that do not have day-ahead schedules, the ISO intends to adjust these resources in the residual unit commitment process in the future. DMM would support this change as it would further improve the accounting of forecasted renewables in the residual unit commitment process.

Market changes related to the ISO's spring 2014 release could also help moderate the differences between day-ahead and real-time prices. For instance, convergence bids will no longer settle against the 5-minute real-time price, which can be significantly affected by ramping limitations, but rather will settle against prices set by the 15-minute market. These prices tend to be less volatile and have

[87] For more information, see Section 4.2.

[88] While this effect was not quantified as part of this study, DMM and ISO staff observed instances where additional generation occurred as a result of configuration changes on multi-stage generation units.

[89] The ISO only adjusts schedules for resources that participate in the participating intermittent resource program (PIRP).

followed the day-ahead market fairly consistently over the past couple years.[90] This will potentially reduce the risk of taking a virtual supply position.

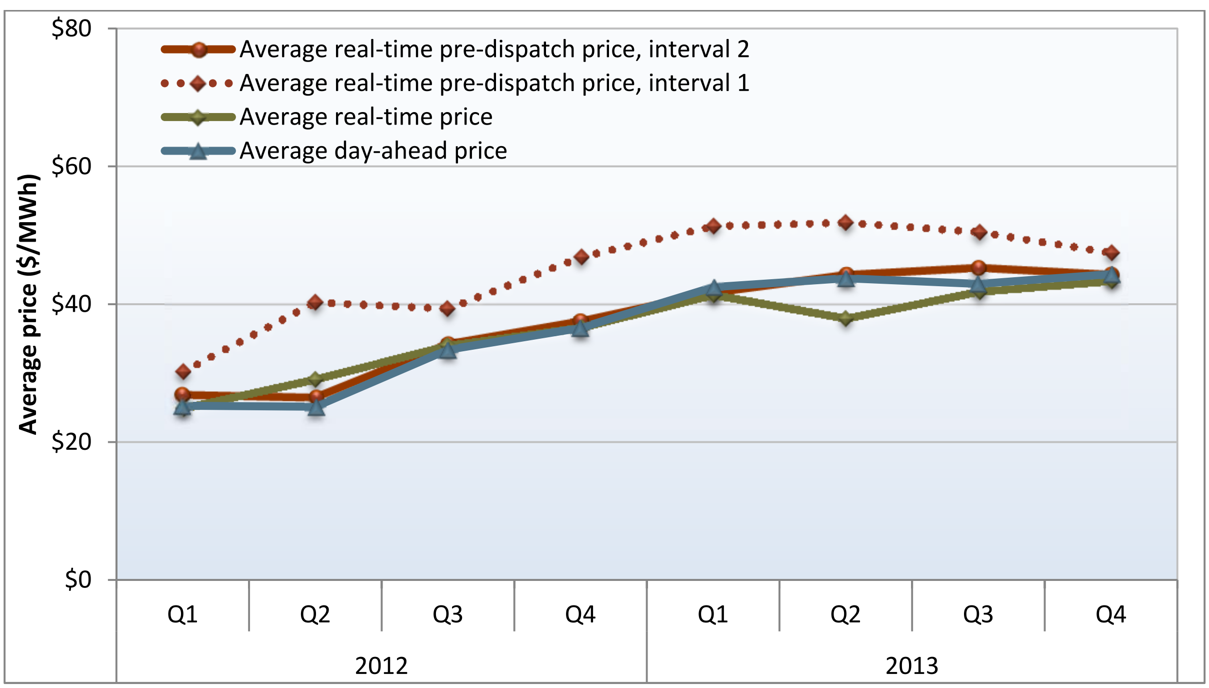
The spring 2014 changes will also allow for 15-minute scheduling at the inter-ties, which will allow for more commitment flexibility to deal with ramping limitations in both the upward and downward direction. Furthermore, the bid floor will drop from -$30/MWh to -$150/MWh. This will also change the risk profile of net virtual supply positions relative to virtual demand as virtual demand will become somewhat more risky and virtual supply will become somewhat more advantageous.

3.4 Differences between 15-minute and 5-minute real-time prices

The ISO is scheduled to implement a new 15-minute market in spring 2014. Specifically, the ISO will change inter-tie scheduling and settlement from an hourly to a 15-minute basis, and establish a 15-minute settlement for internal resources and convergence bids. The existing 5-minute dispatch will remain to provide real-time balancing. The ISO's current 15-minute real-time pre-dispatch market already produces energy prices for each 15-minute interval which are non-binding (i.e., not used in 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.

When the changes to the 15-minute market are implemented, market prices will be based on the second 15-minute interval of the 15-minute process, which looks out several intervals over two and a half hours. As illustrated in Figure 3.17, average second interval 15-minute prices (represented by the solid red line) have been fairly consistent with average day-ahead and real-time prices and do not exhibit a systematic trend of being over or under day-ahead and real-time prices.

Figure 3.17 Average system marginal 15-minute real-time pre-dispatch compared to day-ahead and real-time prices



90 Further detail is provided in Section 3.4.

The second interval prices are also much lower than the first interval 15-minute prices (dashed red line) and were chosen for scheduling and settlement to allow sufficient time for e-tagging inter-ties. Prices in this second 15-minute interval have fewer price spikes driven by the flexible ramping constraint than the first 15-minute interval, since there is more ramping capacity and flexibility available over this additional 15 minute period.

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

- The requirement that is set for flexible ramping capacity will be closely monitored and adjusted if necessary as the new 15-minute market is implemented. The ISO may consider lowering the requirement if analysis shows that doing so would not cause excessively frequent power balance constraint relaxation.[91]
- The ISO will also monitor and adjust the use of load adjustments in the 15-minute market. Grid operators may address reliability concerns by increasing the projected system load in the 15-minute pre-dispatch process to ensure commitment of additional short-start units. This can impact the 15-minute prices, which will be used for settlement. Thus, the use of load adjustments and the impact it has on pricing will be closely monitored by the ISO as it implements the new 15-minute market.
- Another factor that is expected to help mitigate price differences between the 15-minute market and the other markets is the reduction in the penalty price for the flexible ramping constraint. The ISO intends to lower the penalty price from $247/MW to $60/MW with implementation of the 15-minute market in May 2014.[92] Lowering the penalty price would tend to reduce the level of price spikes in the 15-minute market when the constraint is binding.

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

[91] The ISO reduced the requirement in early 2014 based on its analysis of flexible ramping capacity performance. See Section 3.2 for further details.

[92] For more information see: http://caiso.com/Documents/TechnicalBulletin-FlexibleRampingConstraintPenaltyPrice-FifteenMinuteMarket.pdf.

4 Convergence Bidding

Convergence bidding is a part of the Federal Energy Regulatory Commission's standard market design and is in place at all other ISOs with day-ahead energy markets. In the California ISO markets, virtual bidding is formally referred to as convergence bidding. The ISO implemented convergence bidding in the day-ahead market in February 2011.

Virtual bidding on inter-ties was temporarily suspended in November 2011. In May 2013, FERC issued an order conditionally accepting elimination of convergence bidding on inter-ties, with the expectation that convergence bidding at the inter-ties would be brought back when a feasible long-term solution exists.[93] Convergence bidding on the inter-ties will be slowly phased in by the ISO one year after implementation of FERC Order No. 764 in the spring of 2014.[94] The delay in implementation and the phasing in of convergence bidding were done as precautionary measures "to serve as an additional safety net to prevent unforeseen and unintended market outcomes."[95]

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

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

In 2013, average hourly cleared virtual supply outweighed virtual demand by about 380 MW per hour. Virtual demand averaged 1,860 MW per hour, while virtual supply averaged about 2,240 MW per hour. This represents a change from prior years in which virtual demand exceeded virtual supply in most hours. As explained in Chapter 3, this change reflects the change in price trends during 2013, when average day-ahead prices exceeded average real-time prices.

Because virtual bids can result in additional commitment of physical generation in the day-ahead energy market or residual unit commitment process, virtual bids can be charged for bid cost recovery payments resulting from day-ahead unit commitments. In 2013, virtual bidders were allocated about $9 million in bid cost recovery payments, compared to only $3.5 million in 2012. This increase is the result of the trend of increased net virtual supply in the day-ahead market, which can increase unit commitment in the residual unit commitment process.

After taking this cost allocation into account, total net revenues paid to entities engaging in convergence bidding totaled around $17 million in 2013, down from over $52 million in 2012. Most of these net revenues resulted from virtual supply bids, as well as offsetting virtual demand and supply bids at different locations designed to profit from higher congestion between these locations in real-time.

This type of offsetting bids, which are designed to hedge or profit from congestion, represented over 70 percent of all accepted virtual bids in 2013, up from 55 percent in 2012. The increase in both the quantity and net revenues of offsetting virtual bids likely stems from the differences in congestion

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

[94] For more information see the ISO 764 compliance filing: http://www.caiso.com/Documents/Nov27_2013_TariffAmendment-ComplianceFERCOrder764_ER14-495.pdf.

[95] Ibid, p. 47.

between the day-ahead and real-time markets in the first two quarters of 2013. Congestion in general, and congestion differences between the day-ahead and real-time market, decreased dramatically in the last two quarters of 2013.[96] However, revenues from non-offsetting virtual supply bids increased in these quarters.

Background

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

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

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 the commitment of additional physical generating units in the day-ahead market, which in turn could tend to reduce average real-time prices. In this scenario, virtual demand could help improve price convergence by increasing day-ahead prices and reducing real-time prices.
- If real-time market prices tend to be lower than day-ahead market prices, convergence bidders will seek to profit by placing virtual supply bids. Virtual supply will tend to lower day-ahead prices by increasing supply in the day-ahead market. This increase in virtual supply and decrease in day-ahead prices could also reduce the amount of physical supply committed and scheduled in the day-ahead market.[97] 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.

However, the degree to which convergence bidding has actually increased market efficiency by improving unit commitment and dispatches has not been assessed.

[96] For further detail, see Section 2.4.

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

4.1 Convergence bidding trends

Convergence bidding volumes increased steadily over the year, with net cleared volumes shifting from net virtual demand to net virtual supply beginning in the second quarter of 2013. Figure 4.1 shows the quantities of both virtual demand and supply offered and cleared in the market. Figure 4.2 shows the average net cleared virtual positions for each operating hour.

Key convergence bidding trends include the following:

- On average, 57 percent of virtual supply and demand bids offered into the market cleared in 2013, an increase from about 52 percent in 2012.
- The average hourly cleared volume of virtual supply outweighed virtual demand during each of the last three quarters. For the year, average hourly cleared virtual supply outweighed virtual demand by about 380 MW per hour. Last year the opposite occurred as average hourly cleared virtual demand outweighed virtual supply by about 350 MW in each hour. This switch to net virtual supply is due to the changes in price differences between the day-ahead and real-time markets in 2013 (see Section 3.3).
- The net position of all cleared virtual bids shifted dramatically in 2013 from typically virtual demand in the peak hours and virtual supply in the off-peak hours to virtual supply in all but three hours (hours ending 18, 19 and 20).
- About 78 percent of cleared virtual positions were held by pure financial trading entities that do not serve load or transact physical supply. In 2012, about 64 percent of cleared virtual positions were held by pure financial trading entities.

Figure 4.1 Quarterly average virtual bids offered and cleared

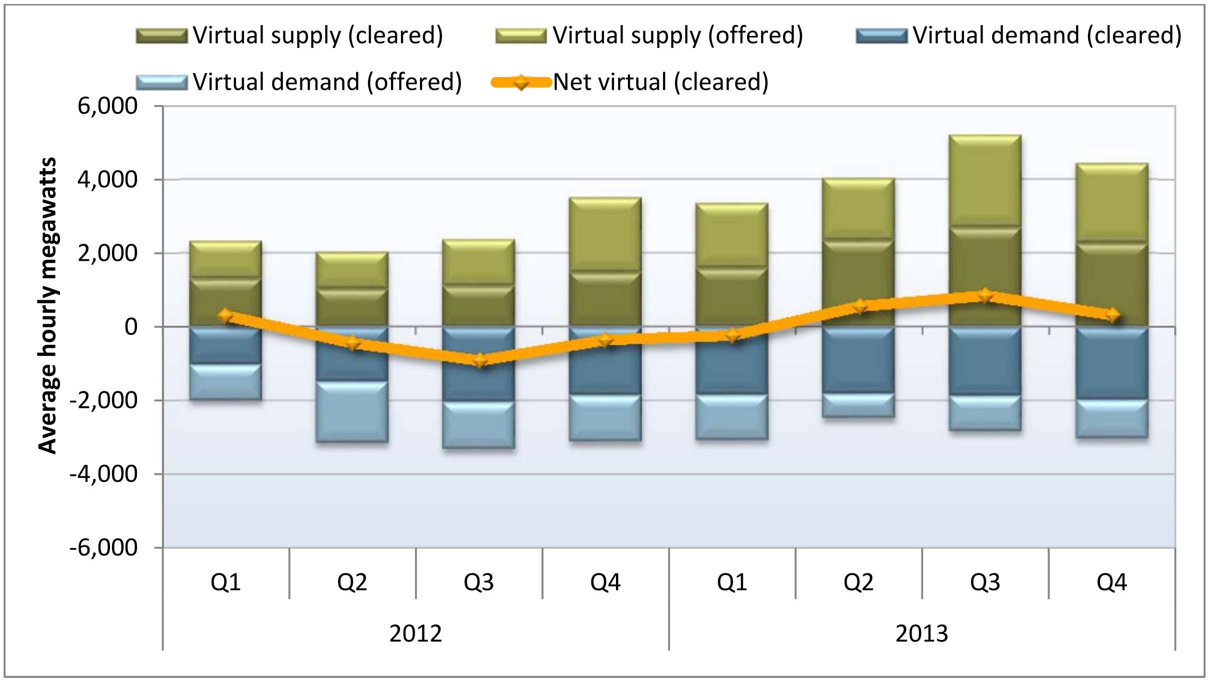
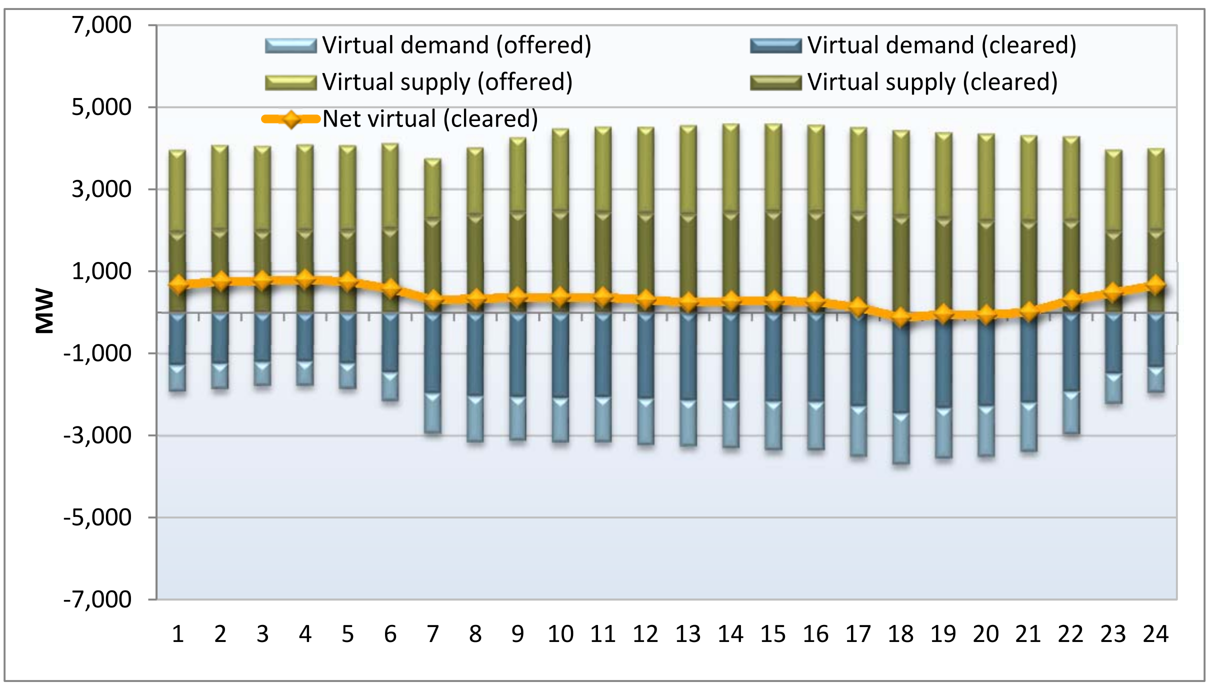


Figure 4.2 Average net cleared virtual bids in 2013

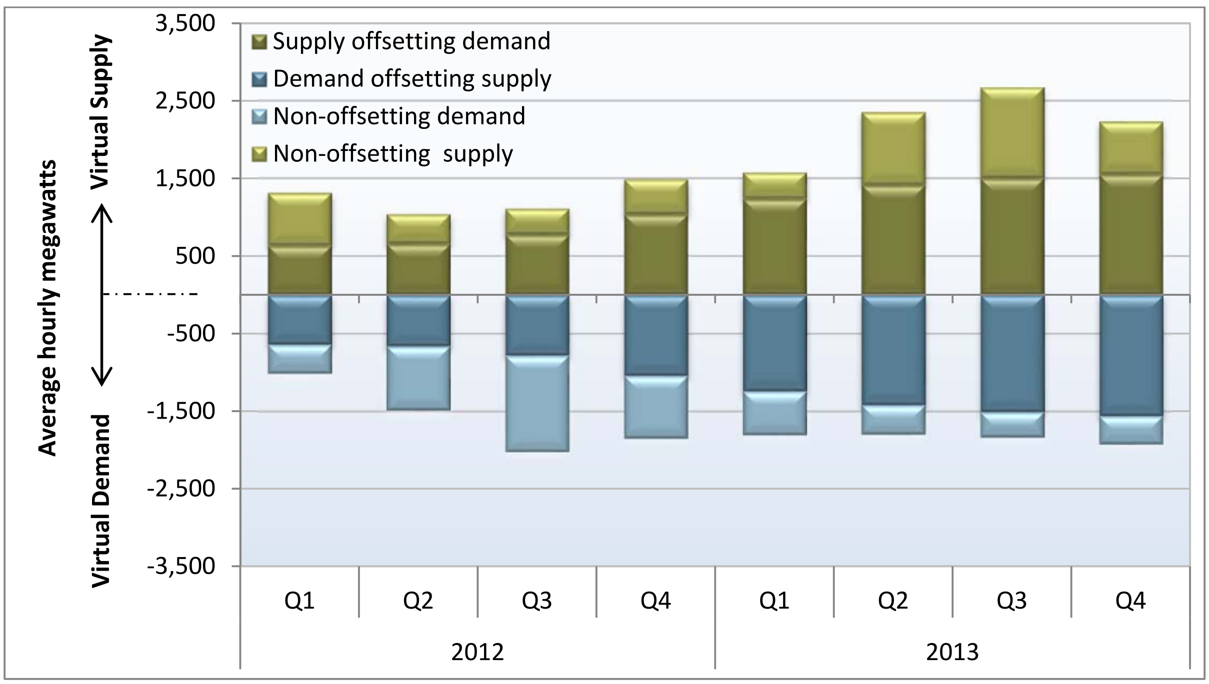


Offsetting virtual supply and demand bids

Market participants can also hedge congestion costs or seek to profit from differences in congestion between different points within the ISO by placing equal quantities of 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 profitable if there are differences in congestion in the day-ahead and real-time markets between these two locations.

Although the majority of cleared virtual bids in 2013 were related to such offsetting bids, an increase in non-offsetting supply began in the second quarter. Figure 4.3 shows the average hourly volume of offsetting virtual supply and demand positions at locations. The dark blue and dark green bars represent the average hourly overlap between demand and supply by the same participants. The light blue bars represent the remaining portion of virtual demand that was not offset by virtual supply by the same participants. The light green bars represent the remaining portion of virtual supply that was not offset by virtual demand by the same participants.

Figure 4.3 Average hourly offsetting virtual supply and demand positions



As shown in Figure 4.3:

- Offsetting virtual positions accounted for an average of about 1,400 MW of virtual demand offset by 1,400 MW of virtual supply in each hour of the year. These offsetting bids represent over 70 percent of all cleared virtual bids in 2013, up from 55 percent of bids in 2012. This suggests that virtual bidding has been increasingly used to hedge or profit from congestion.
- Over the course of the year, the amount of offsetting virtual bidding positions taken by participants fluctuated in volume and as a share of total virtual bids. The share of offsetting virtual positions was

highest in both the first and fourth quarters and lowest in the second and third quarters, at about 74 percent and 67 percent, respectively.

- As discussed later in this chapter, virtual demand bids tended to be placed in selected peak hours during periods when average real-time prices tended to be higher than average day-ahead prices, coincident with real-time price spikes.
- Virtual supply bids were the dominant bid type and tended to be placed in all off-peak hours and in many peak hours during periods when average real-time prices tended to be lower than average day-ahead prices.

Consistency of price differences and volumes

Convergence bidding is designed to bring together day-ahead and real-time prices when the net market virtual position is directionally consistent (and profitable) with the price difference between the two markets. Net convergence bidding volumes were the least consistent with price differences in the first quarter of 2013, with only 10 consistent hours. However, second quarter consistency improved dramatically and the third and fourth quarters were also very consistent. Compared to the previous year, the 2013 net convergence bidding volumes, on average, were fairly consistent with price differences between the day-ahead and real-time markets for most of the year.

Figure 4.4 compares cleared convergence bidding volumes with the volume weighted average price differences at which these virtual bids were settled. The difference between day-ahead and real-time prices shown in this figure represents the average price difference weighted by the amount of virtual bids clearing at different locations.

Periods when the red line is negative indicates that the weighted average price charged for virtual demand in the day-ahead market was lower than the weighted average real-time price paid for this virtual demand. In 2013, virtual demand positions were not profitable in most quarters, with the exception of the fourth quarter. In 2012, virtual demand volumes were consistent with weighted average price differences in all quarters.

Quarters when the yellow line is positive indicates that the weighted average price paid for virtual supply in the day-ahead market was higher than the weighted average real-time price charged when this virtual supply was liquidated in the real-time market. Virtual supply was consistently profitable in all quarters in 2013.

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 participant. Such offsetting virtual supply and demand bids are likely used as a way of hedging or speculating from congestion within the ISO. When virtual supply and demand bids are paired in this way, one of these bids may be unprofitable independently, but the combined bids may break even or be profitable due to congestion.

Figure 4.4 Convergence bidding volumes and weighted price differences

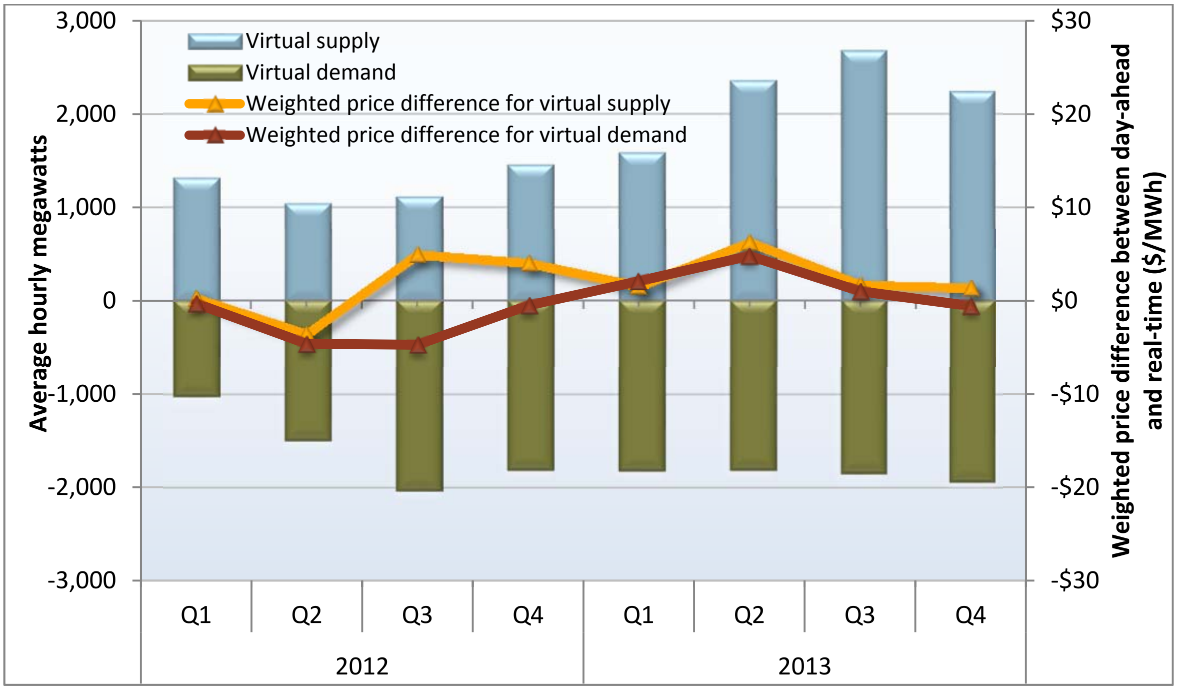


Figure 4.5 through Figure 4.8 show average hourly net cleared convergence bidding volumes compared to the difference in the day-ahead and real-time system marginal energy prices in each quarter of the year. The blue bars represent the net cleared virtual position, whereas the green line represents the difference between the day-ahead and real-time system marginal energy prices.

In anticipation of real-time price spikes, market participants often bid virtual demand in peak hours. Previously, even though these spikes did not occur often, the revenues received during these periods outweighed the losses during other periods. However, in 2013 this only occurred during the fourth quarter (see Section 4.2 for further detail).

- As shown in Figure 4.5, convergence bidding volumes in the first quarter were consistent with price convergence in 10 hours. Convergence bidding positions were most inconsistent during the afternoon and evening hours and most consistent during the mid-morning hours.
- In the second quarter, as seen in Figure 4.6, convergence bidding volumes were directionally consistent with differences between day-ahead and real-time prices in 23 hours. The consistency of the net cleared convergence bidding positions dramatically improved from the first quarter.
- Figure 4.7 shows that convergence bidding volumes in a majority of hours in the third quarter were consistent with price convergence. In total, there were 16 hours where net convergence bidding volumes were consistent with day-ahead and real-time price differences.
- As shown in Figure 4.8, virtual net positions were consistent in 17 hours in the fourth quarter. Consistency was greatest during morning and mid-day hours.

Figure 4.5 Hourly convergence bidding volumes and prices (January – March)

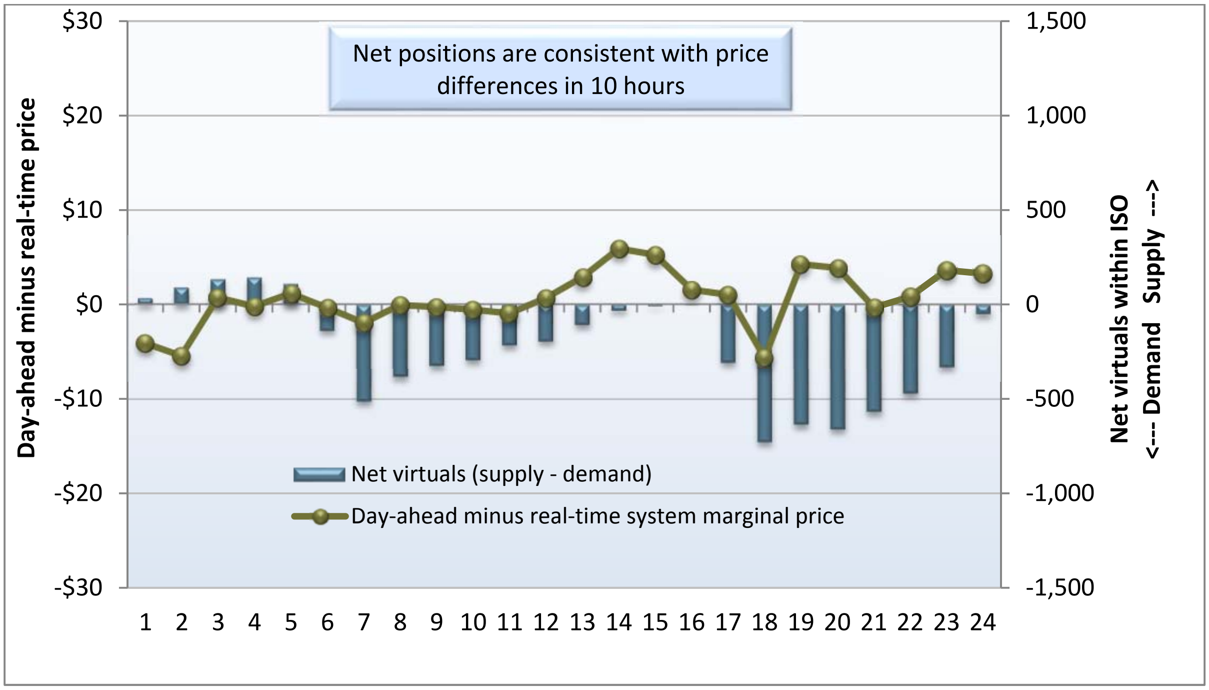


Figure 4.6 Hourly convergence bidding volumes and prices (April – June)

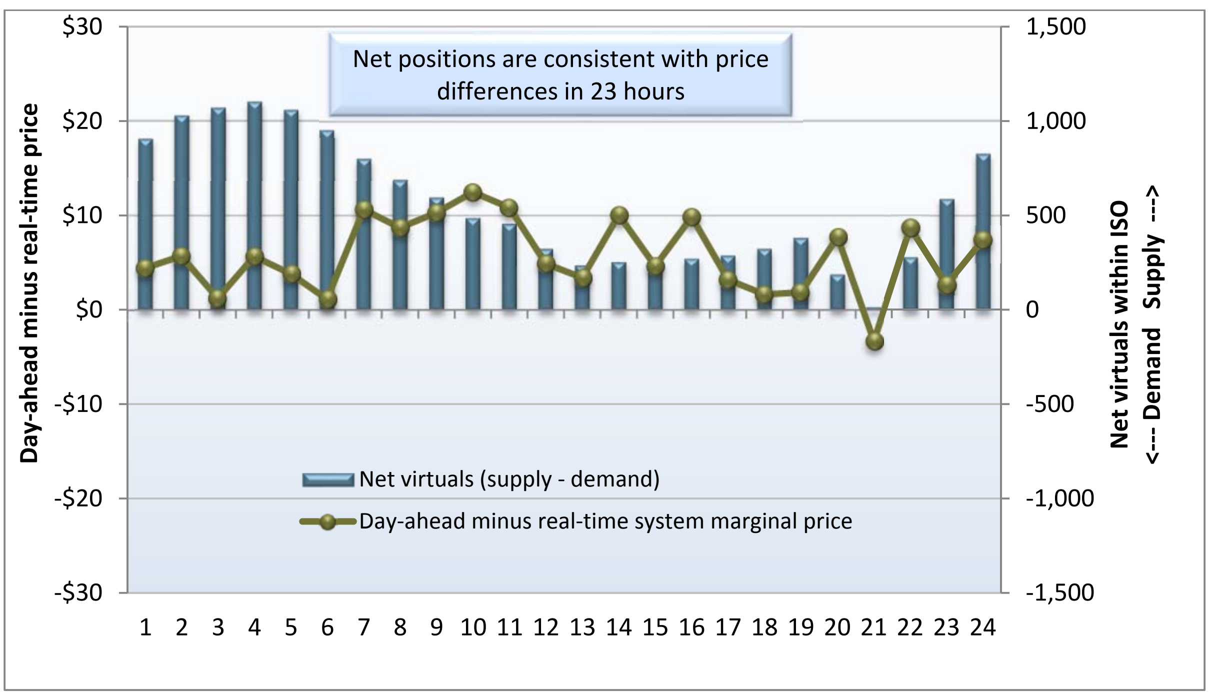


Figure 4.7 Hourly convergence bidding volumes and prices (July – September)

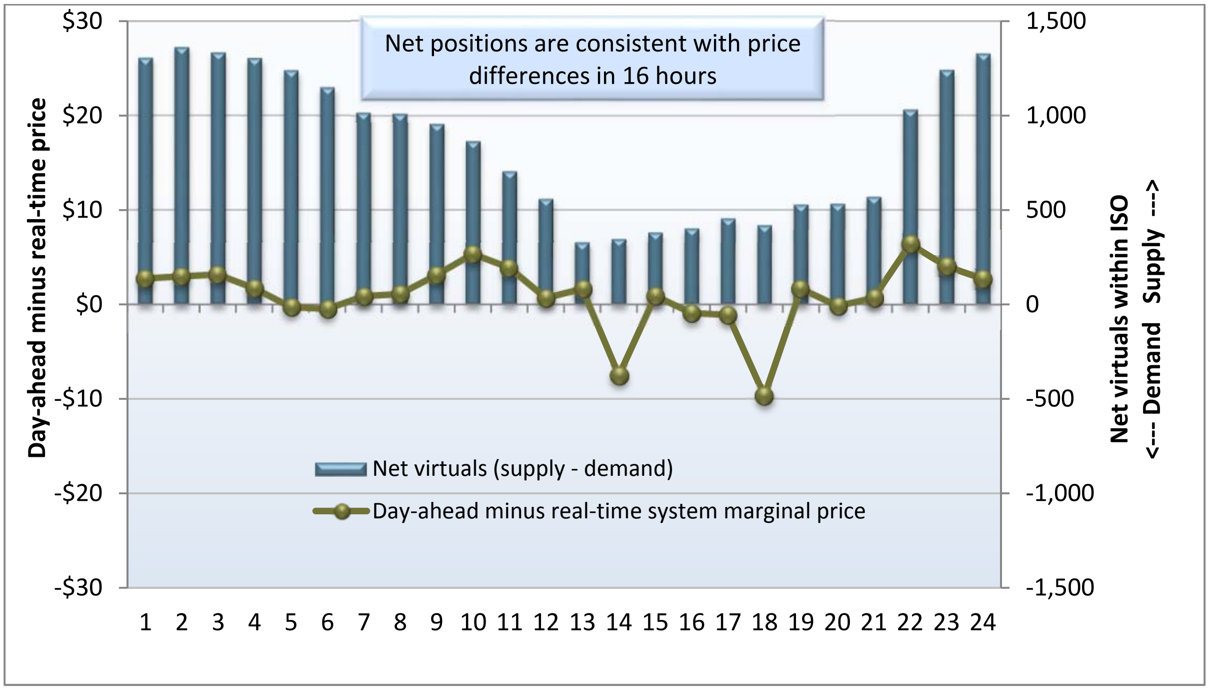
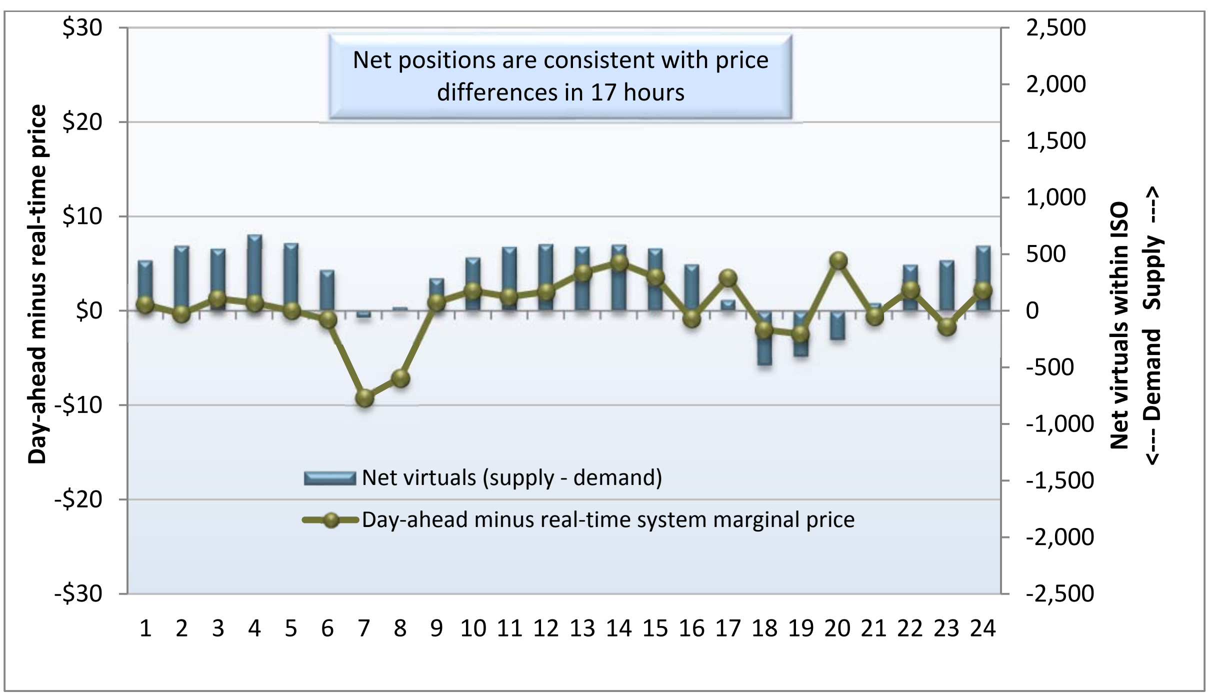


Figure 4.8 Hourly convergence bidding volumes and prices (October – December)

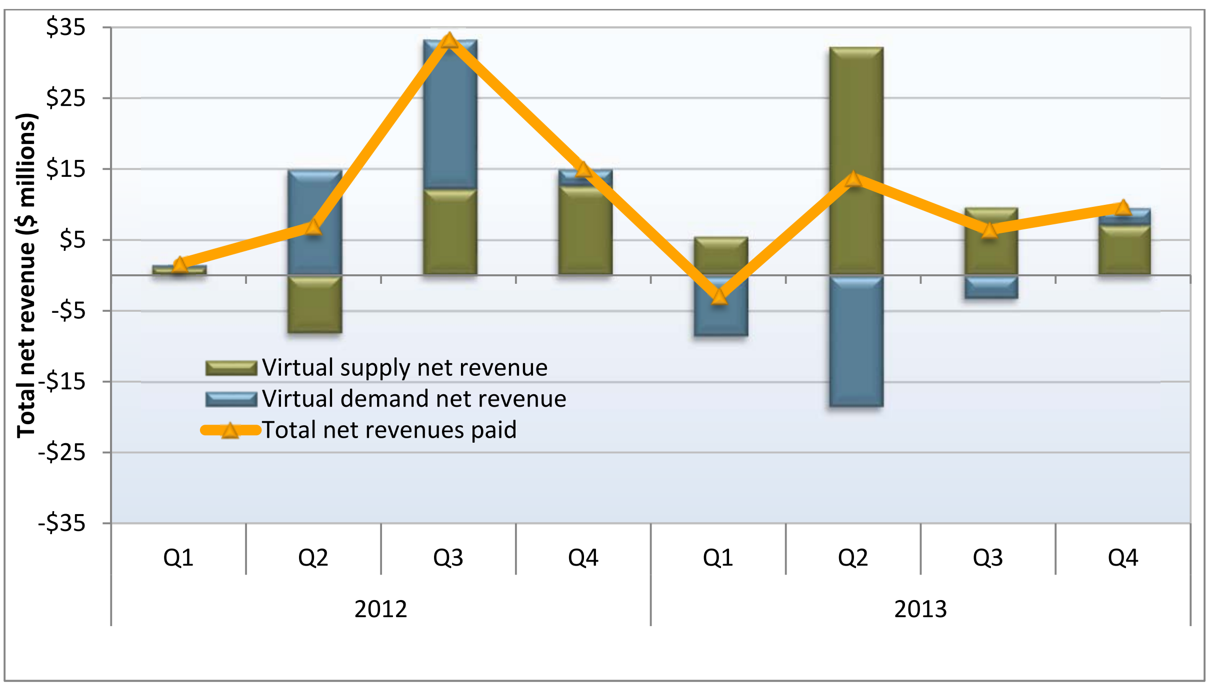


4.2 Convergence bidding payments

Net revenues paid to convergence bidders (prior to any allocation of bid cost recovery payments) totaled about $26 million in 2013, down from $56 million in 2012, or a decrease of about 53 percent. The majority of these profits were associated with virtual supply. Figure 4.9 shows total quarterly net profits paid for accepted virtual supply and demand bids. As shown in this figure:

- All net revenues ($55 million) came from virtual supply. Nearly $28 million in losses were received by virtual demand.
- In 2013, virtual supply positions were profitable in all quarters. This trend reflects that revenues on virtual supply bids placed in nearly all hours are less volatile, and negative price spikes are smaller in magnitude and typically last longer.
- In the first three quarters virtual demand positions were unprofitable with losses of over $30 million. Profitability switched in the last quarter with revenue of over $2 million. This trend reflects that real-time prices were lower than day-ahead prices for most of the year. At the end of the year, there were specific events that caused real-time prices to spike above day-ahead prices, driving virtual demand revenues up.
- Total net revenues paid to virtual bidders peaked in the second quarter at almost $14 million. Total net revenues were negative in the first quarter ($3 million) and reached $6 million and $9 million in the third and fourth quarters, respectively.

Figure 4.9 Total quarterly net revenues from convergence bidding



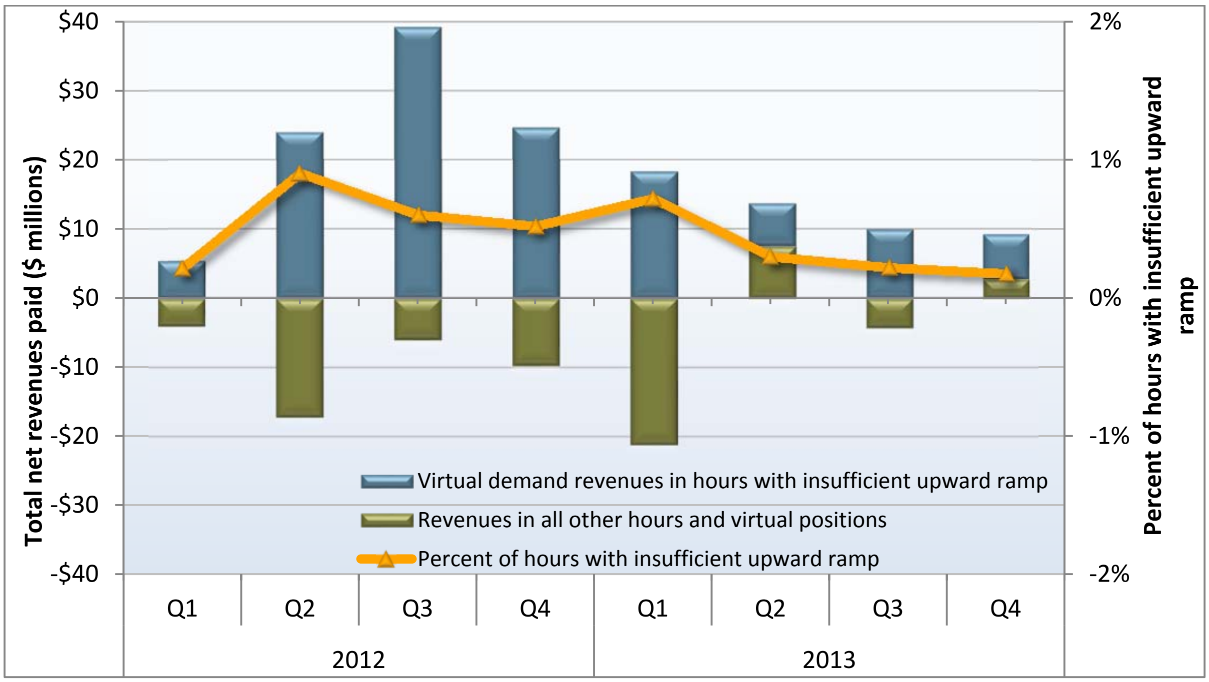
Net revenues during periods of insufficient upward ramp

In 2013, virtual demand accounted for about 45 percent of cleared bids, compared to 57 percent in 2012. Virtual demand bids are typically profitable when real-time prices spike in the 5-minute real-time market. Almost all profits from these virtual demand positions have resulted from a relatively small portion of intervals when the power balance constraint was relaxed as a result of insufficient ramp either on a system or regional basis (see Section 3.1).

Figure 4.10 compares total revenues from virtual bids during hours when the power balance constraint was binding due to short-term shortages of upward ramping capacity with the overall net revenues of virtual bids, both virtual supply and demand, during all other hours.

As shown in Figure 4.10, upward ramping capacity was insufficient during an average of less than 0.4 percent of intervals in 2013, trending down from about 0.7 percent in the first quarter to under 0.2 percent in the fourth quarter. In previous years, net revenues from virtual demand during these brief but extreme price spikes were frequent and high enough to outweigh losses when the day-ahead price exceeded the real-time market price. This did not occur as frequently in 2013, resulting in losses for virtual demand for the year.

Figure 4.10 Convergence bidding net revenues during periods of insufficient upward ramp



These price spikes are typically associated with brief shortages of ramping capacity. Virtual demand can potentially result in additional capacity being committed and available in the real-time market. In practice, however, the impact of virtual demand on real-time price spikes appears to have been limited by a number of factors:

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

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

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 nearly $17 million (almost 65 percent) of the total convergence bidding revenues in 2013.

Table 4.1 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 revenues in millions of dollars.

DMM has defined financial entities as participants who own no physical power and participate in only the convergence bidding and congestion revenue rights markets. Physical generation and load are represented by participants that primarily participate in the ISO 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 markets.

As shown in Table 4.1, financial participants represent the largest segment of the virtual market, accounting for about 78 percent of volumes and about 65 percent of revenues. Generation owners and load-serving entities represent about 32 percent of the revenues but only about 10 percent of volumes. Marketers represent about 12 percent of the trading volumes and 3 percent of the revenues.

Table 4.1 Convergence bidding volumes and revenues by participant type (2013)

Trading entities	Average hourly megawatts			Revenues\Losses ($ millions)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	1,578	1,578	3,156	-$21.7	$38.4	$16.7
Marketer	193	293	486	-$4.9	$5.8	$0.9
Physical generation	67	186	253	$0.1	$4.6	$4.6
Physical load	2	158	160	-$0.2	$3.8	$3.6
Total	**1,840**	**2,216**	**4,056**	**-$26.7**	**$52.5**	**$25.8**

4.3 Bid cost recovery charges to virtual bids

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.[98]

[98] 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

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.[99] 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.[100]

- Integrated forward market bid cost recovery tier 1 allocation addresses costs associated with situations when the market clears with positive net virtual demand.[101] In this case, virtual demand leads to increased unit commitment in the day-ahead market, which may not be economic.
- Day-ahead residual unit commitment tier 1 allocation relates to situations where the day-ahead market clears with positive net virtual supply.[102] 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.

Figure 4.11 highlights the significance of the day-ahead residual unit commitment tier 1 allocation charge associated with net virtual supply bids in 2013. The net virtual supply charges in 2013 reached a peak of about 20 percent of total bid cost recovery charges in December compared to the previous high of 16 percent in June. This is consistent with an increase in net virtual supply and associated residual unit commitment costs in December compared to previous months.

The integrated forward market bid cost recovery costs associated with net virtual demand remained very low throughout 2013. Previously, this charge reached its high in the third quarter of 2012 when the market was significantly net virtual demand.

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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.

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

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

[101] 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.

[102] 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 4.11 Convergence bidding costs associated with bid cost recovery tier 1 and RUC tier 1 as a percent of total bid cost recovery

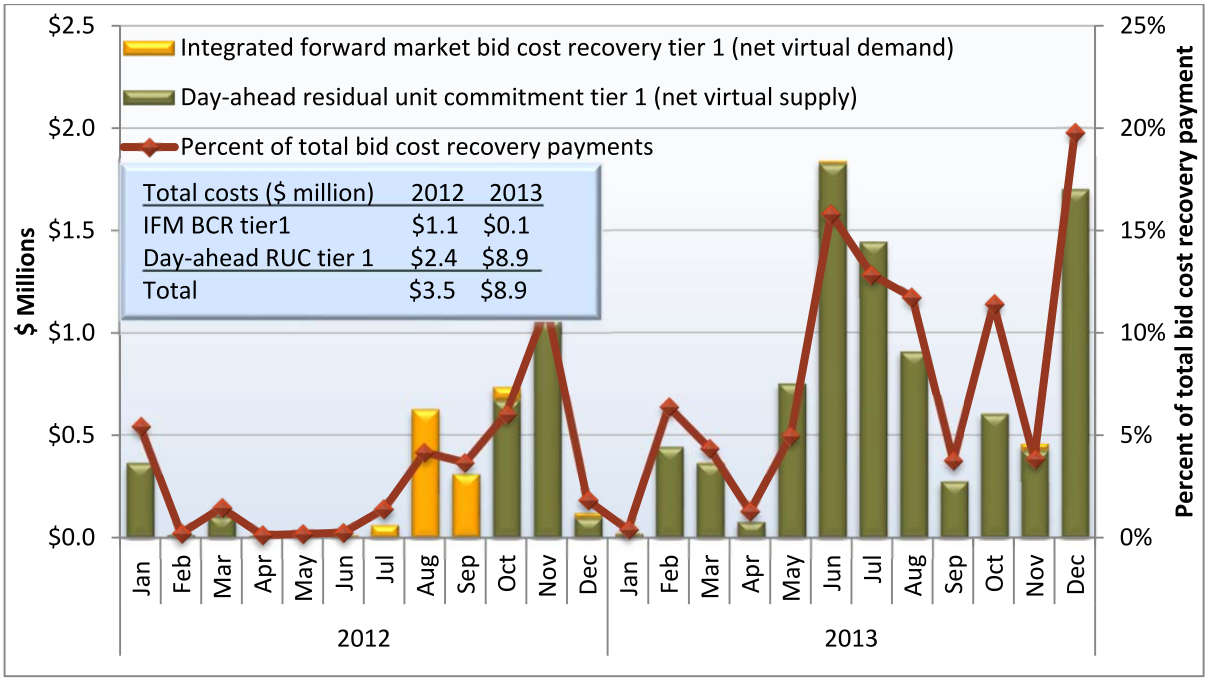

Figure 4.12 Convergence bidding revenues and costs associated with bid cost recovery tier 1 and RUC tier 1

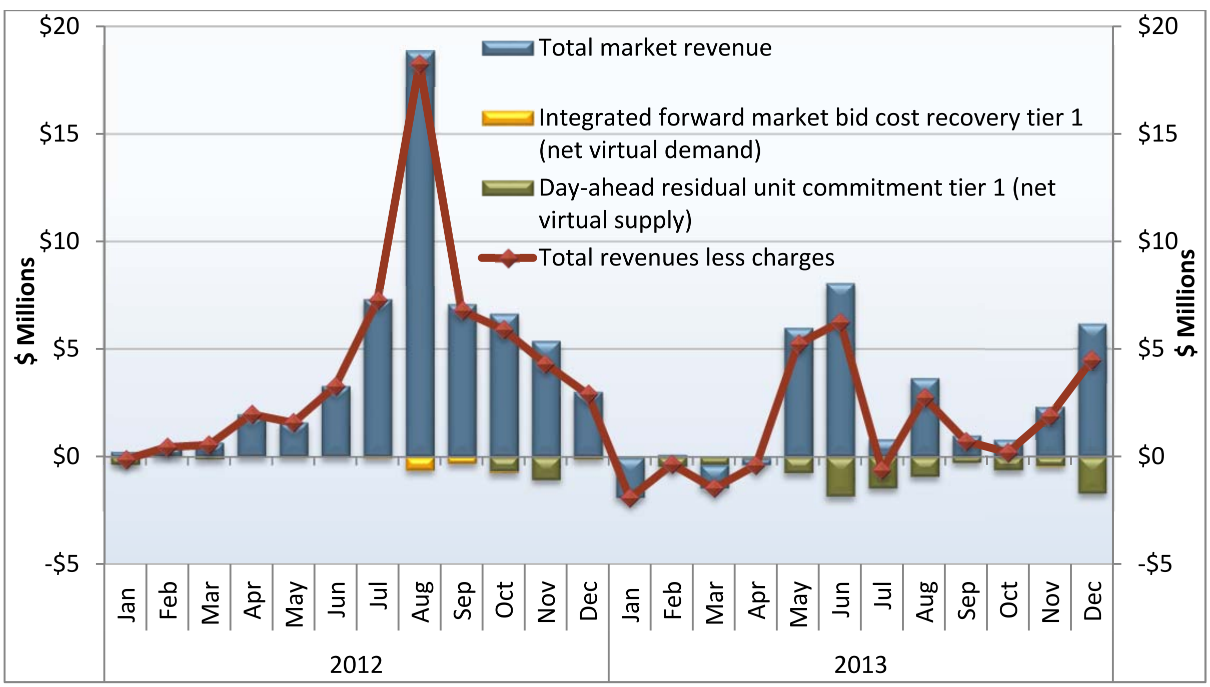

Figure 4.12 shows estimated total convergence bidding revenues, total revenues less bid cost recovery charges and costs associated with the two bid cost recovery charge codes. For the year, total convergence bidding bid cost recovery costs were nearly $9 million, compared to about $3.5 million in 2012. Adjusting convergence bidding revenues for total convergence bid cost recovery costs results in total revenues of around $17 million in 2013, compared to about $52.5 million in 2012.

5 Greenhouse gas cap-and-trade program

Resources selling into the ISO market became subject to the state's greenhouse gas cap-and-trade program starting in January 2013. The program requires suppliers to purchase carbon emission allowances to offset emissions for power generated or imported into California. This section assesses the impact of these requirements in 2013. Key findings include the following:

- Based on statistical analysis of changes in day-ahead market energy prices following cap-and-trade implementation, DMM estimates that average wholesale prices are about $6/MWh higher due to cap-and-trade compliance costs in 2013. This is consistent with the emissions costs for gas units typically setting prices in the ISO market.
- The impact of the cap-and-trade program on wholesale electricity prices declined over the second half of the year as the cost of greenhouse gas allowances in state auctions and bilateral markets dropped. Bilateral market prices averaged about \$14.50/mtCO_2e for the first half of the year and about \$12.50/mtCO_2e in the second half of the year, before ending the year at \$11.75/mtCO_2e.[103]
- A simple review of bilateral market prices outside of California does not clearly indicate whether or not regional bilateral prices were affected by the cap-and-trade program. Further analysis would be needed to determine the nature of the impact, if any.
- One concern about the cap-and-trade program was that it might reduce imports since some suppliers in other states would not want to incur compliance obligations to procure emission allowances. However, DMM did not see any evidence that the program had any significant impact on the total supply of imports. In 2013, import megawatts offered increased by 1 percent and import megawatts scheduled into the ISO system decreased by 6 percent compared to 2012.

5.1 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.

The cap-and-trade program covers major sources of greenhouse gas emissions including power plants.[104] The program includes an enforceable emissions cap that will decline over time. Under the program, California directly distributes and auctions allowances, which are tradable permits equal to the emissions allowed under the cap.

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

[104] 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.

Sources with compliance obligations are required to procure and then surrender allowances and offsets equal to their emissions at the end of each compliance period, with a partial annual surrender in the interim years. Imports from unspecified sources and electric generation resources emitting more than 25,000 metric tons of greenhouse gas annually, either within California or as imports into California, are covered under the first phase of the cap-and-trade program. Emissions compliance obligations began being enforced on January 1, 2013.

Allowances are associated with a specific year, known as the *vintage*. Allowances are *bankable*, meaning that an allowance may be submitted for compliance in years subsequent to the vintage of the allowance.[105] *Borrowing* of allowances is not allowed, meaning that permits for future years cannot satisfy compliance requirements in an earlier year.[106] Generators and importers covered by the regulations are required to submit allowances covering 30 percent of emissions in each year and the remainder of their emissions in the final year of each three year compliance period. In addition to allowances, covered generators and importers may submit emissions offsets to cover up to 8 percent of their emissions.[107] The total cap on emissions is set to decline 2 percent annually through 2014 and then about 3 percent annually through 2020.

Allowances are available at quarterly auctions held by CARB and may also be traded bilaterally. In addition, financial derivatives based on allowance prices are traded on public exchanges such as the InterContinental Exchange (ICE). 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).[108]

The impact of higher wholesale prices caused by the cap-and-trade program on retail electric rates will depend on policies adopted by the CPUC and other state entities. As part of the 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 cap and trade. The investor-owned electric utilities are required to sell all of their allowances at CARB's quarterly auctions. 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

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

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

[107] The first offsets were issued in September 2013: http://www.arb.ca.gov/newsrel/newsrelease.php?id=504.

[108] 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.

decision, revenue from carbon emission allowances sold at auction will be used to offset impacts on retail costs.[109]

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

These rules included a requirement that each year market participants attest that they have not engaged in resource shuffling. However, prior to the start of the cap-and-trade program compliance obligations in 2013, concerns were raised that potential ambiguity and uncertainty about this rule could result in a significant reduction in imports into California.[110] Consequently, this rule was temporarily suspended in late 2012.

Proposed regulation changes that incorporate resource shuffling definitions into the regulation and clarify resource shuffling safe harbors were released in draft form in July and presented to CARB's board for public comment and consideration on October 25, 2013.[111] The proposed rule changes would also permanently eliminate the requirement that market participants attest they have not engaged in resource shuffling which is now temporarily suspended.[112]

5.2 Greenhouse gas allowance prices

When calculating various cost-based bids used in the ISO market software, the ISO uses a calculated greenhouse gas allowance index price as a daily measure of the cost of greenhouse gas allowances. The ISO greenhouse gas allowance price is calculated as the average of two market based indices.[113] Daily values of the ISO greenhouse gas allowance index are plotted in Figure 5.1. This figure also shows market clearing prices in CARB's first four quarterly auctions of emission allowances that can be used for the 2013 compliance year.

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109 Pursuant to CPUC decision in Rulemaking 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.

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

111 The proposed regulation changes are posted here: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm. A presentation describing the proposed cap-and-trade program regulation changes is available here: http://www.arb.ca.gov/cc/capandtrade/meetings/071813/workshoppresentation.pdf. The draft resolution presented at the October 25 CARB board meeting is available here: http://www.arb.ca.gov/cc/capandtrade/oct-25-drft-brd-res.pdf. Also, see CARB Regulatory Guidance document: *What is Resource Shuffling*, dated November 2012: http://www.arb.ca.gov/cc/capandtrade/guidance/appendix_a.pdf.

112 See proposed regulation cited above and the letter from the CARB Chairman Mary Nichols to Commissioner Moeller of the Federal Energy Regulatory Commission dated August 16, 2012: http://www.arb.ca.gov/newsrel/images/2012/response.pdf.

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

The average price of this bilateral price index in 2013 was \$13.55/ $mtCO_2e$, which would represent an additional cost of about \$5.75/MWh for a relatively efficient gas unit.[114]

As shown in Figure 5.1, the cost of greenhouse gas allowances in bilateral markets fell over the course of the year. The cost of greenhouse gas allowances in bilateral markets averaged about \$14.50/$mtCO_2e$ for the first half of the year and averaged about \$12.50/$mtCO_2e$ in the second half of the year. In the fourth quarter, allowance costs fell to an average \$11.86/$mtCO_2e$, ending the quarter at \$11.75/$mtCO_2e$, one of the lowest values observed this year.

The ISO's greenhouse gas allowance price index generally exceeded clearing prices in the CARB's quarterly allowance auctions, but varied in a similar pattern, reflecting current market conditions. As shown in Figure 5.1, the price in CARB's first auction held in November 2012 was just above the \$10/$mtCO_2e$ floor set by CARB and well below bilateral market prices during the first few weeks of 2013, \$15 to \$16/$mtCO_2e$. This may be due at least in part to uncertainty that existed when this auction was held about whether the program would be implemented on schedule in 2013.

Figure 5.1 ISO's greenhouse gas allowance price index

114 DMM calculates this cost by multiplying the average index price by the heat rate of a relatively efficient gas unit (8,000 Btu/kWh) and an emissions factor for natural gas: 0.0530731 $mtCO_2e$ /MMBtu. Calculation of the emissions factor is explained in further detail in footnote 126.

5.3 Changes in market prices

Background

Greenhouse gas compliance costs can be expected to increase wholesale electricity costs, since market participants submitting bids reflective of their costs would be expected to include these additional compliance costs in their bids. As summarized in DMM's first quarterly report for 2013, analysis by DMM indicates that bids for most gas-fired units increased by up to $10/MWh during early January 2013 compared to the end of December.[115] An increase of this magnitude is within the range of the additional cost associated with carbon emissions for generating units with different efficiencies given the cost of emission allowances during this time period (which ranged from about $14 to $16/mt$CO_2$e).[116]

The additional incremental variable cost of greenhouse gas compliance is also included in the ISO's calculation of default energy bids used in local market power mitigation. The ISO also includes these costs in start-up and minimum load bids, which could indirectly raise prices in some cases by making it uneconomic to commit additional resources which might have lower energy bid prices than other resources available in the market.

Analysis of change in market prices

DMM has developed a statistical approach to estimate the impact of greenhouse gas costs on day-ahead market prices during the first year of greenhouse gas compliance. This approach relies on the comparison of market data before cap-and-trade implementation with data from 2013.[117] DMM used the same model as in our fourth quarter 2013 analysis, controlling for differences in convergence bidding volumes, assumed to be exogenous.[118] 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.[119]

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[115] *First Quarter 2013 Report on Market Issues and Performance*, May 29, 2013, Department of Market Monitoring, pp. 44-45: http://www.caiso.com/Documents/2013FirstQuarterReport-MarketIssues_Performance-May2013.pdf.

[116] $14/mt$CO_2$e x 0.053165 mt$CO_2$/MMBtu x 8,000 Btu/kWh = $5.95/MWh

$16/mt$CO_2$e x 0.053165 mt$CO_2$/MMBtu x 12,000 Btu/kWh = $10.21/MWh

[117] As demonstrated in Figure 5.1, 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.

[118] 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 *Third Quarter Report on Market Issues and Performance*, November 14, 2013, Section 3.2: http://www.caiso.com/Documents/2013ThirdQuarterReport-MarketIssues_Performance-Nov2013.pdf.

[119] 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.

The energy price used in the analysis is the day-ahead system marginal energy cost.[120] Changes in these prices were analyzed in order 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.[121]

The impact of greenhouse gas compliance on wholesale energy prices is estimated by analyzing average daily system energy prices as a linear function of the following factors: a measure of greenhouse gas compliance cost, a weighted gas price index, a non-linear function of expected load, indicator variables for holidays, Saturday, and Sunday, net virtual supply, scheduled generation availability for fuel types that we assume to be exogenous (hydro, wind, solar, geo-thermal, and nuclear), and imports (as modeled by exogenous gas price indices).[122]

$$\begin{aligned}\text{Average Electricity Price} = {} & \beta_0 + \beta_1 \text{GHG} + \beta_2 \text{Load} + \beta_3 \text{Load}^2 + \beta_4 \text{Load}^3 + \beta_5 \text{Gas}_{\text{Weighted}} + \\ & \beta_6 \text{Holiday} + \beta_7 \text{Saturday} + \beta_8 \text{Sunday} + \beta_9 \text{NetVS} + \beta_{10} \text{Wind} + \\ & \beta_{11} \text{Solar} + \beta_{12} \text{Hydro} + \beta_{13} \text{Nuclear} + \beta_{14} \text{Geothermal} + \\ & + \beta_{15} \text{Imports\_IV} + \varepsilon\end{aligned}$$

Using this model, DMM estimates that in 2013 the average impact of greenhouse gas compliance was about \$5.85/MWh or \$0.41 per dollar of the allowance price.[123] DMM also performed this analysis by quarter, developing the following estimates of greenhouse gas compliance impact:[124]

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[120] 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.

[121] For further discussion on the system marginal energy price, please see Appendix C of the ISO tariff: http://www.caiso.com/Documents/ConformedTariff-Feb18_2014.pdf.

[122] 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/.)

[123] 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 \$/mtCO_2e). DMM's regression results are based on values from January 2012 through December 2013 to limit bias introduced by factors not yet included in the model. Load is the ISO's hourly day-ahead forecast of ISO load. We assume that the load forecast, which is based on weather indices and historical time series data, is not price responsive in the short-term, which allows us to estimate this model using ordinary least squares, rather than as a system of demand and supply equations. We also assume that the greenhouse gas allowance index price is exogenous rather than endogenously determined by electricity prices. Resource specific day-ahead schedules are summed by fuel type to calculate generation from wind, geothermal, nuclear, solar, hydro, and import sources. The gas price is a weighted average of three regional gas price indices (weights are given in parentheses): PGE2 (0.4), SCE1 (0.5), and SCE2 (0.1). These gas price indices are used by the ISO in calculating default energy bids and other market calculations. Net virtual supply is the average of the hourly difference between cleared virtual supply and virtual demand in each hour.

First quarter: $5.18/MWh

Second quarter: $8.11/MWh

Third quarter: $4.51/MWh

Fourth quarter: $2.88/MWh

This relatively simple model predicts the average ISO day-ahead system energy prices fairly well, explaining approximately 93 percent of the variation in this measure in both annual models.[125] This analysis may be refined as further data becomes available.

The statistical approach outlined above produces estimates that are consistent with expectations of the impact of greenhouse gas compliance costs on wholesale electricity costs during a period when market prices are being set close to the marginal operating cost of relatively efficient units. For example, a gas-fired unit with a heat rate of 8,000 Btu/kWh would have an expected emissions cost of 42.5 cents per dollar of greenhouse gas allowance costs. The 41 cents per dollar of the allowance price estimate represents the additional emissions cost of a unit with a heat rate of almost 7,750 Btu/kWh.[126]

Figure 5.2 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.[127]

DMM calculates the implied heat rate adjusted for greenhouse gas compliance costs by subtracting our estimate of the greenhouse gas compliance cost price impact derived above from the energy price and then dividing the result by the gas price index. In this case, DMM chose to use quarterly estimates of the greenhouse gas impact: $0.35 per dollar of allowance cost in the first quarter, $0.56 in the second quarter, $0.36 in the third quarter, and $0.24 in the fourth quarter.[128] As reflected in the quarterly estimates derived from the regression model described above, the price impact of the greenhouse gas costs appears to be lower during periods of relatively high day-ahead prices.

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[124] These estimates were generated by using a set of four quarterly indicator variables multiplied by the greenhouse gas measure in place of single greenhouse gas measure. Estimates presented here differ from those presented in DMM's fourth quarter report due to corrections made in the process used to fill non-ISO gas index data on days when gas trading does not take place, such as weekends and holidays. The impact on DMM's GHG impact estimates is not substantial.

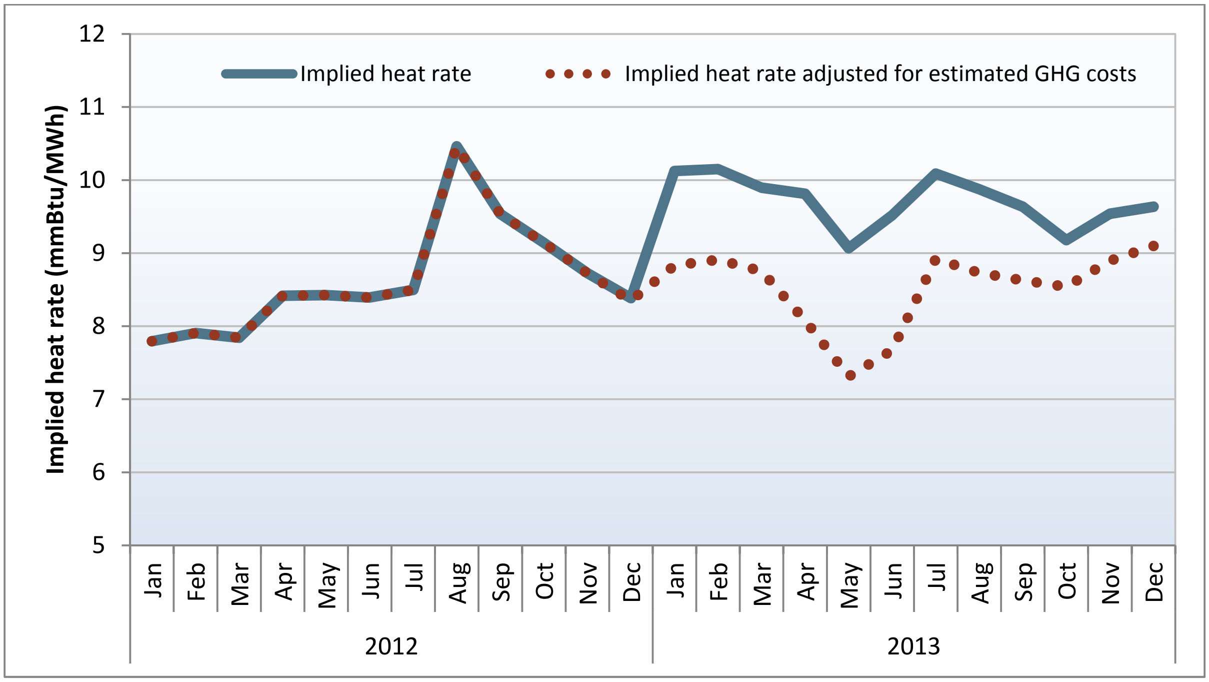
[125] In the first case, R^2 = 0.9337 and the adjusted R^2 = 0.9322. In the second case, R^2 = 0.9364 and the adjusted R^2 = 0.9349.

[126] 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. 0.410966 divided by 0.0530731 = 7.743395.

[127] For this calculation, DMM uses 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.

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

Figure 5.2 Implied heat rates with and without greenhouse gas compliance costs



The implied heat rate analysis shows that changes in gas prices and greenhouse gas compliance costs account for most of the electricity price increase between 2012 and 2013. Although the average implied heat rate in 2013 was about 13 percent higher than in 2012, the greenhouse gas adjusted implied heat rate is about 1 percent lower. This suggests that greenhouse gas allowance costs may account for much of the day-ahead price increase not accounted for by higher natural gas prices.

5.4 Effects on regional trading hub prices

Background

Since California is a major importer of power, another question that has been raised is the extent to which increases in prices due to the cap-and-trade program may have increased bilateral market prices in other balancing areas of the west.

Historically, California prices have tended to be higher than prices in surrounding regions outside of California. These higher prices often create opportunities for excess hydro-electric and renewable generation in the Pacific Northwest and excess lower cost energy from the Southwest to import into California. During some conditions, higher prices within California could theoretically increase prices in neighboring areas by increasing demand for exports to California.

However, under other conditions, the cap-and-trade program could be expected to increase prices in California without raising bilateral prices in other balancing areas or trading hubs. In many hours exports to California from other areas are limited by transmission. In addition, non-renewable energy exported to California is subject to cap-and-trade obligations and must ultimately pay the cost of emission allowances.

Imports into California not e-tagged as being from a specific resource ultimately incur a compliance obligation based on emission rates comparable to those of a typical gas-fired combined cycle unit.[129] These suppliers would be expected to build this extra cost into any bids or decisions to sell into California, but would not incur such cost if this same power was sold outside of California. This would tend to create a systematic price difference between California and other areas in the west that reflect the additional greenhouse gas compliance costs of power that is either generated in or imported into California.

The first part of our analysis compares prices within Southern California (the SP15 trading hub) and the Palo Verde trading hub price in Arizona. The second part of our analysis compares prices within Northern California (the NP15 trading hub) and the Mid-Columbia trading hub price in the Pacific Northwest.

Analysis of Palo Verde prices

Figure 5.3 shows the weekly average peak prices for Palo Verde and SP15 between December 2012 and January 2013. As shown in this figure, peak SP15 prices jumped by around $10/MWh right after implementation of the cap-and-trade program, whereas Palo Verde prices did not show a visible increase. Figure 5.4 through Figure 5.6 show medium to long-term views of these prices.

Figure 5.4 illustrates the weekly average peak prices for Palo Verde and SP15 between October 2012 and December 2013. In January 2013, SP15 prices showed an initial jump and higher prices continued in the first few months of the year. However, increases in Palo Verde prices were less significant compared to the rise in SP15 prices. On average, peak SP15 prices increased by around $8/MWh and Palo Verde prices increased only by around $1.50/MWh in the first quarter of 2013, compared to the fourth quarter of 2012. Therefore, the spread between the two prices grew in the first few months of 2013. This spread was also clearly shown in the market heat rates for these regions, as illustrated in Figure 5.5.

[129] The default emissions rate for an unspecified import is 0.428 mtCO_2e/MWh. This rate roughly refers to a 8,050 MMBtu/kWh heat rate, which is equivalent to a fairly efficient combined cycle gas unit. Details of emission rate calculations for unspecified imports can be found under section 95111(b)(1) in the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (Cal. Code Regs., tit. 17, § 95100 et seq.) at: http://www.arb.ca.gov/cc/reporting/ghg-rep/regulation/mrr-2013-clean.pdf.

Figure 5.3 Weekly average prices for Southern California (SP15) and Palo Verde trading hub (December 2012 to January 2013)

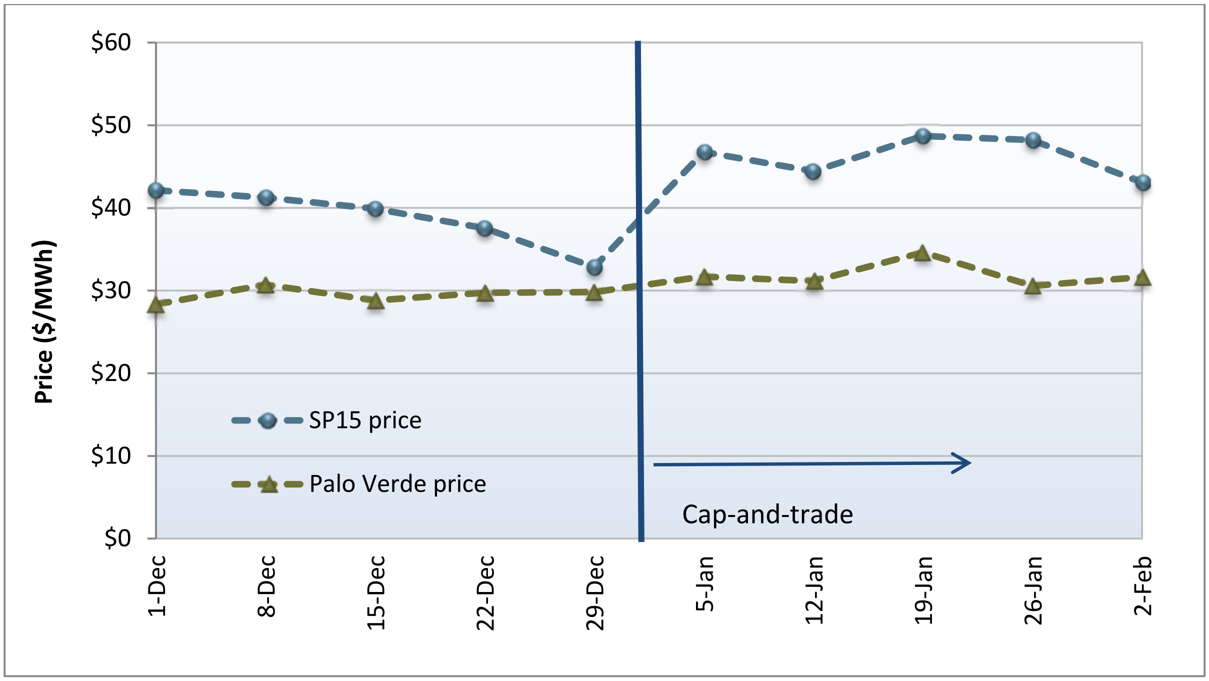


Figure 5.4 Weekly average prices for SP15 and Palo Verde trading hub (October 2012 to December 2013)

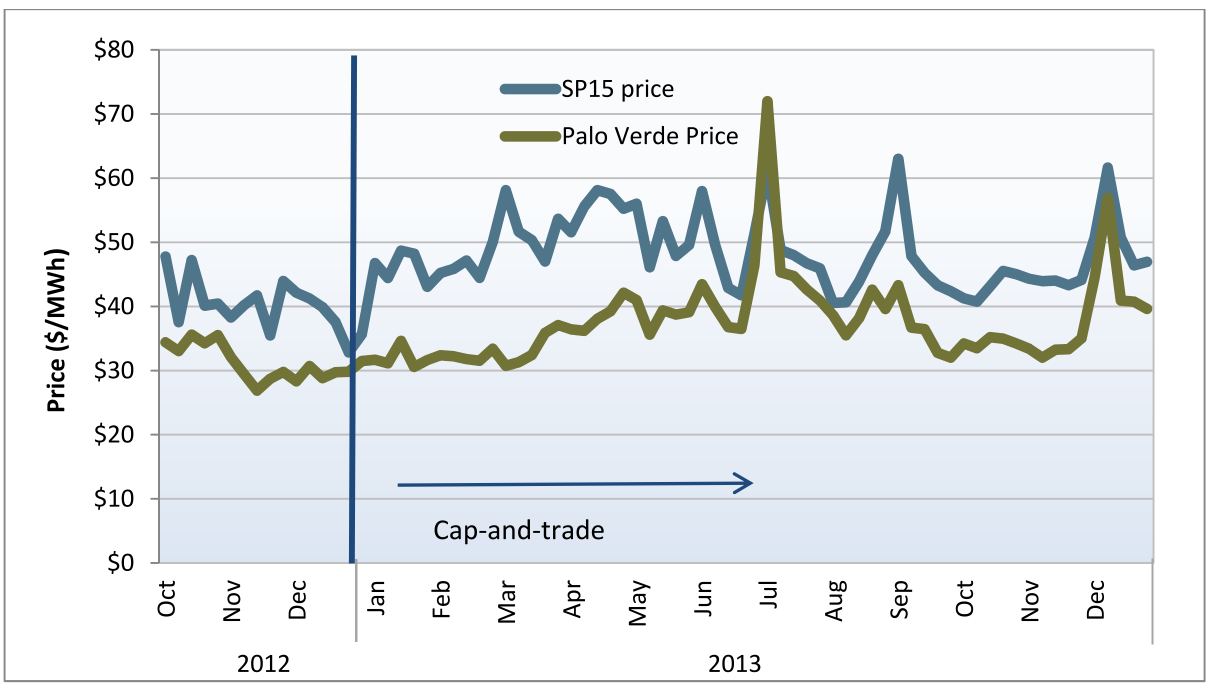


Figure 5.5 Difference in market heat rates for SP15 and Palo Verde trading hub

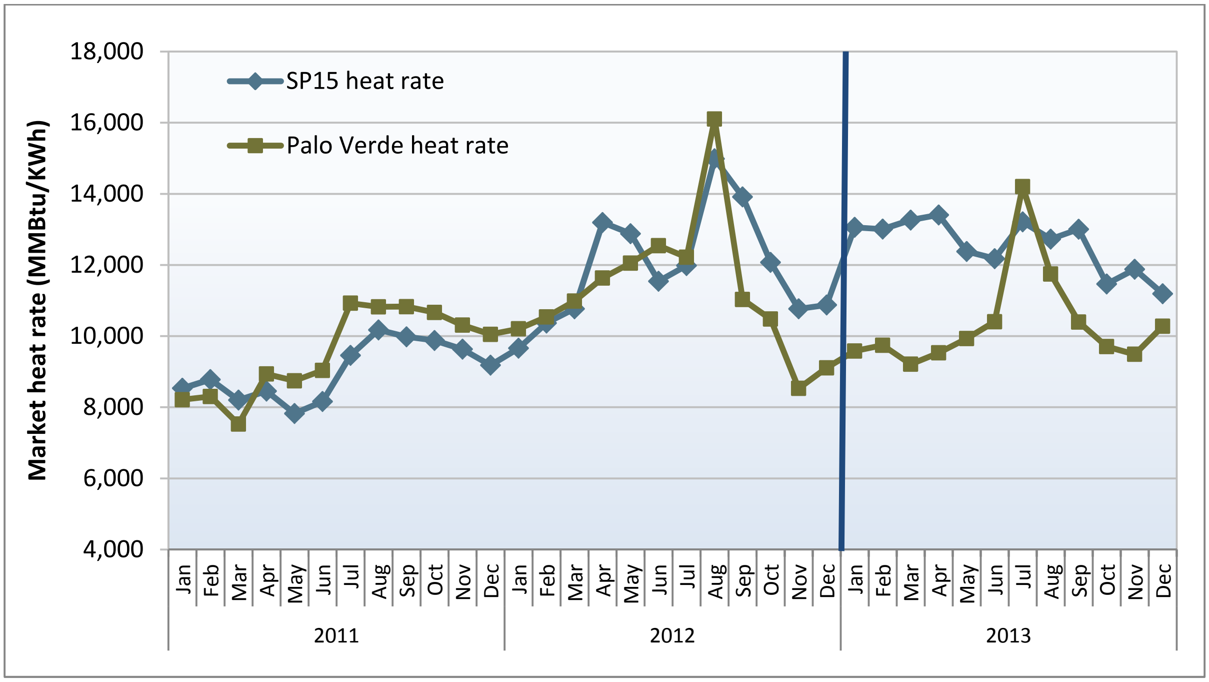


Figure 5.6 Difference in prices for the SP15 and Palo Verde trading hub

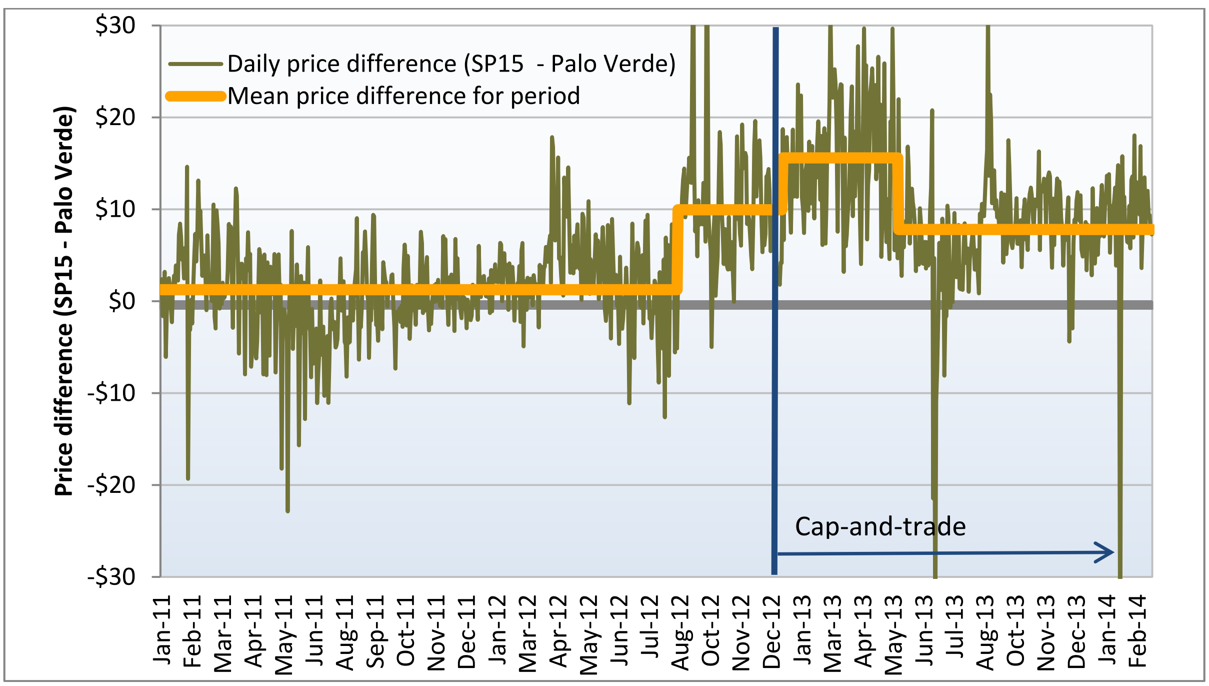


Figure 5.6 shows the daily average peak price differences between Palo Verde and SP15 trading hubs, along with average price differences for different periods over this time frame. The differences in periods shown in Figure 5.6 are based on statistical analysis designed to identify periods for which the relationship between these prices was statistically different.[130]

As shown in Figure 5.6, the average difference in peak prices within Southern California and Palo Verde increased by almost $6/MWh in the period immediately after implementation of the cap-and-trade compliance obligation in January 2013. This suggests that the initial effect of the cap-and-trade program under market conditions at that time was to raise prices in California by about $6/MWh more than at the Palo Verde trading hub.

By June 2013, the difference in prices in California dropped about $2/MWh below the difference in average prices during the last quarter of 2012. The price difference beginning in June was about $6.50/MWh more than the moderate price difference that existed from January 2011 to August 2012. However, it is important to note that during this period, significant congestion occurred in Southern California, limiting imports into the region. This congestion began in the fall of 2012 and continued into the summer of 2013.

Analysis of Pacific Northwest prices

Figure 5.7 shows the weekly average peak prices for NP15 and Mid-Columbia between December 2012 and January 2013. Peak NP15 prices increased by around $6/MWh right after the start of greenhouse gas regulations, whereas Mid-Columbia prices increased by around $1/MWh.

Figure 5.8 shows the weekly average peak prices for these two areas between October 2012 and December 2013. Mid-Columbia prices seem to follow movements in NP15 prices fairly closely for much of the year. However, there appears to have been different spreads between the first and second halves of the year. On average, peak NP15 prices increased by around $3/MWh and Mid-Columbia prices increased only by around $1/MWh in the first quarter of 2013, compared to the fourth quarter of 2012.

Figure 5.9 shows the market heat rates for the two regions. Similar to comparisons with the Southwest, the spread between market heat rates stayed consistently large in the first few months of 2013 and tightened in the second half of the year.

Figure 5.10 shows the daily average peak price differences between Mid-Columbia and NP15 trading hubs, along with average price differences for different periods over this time frame.[131] The figure shows that the average price difference within NP15 and Mid-Columbia increased by only $1/MWh for the first few months immediately after January 2013. In the second half of the year, decreases in hydro-electric generation in the Northwest seem to have increased the Mid-Columbia prices and this appears to have caused price convergence between these two markets. The absence of significant congestion may also help explain why Mid-Columbia prices follow NP15 prices during this period.

[130] DMM used the changepoint package in the R software by Rebecca Killick and Idris Eckley (2013). changepoint: An R package for changepoint analysis. R package version 1.1: http://CRAN.R-project.org/package=changepoint.

[131] This analysis used the same statistical analysis that was used in our analysis of Southwest prices to determine points where the relationship between prices changes. See footnote 130 for more information.

Figure 5.7 Weekly average prices for Northern California (NP15) and Mid-Columbia trading hub (December 2012 to January 2013)

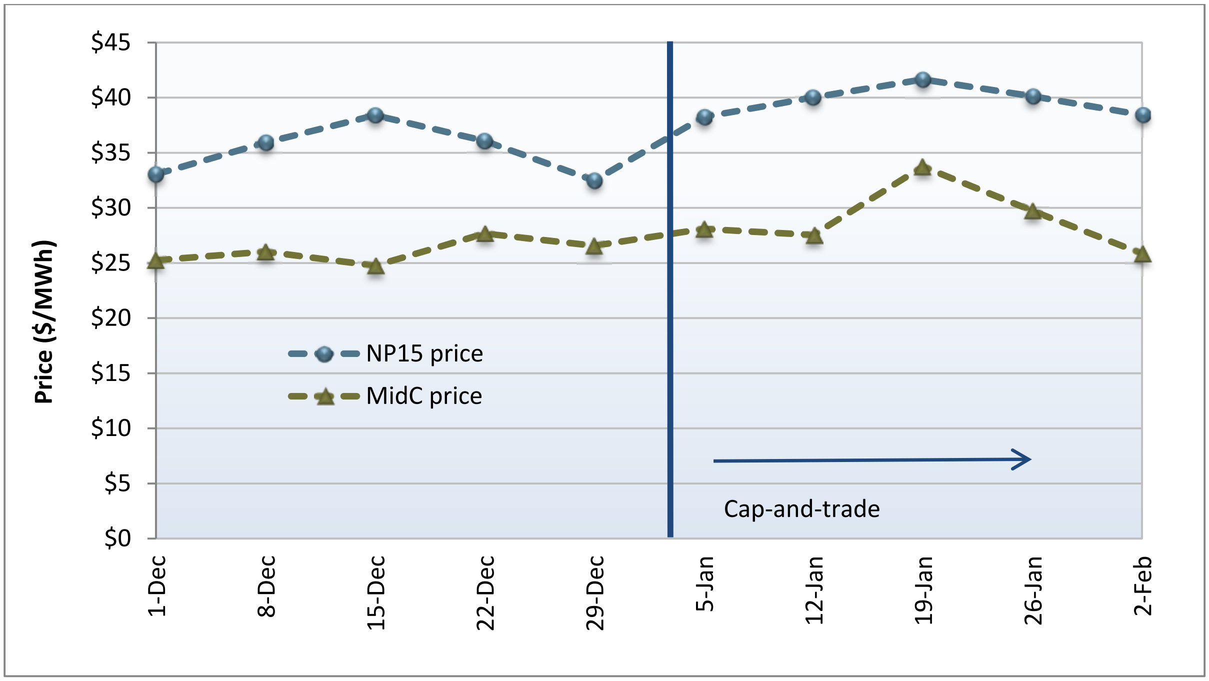


Figure 5.8 Weekly average prices for NP15 and Mid-Columbia trading hub (October 2012 to December 2013)

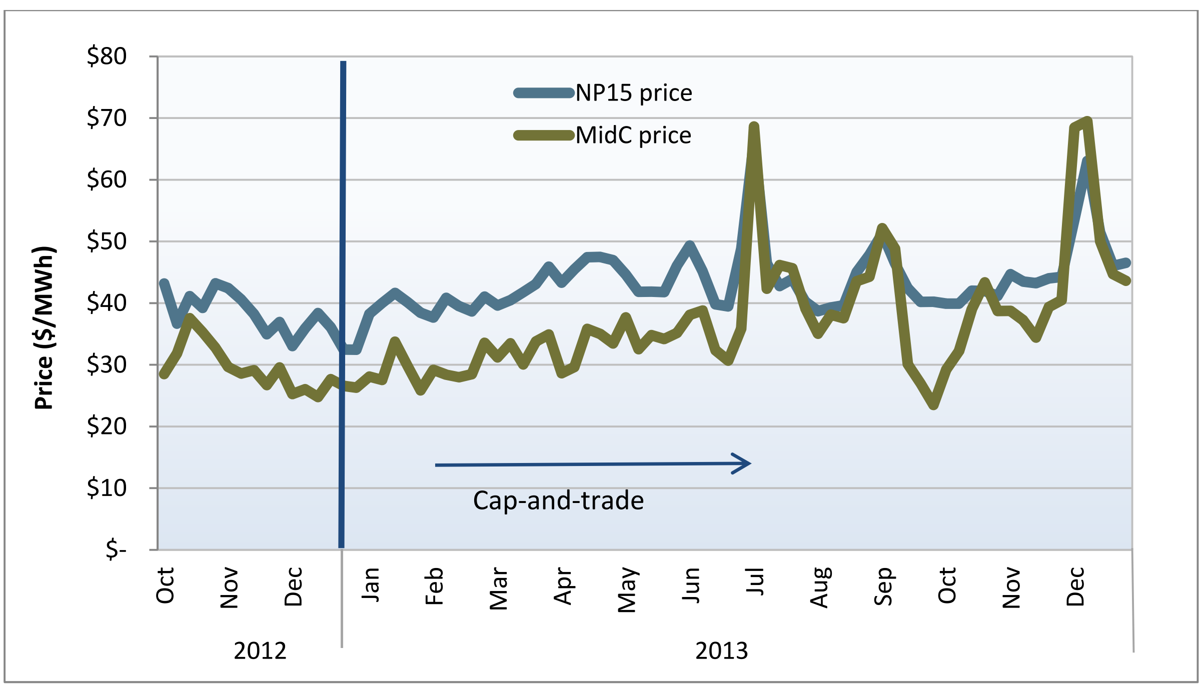


Figure 5.9 Difference in market heat rates for NP15 and Mid-Columbia trading hub

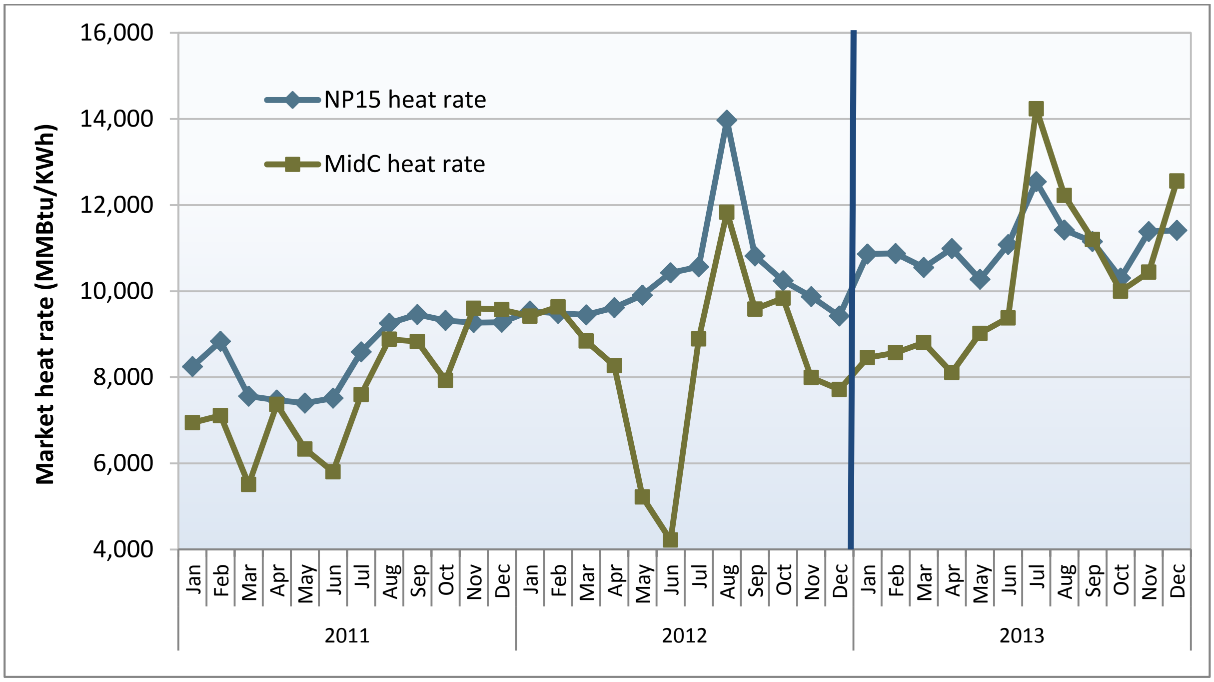
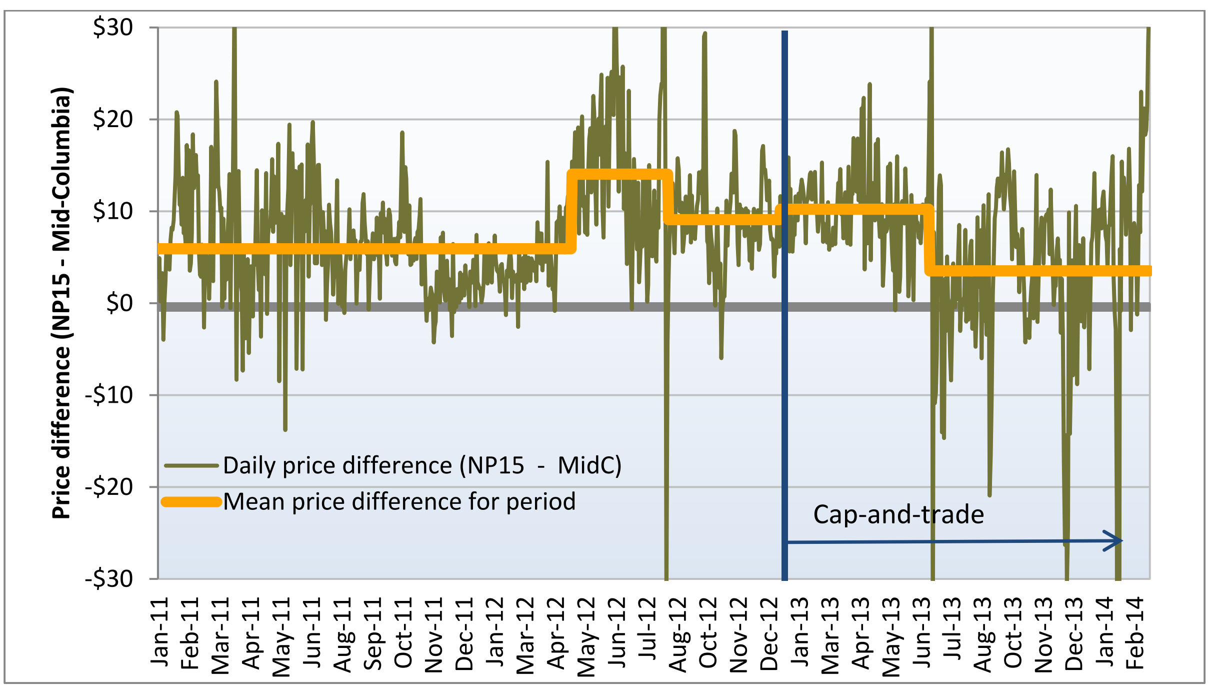


Figure 5.10 Difference in prices for NP15 and Mid-Columbia trading hub

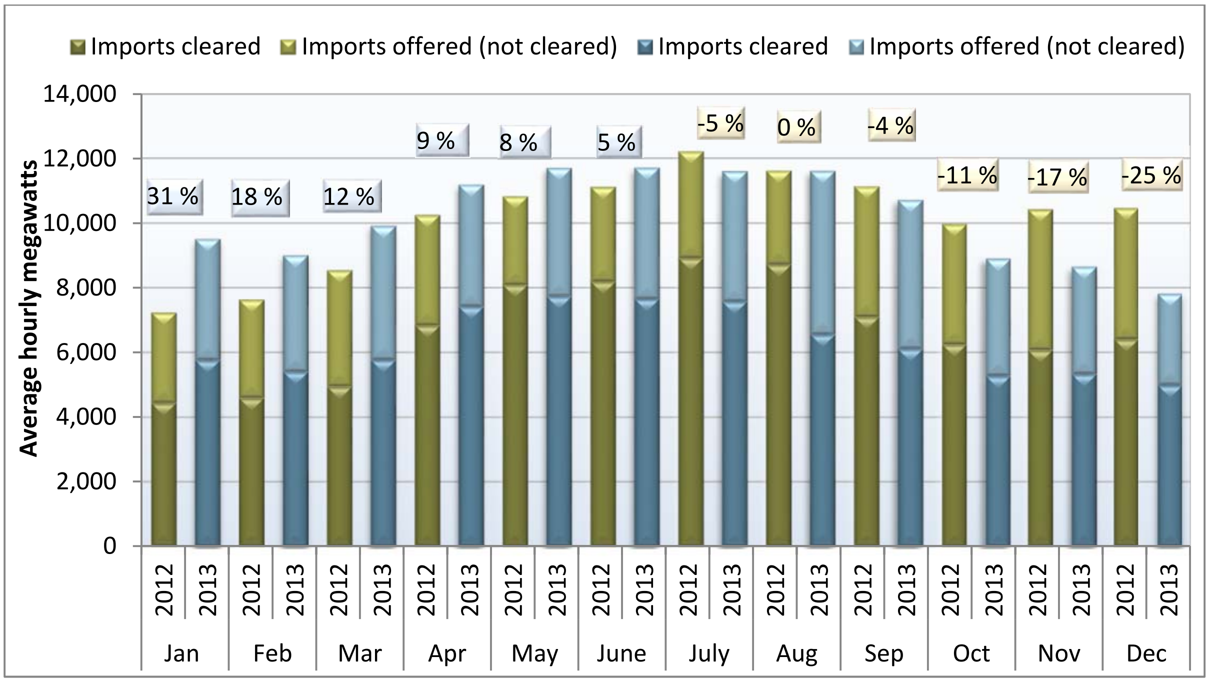


5.5 Changes in import levels and participation

Prior to the implementation of the cap-and-trade program, some stakeholders and regulators were concerned that certain rules related to resource shuffling would result in reduced imports into California as some participants would elect to exit the import market.[132] Ultimately, while the mix of participants importing power into California has changed slightly in 2013, the levels of imports offered to the market increased by 1 percent compared to 2012.[133] About 28 percent of ISO load was served by imports from outside the ISO system in 2013, with most of these imports coming from outside California.[134]

Figure 5.11 shows the quantity of imports bid in and cleared at inter-ties in the day-ahead market in 2012 and 2013.[135] Percentages in the boxes in Figure 5.11 highlight the percentage change in total volume of import bids offered each month in 2013 compared to the same month in 2012. Total import megawatts offered increased by around 13 percent in the first six months of 2013 compared to the same period in 2012.

Figure 5.11 Imports offered and cleared in the day-ahead market[136]



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

[133] There were a small number of participants, specifically public entities, and their associated imports into California, which explicitly stopped importing as a result of the program. However, new market entrants have begun to import into California and include a mix of public entities and private companies. In total, the new entrant imports exceeded the quantity of megawatts associated with participants that are no longer importing into California.

[134] For further detail, see Section 1.2.

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

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

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

As shown by the darker bars in Figure 5.11, the volume of import bids that cleared the market increased in the first four months of 2013 compared to 2012 and decreased in the remaining months of 2013. In the second half of 2013, import megawatts cleared in the market decreased by around 18 percent compared to the same period in 2012. This change is likely affected by relative price differences between prices inside and outside of California. DMM observed that bilateral prices at the Mid-Columbia and Palo Verde hubs were much closer to California hub prices during the second half of 2013 (especially in July, August and December), which could partially explain the change in cleared imports.

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

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

6 Ancillary Services

The ancillary service market continued to perform efficiently and competitively in 2013. The cost of ancillary services fell substantially, driven primarily by a decrease in prices but also by a decrease in procurement levels. Key trends highlighted in this chapter include:

- Ancillary service costs decreased to $57 million in 2013, representing a 31 percent decrease from $83 million in ancillary service costs in 2012.
- Costs decreased from 1 percent of total energy costs in 2012 to 0.5 percent in 2013. The annual cost of $0.25 per MWh was the lowest value since the nodal market began in 2009.
- Ancillary service prices were lower in 2013, driving the decrease in overall cost. The decrease is likely due to an increase in spinning reserves from hydro-electric generators compared to 2012 and fewer peak load days in the summer causing non-spinning reserve costs to drop.
- The value of self-providing ancillary services accounted for $4.6 million of total ancillary service costs in 2013, or about 8 percent.[137] By using their own resources to meet ancillary service requirements, load-serving entities are able to hedge against the risk of higher costs in the ISO market. In 2012, self-provided ancillary services accounted for about 17 percent of total ancillary service costs, or about $14 million.
- Both day-ahead and real-time ancillary service requirements decreased in 2013. The average hourly day-ahead requirement for operating reserves was 1,717 MW. This is down 2 percent from 1,757 MW in 2012, but very close to 1,715 MW, the average in 2011. The average hourly real-time operating reserve requirement was 1,566 MW in 2013, a 7 percent decrease from 1,686 MW in 2012. The average hourly day-ahead regulation down requirement was 325 MW in 2013, a decrease from 351 MW in 2012. The average hourly day-ahead regulation up requirement was 338 MW, roughly equal to the 332 MW requirement in 2012.
- The ISO implemented an updated algorithm for determining the operating reserve requirement in the real-time market in August 2012. In 2013, the ISO procured an average of about 151 MW less of spinning and non-spinning reserves combined in the real-time market than in the day-ahead market.
- Only one ancillary service scarcity event occurred in 2013. The scarcity was limited to 0.46 MW of regulation down during three 15-minute intervals in the 15-minute real-time market. As no additional regulation down was procured, there was no estimated incremental cost.
- The ISO began ancillary service compliance testing in late 2012 and continued the program through 2013. DMM anticipates that the ISO will revise and clarify the ancillary service compliance testing procedures in 2014 in response to implementation challenges. Ancillary service compliance testing will continue to be an important part of maintaining reliability.

[137] Load-serving entities reduce their ancillary service requirements by self-providing ancillary services. While this is not a direct cost to the load-serving entity, economic value exists.

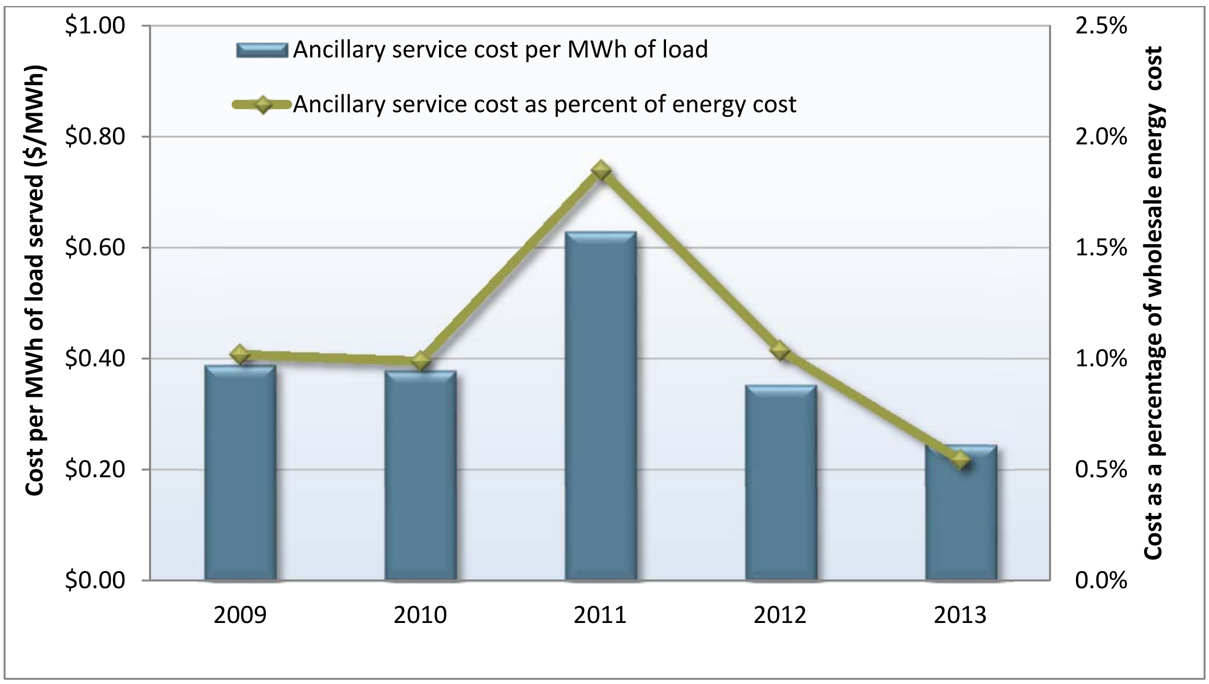
A detailed description of the ancillary service market design, implemented in 2009, is provided in DMM's 2010 annual report.[138] This market design includes co-optimizing energy and ancillary service bids provided by each resource. With co-optimization, units are able to bid all of their capacity into the energy and ancillary service markets without risking the loss of revenue in one market when their capacity is sold in the other. Co-optimization allows the market software to determine the most efficient use of each unit's capacity for energy and ancillary services.

6.1 Ancillary service costs

Ancillary service costs decreased to $0.25/MWh of load served in 2013 from $0.36/MWh in 2012. On a per MWh basis, ancillary service costs in 2013 were lower than in any year since the ISO's nodal market implementation in 2009. Ancillary service costs represent 0.5 percent of wholesale energy costs, down from 1.0 percent in 2012.

Figure 6.1 illustrates ancillary service costs both as a percentage of wholesale energy costs and per MWh of load from 2009 through 2013. Ancillary service costs per MWh were lower in 2013 than in any other year in the last five years.

Figure 6.1 Ancillary service cost as a percentage of wholesale energy costs (2009 – 2013)



Ancillary service costs were highest during the third quarter of 2013. Figure 6.2 shows the cost of ancillary services by quarter, measured both as a percentage of wholesale energy costs and per MWh of load served. Costs per MWh were lowest in the second quarter ($0.22/MWh) and highest in the third quarter ($0.26/MWh).

138 *2010 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2011, pp. 139-142: http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf.

Figure 6.2 Ancillary service cost by quarter

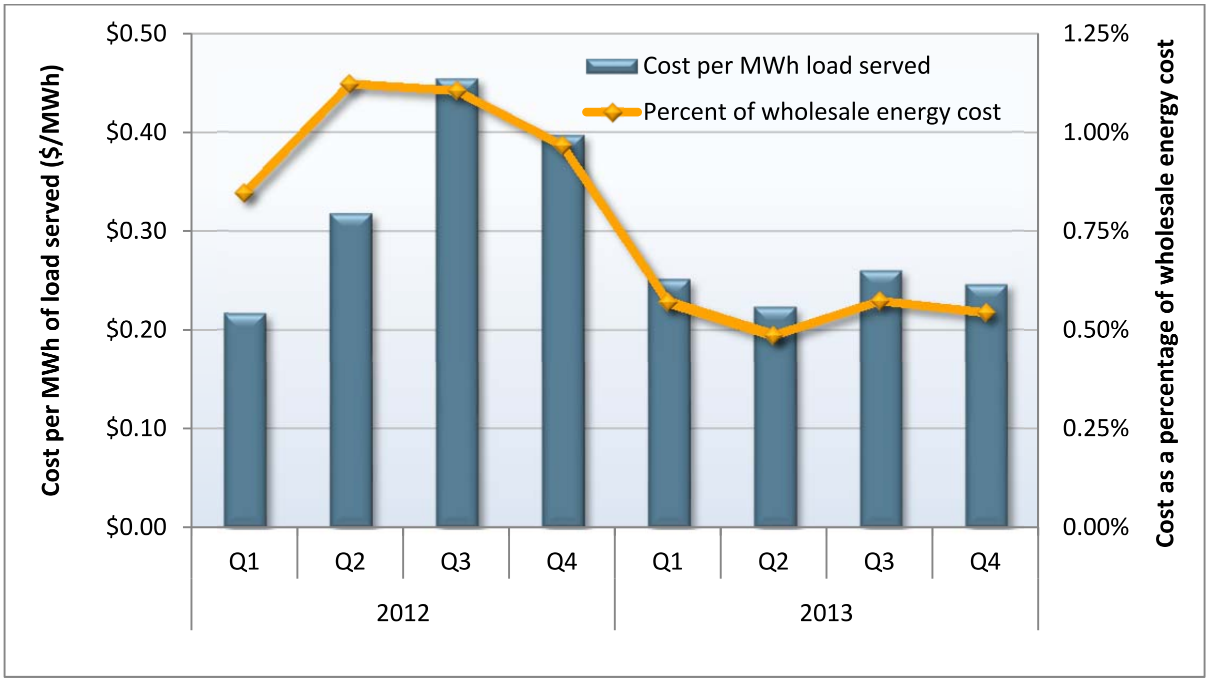
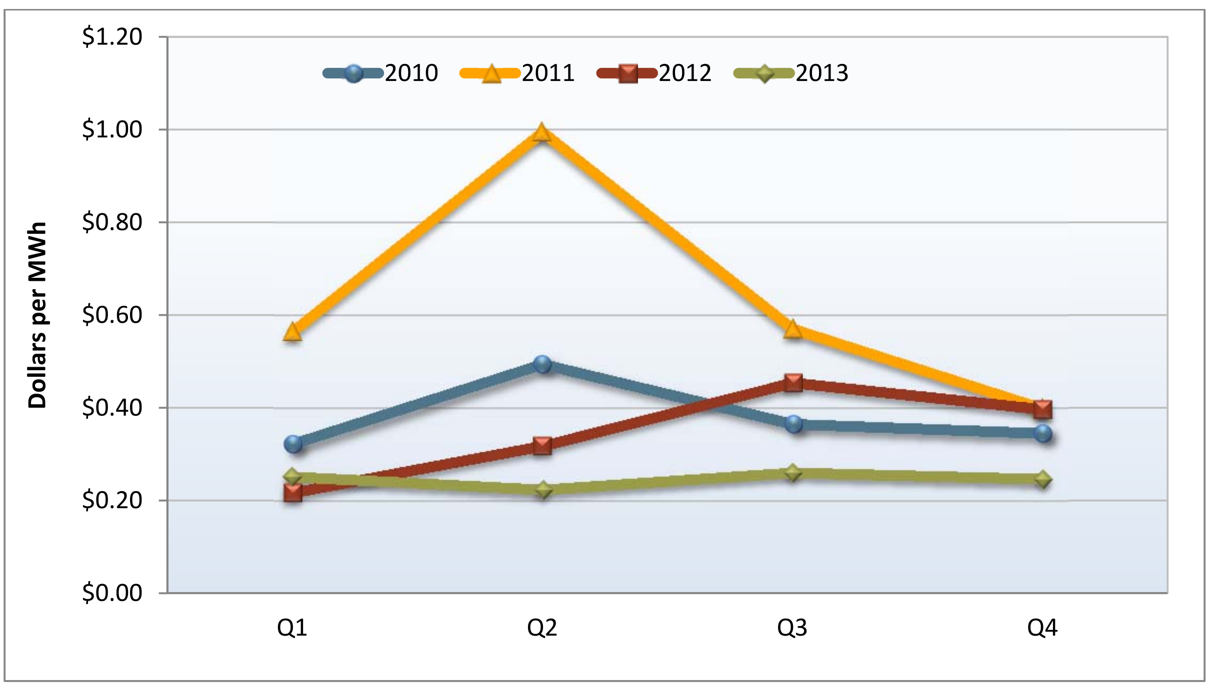


Figure 6.3 Ancillary service cost per MWh of load (2010 – 2013)



While this pattern is similar to 2012, this represents a departure from typical seasonal patterns. Historically, ancillary service costs have peaked in the spring and early summer months, when the snowmelt in the Sierra Nevada Mountains creates high levels of hydro runoff that require hydro-electric resources to produce electricity rather than ancillary services. This change was likely a result of low hydro-electric generation in 2013.

Ancillary service costs measured as a percentage of wholesale energy costs were consistent across quarters, peaking in the third quarter at 0.57 percent. On a quarterly basis, ancillary service costs per MWh were lower than same quarter costs in each year since the nodal market began, with the exception of the first quarter of 2012, as illustrated in Figure 6.3.

6.2 Ancillary service procurement

The ISO procures four ancillary services in the day-ahead and real-time markets: regulation up, regulation down, spinning, and non-spinning.[139] Ancillary service procurement requirements are set for each ancillary service to meet or exceed Western Electricity Coordinating Council's minimum operating reliability criteria and North American Electric Reliability Corporation's control performance standards. The day-ahead requirement is set equal to 100 percent of the estimated requirement, so that most ancillary services are procured in the day-ahead market.

The average hourly day-ahead requirement for operating reserves was 1,717 MW down 2 percent from 1,757 MW in 2012, but very close to 1,715 MW, the average in 2011. The average hourly real-time operating reserve requirement was 1,566 MW in 2013, a 7 percent decrease from 1,686 MW in 2012. The hourly day-ahead requirement applies to operating reserves (spinning and non-spinning) and is typically set by 5 percent of forecasted demand met by hydro-electric resources plus 7 percent of forecasted demand met by thermal resources.[140] Thus, the requirements follow a seasonal load pattern with higher requirements during the peak load months.

Real-time operating reserve requirements were set using the same algorithm until the implementation of a new requirement approach in August 2012 – the *ancillary service requirement setter.* This feature first calculates the ancillary services requirement based on the three following measures: resource mix, single largest contingency in the system, and percentage of load forecast (between 5 and 5.7 percent in real-time depending on system conditions). The final requirement is typically the largest of these three calculated values. The operator has the ability to override the requirement setter if necessary by setting the ancillary service requirement as a fixed percentage of the load forecast.

This automated feature has been utilized to assess the requirement for spinning and non-spinning reserves in the 15-minute real-time pre-dispatch market, but has not been used to set requirements in the day-ahead market. Using different requirement methodologies between the two markets has caused systematic differences in procurement of ancillary services. In 2013, the real-time market procured an average of 151 MW fewer operating reserves, consistent with the average 190 MW difference in 2012 after implementation of the setter on August 21. The ISO plans to revise the

[139] In addition, in June of this year the ISO added a performance payment to the regulation up and regulation down markets, separate from the existing capacity payment system. This product, often referred to as mileage, is discussed in further detail in Section 6.5.

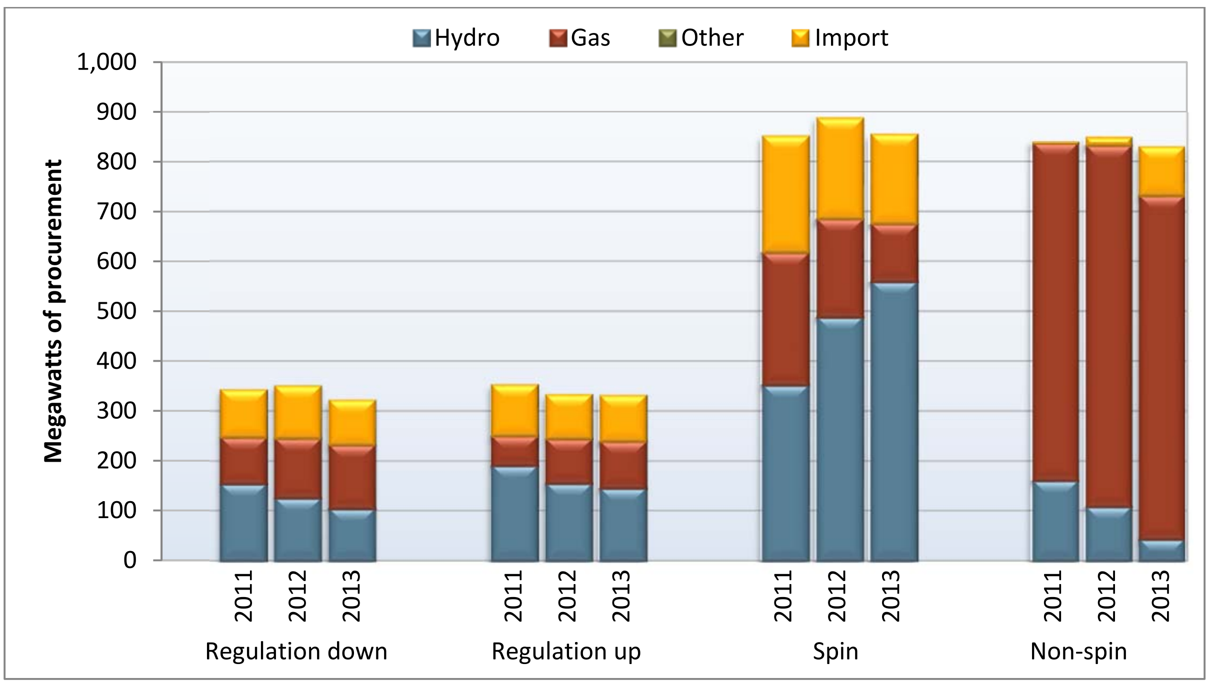
[140] Because of the magnitude of demand, the 5 and 7 percent are typically larger than the single largest contingency, which can also set the requirement.

operating reserve requirement in the fall of 2014 in response to FERC Order No. 789. This change will likely increase the ISO's operating reserve requirements.[141]

The average hourly real-time requirements for both regulation down and regulation up were 300 MW on average in 2013, a decrease from 2012. The requirement for regulation up and down is implemented by running an algorithm based on inter-hour forecast and schedule changes. The average hourly day-ahead regulation down requirement was 325 MW in 2013, a decrease from 351 MW in 2012. The average hourly day-ahead regulation up requirement was 338 MW, comparable to the 332 MW requirement in 2012.

Figure 6.4 shows the portion of ancillary services procured by fuel type. Ancillary service requirements are met by both internal resources and imports. Ancillary service imports are indirectly limited by minimum requirements set for procurement of ancillary services from within the ISO system. In addition, ancillary services bid across the inter-ties have to compete for transmission capacity with energy. If an inter-tie becomes congested, the scheduling coordinator awarded ancillary services will be charged the congestion rate. Thus, most ancillary service requirements continue to be met by ISO resources.

Figure 6.4 Procurement by internal resources and imports



Procurement of ancillary services decreased in 2013, in a pattern consistent with the changes in ancillary service requirements discussed above. The fuel type of resources providing ancillary services was very similar to 2012 with a slight shift from natural gas to imports. The composition of ancillary service resources is characterized as follows:

[141] FERC Order No. 789 can be found here: http://www.ferc.gov/whats-new/comm-meet/2013/112113/E-10.pdf.

- Average hourly provision of ancillary services from hydro-electric resources decreased in 2013 to 853 MW. This is a 3 percent decrease from 878 MW in 2012 and is likely due to lower hydro-electric generation conditions in 2013. Hydro-electric resources provided less of each ancillary service type with the exception of spinning reserves, which was up about 15 percent in 2013 compared to 2012.
- Total ancillary service imports increased from 410 MW in 2012 to 457 MW in 2013 on an average hourly basis. Imports provided 28 percent of regulation down and regulation up capacity, 21 percent of spinning reserves and 12 percent of non-spinning reserves.
- Gas-fired reserves provided 1,026 MW, down 9 percent from 1,129 MW in 2012. These resources provide the vast majority of non-spinning reserves as in previous years.

6.3 Ancillary services pricing

Resources providing ancillary services receive a capacity payment, or market clearing price, in both the day-ahead and real-time markets. Capacity payments in the real-time market are only for incremental capacity above the day-ahead award. Figure 6.5 and Figure 6.6 show the quantity weighted average market clearing prices for each ancillary service product by quarter in the day-ahead and real-time markets in 2012 and 2013.

Overall, 2013 average quarterly day-ahead prices decreased from 2012, as seen in Figure 6.5. In 2013, quarterly weighted average prices ranged from approximately $0.13 per MW to $5.70 per MW. Decreased procurement of ancillary services may have reduced weighted average prices. Day-ahead prices were generally lower than real-time prices, on a weighted quarterly average basis. Prices were generally highest for regulation up and lowest for non-spin resources, as they were in 2012.

Real-time weighted ancillary service prices were generally higher in 2013 than in 2012, with the exception of prices for regulation up, as illustrated in Figure 6.6. Most ancillary service procurement occurs in the day-ahead market, so the increase in real-time market prices had a relatively small impact on overall ancillary service costs.

Real-time regulation down prices in the second quarter were higher than prices in 2012, reaching a weighted average of $10.34 per MW. Real-time regulation up prices were higher than the real-time prices of other ancillary service products in each quarter, with the exception of regulation down prices in the second quarter, discussed above. Real-time regulation up prices were lower than 2012 as a result of multiple factors including decreased requirements and the dynamic ramp rates of ancillary services in the day-ahead market, which was implemented in August 2011.[142]

[142] For more information on dynamic ramp rates of ancillary services, see *2011 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2012, pp. 100-102.

Figure 6.5 Day-ahead ancillary service market clearing prices

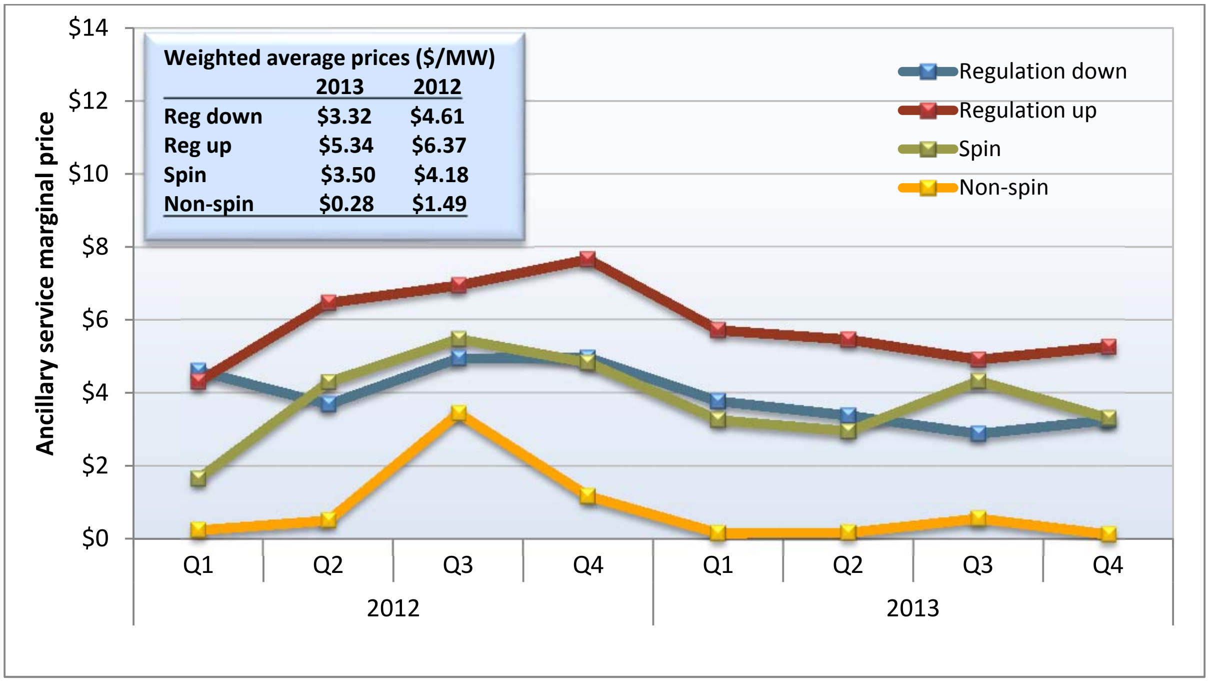
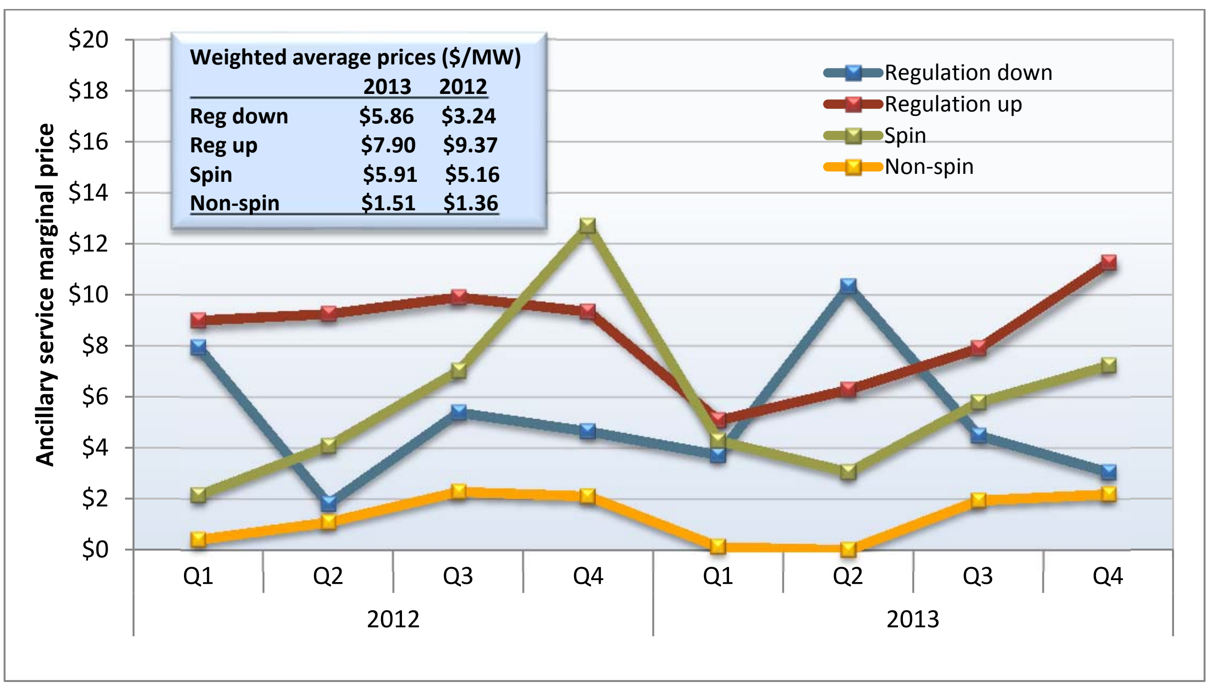


Figure 6.6 Real-time ancillary service market clearing prices

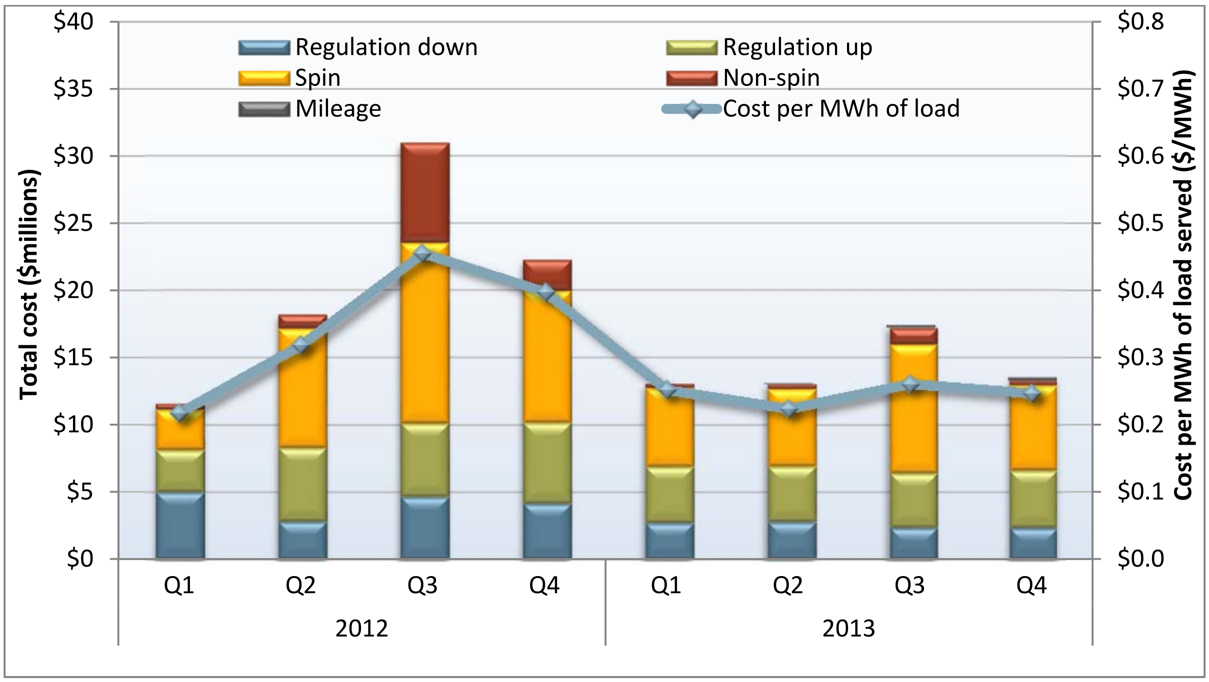


6.4 Ancillary service costs

Ancillary service costs totaled $57 million, a decrease of 31 percent from 2012. The value of self-provided ancillary services by load-serving entities was $4.6 million of this amount, or about 8 percent.

Figure 6.7 shows the total cost of procuring ancillary service products by quarter along with the total ancillary service cost for each MWh of load served. Total ancillary service cost peaked during the third quarter of the year. As discussed previously, lower prices, reduced procurement of ancillary services and increased provision of spinning reserves from hydro-electric generators compared to 2012 contributed to the decrease in total costs.

Figure 6.7 Ancillary service cost by product



6.5 Pay-for-performance regulation market

Summary

The ISO implemented the pay-for-performance product, often referred to as mileage, in June 2013. This product complements the regulation markets by adding a performance payment to the existing capacity payment system.

Overall, mileage has been an extremely small part of the market from a settlement standpoint (see Figure 6.7), totaling about $530,000 in seven months. Prices were low for mileage for much of the year, averaging $0.10 in either direction. High prices occurred occasionally, reaching as high as $23 in some intervals. These high prices are related to changes in resource dispatch between the day-ahead and the real-time markets, and represent a small part of the regulation market in total.

The ISO originally intended to impose a performance standard on regulation resources. The performance standard would disqualify any resource that delivered mileage with less than 50 percent measured accuracy. These resources would no longer be eligible to sell regulation services to the ISO markets.

Once the mileage market was implemented, it quickly became apparent that the proposed standard of performance and measurement of accuracy would disqualify the majority of resources providing regulation and have negative market impacts. The ISO has requested a temporary waiver from FERC allowing it to delay enforcement of this performance standard. During the waiver period, the ISO intends to study the situation in more depth and assess whether a change to the tariff is necessary.[143]

Background

FERC Order No. 755 instructed RTOs and ISOs to correct what they perceived as undue discrimination in procurement and compensation for regulation in the wholesale electricity markets.[144] The order explains that the markets did not recognize the greater provision of regulation services from faster, better performing resources. Order 755 instructed RTOs and ISOs to remedy this by explicitly compensating resource performance.

Under the previous regulation market structure, resources received payments based on the capacity set aside for management of regulation. This management would then be performed by an automated system, based on resource and system parameters. How the automated system used the resource was not relevant to the settlement, but could vary significantly across resources.

More recently, the regulation resource pool has broadened to include resources with different capabilities. This diversification of capabilities means that the amount of real use per unit of capacity varies more across resources that are used for regulation. In order to compensate for this variation, FERC ordered that resources be paid for the service they perform, and not just the capacity reserved. The intent was to provide greater incentive to faster, more capable resources to participate in the market.

New market structure

The regulation capacity market and the mileage market are separate, but are linked in important ways. It is not possible to sell regulation capacity without also selling mileage. The market has a minimum quantity requirement for each product. Like the regulation capacity market, the mileage market is divided into directional sectors, with mileage up linked to regulation up capacity, and mileage down to regulation down capacity.

Market participants that enter into the regulation market now effectively enter into two markets, one for capacity and one for mileage. Participants that enter into the market through economic bidding submit a price for each product, and a quantity for regulation capacity. In addition to the bid prices submitted for the resources, foregone energy market revenues are included to select the lowest cost options. Participants that choose to self-schedule regulation capacity and mileage submit only a

143 For more information, see: http://www.caiso.com/Documents/Jan10_2014_TariffWaiver_Pay-Performance_ER14-971-000.pdf.

144 The order can be found here: https://www.ferc.gov/whats-new/comm-meet/2011/102011/E-28.pdf.

quantity of regulation capacity to the market. The mileage from these resources enters the market optimization with a price of zero.

Under the previous structure, the needs for regulation in the ISO were stated as an amount of capacity reserved to perform the service. Resources that participated in the regulation capacity market offered to reserve capacity (to forego revenues from energy production) in order to provide regulation for the grid.

The new system introduces a specific measure of the service performed, which is known as mileage. Mileage is a measure of the total absolute changes in output made by a resource, or by the system, in the process of performing regulation. Changes in output are measured in megawatts. Since mileage counts both increasing and decreasing output changes, stating the mileage use in megawatts can suggest misleading comparisons. Instead, DMM will refer to units of mileage where each unit is equivalent to one megawatt in any direction.

The quantity requirements for mileage for the system are derived from the requirement for regulation capacity. This relationship is governed by the system mileage multiplier. The system mileage multiplier relates current regulation capacity requirements to mileage needs. Required mileage for any hour is equal to the amount of regulation capacity needed for that hour times the rolling seven day average of the ratio of units of mileage to megawatts of regulation capacity for that hour of the day.

The amount of mileage a unit may sell per megawatt of capacity is determined by the resource's history of accurately following automated control signals as well as the resource's ramp rate. These data are incorporated into a resource specific mileage multiplier. The market software assigns a predicted quantity of mileage to each resource, which is determined according to the resource specific multiplier and expected system needs for mileage.

Quantities of mileage sold into the market represent an estimate of how the system will use those resources. These estimates are based on expected system needs and past resource and system performance. While this is a reasonable way to estimate use, it should be noted that there is nothing in the system that suggests a need to follow or to attempt to meet these estimates.

Resources do not respond perfectly to the control signal, so the amount of mileage instructed is not the same as the amount of mileage delivered. Settlements for mileage are based on an adjusted quantity, and are further adjusted for measured accuracy.

Market performance

Prices for mileage reported in this section are from the day-ahead market, where the vast majority of regulation capacity is procured. This is the price that the majority of regulation resources receive for their service. The quantities reported here are *adjusted mileage*, as opposed to instructed mileage. Adjusted mileage corrects instructed mileage for some resource underperformance. It is the quantity used in settlements, and is closer to actual service performed than instructed mileage.

Average prices for mileage remained low, as seen in Figure 6.8. The average price for mileage up from June through December was $0.09 per unit of mileage. The average hourly quantity of mileage up varied from under 400 units of adjusted mileage in some of the early morning and late night hours, to around 1,000 units in hour ending 7. The largest average use of mileage up came in hours ending 6 and 7, and prices rose in those hours. The highest average prices occurred in hour ending 6, at $0.46 per unit.

Figure 6.8 Mileage up price and adjusted quantity

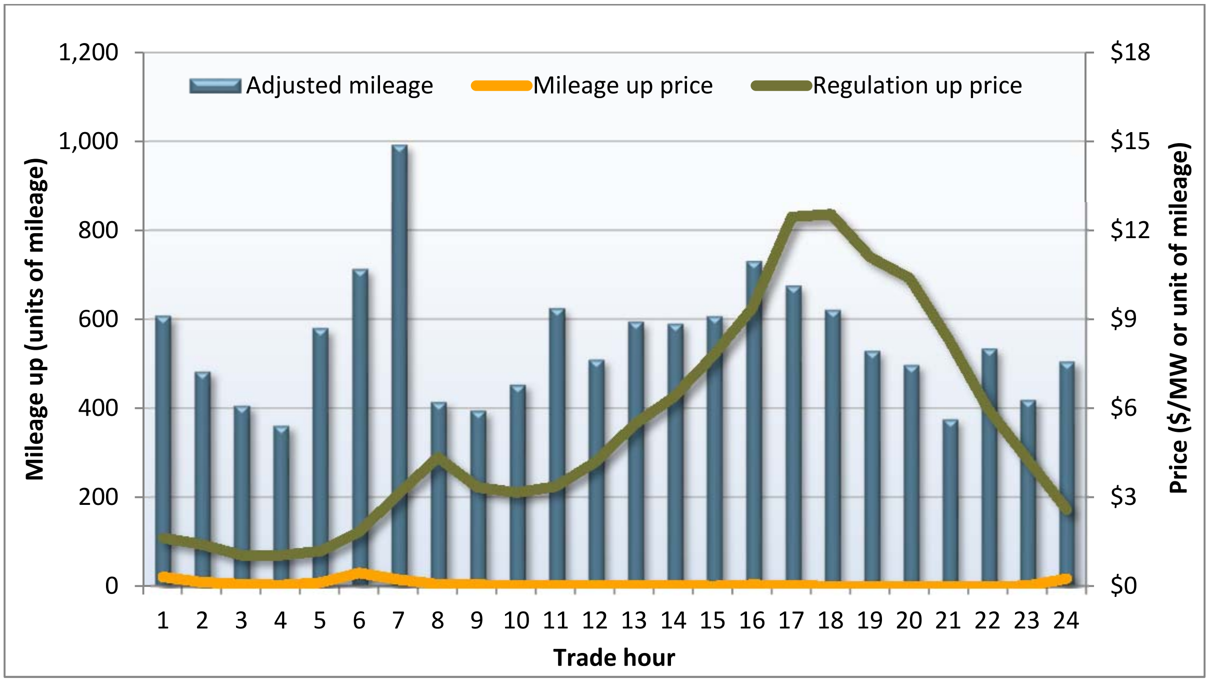
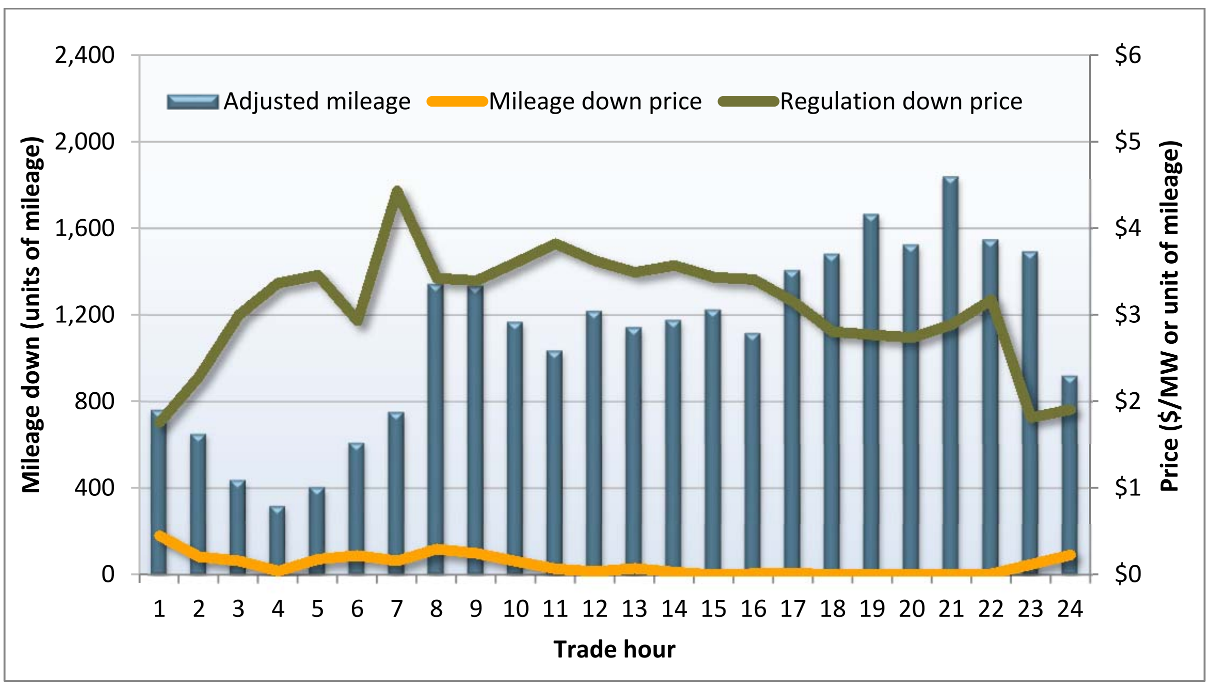


Figure 6.9 Mileage down price and adjusted quantity



In hours ending 19 through 22, the average mileage up price was less than $0.01 and often $0.00. Zero prices in mileage can happen for multiple reasons. One reason is that self-scheduled resources may have provided the entire requirement for regulation capacity and mileage. Another reason is that at least one self-scheduled resource may have had a relatively high ability to provide mileage service, as indicated by the mileage multiplier for that resource. A third reason is that the number of units of mileage needed by the system may be less than the number of megawatts of regulation capacity required. In this case, the system has to buy as many units of mileage as it buys megawatts of regulation capacity from each resource, so this circumstance leads to over-procurement of mileage.

Mileage down prices averaged $0.12 per unit. Figure 6.9 shows that the highest average price came in hour 1, at $0.45 per unit of mileage, followed by hour 8 at $0.30. The figure also shows that largest average use of mileage down came in hour 21, at over 1,800 units per hour. Similar to mileage up, mileage down average hourly prices were below $0.01 in the late evening hours. The circumstances that cause low prices in mileage down are the same as those that cause low prices in mileage up.

Occasionally, the prices for mileage were significantly higher than the average, reaching as high as $23 per unit of mileage. This occurred most often as a result of changes between day-ahead schedules and real-time dispatches for resources that provide regulation service. Typically, these changes did not have an impact. However, if the available pool of regulation resources was small for a given interval, the need to procure more regulation and mileage in the real-time market can have a price impact. The design of the mileage settlement isolates the impact of real-time price increases to apply only to those resources that sell regulation capacity and mileage in the real-time markets.

The price effects of dispatch changes are largest when the resources available to provide regulation in the real-time market are less capable (have a smaller resource specific mileage multiplier) than the resources which were scheduled to provide regulation in the day-ahead market. This can result in a need to procure more regulation capacity than was originally scheduled day-ahead. When total procurement of regulation capacity increases above the required amount, the offer prices of procured regulation capacity can actually impact the mileage price, so that the market clearing mileage price will be equal to the mileage offer price plus the capacity offer price of the marginal resource.

Resource and system performance

As part of the mileage market, the ISO measures the accuracy of response from each resource that contributes to regulation. In its compliance filing for FERC Order No. 755, the ISO included a provision to disqualify from the regulation markets any resource that performed with less than 50 percent accuracy.

When the product was implemented, the system average performance was around 50 percent.[145] This meant that a significant number of the resources participating in the market were eligible for disqualification. If the ISO went through with these disqualifications, the fundamental supply conditions prevalent in the regulation markets would shift drastically. In light of this, the ISO requested a waiver of this provision from FERC.[146]

[145] From a compensation standpoint, resources are paid for how they perform and, thus, low performance affects compensation. Moreover, the system procurement accounts for performance and procures resources accordingly to meet the required amount of regulation to meet system needs.

[146] For more information, see: http://www.caiso.com/Documents/Jan10_2014_TariffWaiver_Pay-Performance_ER14-971-000.pdf.

DMM supports the current ISO position that the accuracy threshold is not necessary for the market to function. Even so, a threshold may still have some use. The remaining challenge is determining what the appropriate threshold would be, and how compliance should be measured.

The original compliance filing requires that the ISO review the first year of market results and evaluate the design and functioning of the market system. The waiver that the ISO has asked for does not exempt them from this requirement, and states that the ISO will also review the systems that control resources in the regulation process. This robust plan for review should provide a good opportunity to evaluate appropriate thresholds and methods of measuring accuracy. Any changes that the ISO proposes to the regulation service markets should be developed by the end of 2014, and, afterwards, the requested waiver would expire.

6.6 Special issues

This section highlights additional features of the ancillary service market:

- scarcity pricing; and
- compliance testing, which began in late 2012.

Ancillary service scarcity pricing

Scarcity pricing of ancillary services occurs when there is insufficient supply to meet reserve requirements. Under the ISO's ancillary service scarcity price mechanism, implemented in December 2010, the ISO pays a pre-determined scarcity price for ancillary services procured during scarcity interval events.

In 2013, there were only three 15-minute intervals in which the ancillary service requirements were not met in either the hour-ahead or real-time markets. This scarcity event occurred on May 26 for regulation down in the 15-minute real-time pre-dispatch market for the first three intervals of hour ending 5 for the SP26 expanded sub-region. In each interval, procurement fell 0.46 MW short of the requirement.

On this day the ISO achieved record levels of wind generation,[147] and entered over-generation conditions later during the day. There were also several transmission outages requiring limits on units providing ancillary services, including a unit that had been scheduled to provide regulation down during these intervals in the day-ahead market. No incremental capacity was procured during these intervals, so the incremental cost of this event to the market was $0. In 2012, the incremental cost of the single scarcity event that occurred was $391.[148] Both costs were substantially below costs in 2011 when 24 ancillary service scarcity events had an estimated market impact of approximately $60,000.

Ancillary service compliance testing

In response to concerns that resources did not perform up to their rated ancillary service level during real-time ancillary service contingency events, the ISO announced that it would begin ancillary service

[147] These levels were surpassed later in the year.

[148] The ISO calculates the incremental cost by multiplying the incremental capacity acquired by the difference between the price for the scarcity interval and the price that occurred in the preceding interval without scarcity. In this case, the incremental reserve capacity procured during this event was 380 MW.

compliance testing in November 2012.[149] In 2013, the ISO used the Ancillary Service Resource Performance Verification protocol to test whether or not resources that were committed to providing ancillary services were able to deliver when called upon.[150]

Most resources that are subject to testing go through two stages: a performance audit and a compliance test. A performance audit occurs when a resource is flagged for failing to meet dispatch during a contingency run. The compliance test is an unannounced test in which a resource is called upon to produce energy at a time when it is scheduled to hold reserves. Failing either or both of these tests can result in disqualification of the resource for ancillary services and rescission of payments that were made to the resource. The ISO also has the authority to initiate a compliance test without the resource first experiencing a contingency related performance audit.

DMM anticipates that the ISO will revise and clarify the ancillary service compliance testing protocols in 2014 in response to implementation challenges. Ancillary service compliance testing will continue to be an important part of maintaining reliability.

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

[150] The documentation can be found here: http://www.caiso.com/Documents/5300%20-%20Resource%20certification%20and%20testing.

7 Market competitiveness and mitigation

This chapter assesses the competitiveness of the energy market, along with the impact and effectiveness of specific market power mitigation provisions. Key findings include the following:

- The day-ahead energy market remained structurally competitive on a system-wide level in almost all hours.
- Supply of local capacity owned by non-load-serving entities meets or exceeds the additional capacity needed to meet local requirements in most areas. However, in some areas, one supplier is individually pivotal, since some portion of this supplier's capacity is needed to meet local requirements.
- In 2013, the ISO implemented the second phase enhancement of the new transmission competitiveness evaluation and mitigation mechanism to address local market power. This new approach, known as *dynamic path assessment*, determines the competitiveness of transmission constraints based on actual system and market conditions each interval.
- The number of units subject to bid mitigation in the day-ahead market was lower in 2013 compared to 2012 as a result of decreased congestion and more competitive bidding.
- Most resources subject to mitigation submitted competitive offer prices, so that their bids were not lowered as a result of the mitigation process. On average, less than 1 unit per hour actually had their bid price lowered in the day-ahead market as a result of mitigation.
- The frequency of bid mitigation in the real-time market in 2013 was lower when compared to 2012. However, the estimated impact of bid mitigation on the amount of additional real-time energy dispatched as a result of bid mitigation was about the same in 2013 as in 2012.
- Mitigation provisions that apply to exceptional dispatch for energy above minimum load reduced costs by $450,000 in 2013, reflecting the fact that exceptional dispatches were relatively low and bids mitigated were not significantly in excess of competitive levels. The impact of mitigation of exceptional dispatches was extremely high in 2012 ($227 million) due to uncompetitive bidding by several suppliers controlling resources frequently needed to meet special reliability constraints.

7.1 Structural measures of competitiveness

Market structure refers to the ownership of the available supply in the market. The structural competitiveness of electric markets is often assessed using two related quantitative measures: the pivotal supplier test and residual supply index. Both of these measures assess the sufficiency of supply available to meet demand after removing the capacity owned or controlled by one or more entities.

- **Pivotal supplier test.** If supply is insufficient to meet demand with the supply of any individual supplier removed, then this supplier is pivotal. This is referred to as a single pivotal supplier test. The two-pivotal supplier test is performed by removing supply owned or controlled by the two largest suppliers. For the three-pivotal test, supply of the three largest suppliers is removed.

- **Residual supply index.** The residual supply index is the ratio of supply from non-pivotal suppliers to the demand.[151] A residual supply index less than 1.0 indicates an uncompetitive level of supply when the largest suppliers' shares are excluded.

In the electric industry, measures based on two or three suppliers in combination are often used because of the potential for oligopolistic bidding behavior. The potential for such behavior is high in the electric industry because the demand for electricity is highly inelastic, and competition from new sources of supply is limited by long lead times and regulatory barriers to siting of new generation.

In this report, when the residual supply index is calculated by excluding the largest supplier, we refer to this measure as the RSI_1. With the two or three largest suppliers excluded, we refer to these results as the RSI_2 and RSI_3, respectively.[152]

7.1.1 Day-ahead system energy

Figure 7.1 shows the hourly residual supply index for the day-ahead energy market in 2013. This analysis is based on system energy only and ignores potential limitations due to transmission limitations.[153] Results are only shown for the 500 hours when the residual supply index was lowest. As shown in Figure 7.1, the residual supply index with the three largest suppliers removed (RSI_3) was less than 1 in about 50 hours and about 10 hours with the two largest suppliers removed (RSI_2). The hourly RSI_3 value was as low as 0.86 in 2013 compared to about 0.91 in 2012.

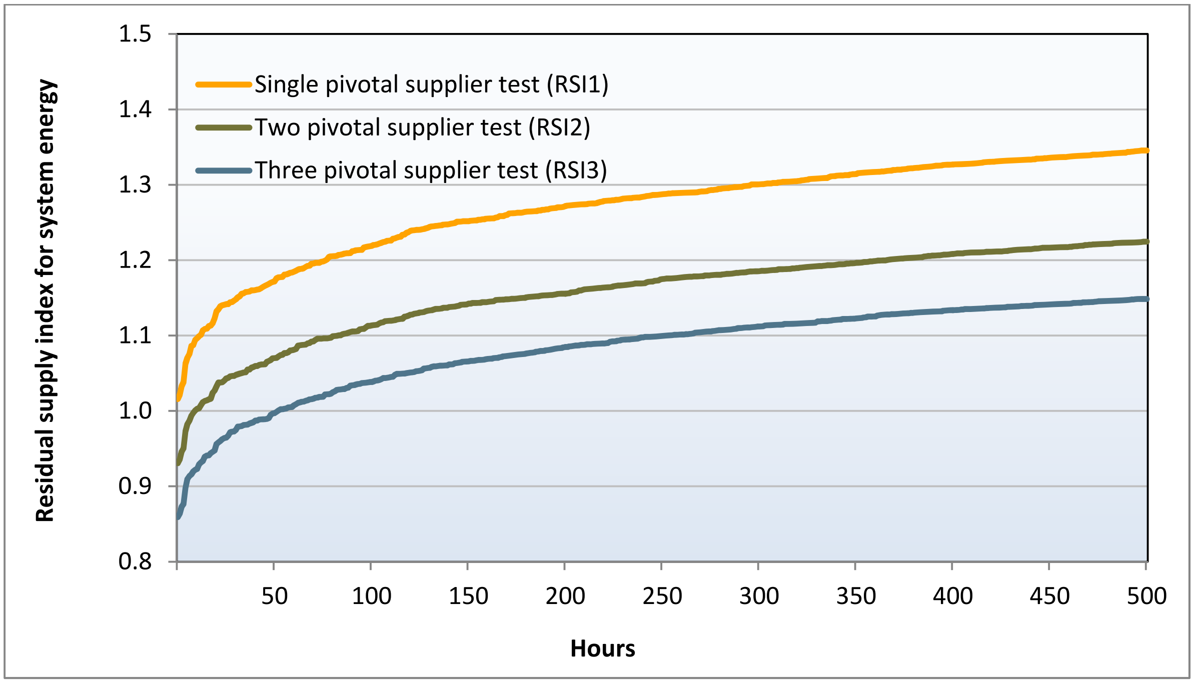
The residual supply index values reflect load conditions and generation availability, as well as resource ownership or control. For 2013, the analysis accounts for the merge of two major market suppliers (NRG Energy and GenOn Energy). However, some generating units have tolling contracts, which transfer the control from unit owners to load-serving entities. These tolling contracts improve overall structural competitiveness in the operating period versus the study period. However, as discussed in the following sections, since ownership of resources within different areas of the ISO grid is highly concentrated, local reliability requirements and transmission limitations give rise to local market power in many areas of the system.

[151] For instance, assume demand equals 100 MW and the total available supply equals 120 MW. If one supplier owns 30 MW of this supply, the residual supply index equals 0.90, or (120 – 30)/100.

[152] A detailed description of the residual supply index was provided in Appendix A of DMM's 2009 annual report.

[153] All internal supply bid into the day-ahead market is used in this calculation. Imports are assumed to be limited to 12,000 MW. Demand includes actual system loads plus ancillary services.

Figure 7.1 Residual supply index for day-ahead energy



7.1.2 Local capacity requirements

The ISO has defined 10 local capacity areas for which separate local reliability requirements are established under the state's resource adequacy program. In most of these areas, a high portion of the available capacity is needed to meet peak reliability planning requirements. One or two entities own most of the generation needed to meet local capacity requirements in each of these areas.

Table 7.1 provides a summary of the residual supply index for major local capacity areas. The demand in this analysis represents the local capacity requirements set by the ISO. Load-serving entities meet these requirements through a combination of self-owned generation and capacity procured though bilateral contracts. For this analysis, we assume that all capacity owned by load-serving entities will be used to meet these requirements with the remainder procured from the other entities that own the remaining resources in the local area.

As shown in Table 7.1, the total amount of supply owned by non-load-serving entities meets or exceeds the additional capacity needed by load-serving entities to meet these requirements in most areas. However, in some areas, one or more suppliers are individually pivotal for meeting the remainder of the capacity requirement. In other words, some portion of these suppliers' capacity is needed to meet local requirements.

Table 7.1 Residual supply index for major local capacity areas based on net qualifying capacity

Local capacity area	Net non-LSE capacity requirement (MW)	Total non-LSE capacity (MW)	Total residual supply ratio	RSI_1	RSI_2	RSI_3	Number of individually pivotal suppliers
PG&E area							
Greater Bay	2,935	5,725	1.95	1.01	0.14	0.09	0
North Coast/North Bay	473	721	1.52	0.01	0.00	0.00	1
SCE area							
LA Basin	6,403	7,312	1.14	0.55	0.22	0.11	2
Big Creek/Ventura	133	2,921	21.98	5.95	0.57	0.21	0
San Diego/Imperial Valley	1,255	2,501	1.99	1.07	0.60	0.14	0

The residual supply index values for both the Big Creek/Ventura and San Diego/Imperial Valley areas reflect more competitive conditions in the market for local capacity in 2013 compared to 2012. The increased competitiveness of the Big Creek/Ventura area stems from a significant reduction in local capacity requirements occurring as a result of infrastructure upgrades. The increased competitiveness of the supply of capacity in the San Diego/Imperial Valley area resulted from the consolidation of the San Diego and Imperial Valley areas into a single local capacity area.

In addition to the capacity requirements for each local area used in this analysis, additional reliability requirements exist for numerous sub-areas within each local capacity area. Some of these require that capacity be procured from specific individual generating plants. Others involve complex combinations of units which have different levels of effectiveness at meeting the reliability requirements.

These sub-area requirements are not formally included in local capacity requirements incorporated in the state's resource adequacy program. However, these additional sub-area requirements represent an additional source of local market power. If a unit needed for a sub-area requirement is not procured in the resource adequacy program and that resource does not make itself available to the ISO in the spot market, the ISO may need to procure capacity from the unit using the backstop procurement authority (the capacity procurement mechanism).

In the day-ahead and real-time energy markets, the potential for local market power is mitigated through bid mitigation procedures. These procedures require that each congested transmission constraint be designated as either competitive or non-competitive. This designation is based on established procedures for applying a pivotal supplier test in assessing the competitiveness of constraints. The following section examines the actual structural competitiveness of transmission constraints when congestion occurred in the day-ahead and real-time markets.

7.2 Competitiveness of transmission constraints

On May 1, 2013, the California ISO implemented the second phase of the new competitiveness assessment and mitigation mechanism to address local market power. Together with the first phase implemented in April 2012, this completes the transition to the new procedure. This section reviews the performance of this new method for determining the structural competitiveness of transmission constraints. Other key components of these new local market power mitigation procedures are discussed in Section 7.3.

Background

Local market power is created by two factors: congestion that limits the supply of imported electricity into the congested area, and insufficient or concentrated control of supply within the congested area.

The ISO local market power mitigation provisions require that each constraint be designated as either *competitive* or *non-competitive* prior to the actual market run. Generation bids are subject to mitigation if mitigation procedures indicate generators are effective to relieve the congestion on constraints that are structurally uncompetitive. For these provisions to be effective, it is important that constraints designated as competitive are in fact competitive under actual market conditions.

The methodology used to designate transmission constraints as competitive or non-competitive is the competitive path assessment. This methodology incorporates a 3-pivotal supplier test which in prior years had been performed in an offline study.[154] The competitive path assessment evaluates if a feasible power flow solution of a full network model can be reached with the supply of any three suppliers excluded from the market.[155]

The dynamic competitive path assessment and new local market power mitigation trigger mechanism work as follows. In the pre-market mitigation run, the market software clears supply and demand using un-mitigated bids. If any internal transmission constraints are binding in the pre-market run they are assessed for competitiveness of supply of counter-flow.

The assessment uses a residual supply index based on supply and demand of counter-flow from internal resources for each binding constraint. If there is sufficient supply of counter-flow for the binding constraint after removing the three largest net suppliers, then the constraint is deemed competitive. Otherwise, it is deemed non-competitive. A non-competitive supply of counter-flow is considered to be indicative of local market power and resources in this pool of supply may subsequently be subject to bid mitigation.

Next, the impact of congested non-competitive constraints on the energy price at each resource is evaluated. If there is a positive impact on the price then the resource could benefit from exercising local market power and consequently is subject to bid mitigation. Bid mitigation lowers the bid price to the higher of the resource's default energy bid or a calculated competitive price. The calculated competitive price is effectively the price at the resource less the contribution to that price from congested non-competitive constraints. The mitigated bids are then used in the actual market run.

This in-line dynamic approach to competitive path assessment has several advantages over the prior static off-line study approach. First, it uses actual market conditions to evaluate the transmission competitiveness. In contrast, the static competitive path assessment studies included a large number of

[154] For a detailed description of the methodology for the static off-line methodology, see *Competitive Path Assessment for MRTU Final Results for MRTU Go-Live,* Department of Market Monitoring, February 2009, http://www.caiso.com/2365/23659ca314f0.pdf. See the 2009 through 2011 editions of the *Annual Report on Market Issues and Performance* at http://www.caiso.com/market/Pages/MarketMonitoring/MarketIssuesPerfomanceReports/Default.aspx for analysis of the prior approach to local market power mitigation in the day-ahead market. Path designations prior to April 2010 were based on a study performed in February 2009.

[155] The static competitive path assessment is performed with relatively high penalty prices assigned to any overflow conditions on paths being tested for competitiveness.

hypothetical scenarios with high, medium, and low anticipated conditions for demand, imports, and generation output levels. Using actual market conditions produces more accurate and less conservative results.

Second, the new mitigation trigger is based directly on the impact of specific resources on prices due to congestion on structurally uncompetitive constraints. The previous mitigation trigger was based on a change in dispatch between a pre-market run without uncompetitive constraints and a second pre-market run with uncompetitive constraints added. While the prior approach was theoretically a very accurate way of identifying units that could relieve congestion on uncompetitive constraints, in practice units were sometimes subject to mitigation under this approach as a result of various modeling issues that could create changes in congestion and unit dispatch between these pre-market runs and the actual day-ahead market.

The new dynamic competitive path assessment and mitigation trigger was implemented in two phases (see Table 7.2). The first phase was implemented in 2012 and the second was implemented in 2013.

Table 7.2 New competitiveness assessment and mitigation implementation phases

Market	Dynamic competitive path assessment	Decomposition-triggered local market power mitigation
Day-ahead	Phase 1	Phase 1
Hour-ahead scheduling process	Phase 2	Phase 1
Real-time pre-dispatch	Phase 2	Phase 2

Competitiveness results

The results of the three-pivotal residual supply index reflect the changing competitiveness of transmission constraints in the day-ahead and real-time markets. Figure 7.2 and Figure 7.3 show the distribution of the three-pivotal residual supply index for the most frequently congested transmission facilities for the day-ahead and real-time market, respectively. The green bars in the chart indicate the range of the 25th to 50th percentile of these values, while the blue bars show the range of the 50th to 75th percentile of the distributions. The horizontal lines represent the remaining range, with the vertical lines showing the minimum and maximum values.

As is shown in these figures, for most constraints the residual supply index tends to be greater than 1 for most of the hours when congestion occurs, so that the constraints are deemed competitive and no units are subject to mitigation. This is particularly true in the real-time market. Only a few constraints are consistently found to be structurally uncompetitive when congestion occurs, with a significant number of units tending to be competitive under some conditions and uncompetitive under other conditions. These results highlight one of the key advantages of the dynamic competitive path assessment implemented in 2012 and 2013, which is the ability to test and designate the competitiveness of constraints based on actual system conditions.

Figure 7.2 Transmission competitiveness in 2013 for the day-ahead market

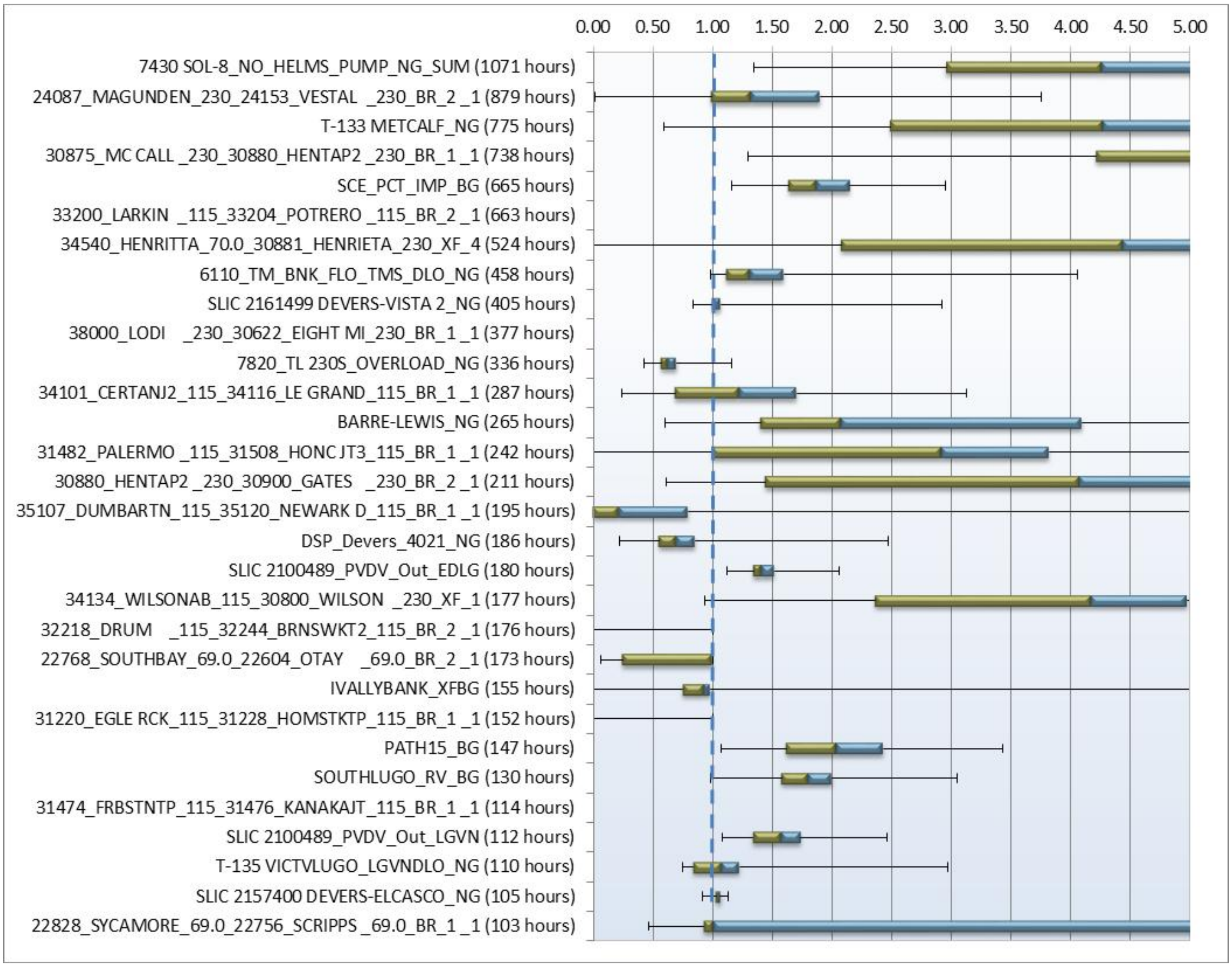
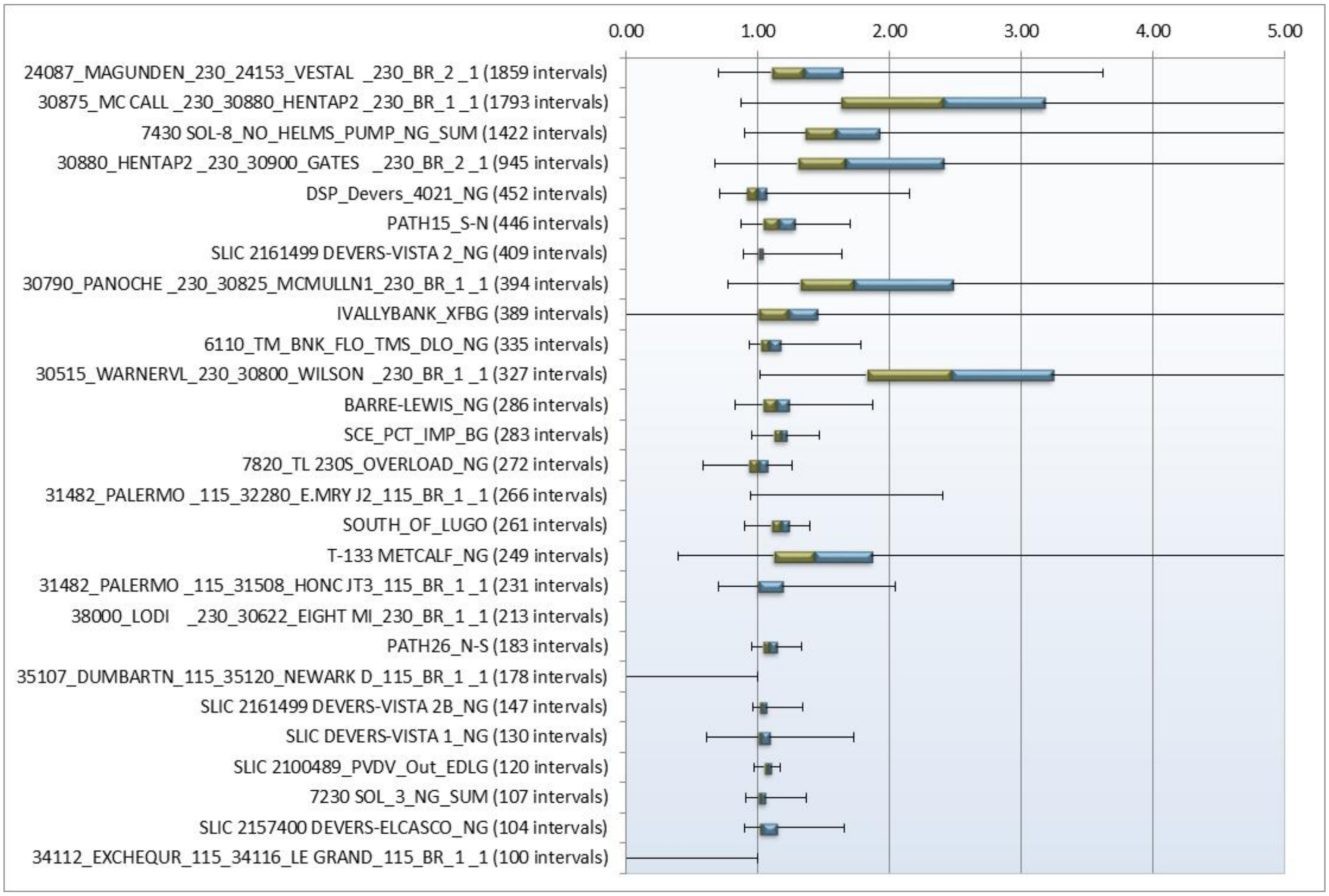


Figure 7.3 Transmission competitiveness in 2013 for the real-time market



Accuracy of transmission competitiveness assessment

As described above, the frequency of mitigation and overall accuracy of the new local market power mitigation procedures depend on a combination of two factors: (1) the accuracy with which the mitigation run predicts congestion in the market run, and (2) the portion of constraints congested in the mitigation or market run which are structurally non-competitive. The way in which DMM has used this framework to assess the overall accuracy of new mitigation procedures is shown graphically in Table 7.3.

As shown in Table 7.3, when congestion is *over-identified*, or is projected to occur in the mitigation run but does not occur in the market, mitigation is not applied when the congested constraint is deemed to be competitive. When congestion is over-identified, mitigation is only applied when the congested constraint is deemed to be non-competitive. This has sometimes been referred to as *unnecessary mitigation*. As described later in this section, the frequency of such unnecessary mitigation has been extremely low in both the day-ahead and real-time markets under the new mitigation procedures.

When congestion is *under-identified*, or is not projected to occur in the mitigation run but then occurs in the market, inaccurate mitigation only results when the congested constraint would have been deemed structurally non-competitive. In these cases, mitigation should be applied but is not. This is also referred to as *under-mitigation*. As described later in this section, the frequency of this type of lack of mitigation has also been extremely low in both the day-ahead and real-time markets under the new mitigation procedures.

Table 7.3 Framework for analysis of overall accuracy of transmission competitiveness

Congestion prediction (mitigation run vs. market)	Dynamic competitive path assessment results	
	Competitive	**Non-competitive**
Consistent (congested in mitigation and market runs)	No mitigation	Correct mitigation
Over-identified (congestion in mitigation run, but not market)	No mitigation	**Mitigation applied, but not needed**
Under-identified (no congestion in mitigation run, but market congestion)	No mitigation	**Mitigation needed, but not applied**

The following sections present results of an assessment of the overall accuracy of the new mitigation procedures using this framework.

One limitation of this framework is that when congestion is not identified in the mitigation run but then occurs in the market run (referred to in this report as under-identification), the market software does not provide results of the three pivotal supplier test that can be used to determine if the constraint was competitive or non-competitive. However, as discussed in the following sections, other analysis by DMM indicates that constraints on which congestion occurs are structurally competitive a very high portion of the time. The next section illustrates how these results can be used to estimate the overall portion of times in which under-mitigation occurs as a result of under-identification of congestion in the market run.

Day-ahead market

In the day-ahead market, the mitigation run is performed immediately before the actual market run and uses the same initial input data – except for bids that are mitigated as a result of the market power mitigation run. Because of this, DMM has found that the frequency of congestion projected in the day-ahead mitigation run is highly consistent with actual congestion that occurs in the subsequent day-ahead market.

As shown in Table 7.4, when congestion occurred during the study period, congestion occurred in both the day-ahead mitigation and market runs about 89 percent of the time. However, these congested constraints were deemed competitive about 86 percent of the time, so that bid mitigation was applied to resources that could relieve this congestion in only about 14 percent of these intervals.[156]

[156] 11,761 ÷ 13,718 = 86 percent.

About 5 percent of the time constraints were congested in the day-ahead mitigation run but not in the day-ahead market. However, since these congested constraints were deemed competitive most of the time (76 percent), bid mitigation was applied when no congestion occurred in the day-ahead market only about 1 percent of the total times that congestion occurred.

Table 7.4 Consistency of congestion and competitiveness of constraints in the day-ahead local market power mitigation process[157]

	Competitive		Non-competitive		Total	
Congestion prediction	**# constraint intervals**	**%**	**# constraint intervals**	**%**	**# constraint hours**	**%**
Consistent	11,761	76%	1,957	13%	13,718	89%
Over-identified	608	4%	189	1%	797	5%
Under-identified	---	---	---	---	957	6%
					15,472	**100%**

***Congestion prediction:**
Consistent = Congestion in mitigation and market runs.
Over-identified = Congestion in mitigation run, but no congestion in market.
Under-identified = No congestion in mitigation run, but congestion in market.`

It should also be noted that over-identification of congestion does not necessarily subject resources to bid mitigation unnecessarily. In some cases, lowering of bids through bid mitigation prior to the market run may cause congestion not to occur in the day-ahead market run.

As shown in Table 7.4, about 6 percent of the time congestion occurred, constraints were congested in the day-ahead market run but not in the day-ahead mitigation run. As previously noted, when congestion is not identified in the mitigation run but then occurs in the market run, the market software does not provide results of the three pivotal supplier test that can be used to determine if the constraint was competitive or non-competitive. However, data from other hours when congestion occurs in the day-ahead market during the mitigation run indicate that constraints are structurally noncompetitive a relatively low portion of the time. This suggests that the frequency of under-mitigation is extremely low and is less than 1 percent of intervals when congestion occurs.[158]

Real-time market

The real-time mitigation process is performed in the real-time pre-dispatch market about 35 minutes before the 5-minute real-time market run. As a result, there may be considerable differences in the model inputs such as load, generation output, transmission limits, generation and transmission outages, and other factors. The differences in model inputs between the mitigation run and the 5-minute market run can reduce the accuracy of congestion prediction by the mitigation runs. In turn, this can impact the accuracy of the process to identify local market power and consequently impact the potential accuracy of the mitigation process.

[157] The mitigation run consistently predicts no congestion in the market run in a very large number of instances.

[158] For example, 5 percent x 15 percent = 0.75 percent.

Results of this analysis show that the accuracy of congestion prediction is notably lower in the real-time local market power mitigation process than in the day-ahead. However, since most congested constraints are deemed competitive in the real-time process, the overall impact of less accurate congestion prediction is still very low in the real-time market.[159]

As shown in Table 7.5, congestion occurred in both the real-time mitigation and market runs about 55 percent of all intervals in which congestion occurred in the real-time process.

About 29 percent of the time constraints were congested in the real-time mitigation run but not in the real-time market. However, since these congested constraints were deemed competitive most of the time, bid mitigation was applied when no congestion occurred in the real-time market only about 4 percent of the total intervals in which congestion occurred.

Table 7.5 Consistency of congestion and competitiveness of constraints in the real-time local market power mitigation process[160]

	Competitive		Non-competitive		Total	
Congestion prediction	**# constraint intervals**	**%**	**# constraint intervals**	**%**	**# constraint intervals**	**%**
Consistent	11,241	48%	1,559	7%	12,800	55%
Over-identified	5,736	25%	1,033	4%	6,769	29%
Under-identified	---	---	---	---	3,761	16%
					23,330	**100%**

Congestion prediction:
Consistent = Congestion in mitigation and market runs.
Over-identified = Congestion in mitigation run, but no congestion in market.
Under-identified = No congestion in mitigation run, but congestion in market.

As shown in Table 7.5, about 16 percent of the time congestion occurred, constraints were congested in the real-time market run but not in the real-time mitigation run. As previously noted, for these intervals the market software does not provide results of the three pivotal supplier test, so data are not available to determine if the constraint was competitive or non-competitive. However, data from other hours when congestion occurs in the real-time market during the mitigation run indicate that constraints are structurally non-competitive a relatively low portion of the time. This suggests that the frequency of under-mitigation is extremely low and is about 2 percent of intervals when congestion occurs.[161]

161 For example, 16 percent x 13 percent = 2 percent.

7.3 Local market power mitigation

This section provides an assessment of the frequency and impact of the automated local market power mitigation procedures described earlier. The section also provides a summary of the volume and impact of non-automated mitigation procedures that are applied for some exceptional dispatches, or additional dispatches issued by grid operators to meet reliability requirements issues not met by results of the market software.

7.3.1 Frequency and impact of automated bid mitigation

The ISO's automated local market power mitigation procedures were enhanced in April 2012 to more accurately identify and mitigate resources with the ability to exercise local market power in the day-ahead and hour-ahead markets. While there was an initial increase in the number of resources subject to mitigation in the day-ahead market as a result of these changes in April 2012, the number of resources with bids lowered remained at similar levels over the past two years.

The real-time mitigation procedures were also enhanced in May 2013. The ISO adopted a new, in-line dynamic approach to the competitive path assessment. This new approach uses actual market conditions and produces a more accurate and less conservative assessment of transmission competitiveness. Although there was an initial increase in the number of units subject to mitigation in May and June 2013, the number of units subject to mitigation in real-time fell in the second half of 2013.

In the day-ahead market, the amount of additional energy that DMM estimates was dispatched from units as a result of bid mitigation was slightly higher in 2012 compared to 2013. This was related to a decreased volume of uncompetitively high energy bids in 2013.

The competitive baseline analysis presented in Section 2.2 is calculated by using default energy bids for all gas-fired units in place of their market bids. Thus, this competitive baseline analysis provides an indication of prices that would result if all gas-fired generators were always subject to bid mitigation. As discussed in Section 2.2, average monthly day-ahead and real-time prices for this competitive baseline are nearly equal to or less than the actual market prices for most months. This indicates that under most conditions enough capacity was offered at competitive prices to allow demand to be met at competitive prices.

The impact on market prices of bids that are actually mitigated can only be assessed precisely by re-running the market software without bid mitigation. This is not a practical approach because it would take an extreme amount of time to re-run the market software for every day-ahead and real-time market run. However, DMM has developed a variety of metrics to estimate the frequency with which mitigation was triggered and the effect of this mitigation on each unit's energy bids and dispatch levels. These metrics identify units which actually have their bids lowered as a result of mitigation each hour and also estimate the increase in energy dispatched from these units as a result of this decrease in bid price.[162]

[162] The methodology used to calculate these metrics is illustrated in Section A.4 of Appendix A of DMM's *2009 Annual Report on Market Issues and Performance*, April 2010, http://www.caiso.com/2777/27778a322d0f0.pdf.

As shown in Figure 7.4 and Figure 7.5:

- The number of units subject to potential mitigation in the day-ahead market increased significantly after the new mitigation procedure was implemented in 2012 and remained high through 2013.
- However, the number of units subject to potential mitigation in the day-ahead was still notably lower in 2013 compared to 2012. This is mainly due to decreases in day-ahead congestion, as well as more competitive bidding by some suppliers in 2013.
- An average of 16 units in each hour were subject to day-ahead mitigation in 2013. This compares to an average of 24 units in 2012.
- An average of 1.3 units had day-ahead bids changed in 2012, despite the significant increase in units subject to mitigation in 2012. An average of only 0.5 units had day-ahead bids changed in 2013.
- The estimated increase in energy dispatched in the day-ahead market from these units averaged about 6 MW per hour in 2013. This compares to an estimated impact from mitigation of 35 MW in 2012. The higher impact of mitigation on energy dispatches in 2012 was due primarily to highly uncompetitive bidding by a few suppliers controlling units which were effective in relieving congestion on uncompetitive constraints.

The frequency of units subject to bid mitigation in the real-time market after the mitigation changes was also higher than before the changes were put in place, but even so the frequency of mitigation remained low. As shown in Figure 7.6 and Figure 7.7:

- In 2013, bids for an average of 1 unit per hour were lowered as a result of the hour-ahead mitigation process. This compares to an average of about 2 units in 2012.
- On average, 0.5 and 0.4 units per hour were dispatched at a higher level in the real-time market as a result of bid mitigation in 2012 and 2013, respectively.
- The estimated increase in real-time dispatches from these units because of bid mitigation averaged about 12 MW in both 2012 and 2013.

Like in the day-ahead market, real-time congestion on uncompetitive constraints within the ISO system was also notably lower in 2013, decreasing the frequency of real-time mitigation.

Figure 7.4 Average number of units mitigated in day-ahead market

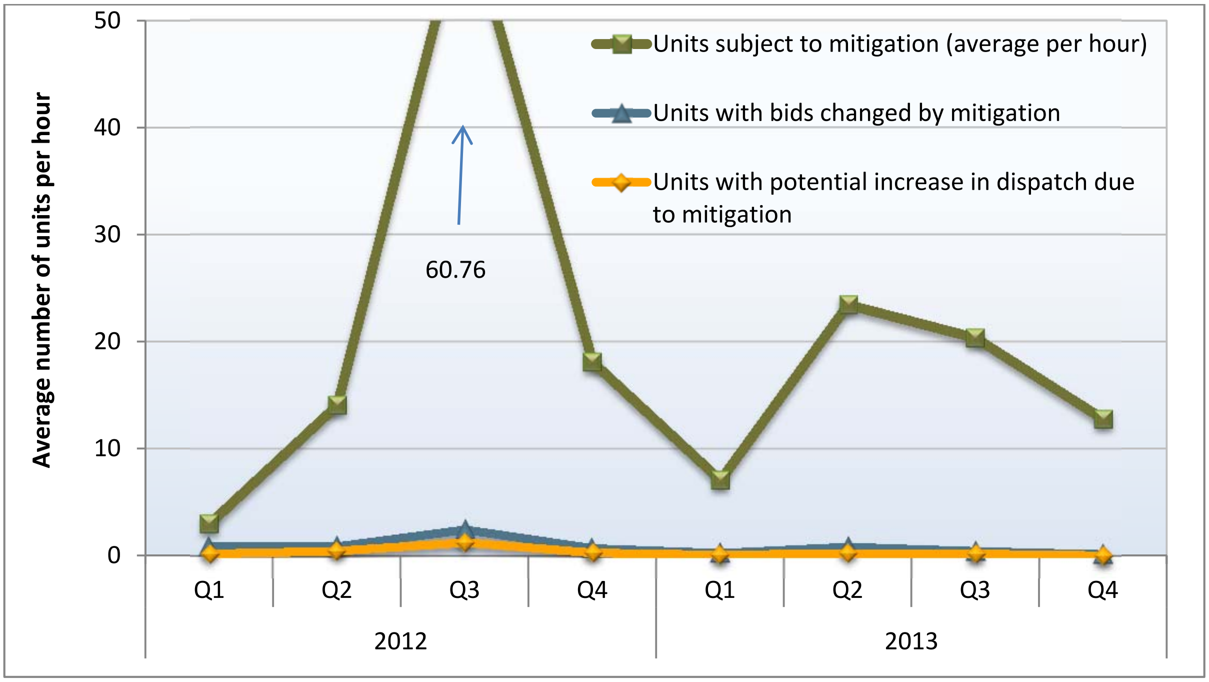


Figure 7.5 Potential increase in day-ahead dispatch due to mitigation (hourly averages)

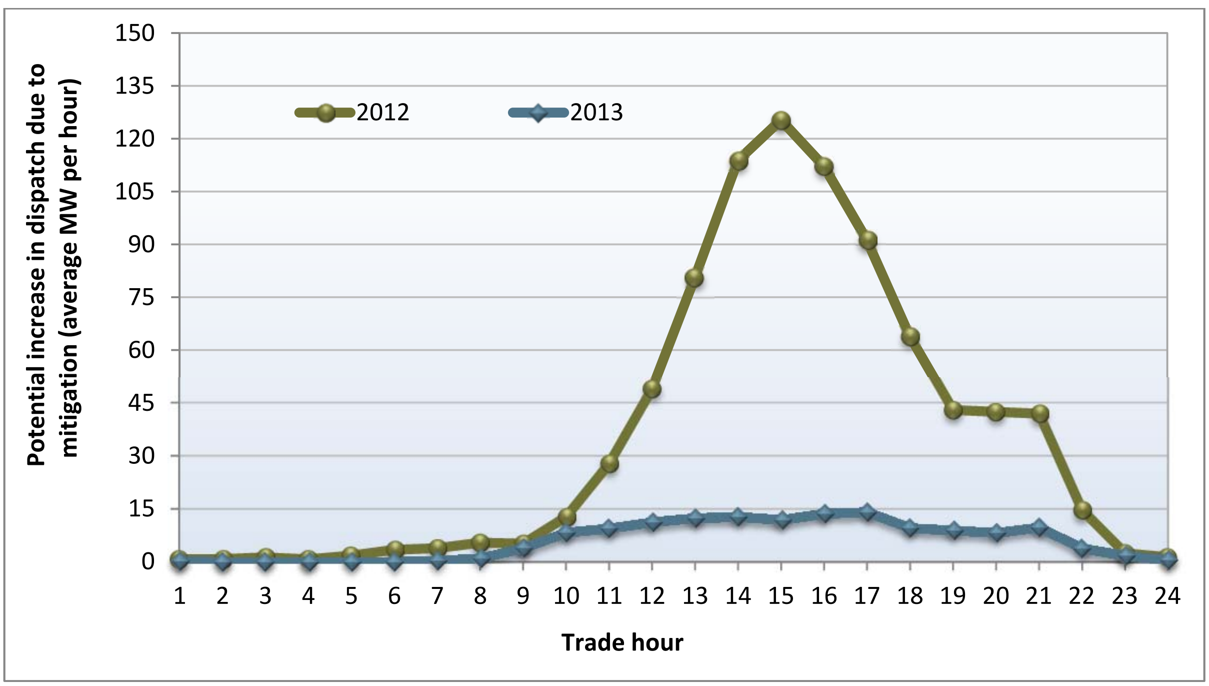


Figure 7.6 Average number of units mitigated in real-time market

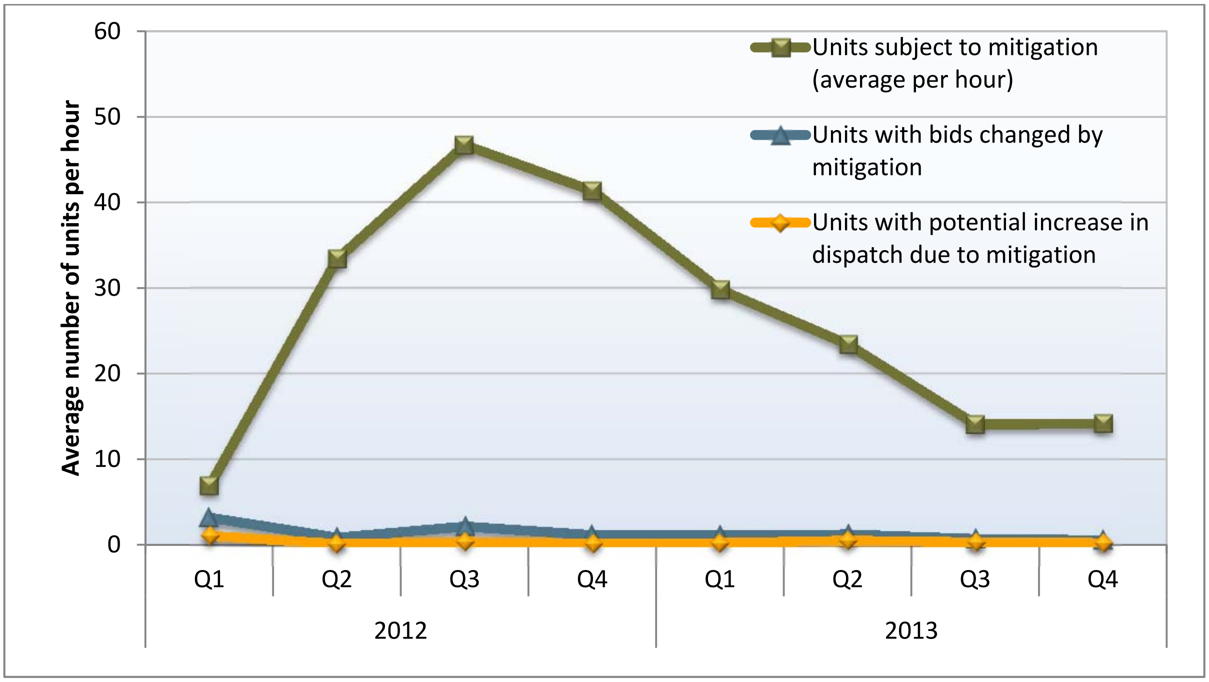
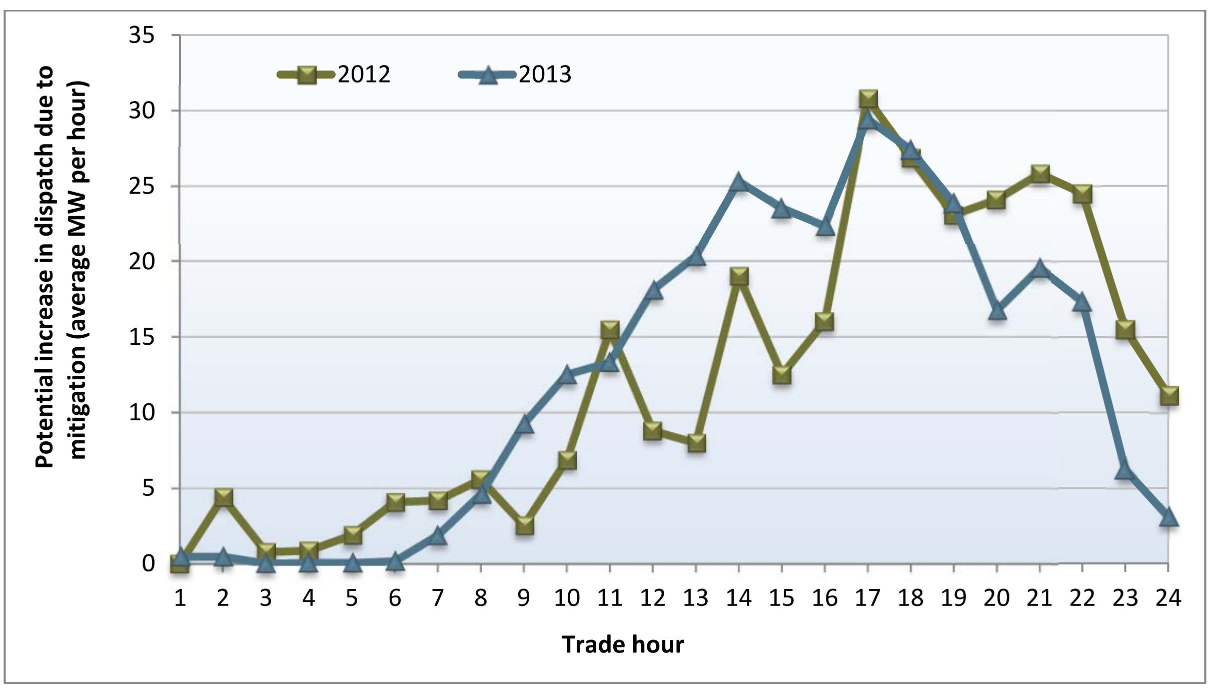


Figure 7.7 Potential increase in real-time dispatch due to mitigation (hourly averages)



7.3.2 Mitigation of exceptional dispatches

Overview

Exceptional dispatches are instructions issued by grid operators when the automated market optimization is not able to address a particular reliability requirement or constraint.[163] Total energy from exceptional dispatches decreased in 2013, with the above-market costs resulting from exceptional dispatches dropping from $34 million in 2012 to $18 million in 2013. This decrease in costs, in large part, reflects the decrease in volume of exceptional dispatches, as well more competitive bidding by some suppliers in 2013 compared to 2012.[164]

Exceptional dispatches are subject to mitigation if the commitment or dispatch is made for any of the following reasons:

- Address reliability requirements related to non-competitive transmission constraints;
- Ramp resources with ancillary services awards or residual unit commitment capacity to a dispatch level that ensures their availability in real-time;
- Ramp resources to their minimum dispatchable level in real-time, allowing the resource to be more quickly ramped up if needed to manage congestion or meet another reliability requirement; or
- Address unit-specific environmental constraints not incorporated into the model or the CAISO's market software that affect the dispatch of units in the Sacramento Delta, which is commonly known as *Delta Dispatch*.

During the second half of 2012, tighter supply conditions due to the loss of the San Onofre Nuclear Generating Station and increased congestion on transmission into the SCE and SDG&E areas substantially increased the potential for local market power in Southern California. A small set of units subject to frequent exceptional dispatch began to place extremely high bids during this time, which resulted in more frequent mitigation. By the end of 2012, uncompetitive conditions in Southern California had been addressed, and the expansion of mitigation provisions for exceptional dispatches in August 2012 provided further deterrent to uncompetitive bidding.[165]

In 2013, the ISO committed to reducing the frequency and volume of exceptional dispatches, where possible, through the use of other tools for reliability management. In addition to ISO actions, scheduling coordinators bid a greater amount of energy at prices below the locational marginal price in 2013, thus reducing the need for exceptional dispatch energy. These factors resulted in a decreased volume and percentage of exceptional dispatches and those subject to mitigation. Although the tariff revisions of August 2012 expanded market power mitigation provisions applicable to exceptional dispatches, mitigation played a smaller role in exceptional dispatch settlement in 2013. The ISO further

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[163] A more detailed discussion of exceptional dispatches is provided in Section 9.1.

[164] See DMM's 2012 *Annual Report on Market Issues and Performance*, Section 6.4, on Market power mitigation in Southern California during July and August 2012, http://www.caiso.com/Documents/2012AnnualReport-MarketIssue-Performance.pdf.

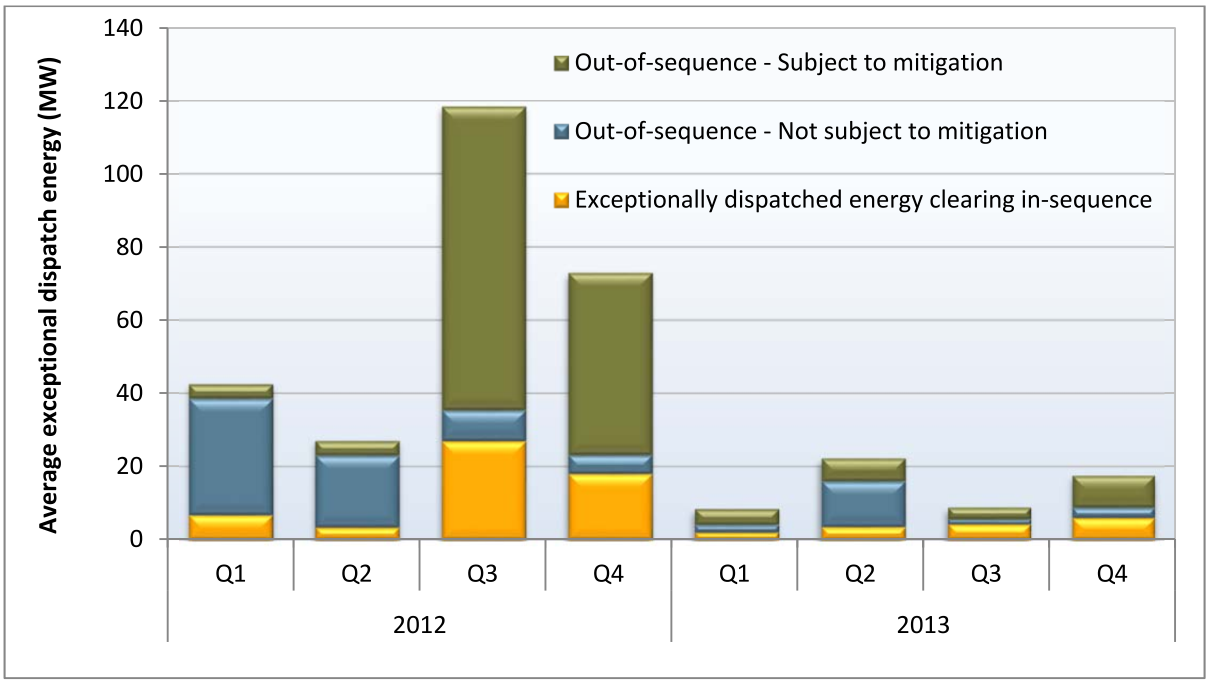
[165] See *Exceptional Dispatch and Residual Imbalance Energy Mitigation Tariff Amendment* in FERC Docket No. ER12-2539-000, August 28, 2012, at: http://www.caiso.com/Documents/August282012ExceptionalDispatch-ResidualImbalanceEnergyMitigationTariffAmendment-DocketNoER12-2539-000.pdf.

enhanced the mitigation process for exceptional dispatches in the second half of 2013. Additional details on these enhancements are provided at the end of this section.

Volume and percent of exceptional dispatches subject to mitigation

As shown in Figure 7.8, the volume of total exceptional dispatch energy significantly decreased in 2013 when compared to 2012, most notably in the third and fourth quarters. Figure 7.8 also shows that the greatest reduction in exceptional dispatch energy occurred in out-of-sequence energy subject to mitigation, which fell 80 percent in 2013 compared to 2012. Out-of-sequence energy is energy with bid prices above the market clearing price. ISO goals to decrease the frequency and volume of exceptional dispatches, and the elimination of uncompetitive bidding by participants in Southern California, influenced the drop in out-of-sequence energy subject to mitigation.

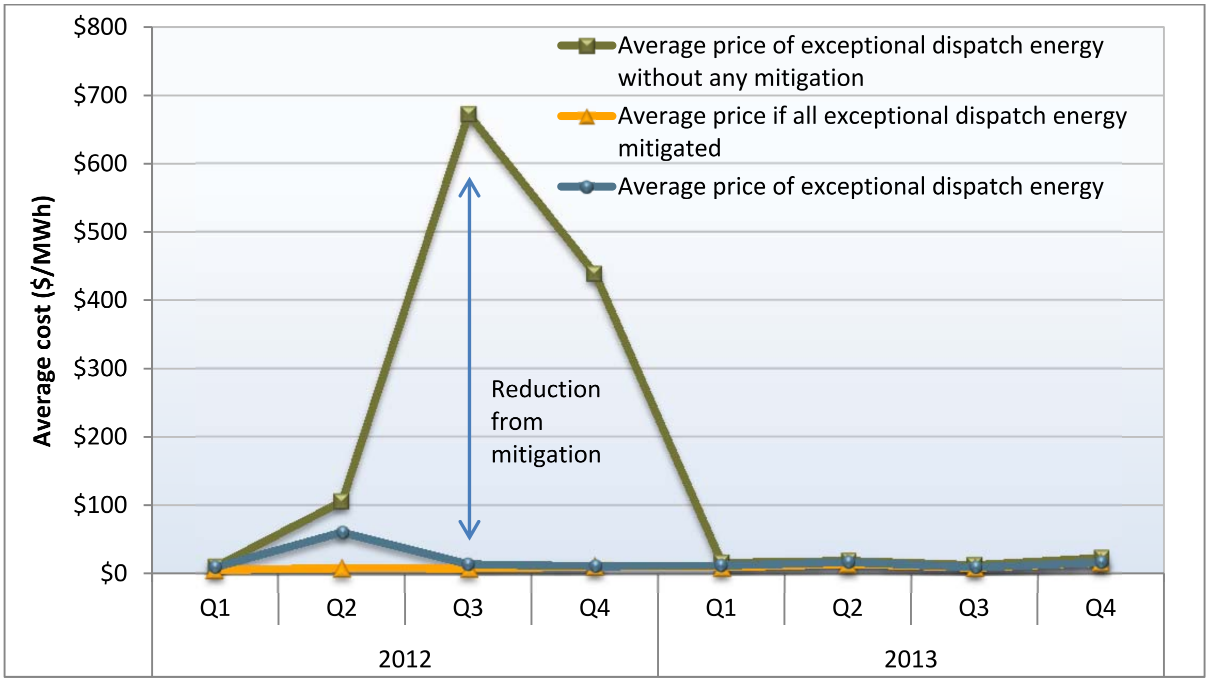
Figure 7.8 Exceptional dispatches subject to bid mitigation



Impact of exceptional dispatch energy mitigation

The impact of applying local market power mitigation to exceptional dispatch energy was greatly reduced in 2013. Figure 7.9 shows the difference in the average price for exceptional dispatch energy under three scenarios to illustrate the effect of mitigation on exceptional dispatch prices. As seen in Figure 7.9, mitigation played a significant role in mitigating prices paid for exceptional dispatch energy during the second half of 2012 due to uncompetitive bidding by some suppliers in Southern California. In 2013, the cessation of this uncompetitive bidding substantially reduced the average price of exceptional dispatch energy without mitigation. The average price for exceptional dispatch energy returned to levels seen in the first quarter 2012 and throughout most of 2011.

Figure 7.9 Average prices for out-of-sequence exceptional dispatch energy



Mitigation of exceptional dispatches averted excess cost of about $450,000 in 2013, down from $227 million in avoided out-of-sequence costs in 2012. The amount that was ultimately paid to exceptional dispatch generation in excess of the market price totaled $1.4 million in 2013, down from $8 million in 2012.[166] Lower prices for exceptional dispatch energy combined with the significant overall reduction in the volume of out-of-sequence energy resulted in lower out-of-sequence costs in 2013.

7.4 Start-up and minimum load bids

Owners of gas-fired generation can choose from two options for their start-up and minimum load bid costs: proxy costs and registered costs.[167] Prior to April 2011, owners electing the registered cost option were required to submit costs for both minimum load and start-up. Beginning in April 2011, participants could elect any combination of proxy or registered minimum load and start-up costs they preferred.[168]

Two changes occurred in 2013 with regards to proxy and registered costs. First, a greenhouse gas cost adder was added beginning in January to account for costs associated with the state's cap-and-trade program for greenhouse gases (see Chapter 5 for further detail). Second, suppliers were allowed to

[166] Exceptional dispatch is discussed in more detail in Section 9.1 of this report.

[167] Under the proxy cost option, each unit's start-up and minimum load costs are automatically calculated each day based on an index of a daily spot market gas price and the unit's start-up and minimum load fuel consumption as reported in the master file. Unit owners selecting the registered cost option submit fixed monthly bids for start-up and minimum load costs, which are then used by the daily market software. Registered cost bids are now capped at 150 percent of projected costs as calculated under the proxy cost option beginning in November 2013, whereas registered costs were capped at 200 percent before. 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. See the following filing for more information: http://www.caiso.com/23fc/23fcb61b29f50.pdf.

[168] See Start-Up Minimum Load Tariff Amendment in Docket Number ER11-2760-000, January 26, 2011: http://www.caiso.com/2b12/2b12b6a22ed60.pdf.

include marginal costs associated with major maintenance and the grid management charge beginning in November. Coincident with the inclusion of the additional major maintenance adder, the cost cap under the registered cost option was reduced from 200 percent of the projected proxy cost to 150 percent.[169]

Capacity under registered cost option

Gas-fired capacity opting for the registered cost option declined slightly in 2013 compared to 2012. As shown in Figure 7.10 and Figure 7.11, no major changes occurred in the amount of capacity under the registered cost option for both start-up and minimum load costs in 2013. As shown in these figures:

- The portion of all gas-fired capacity selecting registered costs for both start-up and minimum load decreased slightly in the last quarter of 2013, particularly for combustion turbine units. This was the result of a handful of existing units electing the proxy cost option.
- In December 2013, about 78 percent of all natural gas fueled capacity,[170] or approximately 23,000 MW, elected the registered cost start-up option. About 63 percent, approximately 27,000 MW, chose the registered cost option for minimum load bids.
- By the end of 2013, around 13 percent of all natural gas fueled capacity chose the registered cost option for start-up costs only. Approximately 27 percent of natural gas fueled capacity solely elected the registered cost minimum load option. These percentages were similar to 2012.[171]
- The portion of capacity at or near the cap for start-up costs decreased compared to 2012, as shown in Figure 7.12. This change was more pronounced after the rule change in November. Even so, DMM estimates that, in aggregate, the total start-up costs remained essentially unchanged after the percentage cap decreased to 150 percent of total calculated proxy costs.

Historically, registered cost bids for minimum load capacity have tended to be lower and ranged more widely relative to actual minimum load costs. This was also true in 2013 as seen in Figure 7.13. After the rule change, much of the minimum load capacity was below the cap, but overall the total costs decreased only slightly.

[169] See 145 FERC ¶ 61,082, order accepting tariff revisions, issued October 29, 2013: http://www.ferc.gov/CalendarFiles/20131029160035-ER13-2296-000.pdf.

[170] Some resources are registered as multi-stage generating (MSG) resources, which means for reasons related to the resource's technical characteristics it can be operated in various discrete configurations. In some cases, these resources can start-up in only a subset of the configurations. This analysis excludes the non-startable configurations.

[171] Only the capacity of units that could start-up was included in this analysis. The 2012 numbers increase from 4 percent, which was reported in 2012, to 16 percent with this adjustment.

Figure 7.10 Gas-fired capacity under registered cost option for start-up cost bids

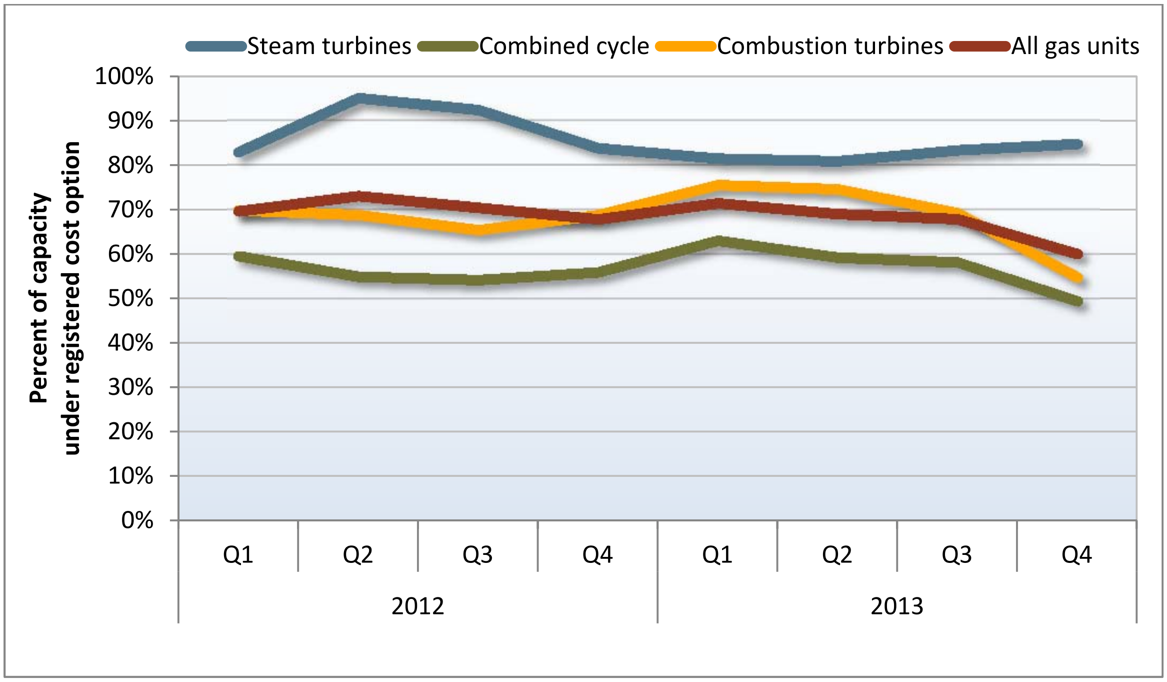


Figure 7.11 Gas-fired capacity under registered cost option for minimum load bids

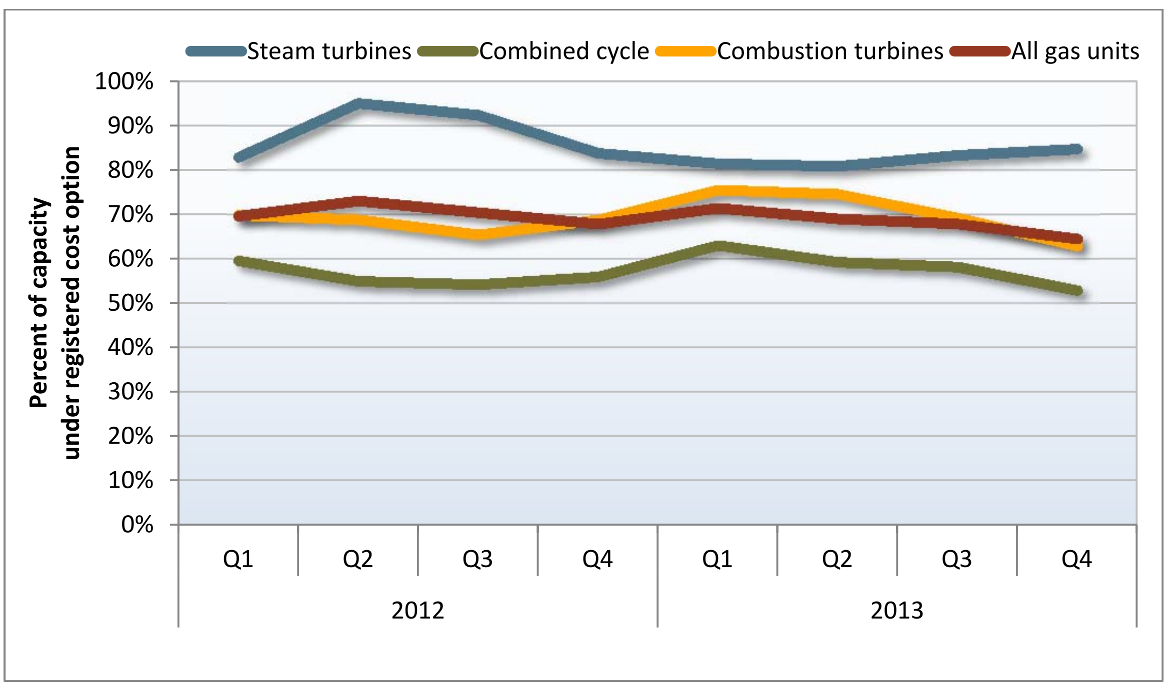


Figure 7.12 Registered cost start-up bids

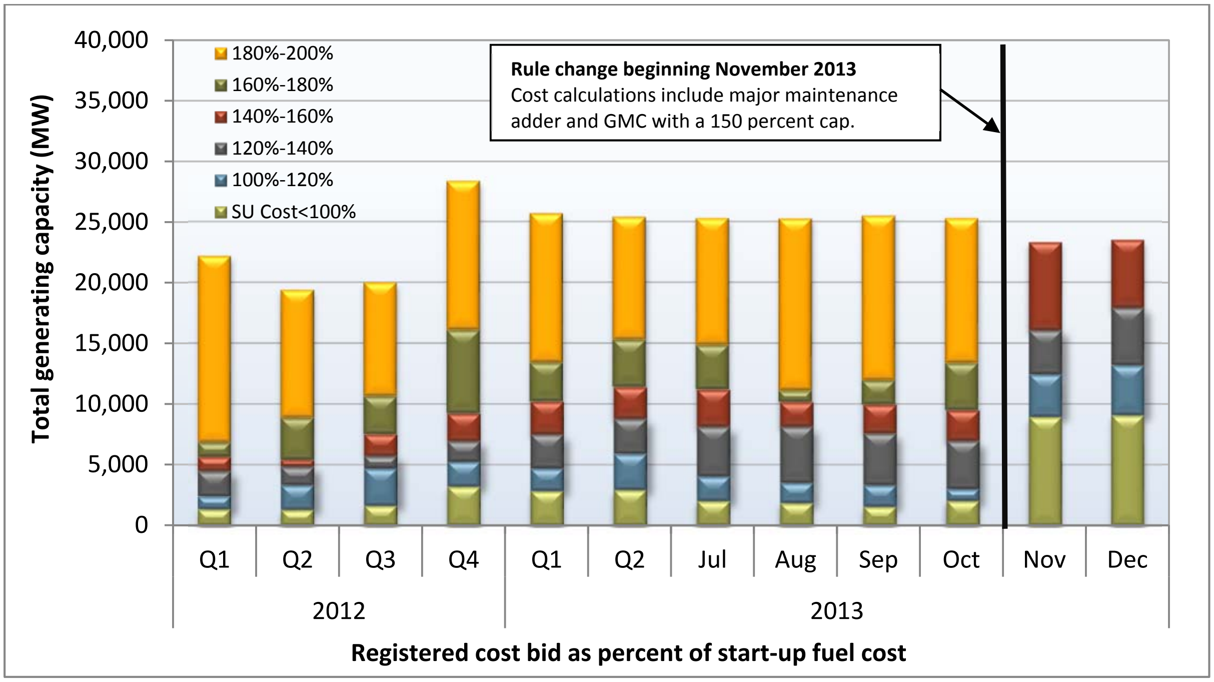


Figure 7.13 Registered cost minimum load bids

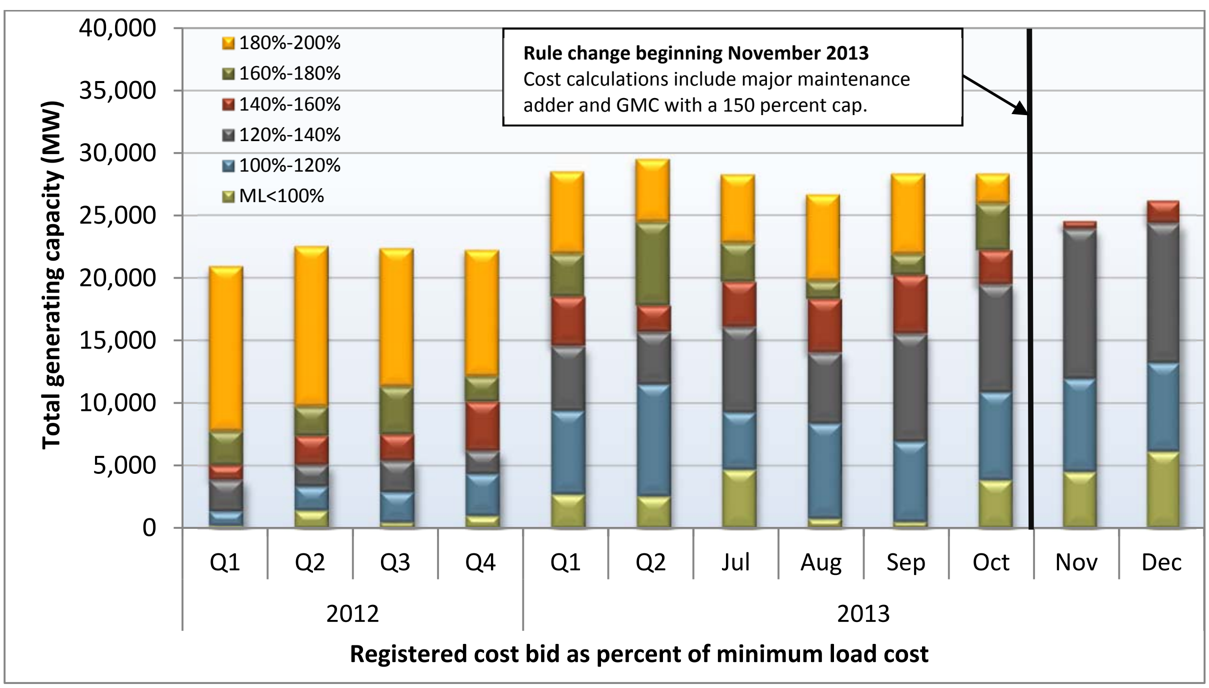


Figure 7.14 and Figure 7.15 show the amount of capacity under the registered cost option bidding at different levels by technology.[172] As illustrated in these figures:

- Of total natural gas capacity in December 2013, the registered cost start-up option was chosen by over 93 percent of steam turbines and 79 percent of combined cycles, whereas only about 60 percent of gas turbines elected this option. These percentages are similar to 2012.
- Of total natural gas capacity in December 2013, the registered cost minimum load option was chosen by nearly 84 percent of steam turbines, about 55 percent of combined cycles, and about 61 percent of gas turbines elected this option.
- Most capacity under the start-up registered cost bid option submitted bids below the bid cap. This is a change from what was observed in previous periods. In December, start-up bids within 10 percent of the bid cap constituted about 25 percent of total capacity under the registered cost option, as shown in Figure 7.14.
- Only about 7 percent of capacity bid registered minimum load costs within 10 percent of the maximum costs for minimum load.
- Steam turbines, gas turbines and combined cycles bid costs just less than the calculated proxy cost price range for start-up costs. This is a change from previous years when steam turbine capacity would bid below the calculated costs.
- Capacity electing the minimum registered cost option was more evenly distributed throughout all ranges, with the exception of the category closest to the cap being the smallest. The range with the largest capacity was from 130 to 140 percent and accounted for about 15 percent of total minimum load capacity on the registered cost option.
- Overall, these results show a shift in bidding both start-up and minimum load registered costs from the cap to closer to the proxy value.

[172] Generation technology consists of steam turbines, gas turbines and combined cycles.

Figure 7.14 Registered cost start-up bids by generation type – December 2013

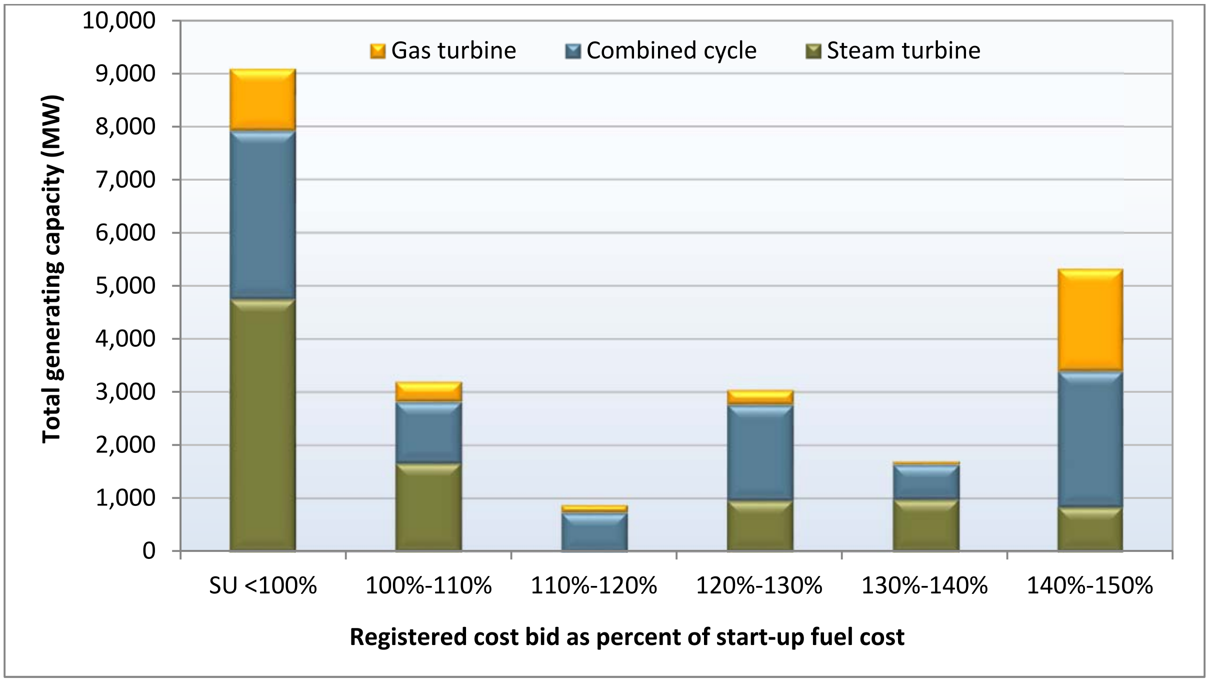
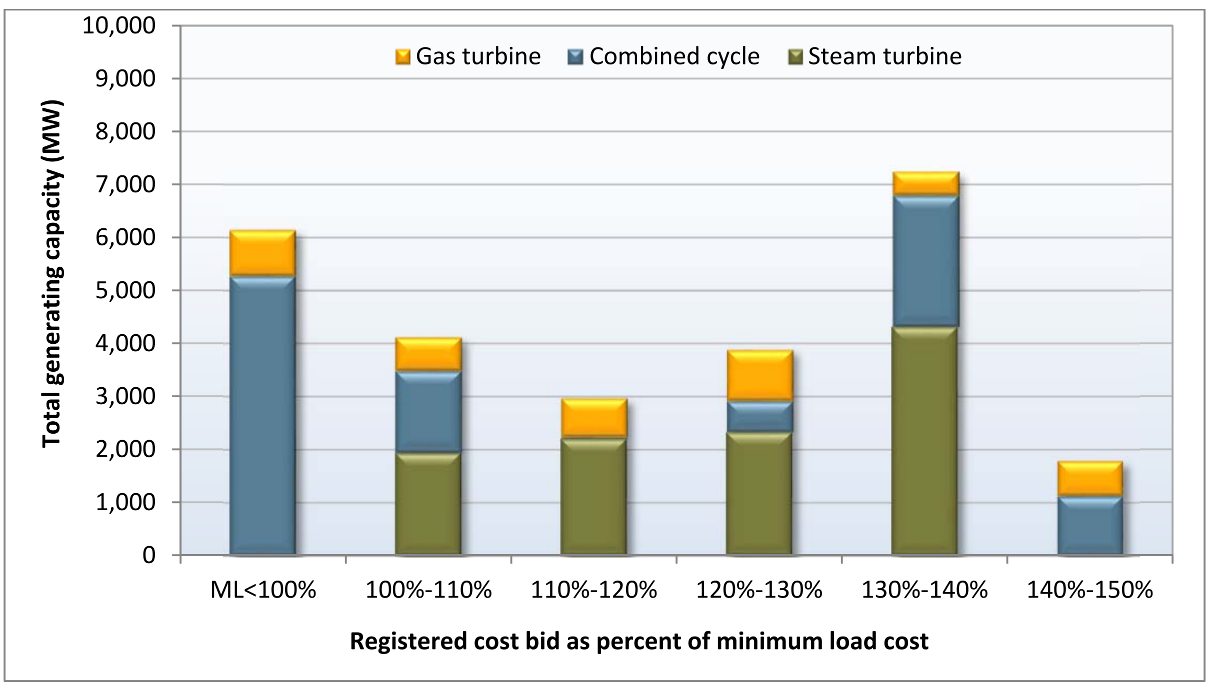


Figure 7.15 Registered cost minimum load bids by generation type – December 2013



8 Congestion

This chapter provides a review of congestion and the market for congestion revenue rights in 2013. The findings include the following:

- Congestion on transmission constraints within the ISO system decreased compared to prior years and had a lower impact on average overall prices across the system.
- Congestion in 2013 decreased significantly in the second half of the year as a result of improved contingency modeling, fewer outages and an upgrade of the Ocotillo 500 kV substation in the San Diego area.
- Prices in the SCE area were impacted the most by internal congestion, which increased average day-ahead and real-time prices in the SCE area above the system average by about $1.70/MWh or 4 percent. About 85 percent of this increase was due to limits on the percentage of load in the SCE area that can be met by total flows on all transmission paths into the SCE area.[173]
- Congestion increased average real-time prices in the San Diego area above the system average by about $0.22/MWh or 0.5 percent. Day-ahead San Diego congestion did not have a significant impact on overall average prices over the year. This was because multiple constraints had offsetting effects, with some increasing congestion and others decreasing congestion.
- The overall impact of congestion on prices in the PG&E area was to reduce prices below the system average by about 3 percent in both the day-ahead and real-time markets. This results from the fact that prices in the PG&E area are lowered when congestion occurs on the constraints that limit flows into the SCE and SDG&E areas.
- Congestion on most major inter-ties connecting the ISO with other balancing authority areas was lower in 2013, particularly for inter-ties connecting the ISO to the Pacific Northwest.
- Average profitability of all congestion revenue rights was about $0.14/MW in 2013, compared to about $0.40/MW in 2012. This increase was driven largely by lower levels of congestion in 2013. Overall, rights in the prevailing flow of congestion were less profitable than rights in the opposite, or counter-flow, direction of the prevailing flow. This is a change from 2012 when prevailing flow congestion was more profitable and is more consistent with the pattern of congestion revenue rights profitability in earlier years.

8.1 Background

Locational marginal pricing enables the ISO to more efficiently manage congestion and provide price signals to market participants to self-manage congestion. Over the longer term, nodal prices are intended to provide efficient signals that encourage development of new supply and demand-side resources within more constrained areas. Nodal pricing also helps identify transmission upgrades that would be most cost-effective in terms of reduced congestion.

[173] This constraint was designed to ensure that enough generation was being supplied from units within the SCE area in the event that an under-frequency load shedding event happens. After further study by SCE and the ISO, this constraint was removed from the market model on October 1.

Congestion in a nodal energy market occurs when the market model estimates flows on the transmission network have reached or exceeded the limit of a transmission constraint. As congestion appears on the network, locational marginal prices at each node reflect marginal congestion costs or benefits from supply or demand at that particular location. Within areas where flows are constrained by limited transmission, higher cost generation is dispatched to meet demand. Outside of these transmission constrained areas, demand is met by lower cost generation. This results in higher prices within congested regions and lower prices in unconstrained regions.

When a constraint is binding, the market software produces a shadow price on that constraint. This generally represents the cost savings that would occur if that constraint had one additional megawatt of transmission capacity available in the congested direction. This shadow price is not directly charged to participants; it only indicates an incremental cost on the objective function of the market software of the limited transmission on the binding constraint.

There are three major types of transmission constraints that are enforced in the market model and may impact prices when they become binding:

- Flowgates represent single transmission lines or paths with a single maximum limit.
- Branch groups represent multiple transmission lines with a limit on the total combined flow on these lines.
- Nomograms are more complex constraints that represent interdependencies and interactions between multiple transmission system limitations that must be met simultaneously.

Congestion on inter-ties between the ISO and other balancing areas decreases the price received for energy imports. This congestion also affects payments for congestion revenue rights. However, this congestion has generally had minimal impact on prices for loads and generation within the ISO system. This is because when congestion has limited additional imports on one or more inter-ties, additional supply from other inter-ties or from within the ISO has been available at a relatively small increase in price.

8.2 Congestion on inter-ties

The frequency and financial impacts of congestion on most inter-ties connecting the ISO with other balancing authority areas was lower in 2013 than in previous years, particularly for inter-ties connecting the ISO to the Pacific Northwest.

Table 8.1 provides a detailed summary of the frequency of congestion on inter-ties along with average and total congestion charges from the day-ahead market. The congestion price reported in Table 8.1 is the shadow price for the binding inter-tie constraint. For a supplier or load-serving entity trying to import power over a congested inter-tie point, this congestion price represents the decrease in the price they receive for imports into the ISO. This congestion charge also represents the amount paid to owners of congestion revenue rights that are sourced outside of the ISO at points corresponding to these inter-ties.

Figure 8.1 compares the percentage of hours that major inter-ties were congested in the day-ahead market over the last three years. Figure 8.2 provides a graphical comparison of total congestion charges on major inter-ties in each of the last three years.

The table and figures highlight the following:

- Congestion decreased substantially from the previous year on the two major inter-ties linking the ISO with the Pacific Northwest: the Nevada / Oregon Border (NOB) and the Pacific A/C Intertie (PACI). Total congestion on these two inter-ties decreased from $144 million in 2012 to about $55 million in 2013. This is likely driven by reduced hydro-electric generation availability in the Northwest and relative price differences between the Northwest and Northern California, most notably in the second half of 2013.[174]

- Congestion increased slightly on Palo Verde, which is the largest inter-tie linking the ISO system with the Southwest. Congestion charges on Palo Verde increased from $19 million in 2012 to about $21 million in 2013.

- The frequency of congestion on the Mead inter-tie linking the ISO system to the Southwest dropped from 18 percent in 2012 to 3 percent in 2013, and congestion charges dropped to about $2 million in 2013 from $15 million in 2012. This drop in congestion was associated with the decrease of both planned and forced outages.

- Congestion charges on the El Dorado inter-tie dropped significantly in 2013. These charges were $1.1 million in 2013, compared to $5.6 million in 2012. This was related to a decrease in forced outages and transmission maintenance.

Table 8.1 Summary of import congestion (2011 - 2013)

Import region	Inter-tie	Frequency of import congestion			Average congestion charge ($/MW)			Import congestion charges (thousands)		
		2010	2011	2012	2010	2011	2012	2010	2011	2012
Northwest	PACI	11%	11%	42%	$9.2	$9.1	$10.5	$20,194	$48,903	$84,657
	NOB	7%	8%	39%	$12.7	$9.2	$11.6	$12,253	$25,471	$59,236
	COTPISO	1%	13%	8%	$10.9	$24.7	$16.5	$20,968	$629	$271
	Summit	0%	1%	2%	$10.0	$46.9	$19.6	$14,884	$317	$195
	Cascade	2%	32%	20%	$6.8	$12.0	$14.8	$78	$2,481	$2,086
	New Melones	0%	17%		$0.0	$33.4		$0	$6,788	$0
	Tracy 230	0%	1%	2%	$0.0	$669.4	$232.4	$0	$3,841	$1,164
Southwest	Palo Verde	14%	19%	11%	$7.0	$10.2	$10.3	$20,712	$25,885	$19,177
	Mead	21%	13%	18%	$5.1	$7.1	$9.2	$8,433	$8,287	$15,248
	IPP DC Adlanto (BG)	26%	0%	11%	$5.9	$11.7	$3.0	$7,859	$186	$1,195
	IID-SDGE_ITC			0%			$963.6			$1,095
	IID - SCE	1%	4%	1%	$34.0	$9.8	$53.8	$1,377	$1,579	$1,646
	El Dorado	1%	2%	6%	$11.4	$8.4	$10.1	$1,222	$2,183	$5,695
	Mona IPP DC (MSL)	0%	14%	6%	$0.0	$3.9	$2.7	$0	$631	$285
	BLYTHE_ITC			1%			$62.0			$749
	Adlanto SP	1%	0%		$5.0	$0.2		$389	$0	$0
	Other							$312	$205	$156
Total								***$108,681***	***$127,386***	***$192,855***

* The IPP DC Adelanto branch group and the Mona IPP DC market scheduling limit are not inter-ties, but is included here because of their function in limiting imports from the Adelanto / Mona regions and the frequency with which they were binding.

174 See Section 1.2 for further details.

Figure 8.1 Percent of hours with congestion on major inter-ties (2011 – 2013)

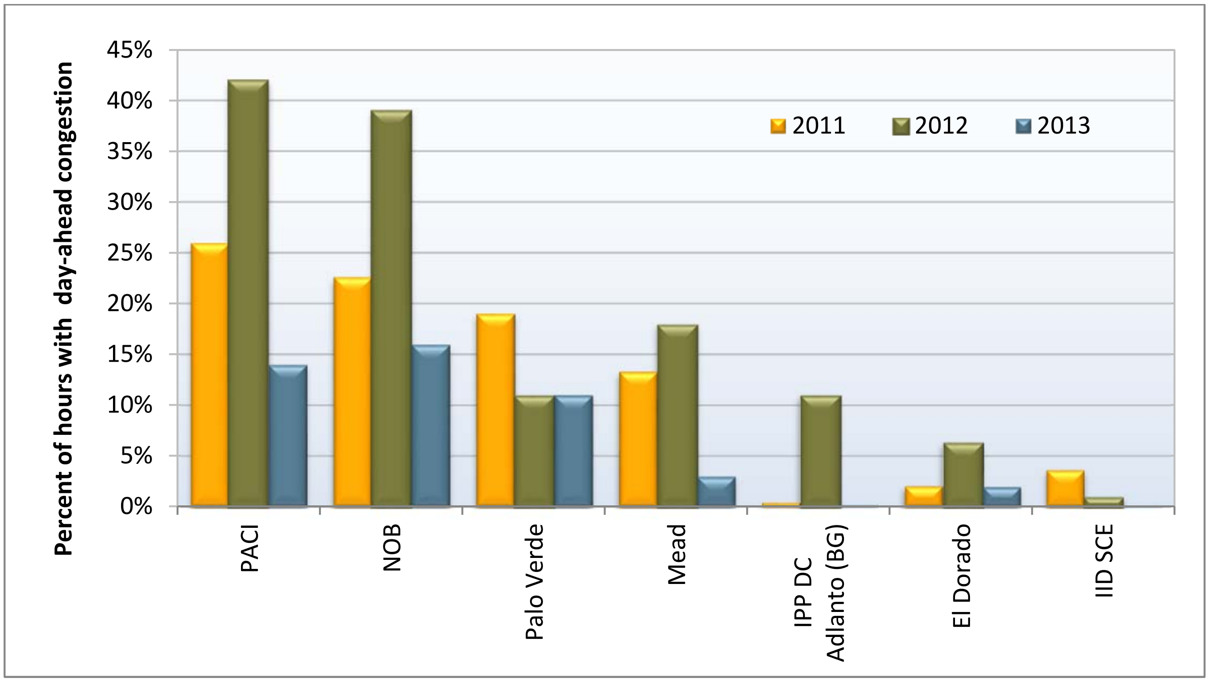
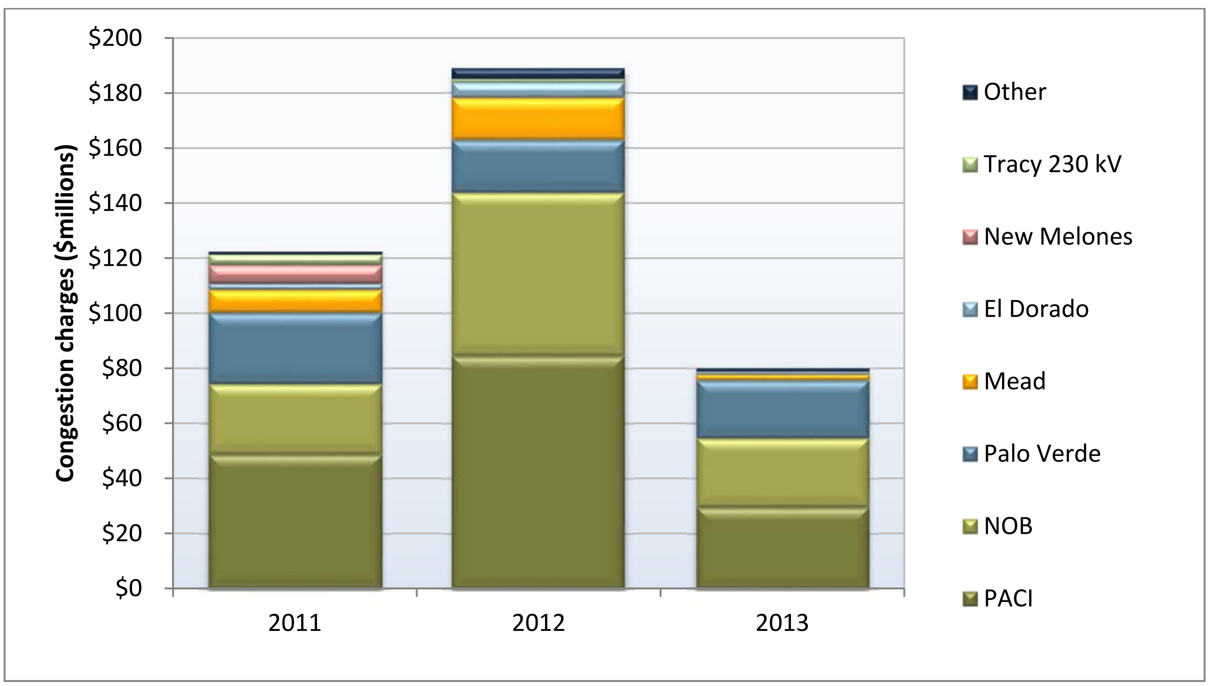


Figure 8.2 Import congestion charges on major inter-ties (2011 – 2013)



8.3 Congestion impacts on internal constraints

When a constraint within the ISO system is congested, resources on both sides of the constraint are re-dispatched to maintain flows under the constraint limit. In this case, congestion has a clear and direct impact on prices within the ISO system.

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.[175]

Congestion on constraints within Southern California generally increases prices within the SCE and SDG&E areas, but decreases prices in the PG&E area. Likewise, congestion within Northern California typically increases prices in the PG&E area, but decreases prices in Southern California.

8.3.1 Day-ahead congestion

Table 8.2 shows the impact of congestion on specific internal constraints during congested hours on average day-ahead prices at the system's three aggregate load areas.

In 2013, the most congested constraint in the ISO system was the constraint limiting imports into the SCE area (i.e., SCE_PCT_IMP_BG). This constraint was congested in the day-ahead market about 71 and 51 percent of the hours in the first and second quarters, respectively, and 16 percent of the hours in the third quarter. The constraint was removed from the ISO's constraint list in the fourth quarter.[176] When congestion occurred on this constraint in the first quarter, day-ahead prices in the SCE area increased about $4.85/MWh and SDG&E and PG&E area prices decreased by about $3.90/MWh. In the second quarter, SCE area prices increased about $4.29/MWh when congestion occurred on this constraint while SDG&E and PG&E area prices decreased about $3.65/MWh.

In the PG&E area, the most congested constraint was 30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1. In the third quarter, congestion on this constraint occurred in 28 percent of hours. During these hours, prices in the PG&E area increased by $0.59/MWh and prices in the SCE and SDG&E areas decreased by about $0.42/MWh. This constraint, located in the Fresno area, is heavily dependent on imports from the 230 kV system through the McCall, Herndon, Henrietta banks, and local hydro generation. The constraint is adjusted to protect thermal overload from the contingency loss of the Panoche-Helms 230 kV line.

In the SDG&E area, the following three constraints were frequently binding and had a significant impact on prices:

- The 7820_TL 230S_OVERLOAD_NG nomogram is conformed down to protect the Imperial Valley-El Centro 230 kV line for a loss of the Imperial Valley-North Gila 500 kV line. This nomogram was binding in the second and fourth quarters in about 14 percent and 1 percent of hours, respectively. In the second quarter, this constraint increased prices in the SDG&E area by $7.69/MWh, while it

[175] Appendix A of DMM's 2009 annual report provides a detailed description of this calculation for both load aggregation points and prices within local capacity areas.

[176] The ISO un-enforced the SCE import percent branch group starting October 1, 2013. For further details, see DMM's *Q4 2013 Report on Market Issues and Performance*, February 10, 2014, pp. 32-33: http://www.caiso.com/Documents/2013FourthQuarterReport-MarketIssues_Performance-Feb2014.pdf.

decreased prices in the PG&E area by $1.01/MWh. In the fourth quarter, this constraint increased prices in the SDG&E area by $2.23/MWh in congested hours and decreased prices in the PG&E area by $0.22/MWh.

- The SLIC 2100489_PVDV_Out_LGVN nomogram was activated during the planned outage of the Palo Verde to Devers 500 kV line in the fourth quarter. This nomogram increased prices in the SDG&E and SCE areas by $1.27/MWh and $0.99/MWh, respectively, and decreased prices in the PG&E area by $1.39/MWh.
- The SOUTHLUGO_RV_BG constraint was binding because of the planned outages of Lugo – Rancho Vista and Lugo – Mira Loma 500 kV lines. This constraint was binding in about 3 and 4 percent of the hours in the second and fourth quarters, respectively, and less than 1 percent of hours in the remaining quarters of the year. During these hours, the SDG&E and the SCE area prices increased, while the PG&E area prices decreased.

As shown in these figures and tables, congestion on some constraints significantly affected prices during hours when congestion occurred. The frequency and magnitude of congestion on transmission constraints within the ISO system decreased compared to prior years and had a smaller impact on average overall prices in the different load areas. Additional analysis and discussion of the impact of congestion on average annual prices for different areas within the ISO is provided in the following section of this chapter.

Table 8.2 Impact of congestion on day-ahead prices during congested hours

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

Overall day-ahead price impacts

This section provides an assessment of differences on overall average prices caused by congestion between different areas of the ISO system. Unlike the analysis provided in the previous section, this assessment is made based on the average congestion component of the locational marginal prices as a percent of the total average system energy price during all hours – including both congested and non-congested hours. This approach shows the impact of congestion taking into account the frequency that congestion occurs as well as the magnitude of the impact of congestion during hours when it occurs.[177]

Table 8.3 shows the overall impact of congestion on different constraints on average prices in each load aggregation area in 2013. These results show that:

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

- Prices in the San Diego area were impacted by the most number of internal constraints. However, the combined effect was to decrease average prices in the San Diego area below the system average by about $0.01/MWh or about 0.01 percent. The sum of all constraints that increased prices in the San Diego area was almost equally offset by the decrease in prices from the SCE_PCT_IMP_BG constraint.

- Congestion drove prices in the SCE area above the system average prices by about $1.72/MWh or almost 4 percent. Nearly all the increase was due to limits on the percentage of load in the SCE area that can be met by total flows on all transmission paths into the SCE area (i.e., SCE_PCT_IMP_BG). The ISO un-enforced this constraint starting October 1, 2013.[178]

- The overall impact of congestion on prices in the PG&E area was to reduce prices below the system average by about $1.35/MWh or a decrease of about 3 percent. This results from the fact that prices in the PG&E area are lowered when congestion occurs on the constraints that limit flows into the SCE and SDG&E areas.

Table 8.4 shows the overall impact of congestion on day-ahead prices within each of the local capacity areas within the ISO system during 2012 and 2013. These data show that the impact of congestion on day-ahead prices in almost all of these areas decreased in 2013, the primary exception being the SCE area. In addition, these results show that the impact of congestion did not vary widely between major local capacity areas in the SCE and PG&E areas, the Fresno local capacity area being the exception. This was due to flow adjustments related to Helms Pump operations and planned outages in the McCall region. Overall, the difference in the average congestion component for generation nodes within these local capacity areas was minimal.

[178] This constraint was designed to ensure reliability of the generation supply from units within the SCE area in the event of a contingency that significantly limits imports into SCE or decreases generation within the SCE area. The ISO found greater reliability benefits could be achieved from modifying the physical Under Frequency Load Shedding Relay scheme.

Table 8.3 Impact of constraint congestion on overall day-ahead prices during all hours

	PG&E		SCE		SDG&E	
Constraint	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
SCE_PCT_IMP_BG	-$1.24	-2.93%	$1.49	3.30%	-$1.22	-2.78%
7820_TL 230S_OVERLOAD_NG	-$0.02	-0.04%			$0.43	0.97%
SOUTHLUGO_RV_BG	-$0.09	-0.22%	$0.06	0.14%	$0.10	0.22%
BARRE-LEWIS_NG	-$0.10	-0.23%	$0.13	0.29%	$0.00	0.01%
PATH15_BG	$0.09	0.20%	-$0.07	-0.16%	-$0.07	-0.16%
SLIC 2090466 and 2090467 SOL					$0.09	0.19%
24016_BARRE _230_24044_ELLIS _230_BR_1 _1	-$0.01	-0.02%			$0.07	0.15%
SLIC 2138237 TL50003_CFE_NG					$0.07	0.16%
24087_MAGUNDEN_230_24153_VESTAL _230_BR_2 _1			$0.07	0.16%		
6110_TM_BNK_FLO_TMS_DLO_NG	$0.05	0.11%	-$0.01	-0.02%	-$0.01	-0.03%
T-135 VICTVLUGO_LGVNDLO_NG	-$0.02	-0.06%	$0.02	0.03%	$0.02	0.04%
30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1	$0.05	0.11%	-$0.01	-0.01%	-$0.01	-0.01%
24138_SERRANO _500_24137_SERRANO _230_XF_3	-$0.02	-0.04%			$0.04	0.09%
SDGE_PCT_UF_IMP_BG					$0.04	0.09%
SLIC 2100489_PVDV_Out_LGVN	-$0.02	-0.04%	$0.01	0.03%	$0.02	0.04%
PATH26_BG	-$0.02	-0.04%	$0.01	0.03%	$0.01	0.03%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					$0.04	0.09%
SLIC 2164068 TL50001_NG					$0.04	0.08%
7830_SXCYN_CHILLS_NG					$0.03	0.07%
24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.01	-0.02%	$0.01	0.01%	$0.02	0.04%
SLIC 2100489_PVDV_Out_EDLG	$0.01	0.02%			-$0.02	-0.03%
SLIC 2122013 Barre-Ellis DLO					$0.02	0.05%
22831_SYCAMORE_138_22117_CARLTHT2_138_BR_1 _1					$0.03	0.06%
22372_KEARNY _69.0_22496_MISSION _69.0_BR_1 _1					$0.02	0.06%
SLIC 2111709_IV500North_BUS_NG					$0.02	0.05%
LOSBANOSNORTH_BG	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.02%
24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	-$0.01	-0.01%			$0.01	0.03%
SLIC 2122013 BARRE-ELLIS-230S_NG					$0.02	0.04%
30735_METCALF _230_30042_METCALF _500_XF_13	$0.01	0.02%	-$0.01	-0.01%	-$0.01	-0.01%
SLIC 2067610 TL50001_NG					$0.02	0.04%
SLIC 2051445 TL23050_NG					$0.02	0.04%
SLIC 2094078 IV Bank81_NG					$0.01	0.03%
22768_SOUTHBAY_69.0_22604_OTAY _69.0_BR_2 _1					$0.02	0.03%
SLIC 2112931 EL CENTRO BK1_NG					$0.02	0.03%
SLIC 2122013 Barre-Ellis DLO_20					$0.01	0.03%
MIGUEL_BKs_MXFLW_NG					$0.01	0.03%
22831_SYCAMORE_138_22124_CHCARITA_138_BR_1 _1					$0.01	0.03%
22828_SYCAMORE_69.0_22756_SCRIPPS _69.0_BR_1 _1					$0.01	0.03%
24016_BARRE _230_24044_ELLIS _230_BR_4 _1					$0.01	0.02%
30880_HENTAP2 _230_30900_GATES _230_BR_2 _1	$0.01	0.03%				
Other			$0.03	0.08%	$0.06	0.14%
Total	-$1.35	-3.2%	$1.72	3.8%	-$0.01	-0.01%

Table 8.4 Day-ahead congestion by local capacity area[179]

LAP	LCA	Average of congestion LMP as percent of system LMP 2012 Avg. LMP (congestion)	2012 Avg.	2013 Avg. LMP (congestion)	2013 Avg.
PGAE	Bay Area	-$1.12	-3.7%	-$1.56	-3.6%
	Fresno	-$1.23	-4.1%	-$0.18	-0.4%
	Humboldt	-$1.78	-5.9%	-$1.63	-3.7%
	Kern	-$1.44	-4.8%	-$1.85	-4.3%
	NCNB	-$1.35	-4.5%	-$1.87	-4.3%
	Sierra	-$0.72	-2.4%	-$1.61	-3.7%
	Stockton	$0.34	1.1%	-$1.83	-4.2%
SCE	Big Creek-Ventura	$0.70	2.3%	$1.91	4.4%
	LA Basin	$0.88	2.9%	$1.62	3.7%
SDGE	San Diego-IV	$2.03	6.7%	$0.11	0.2%

8.3.2 Real-time congestion

Congestion in the real-time market differs from congestion in the day-ahead market. Real-time congestion typically occurs less frequently overall, but often occurs on a larger number of constraints and has a bigger impact on prices when it occurs. A more detailed discussion of differences in day-ahead and real-time congestion is provided in Section 8.4.

Table 8.5 shows the frequency and average shadow prices of real-time congestion by quarter. The SCE_PCT_IMP_BG constraint was the most frequently binding constraint in the first three quarters of the year, which made it the most congested constraint during 2013.[180] This constraint was directly affected by the San Onofre outages and retirement, and was binding in 10 percent of the intervals in the first quarter and about 2 percent of the intervals in the second and third quarters. During these intervals, the constraint increased prices in the SCE area by $41/MWh in the first quarter, $58/MWh in the second quarter and $18/MWh in the third quarter. During these periods, this constraint decreased prices in the SDG&E and PG&E areas almost as much as it increased prices in the SCE area.

The second significant constraint in the SCE area was the Barre-Lewis nomogram, which was binding in about 5 percent of hours in the first quarter and about 2 percent of hours in the third quarter. This constraint increased prices in the SCE area by $5.50/MWh in the first half of the year. This constraint was also directly affected by the SONGS outages and retirements.

In the San Diego area, real-time congestion and prices were affected by multiple constraints during the year. The 7820_TL 230S_OVERLOAD_NG constraint was binding in every quarter of the year. This nomogram protects the Imperial Valley-El Centro 230 kV line for a loss of the Imperial Valley-North Gila

[179] Unlike the prices in Table 8.3, which are load weighted, prices in Table 8.4 are generation weighted.

[180] The ISO un-enforced the SCE import percent branch group starting October 1, 2013. For further details, see DMM's *Q4 2013 Report on Market Issues and Performance*, February 10, 2014, pp. 32-33: http://www.caiso.com/Documents/2013FourthQuarterReport-MarketIssues_Performance-Feb2014.pdf.

500 kV line. It was binding most frequently during the second and third quarters at about 2.6 and 1.6 percent, respectively. It increased prices in the SDG&E area by about $35/MWh in the first, second and third quarters, and decreased prices in the PG&E area by $1.75/MWh and $4.82/MWh in the second and third quarters, respectively. This constraint did not materially impact prices in the SCE area.

The South_of_Lugo constraint was binding in the last three quarters of the year, with a significant impact on the SDG&E area prices. This constraint, which is located in the SCE territory, increased prices in both the SCE and SDG&E areas, while decreasing prices in the PG&E area. The largest price impact occurred in the third quarter. It increased the SDG&E area prices by $93/MWh and the SCE area prices by $58/MWh, and decreased prices in the PG&E area by $81/MWh. This constraint was affected by planned outages on the Lugo-Rancho Vista and Lugo-Mira Loma lines.

The other remaining constraints were binding less frequently, but had significant price impact on the SDG&E area prices when they were binding. These constraints include the IVALLYBANK_XFBG, the TL50001_NG, the Doublet Tap-Friars 138 kV line, and the SERRANO (located in SCE) and SANLUSRY transformers.

PG&E area prices in the real-time market were most influenced by congestion on the PATH15_S-N. This constraint was binding in every quarter of the year, with the highest impact on prices during the first quarter. During the first quarter, it increased the PG&E prices by $52/MWh, while decreasing prices of the SCE and SDG&E areas by about $44/MWh. This constraint was influenced by maintenance outages on the Los Banos-Gates 500 kV and Midway-Los Banos 500 kV lines, variable resources and unscheduled flows on the California-Oregon Inter-tie (COI).

Real-time prices in the PG&E area were also affected by congestion on the 30875_MC CALL _230_30880_HENTAP2 constraint, which was binding in about 14 percent of intervals in the third quarter. The McCall system is heavily dependent on imports from the 230 kV system through McCall, Herndon, Henrietta banks, and local hydro generation.

Table 8.5 Impact of congestion on real-time prices during congested intervals

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

Table 8.6 shows the overall impact of real-time congestion on average prices in each load area for 2013 by constraint.

Congestion drove overall prices in the SCE area above system average prices by about $1.70/MWh or about 4 percent. Most of this increase was due to limits on the percentage of load in the SCE area that can be met by total flows on all transmission paths into the SCE area (i.e., SCE_PCT_IMP_BG). Other major drivers of increasing congestion costs were related to the north-to-south congestion on Path 26, the Southern California Import Transmission branch group (SCIT_BG) and the South of Lugo constraint, $0.36/MWh (1 percent), $0.27/MWh (0.6 percent) and $0.15/MWh (0.4 percent) respectively. The PATH15_S-N constraint had the largest offsetting effect with a decrease of nearly $0.50/MWh or 1 percent. The overall net impact of congestion caused average real-time prices in the SCE area to be the highest of all load aggregation points within the ISO system in 2013.

Prices in the San Diego area were below the system average by about $0.22/MWh or about 0.5 percent. While numerous constraints drove SDG&E congestion up, congestion in other areas drove the SDG&E area prices down. For instance, the SCE_PCT_IMP_BG drove down the SDG&E area price by $1.16/MWh or nearly 3 percent.

Average prices in the PG&E area were lowered by congestion within the ISO system by about $1.21/MWh or 3 percent. This resulted in lower prices in the PG&E area when congestion occurred on the major constraints that limit flows in the north-to-south direction (Path26_N-S) and on constraints limiting flows into the SCE and SDG&E areas. The impact of these constraints' lowered prices in the PG&E area outweighed the offsetting impact of congestion on Path 15 in the south-to-north direction, which increased overall annual prices in the PG&E area by about $0.60/MWh or about 1.5 percent.

Table 8.6 Impact of constraint congestion on overall real-time prices during all hours

	PG&E		SCE		SDG&E	
Constraint	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
SCE_PCT_IMP_BG	-$1.19	-2.97%	$1.44	3.36%	-$1.16	-2.82%
PATH15_S-N	$0.58	1.45%	-$0.48	-1.13%	-$0.48	-1.17%
PATH26_N-S	-$0.45	-1.11%	$0.36	0.84%	$0.36	0.87%
SCIT_BG	-$0.35	-0.88%	$0.27	0.62%	$0.29	0.70%
SOUTH_OF_LUGO	-$0.20	-0.50%	$0.15	0.35%	$0.22	0.54%
30735_METCALF _230_30042_METCALF _500_XF_13	$0.16	0.40%	-$0.17	-0.40%	-$0.17	-0.41%
7820_TL 230S_OVERLOAD_NG	-$0.02	-0.05%			$0.45	1.09%
30880_HENTAP2 _230_30900_GATES _230_BR_2 _1	$0.15	0.37%	-$0.10	-0.23%	-$0.10	-0.24%
SOUTHLUGO_RV_BG	-$0.09	-0.24%	$0.07	0.16%	$0.10	0.24%
BARRE-LEWIS_NG	-$0.14	-0.34%	$0.09	0.21%		
LBN_S-N	$0.09	0.21%	-$0.07	-0.16%	-$0.07	-0.17%
TRACY500_BG	-$0.06	-0.14%	$0.04	0.10%	$0.04	0.10%
24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.04	-0.09%	$0.02	0.04%	$0.08	0.20%
NSONGS_BG	$0.01	0.02%	$0.01	0.03%	-$0.11	-0.26%
SLIC 2161499 DEVERS-VISTA 2_NG	-$0.04	-0.09%	$0.02	0.05%	$0.07	0.16%
30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1	$0.05	0.13%	-$0.03	-0.08%	-$0.03	-0.08%
6110_TM_BNK_FLO_TMS_DLO_NG	$0.05	0.13%	-$0.03	-0.08%	-$0.03	-0.08%
30735_METCALF _230_30750_MOSSLD _230_BR_1 _1	$0.03	0.08%	-$0.03	-0.08%	-$0.03	-0.08%
SLIC 2126995 SONGS_NG1	-$0.01	-0.02%			$0.09	0.21%
30060_MIDWAY _500_24156_VINCENT _500_BR_2 _2	-$0.03	-0.07%	$0.02	0.05%	$0.02	0.06%
SLIC 2077347 TL50003_NG					$0.07	0.16%
7830_TL 230S_IV-SX-OUT_NG					$0.06	0.15%
SLIC 2138237 TL50003_CFE_NG					$0.06	0.14%
SLIC 2122013 Barre-Ellis DLO_17	-$0.01	-0.02%			$0.05	0.11%
SLIC 2164068 TL50001_NG					$0.05	0.11%
SLIC 2122013 Barre-Ellis DLO_16	-$0.01	-0.01%			$0.04	0.09%
24138_SERRANO _500_24137_SERRANO _230_XF_3	-$0.01	-0.03%			$0.03	0.06%
SLIC 2100489_PVDV_Out_EDLG	$0.01	0.03%	-$0.01	-0.01%	-$0.02	-0.05%
22342_HDWSH _500_22536_N.GILA _500_BR_1 _1					$0.03	0.07%
SLIC 2100489_PVDV LGMV_Out_EDLG	$0.01	0.02%			-$0.02	-0.04%
SLIC 2200107 ELDORADO-LUGO_1_NG	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.03%
24155_VINCENT _230_24091_MESA CAL_230_BR_1 _1	-$0.01	-0.03%	$0.01	0.02%	$0.01	0.02%
SLIC 2165837 ELDORADO_BUS_NG	$0.01	0.02%	-$0.01	-0.01%	-$0.01	-0.03%
22886_SUNCREST_230_22832_SYCAMORE_230_BR_1 _1					$0.02	0.06%
SLIC 2051445 TL23050_NG					$0.02	0.06%
T-135 VICTVLUGO_PVDV_NG	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.02%
22841_PICOTAP _138_22396_LAGNA NL_138_BR_1 _1	-$0.01	-0.02%	$0.01	0.02%	$0.01	0.02%
SLIC 2112931 EL CENTRO BK1_NG					$0.02	0.06%
SLIC 2090466 and 2090467 SOL					$0.02	0.05%
SDGE_PCT_UF_IMP_BG					$0.02	0.05%
30055_GATES1 _500_30900_GATES _230_XF_11_P	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.02%
IVALLYBANK_XFBG					$0.02	0.05%
SLIC 2122013 Barre-Ellis DLO_21					$0.02	0.04%
Other	$0.28	0.70%	$0.14	0.32%	-$0.19	-0.46%
Total	-$1.21	-3.0%	$1.69	3.9%	-$0.22	-0.53%

8.4 Consistency of day-ahead and real-time congestion

Congestion in the real-time market differs from congestion in the day-ahead market. Real-time congestion typically occurs less frequently overall, but often occurs on a wider number of constraints and has a larger impact on prices when it happens.

The frequency of real-time congestion is typically lower than in the day-ahead market for several reasons. For instance, congestion is often managed in the day-ahead market so that the chance of congestion occurring in real-time is lower. In 2013, the potential for congestion in the day-ahead market was also increased by virtual bidding, which often occurred as pairs of offsetting virtual supply and demand bids in an attempt to mimic congestion. These virtual bids liquidated in real-time.

Real-time congestion can occur as system conditions change and as constraints are sometimes adjusted to account for unscheduled flows being observed in real-time and the need to maintain a reliability margin to protect against unpredictable changes in actual flows. When congestion does occur in real-time, prices are often much higher since there are fewer resources that can be quickly re-dispatched to manage the congestion. For example, hourly imports scheduled in the hour-ahead market cannot be re-dispatched in the 5-minute real-time market to reduce congestion.

Because most load and generation are scheduled in the day-ahead market, congestion in this market has the greatest overall market impact. Congestion revenue rights are also settled based on day-ahead prices. When real-time congestion occurs, it sometimes results in very high prices because the ability to re-dispatch resources in real time to relieve congestion is much more limited. However, the overall cost impact of this real-time congestion was very low because of the high level of day-ahead scheduling.

Nevertheless, the consistency of day-ahead congestion with congestion in the hour-ahead and real-time energy markets provides a potential indicator of the degree to which the market and network model efficiently incorporate and manage similar conditions and congestion. For example, if a constraint is frequently not binding in the day-ahead market but is in the real-time market, this may warrant further review of how the constraint is modeled in the day-ahead and real-time markets.

This was a particular challenge for the ISO in 2012, as systematic differences in congestion on select constraints contributed to large real-time congestion imbalance offset costs. The ISO modified its procedures to allow operators to adjust day-ahead limits to better reflect expected line limits and flows in real time. As a result of this change, the systematic differences in modeling reduced in 2013.

Figure 8.3 compares the frequency and consistency of congestion on binding constraints influencing prices at load aggregation points in 2013. Table 8.7 provides a more detailed comparison of this data.

As shown in Table 8.7, congestion was low in both the day-ahead and real-time markets on most internal constraints. On many constraints, the overall frequency of congestion in the day-ahead market tended to be slightly higher than in the real-time market. Generally, reasons for this difference in congestion include the following:

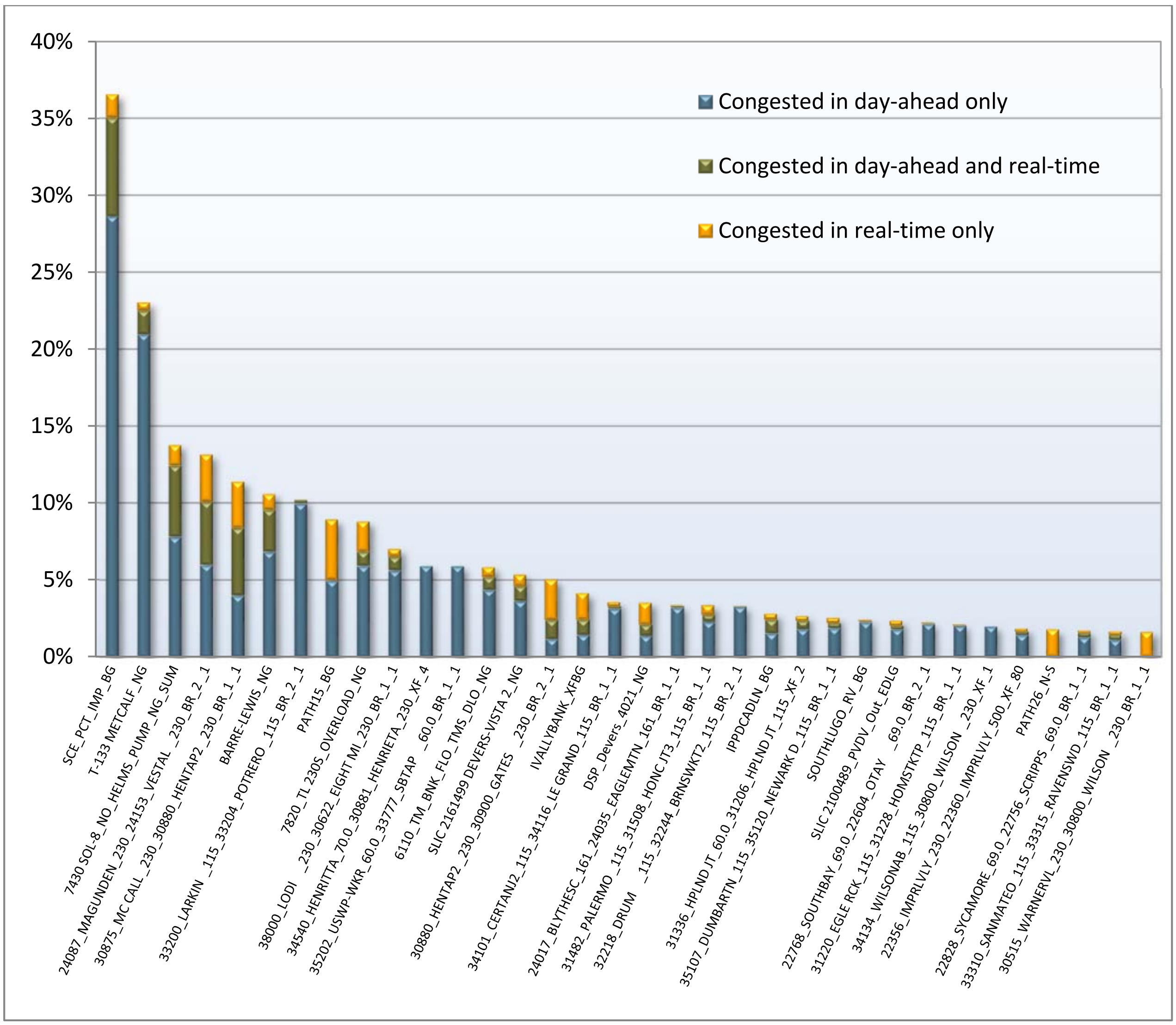
- Additional real-time generation including net imports, exceptional dispatch energy and post day-ahead market reliability commitments including exceptional dispatches and long-start units committed in the residual unit commitment process;
- Differences in flows as a result of convergence bidding only being in the day-ahead market;
- Differences in generation and transmission derates and outages; and

- Differences in load.

While the consistency of internal constraints was relatively inaccurate between the day-ahead and real-time markets, the consistency of external constraints was more accurate between the day-ahead and hour-ahead markets. Table 8.8 provides a more detailed comparison of the frequency and consistency of congestion on inter-ties with neighboring control areas in the day-ahead and hour-ahead markets. The table highlights the following:

- The Nevada / Oregon Border (NOB) inter-tie was congested about 30 percent of the time in both the day-ahead and hour-ahead markets. This was primarily due to seasonal flows of hydro generation, planned and forced outages, and line maintenance coupled with unscheduled flows.

Figure 8.3 Consistency of internal congestion in day-ahead and real-time markets



The Pacific AC inter-tie was congested about 25 percent of the time in the day-ahead market but increased to nearly 37 percent in the hour-ahead market. As with the NOB, the Pacific AC inter-tie was also congested primarily due to seasonal flows of hydro generation, planned/forced outages and line maintenance coupled with unscheduled flows.

Table 8.7 Summary of day-ahead and real-time congestion on internal constraints

Constraint name	Average binding limit (MW)	Total binding frequency in IFM	Total binding frequency in RTD	Binding in IFM only		Binding in RTD only		Binding in both IFM and RTD		
				Frequency of congestion	Average shadow price	Frequency of congestion	Average shadow price	Freq. of cong.	Avg. SP IFM	Avg. SP RTD
SCE_PCT_IMP_BG	6,495	35.1%	7.9%	28.7%	$8	1.5%	$84	6.4%	$9	$65
T-133 METCALF_NG	145	22.6%	2.1%	21.0%	$13	0.5%	$398	1.5%	$15	$284
7430 SOL-8_NO_HELMS_PUMP_NG_SUM	307	12.5%	6.0%	7.9%	$45	1.3%	$123	4.6%	$52	$139
24087_MAGUNDEN_230_24153_VESTAL _230_BR_2 _1	357	10.1%	7.2%	6.0%	$53	3.1%	$61	4.1%	$47	$79
30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1	379	8.4%	7.4%	4.0%	$18	3.0%	$60	4.4%	$25	$55
BARRE-LEWIS_NG	1,408	9.6%	3.7%	6.9%	$21	1.0%	$145	2.7%	$30	$159
33200_LARKIN _115_33204_POTRERO _115_BR_2 _1	147	10.3%	0.2%	10.1%	$36	0.02%	$1,000	0.2%	$108	$994
PATH15_BG	2,390	5.0%	4.0%	5.0%	$30	4.0%	$49	0.01%	$6	$10
7820_TL 230S_OVERLOAD_NG	351	6.9%	2.9%	6.0%	$59	2.0%	$308	0.9%	$72	$345
38000_LODI _230_30622_EIGHT MI_230_BR_1 _1	310	6.6%	1.4%	5.7%	$10	0.5%	$118	0.9%	$14	$190
34540_HENRITTA_70.0_30881_HENRIETA_230_XF_4	194	6.0%		6.0%	$9					
35202_USWP-WKR_60.0_33777_SBTAP _60.0_BR_1 _1	45	6.0%		6.0%	$11					
6110_TM_BNK_FLO_TMS_DLO_NG	733	5.2%	1.5%	4.4%	$37	0.7%	$267	0.8%	$87	$174
SLIC 2161499 DEVERS-VISTA 2_NG	310	4.6%	1.7%	3.7%	$53	0.8%	$302	1.0%	$49	$487
30880_HENTAP2 _230_30900_GATES _230_BR_2 _1	472	2.4%	3.9%	1.2%	$17	2.7%	$168	1.2%	$22	$143
IVALLYBANK_XFBG	872	2.5%	2.7%	1.5%	$8	1.7%	$29	1.0%	$13	$34
34101_CERTANJ2_115_34116_LE GRAND_115_BR_1 _1	80	3.3%	0.4%	3.2%	$11	0.3%	$184	0.2%	$23	$90
DSP_Devers_4021_NG	661	2.1%	2.2%	1.4%	$11	1.4%	$17	0.7%	$18	$22
24017_BLYTHESC_161_24035_EAGLEMTN_161_BR_1 _1	177	3.3%	0.1%	3.3%	$12	0.1%	$763	0.1%	$33	$4
31482_PALERMO _115_31508_HONC JT3_115_BR_1 _1	76	2.8%	1.1%	2.3%	$26	0.6%	$387	0.5%	$21	$460
32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1	75	3.3%	0.1%	3.3%	$38	0.02%	$1,034	0.02%	$21	$468
IPPDCADLN_BG	398	2.4%	1.3%	1.6%	$4	0.4%	$88	0.9%	$6	$78
31336_HPLND JT_60.0_31206_HPLND JT_115_XF_2	47	2.4%	0.8%	1.8%	$73	0.3%	$253	0.5%	$88	$408
35107_DUMBARTN_115_35120_NEWARK D_115_BR_1 _1	311	2.2%	0.7%	1.9%	$15	0.3%	$161	0.3%	$16	$102
SOUTHLUGO_RV_BG	3,685	2.4%	0.2%	2.3%	$17	0.1%	$374	0.1%	$32	$799
SLIC 2100489_PVDV_Out_EDLG	2,400	2.1%	0.6%	1.8%	$9	0.3%	$194	0.2%	$9	$117
22768_SOUTHBAY_69.0_22604_OTAY _69.0_BR_2 _1	108	2.2%	0.1%	2.2%	$21	0.1%	$1,000	0.03%	$13	$1,000
31220_EGLE RCK_115_31228_HOMSTKTP_115_BR_1 _1	119	2.1%	0.1%	2.1%	$12	0.1%	$82	0.02%	$32	$84
34134_WILSONAB_115_30800_WILSON _230_XF_1	228	2.0%		2.0%	$7					
22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_80	868	1.7%	0.4%	1.5%	$8	0.2%	$154	0.2%	$9	$70
22828_SYCAMORE_69.0_22756_SCRIPPS _69.0_BR_1 _1	162	1.6%	0.4%	1.3%	$40	0.1%	$277	0.3%	$89	$389
33310_SANMATEO_115_33315_RAVENSWD_115_BR_1 _1	112	1.5%	0.5%	1.1%	$233	0.2%	$1,000	0.3%	$257	$939
31464_COTWDPGE_115_31463_WHEELBR _115_BR_1 _1	87	1.6%	0.03%	1.6%	$15	0.0%	$63	0.02%	$10	$64
SLIC 2157400 DEVERS-ELCASCO_NG	310	1.2%	0.6%	1.0%	$35	0.4%	$104	0.2%	$30	$278
32314_SMRTSVLE_60.0_32316_YUBAGOLD_60.0_BR_1 _1	25	1.2%	0.4%	1.2%	$54	0.3%	$260	0.1%	$59	$336
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	170	1.0%	0.5%	0.9%	$59	0.4%	$502	0.1%	$284	$354
35648_LLAGAS _115_35909_HOLLISTR_115_BR_1 _1	56	1.4%		1.4%	$58					
30525_C.COSTA _230_30543_ROSSTAP1_230_BR_1 _1	202	0.7%	0.7%	0.7%	$50	0.7%	$208			
SUTTEROBANION_BG	525	1.2%	0.2%	1.2%	$13	0.1%	$28	0.03%	$2	$4
31474_FRBSTNTP_115_31476_KANAKAJT_115_BR_1 _1	124	1.3%		1.3%	$9					
SLIC 2100489_PVDV_Out_LGVN	2,400	1.3%		1.3%	$11					
T-135 VICTVLUGO_LGVNDLO_NG	2,700	1.3%	0.01%	1.3%	$19	0.0%	$2			
25406_J.HINDS _230_24806_MIRAGE _230_BR_1 _1	328	1.1%	0.2%	1.1%	$13	0.2%	$439	0.01%	$8	$8
SLIC 2191830 PNOCHE SOL 1	170	1.1%	0.2%	1.0%	$10	0.2%	$143	0.1%	$19	$72
SLIC 1941346 SOL4	80	1.0%	0.1%	1.0%	$56	0.1%	$896			
33203_MISSON _115_33204_POTRERO _115_BR_1 _1	132	0.8%	0.3%	0.8%	$27	0.3%	$1,000	0.02%	$35	$1,000
35120_NEWARK D_115_36851_NORTHERN_115_BR_1 _1	181	0.7%	0.6%	0.5%	$38	0.3%	$175	0.2%	$47	$214
35105_EASTSHRE_115_35106_MT EDEN _115_BR_1 _1	162	0.9%	0.2%	0.8%	$17	0.1%	$522	0.1%	$10	$670
SLIC DEVERS-VISTA 1_NG	310	0.7%	0.5%	0.6%	$52	0.3%	$275	0.2%	$61	$255
31482_PALERMO _115_32280_E.MRY J2_115_BR_1 _1	65	0.1%	1.0%	0.1%	$100	1.0%	$695	0.01%	$113	$566
22569_NCMTGTAP_138_22264_ESCNDO50_138_BR_1 _1	80	1.0%	0.2%	0.9%	$40	0.1%	$82	0.1%	$26	$246
SLIC 2124897 Rector-Vestal 2	351	0.5%	0.6%	0.4%	$27	0.5%	$210	0.1%	$291	$432

Table 8.8 Summary of day-ahead and hour-ahead congestion on inter-ties

Inter-Tie name	Full (import) rating (MW)	Total binding frequency in IFM	Total binding frequency in HASP	Binding in IFM only		Binding in HASP only		Binding in IFM and HASP		
				Binding frequency	Avg. shadow price	Binding frequency	Avg. shadow price	Binding frequency	Avg. SP IFM	Avg. SP HASP
NOB_ITC	1,564	28%	30%	6.9%	$8	8.7%	$13	22%	$11	$20
PACI_ITC	3,200	25%	37%	3.9%	$10	16%	$18	21%	$9	$24
CASCADE_ITC	80	20%	3.9%	18%	$28	1.5%	$19	2.4%	$20	$18
PALOVRDE_ITC	3,328	14%	11%	7.5%	$17	4.0%	$27	6.9%	$19	$27
COTPISO_ITC	33	4.7%	3.0%	4.0%	$10	2.2%	$54	0.8%	$15	$40
TRACY500_ITC	5,163	3.9%	0.0%	3.9%	$17	0.01%	$73	0.02%	$1	$7
IID-SCE_ITC	600	3.4%	3.1%	2.7%	$53	2.4%	$63	0.7%	$37	$57
MEAD_ITC	1,619	3.3%	5.8%	1.2%	$8	3.6%	$12	2.1%	$8	$12
ELDORADO_ITC	1,655	2.8%	2.7%	1.3%	$9	1.1%	$15	1.5%	$7	$15
SUMMIT_ITC	90	1.0%	2.1%	0.9%	$27	2.0%	$217	0.2%	$13	$22
BLYTHE_ITC	218	0.1%	1.6%	0.1%	$40	1.6%	$122	0.01%	$19	$264

Day-ahead and real-time price differences by local capacity area

This section provides a more detailed analysis of locational price differences in the day-ahead and real-time markets as a result of congestion. Locations examined in this analysis represent the aggregation of all generation nodes within the local capacity areas used for determining local resource adequacy requirements (see Section 1.1.2). These areas have been identified as the major transmission constrained load pockets in the system.

As noted above, day-ahead and real-time prices in local capacity areas can diverge as a result of differences in congestion between these two markets. Table 8.9 and Table 8.10 show quarterly average price differences during peak and off-peak hours by local capacity area. Various shades of red in the tables indicate areas where average monthly real-time prices were higher than day-ahead prices, while various shades of blue indicate areas where average monthly real-time prices were lower.

As shown in Table 8.9 and Table 8.10, differences in day-ahead and real-time prices between local capacity areas and sub-areas within each load aggregation point varied less in 2013 than in 2012. This illustrates that divergences in day-ahead and real-time prices have been primarily driven by grid level conditions rather than congestion. In 2013, the most notable difference was in the Fresno area. This area experienced positive price divergence during peak hours in the fourth quarter of 2013. This was primarily due to the planned outages on the McCall banks and local hydro generation conditions. The Bay Area prices were driven by the outages on the Moss Landing – Los Banos 500 kV line and the Moss Landing – Metcalf 500 kV line during the first half of 2013. The Kern area prices were impacted by the Rector-Vestal and Magunden-Vestal congestion during the first two quarters of 2013.

Table 8.9 Average difference between real-time and day-ahead price by local capacity area – peak hours

Region	LCA (Sub-Area)	2012 Q1	2012 Q2	2012 Q3	2012 Q4	2013 Q1	2013 Q2	2013 Q3	2013 Q4
NP26	Humboldt	2%	9%	-25%	-6%	-2%	-16%	-2%	-1%
	Sierra	-1%	53%	31%	-6%	-2%	-11%	-8%	-1%
	North Coast North Bay	-1%	24%	-13%	-5%	-4%	-13%	-6%	-1%
	Bay Area	-1%	32%	-10%	-4%	-3%	-6%	-8%	-1%
	Stockton	-1%	45%	-3%	-5%	-2%	-13%	-7%	-1%
	Fresno	0%	11%	-10%	-4%	-2%	-13%	-7%	8%
SP26	Kern	-2%	8%	-11%	-8%	-7%	-17%	-7%	-3%
	Big Creek-Ventura	1%	6%	-15%	-14%	2%	-15%	-8%	-4%
	LA Basin	3%	14%	4%	-2%	1%	-14%	-2%	-1%
	San Diego-IV	7%	13%	20%	0%	-3%	-11%	-3%	-3%
	No LCA	-1%	18%	-9%	-5%	-2%	-16%	-8%	-2%

Table 8.10 Average difference between real-time and day-ahead price by local capacity area – off-peak hours

Region	LCA (Sub-Area)	2012 Q1	2012 Q2	2012 Q3	2012 Q4	2013 Q1	2013 Q2	2013 Q3	2013 Q4
NP26	Humboldt	-8%	-16%	-7%	2%	-5%	-16%	1%	-5%
	Sierra	-6%	14%	5%	4%	-6%	-15%	2%	-4%
	North Coast North Bay	-6%	-10%	-8%	3%	-7%	-17%	-2%	-5%
	Bay Area	-6%	-8%	-9%	3%	-11%	-17%	-3%	-5%
	Stockton	-6%	12%	-1%	3%	-7%	-17%	-1%	-5%
	Fresno	-6%	-4%	-6%	4%	-6%	-14%	1%	0%
SP26	Kern	-6%	-5%	-7%	0%	-11%	-17%	-1%	-4%
	Big Creek-Ventura	0%	45%	7%	8%	-4%	-15%	0%	-4%
	LA Basin	-4%	23%	12%	12%	-4%	-16%	0%	-4%
	San Diego-IV	-7%	-3%	16%	-1%	-10%	-15%	-2%	-7%
	No LCA	-6%	1%	-1%	5%	-6%	-17%	-1%	-5%

8.5 Conforming constraint limits

Constraint limits in the market software are sometimes adjusted or *conformed* to account for differences in flows calculated by the market model and actual flows observed in real-time. The two most common reasons to adjust transmission limits are the following:

- Achieve greater alignment between the energy flows calculated by the market software and those observed or predicted in real-time operation across various paths. For example, operators sometimes adjust operating limits upward to avoid *phantom congestion* in the day-ahead or real-time market. Phantom congestion refers to cases when congestion occurs in the market model when the actual physical flows are below the limit in the market model. In other cases, operators adjust constraints in the day-ahead market to mitigate the potential for congestion occurring in the real-time market.

- Set prudent operating margins, consistent with good utility practice, to ensure reliable operation under conditions of unpredictable and uncontrollable flow volatility.

Table 8.11 lists constraints conformed in the real-time market by percent conformed and averages for megawatt bias, limit and conformed limit, and shadow prices. This table only presents the statistics calculated for intervals in which the conforming action moved the effective limit from the actual limit.

As shown in Table 8.11:

- Out of the 52 constraints presented, about 30 (58 percent of the constraints) were conformed greater than 10 percent of the time in 2013, of which 6 were conformed greater than 50 percent of the time. Also, 20 of the conformed constraints in 2013 were adjusted in real-time more than 20 percent of the time.
- Out of the 52 constraints, about 23 percent – or 12 constraints – were conformed only in the upward direction to avoid congestion that was not actually occurring based on observed flows.
- Only 10 percent or 5 constraints were conformed only in the downward direction, mainly for transmission management. Operators tend to conform down the operating limit of these major transmission lines to maintain an adequate reliability margin. The margin ensures the flows stay within the lines' operating limits, even when sudden unpredictable flow changes occur in real-time.

There was strong consistency in conforming between the hour-ahead and real-time markets in both frequency and level of adjustment. Table 8.12 compares the consistency of conforming limits in the real-time market to the hour-ahead market for every interval. This analysis indicates conforming performed in these markets was consistently applied across most constraints. Only 4 constraints had differences between the hour-ahead and real-time markets greater than 3 percent of the time.

Table 8.11 Real-time congestion and conforming of limits by constraint

Flowgate name	Conformed downward							Conformed upward							Conformed intervals
	Conformed interval	Average percent of conformed limit	Average conformed limit	Average MW Limit	Average MW bias	Congested intervals	Average shadow price	Conformed interval	Average percent of conformed limit	Average conformed limit	Average MW Limit	Average MW bias	Congested intervals	Average shadow price	
T-135 VICTVLUGO_EDLG_NG	3%	96%	2,307	2,564	-257	0.1%	$219	88%	114%	2,649	2,564	85	0.03%	$25	90%
T-135 VICTVLUGO_PVDV_NG	3%	94%	2,312	2,564	-252	0.1%	$509	84%	117%		2,564				87%
LBS_WITH_PUMPS_NG	82%	72%		4,200				1%	109%		4,200				83%
PATH15_S-N	69%	57%	1,844	5,400	-3,556	2.3%	$56								69%
SCE_PCT_IMP_BG	21%	91%	10,707	23,397	-1,758	2.2%	$62	35%	107%	6,456	6,656	321	1.50%	$74	56%
T-135 VICTVLUGO_HDW_NG								55%	118%		2,564				55%
T-135 VICTVLUGO_LGMH_NG								49%	119%		2,564				49%
T-135 VICTVLUGO_LGVNDLO_NG	0%	95%	2,403	2,564	-161	0.0%	$2	49%	119%		2,564				49%
SUTTEROBANION_BG								45%	100%		466				45%
IID-SCE_BG								41%	197%	392	262	41	0.01%	$496	41%
DSP_Devers_4021_NG	0%	94%	462	483	-21	0.0%	$16	40%	135%	617	483	134	1.10%	$23	40%
30515_WARNERVL_230_30800_WILSON _230_BR_1 _1	7%	85%	300	363	-103	1.1%	$244	33%	122%	300	246	30	0.68%	$200	40%
6110_TM_BNK_FLO_TMS_DLO_NG	5%	89%	753	1,066	-313	0.8%	$313	32%	185%	1,096	1,066	30	0.01%	$311	37%
SLIC 2054754 LLAGAS SOL1	0%	88%	130	145	-15	0.0%	$9	27%	118%	229	145	84	0.02%	$1,152	27%
LBN_S-N	27%	50%	688	3,800	-3,112	0.4%	$70								27%
7430 SOL-8_NO_HELMS_PUMP_NG_WIN								24%	107%		410				24%
SLIC 2090905 SOL4	0%	81%	358	440	-82	0.11%	$861	23%	122%		418				24%
IVALLYBANK_XFBG	6%	83%	999	1,215	-247	1.8%	$34	17%	134%	999	818	23	0.04%	$20	24%
SLIC 2100507 CALCAP_NG								21%	105%		2,564				21%
7820_TL 230S_OVERLOAD_NG	14%	90%	341	400	-59	1.1%	$311	7%	174%	419	400	19	0.08%	$887	21%
PATH26_N-S	20%	62%	1,344	4,000	-2,656	1.1%	$78	0%	104%		4,000				20%
7230 SOL_5_NG_SUM								18%	198%	94	32	62	0.04%	$529	18%
T-133 METCALF_NG	6%	88%	119	145	-26	0.6%	$14	9%	130%	235	145	90	0.32%	$647	16%
7430 SOL-8_NO_HELMS_PUMP_NG_SUM	10%	88%	258	307	-49	3.6%	$141	5%	120%	317	307	10	0.15%	$113	16%
BARRE-LEWIS_NG	14%	95%	1,392	1,470	-78	1.7%	$122	2%	112%	1,506	1,470	36	0.12%	$606	15%
24804_DEVERS _230_24806_MIRAGE _230_BR_1 _1								13%	161%	558	310	186	0.00%	$706	13%
30500_BELLOTA _230_38206_COTTLE A_230_BR_1 _1								12%	198%	312	176	156	0.05%	$869	12%
SLIC 1941346 SOL4	2%	87%	72	94	-22	0.1%	$495	8%	200%		99				10%
TRACY500_BG	1%	92%	733	812	-103	0.4%	$192	9%	176%	650	543	239	0.18%	$121	10%
30790_PANOCHE _230_30825_MCMULLN1_230_BR_1 _	6%	84%	361	438	-201	0.9%	$136	4%	114%	372	324	18	0.01%	$103	10%
30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1	8%	86%	367	433	-88	1.7%	$53	2%	107%	374	354	8	0.36%	$59	9%
SLIC 2161499 DEVERS-VISTA 2_NG	5%	92%	272	312	-40	0.7%	$322	4%	111%	362	312	50	0.30%	$733	9%
24087_MAGUNDEN_230_24153_VESTAL _230_BR_2 _1	5%	87%	370	429	-79	1.2%	$106	5%	107%	368	353	11	0.12%	$196	9%
31996_HALEJ1 _115_32006_VCVLLE1J_115_BR_1 _1								8%	156%		56				8%
T163-Pastoria-Pardee_NG	7.5%	78%		1,280				0%	198%	2,192	1,280	912	0.010%	$977	8%
34101_CERTANJ2_115_34116_LE GRAND_115_BR_1 _1	1%	82%	74	104	-59	0.1%	$64	7%	133%	75	59	7	0.06%	$100	7%
30055_GATES1 _500_30900_GATES _230_XF_11_P	1%	96%	1,087	1,131	-58	0.1%	$36	6%	125%	1,082	863	52	0.02%	$44	7%
31482_PALERMO _115_31508_HONC JT3_115_BR_1 _1	4%	74%	81	112	-45	0.7%	$459	2%	102%	77	79	5	0.03%	$631	6%
7430_SOL-10_NG	0%	95%		300				6%	228%		300				6%
38000_LODI _230_30622_EIGHT MI_230_BR_1 _1	0%	96%	345	358	-13	0.2%	$345	5%	106%	359	337	18	0.33%	$136	6%
31482_PALERMO _115_32280_E.MRY J2_115_BR_1 _1	4.2%	68%	80	126	-59	2.52%	$1,004	1%	100%		79				5%
SOUTH_OF_LUGO	5%	65%	3,265	5,900	-2,635	0.8%	$107								5%
PATH26_S-N	5.2%	67%		3,000											5%
30735_METCALF _230_30042_METCALF _500_XF_13	3%	94%	1,045	1,127	-63	1.2%	$673	2%	111%	1,020	935	87	1.10%	$805	5%
33200_LARKIN _115_33204_POTRERO _115_BR_2 _1	0%	90%		177				5%	122%	152	127	15	0.15%	$995	5%
7830_SXCYN_CHILLS_NG	0%	92%	224	251	-27	0.1%	$523	5%	198%	254	251	3	0.00%	$1,394	5%
30525_C.COSTA _230_30543_ROSSTAP1_230_BR_1 _1	4%	53%	327	664	-497	0.2%	$210	0%	107%	320	376	7	0.00%	$368	5%
7230 SOL_3_NG_SUM	4%	81%	140	205	-65	0.2%	$222	0%	6709%	265	205	60	0.030%	$617	5%
MKTPCADLN_MSL								4%	150%		419				4%
SLIC 2100489_PVDV_Out_EDLG	4.2%	93%	2,340	2,700	-360	0.29%	$185								4%
30500_BELLOTA _230_30505_WEBER _230_BR_1 _1								4%	164%	335	210	138	0.01%	$1,000	4%
SLIC 2124897 Rector-Vestal 2	3%	95%	333	350	-17	0.1%	$43	1%	107%	438	350	88	0.12%	$699	4%

Table 8.12 Conforming of constraint limits in hour-ahead and real-time markets

Flowgate name	Conforming in RTD	Conforming level match in RTD and HASP	Conforming level does not match in RTD and HASP	Average conforming level match in RTD and HASP (%)	Average conforming level does not match in RTD and HASP (%)
SCE_PCT_IMP (BG)	44.5%	21.8%	22.6%	99	99
PATH15 (BG)	25.9%	25.9%		200	200
WARNERVL to WILSON 230kV (Line)	25.1%	21.9%	3.2%	119	101
PATH26 (BG)	22.6%	22.5%		200	200
IVALLYBANK (XF)	14.8%	11.0%	3.8%	147	85
IID-SCE (BG)	13.9%	13.9%		192	166
PANOCHE to MCMULLN1 230kV (Line)	8.3%	6.4%	1.9%	103	82
TRACY500 (BG)	8.1%	6.7%	1.4%	169	115
DEVERS to MIRAGE 230kV (Line)	8.0%	7.9%		168	141
SCIT (BG)	7.3%	1.8%	5.5%	78	63
MAGUNDEN to VESTAL 230kV (Line)	6.9%	5.7%	1.2%	98	85
SUTTEROBANION (BG)	6.8%	6.8%		100	100
MC CALL to HENTAP2 230kV (Line)	5.9%	4.3%	1.6%	92	91
BELLOTA to COTTLE A 230kV (Line)	4.9%	4.9%		174	181
LOSBANOSNORTH (BG)	4.9%	2.9%	1.9%	199	117
C.COSTA to ROSSTAP1 230kV (Line)	4.7%	4.1%	0.6%	55	69
GATES1 11_P (XF)	4.1%	3.5%	0.6%	128	99
CERTANJ2 to LE GRAND 115kV (Line)	3.9%	3.5%	0.4%	123	94
LARKIN to POTRERO 115kV (Line)	3.8%	3.2%	0.6%	118	124
LODI to EIGHT MI 230kV (Line)	3.5%	2.6%	0.9%	105	107
DEVERS to TOT032 230kV (Line)	3.3%	1.7%	1.6%	94	99
BELLOTA to WEBER 230kV (Line)	3.0%	3.0%		163	157
PALERMO to HONC JT3 115kV (Line)	3.0%	1.2%	1.8%	82	93
SANMATEO to RAVENSWD 115kV (Line)	2.5%	2.3%	0.2%	122	109
SOUTHLUGO_RV (BG)	2.4%	2.2%	0.2%	198	94
HALEJ1 to VCVLLE1J 115kV (Line)	2.2%	2.2%		172	156
J.HINDS to MIRAGE 230kV (Line)	2.2%	0.1%	2.0%	99	96
PALERMO to E.MRY J2 115kV (Line)	2.1%	0.7%	1.4%	76	89
GRANT to EASTSHRE 115kV (Line)	2.1%	2.0%		204	223
SMRTSVLE to YUBAGOLD 0.0kV (Line)	2.0%	0.9%	1.0%	80	58
MISSON to POTRERO 115kV (Line)	1.9%	1.3%	0.5%	139	104
METCALF 13 (XF)	1.8%	1.0%	0.8%	102	101
ENCL TAP to PEASE 0.0kV (Line)	1.8%	0.1%	1.7%	89	101
MCMULLN1 to KEARNEY 230kV (Line)	1.7%	1.3%	0.4%	90	69
VINCENT to RIOHONDO 230kV (Line)	1.7%	1.7%		108	107
SN LS OB to SNTA MRA 115kV (Line)	1.5%	1.5%		200	200
MISSON to HNTRS PT 115kV (Line)	1.5%	1.4%		135	115
PALERMO to HONC JT1 115kV (Line)	1.4%	1.2%	0.2%	73	80
IMPRLVLY 80 (XF)	1.4%	0.6%	0.8%	97	95
NEWARK D to NORTHERN 115kV (Line)	1.4%	0.3%	1.1%	95	91
WINDHUB 4 _P (XF)	1.4%	1.3%		137	113
BLYTHESC to EAGLEMTN 161kV (Line)	1.3%	1.1%	0.2%	154	93
MESA to 36267 115kV (Line)	1.2%	1.2%		125	125
RICHMOND to SOBRANTE 115kV (Line)	1.2%	1.2%		149	130
PEABODY to BRDSLDNG 230kV (Line)	1.2%	0.5%	0.7%	100	95
HENTAP2 to GATES 230kV (Line)	1.2%	0.7%	0.4%	75	55
WEBER to TESLA E 230kV (Line)	1.2%	1.1%		165	108
SYLMAR_SIM (MSL)	1.1%	1.1%		200	180
NEWARK to RAVENSWD 230kV (Line)	1.1%	1.1%		122	111
EASTSHRE to MT EDEN 115kV (Line)	1.1%	0.9%	0.2%	87	99
BARRE to ELLIS 230kV (Line)	1.1%	1.1%		95	95
OTAY to OTAYLKTP 9.0kV (Line)	1.0%	0.9%	0.1%	107	69
TRES VIS to TBLE MTN 0.0kV (Line)	1.0%	0.9%	0.1%	92	91

Congestion in the day-ahead market is reviewed on a regular basis to determine the need for conforming the constraints' operating limits. Compared to previous years, the day-ahead market constraint limits were conformed to a greater degree in 2013. For instance, 6 constraints were conformed in over 60 percent of the hours. This is consistent with changes in ISO practices to better align congestion limits in the day-ahead and real-time markets. This occurred mostly in the first half of the year on a few large constraints including SCE_PCT_IMP_BG and 22342_HDWSH _500_22536_N.GILA _500_BR_1 _1.

Table 8.13 lists all internal constraints conformed in the day-ahead market. In the previous year, the majority of the conformed hours were conformed downward to better align the day-ahead modeling with anticipated real-time modeling. In 2013, 11 constraints were conformed upward in more than 14 percent of hours, whereas no constraints were conformed in the upward direction in more than 14 percent of hours in 2012. In 2013, six constraints were conformed in both directions to account for transmission outages and inconsistencies between the market software and actual values, compared to three constraints in 2012.

Table 8.13 Conforming of internal constraints in day-ahead market

	Conformed downward							Conformed upward							
Flowgate name	Conformed interval	Average percent of conformed limit	Average conformed limit	Average MW Limit	Average MW bias	Congested intervals	Average shadow price	Conformed interval	Average percent of conformed limit	Average conformed limit	Average MW Limit	Average MW bias	Congested intervals	Average shadow price	Conformed intervals
HUMBSB_BK_NG	95%	84%	52	62	-10	0.01%	$20								95%
T-135 VICTVLUGO_EDLG_NG								91%	106%	2,700	2,564	136	0.02%	$7	91%
T-135 VICTVLUGO_PVDV_NG								89%	106%	2,700	2,564	136	0.04%	$14	89%
7820_TL 230S_OVERLOAD_NG	44%	79%	336	466	-153	0.01%	$60	31%	107%	397	356	27	0.11%	$49	74%
22342_HDWSH _500_22536_N.GILA _500_BR_1 _1	63%	90%	1,609	1,788	-179	0.01%	$62								63%
SCE_PCT_IMP_BG	61%	93%	7,002	7,717	-550	0.01%	$8								61%
T-135 VICTVLUGO_HDW_NG								56%	106%		2,564				56%
6110_TM_BNK_FLO_TMS_DLO_NG	33%	78%	719	1,066	-347	0.01%	$46	21%	160%		1,066				53%
BARRE-LEWIS_NG	53%	93%	1,382	1,470	-88	0.01%	$28								53%
T-135 VICTVLUGO_LGVNDLO_NG	0%	96%		2,564				50%	106%	2,700	2,564	136	0.10%	$19	50%
T-135 VICTVLUGO_LGMH_NG								50%	106%		2,564				50%
38000_LODI _230_30622_EIGHT MI_230_BR_1 _1	49%	92%	358	392	-27	0.02%	$12								49%
PATH15_BG	34%	95%	2,498	3,502	-141	0.01%	$55	0%	110%	2,300	2,100	200	0.00%	$1	34%
SLIC 2054754 LLAGAS SOL1								27%	117%		145				27%
7430 SOL-8_NO_HELMS_PUMP_NG_WIN								25%	105%		410				25%
SLIC 2090905 SOL4								23.1%	122%		418				23%
SLIC 2100507 CALCAP_NG								21.6%	105%		2,564				22%
SLIC 2161499 DEVERS-VISTA 2_NG	9.5%	99%	310	312	-2	0.01%	$52								9.5%
T163-Pastoria-Pardee_NG	7.3%	78%	1,000	1,280	-280	0.01%	$16								7.3%
DSP_Devers_4021_NG	0.7%	51%	663	1,300	-637	0.02%	$5	2.5%	137%		483				3.2%
PATH26_BG	2.7%	92%	2,753	3,163	-188	0.01%	$4	0.3%	120%		2,475				3.0%
SLIC 2112913 PANOCHE SOL1								1.6%	201%		87				1.6%
33315_RAVENSWD_115_33316_CLYLDG _115_BR_1 _1								1.1%	110%		120				1.1%
33200_LARKIN _115_33204_POTRERO _115_BR_2 _1								1.1%	123%	151	124	27	0.040%	$78	1.1%
35642_METCALF _115_30735_METCALF _230_XF_2	1%	95%	420	442	-22	0.02%	$26								1.1%

8.6 Congestion revenue rights

Congestion revenue rights are financial instruments that allow participants to hedge against congestion costs in the day-ahead market. This section provides an overview of congestion revenue market results and trends. Our analyses show the following:

- The volume of congestion revenue rights awarded in 2013, particularly in the third and fourth quarters, notably increased when compared to 2012.
- A $3 million revenue surplus existed at the end of 2013, which will be allocated to measured demand. While revenue deficiencies occurred in the second half of 2013, these were offset by additional revenues collected through auctions during the first two quarters.

- Average profitability of all congestion revenue rights was about $0.14/MW in 2013, compared to about $0.40/MW in 2012. This decrease in profitability was partly due to increases in the cost of congestion revenue rights purchased at auction.

- In 2013, more profitable congestion revenue rights were those in the counter-flow direction of prevailing congestion patterns. Between 2009 and 2011, congestion revenue rights in the counter direction of prevailing congestion were more profitable, whereas congestion revenue rights in the same direction of prevailing congestion were more profitable in 2012.[181]

Background

Locational marginal prices are composed of three components: energy, congestion, and transmission losses. The congestion component can vary widely depending on the location and severity of congestion, and it can be volatile. Market participants can acquire congestion revenue rights as a financial hedge against volatile congestion costs. As a market product, congestion revenue rights are defined by the following five elements:

- ***Life term —*** Each congestion revenue right has one of two categories of life term: one month or one calendar season. The long-term allocation process extends seasonal congestion revenue rights awarded in the annual allocation for an additional 9 years to provide a hedge for a total of 10 years. There are four calendar seasons corresponding to the four quarters of the calendar year.

- ***Time-of-use —*** Each congestion revenue right is defined as being for either peak or off-peak hours as defined by Western Electricity Coordinating Council guidelines.[182]

- ***Megawatt quantity —*** This is the volume of congestion revenue rights allocated or purchased. For instance, one megawatt of congestion revenue rights with a January 2013 monthly life term and on-peak time-of-use represents one megawatt of congestion revenue rights during each of the 416 peak hours during this month.

- ***Sink —*** The sink of a congestion revenue right can be an individual node, load aggregation point, or a group of nodes.

- ***Source —*** The source of a congestion revenue right can be an individual node, load aggregation point or a group of nodes.

The amount received or paid by the congestion revenue right holder each hour is the day-ahead congestion price of the sink minus the congestion price for the source. Prices used to settle congestion revenue rights involving load aggregation points or a group of nodes represent the weighted average of prices at individual nodes.

The congestion revenue rights market is organized into annual and monthly allocation and auction processes.

[181] Participants pay for prevailing congestion revenue rights in the auction and receive payment when congestion occurs in the day-ahead market. Participants are paid to receive counter-flow congestion revenue rights in the auction and pay when congestion occurs in the day-ahead market.

[182] Peak hours are defined as hours ending 7 through 22 excluding Sundays and WECC holidays. All other hours are off-peak hours.

- In the annual process, rights are allocated and auctioned separately for each of the four calendar seasons. Long-term rights are valid for one calendar season for 10 years and are only available through the allocation process. A short-term right is valid for one calendar season of one specific year.
- The monthly process is an allocation and auction for rights that are valid for one calendar month of one specific year.

A more detailed explanation of the congestion revenue right processes is provided in the ISO's *2013 Annual CRR Market Results Report.*[183]

Figure 8.4 and Figure 8.5 show the monthly average amount of the various types of congestion revenue rights awarded within a quarter since 2011 for peak and off-peak hours, respectively. The following is shown in these figures:

- The total volume of congestion revenue rights increased by 20 percent in 2013 compared to 2012. This was in part the result of more cleared megawatts in the counter-flow direction from the monthly auctions. The short-term auction for 2013 was conducted in November 2012.
- During 2013, rights purchased through the monthly auctions notably increased in the second half of the year. All other processes for acquiring congestion revenue rights for 2013 were completed in 2012. Therefore, market participants wanting to increase participation in the congestion revenue rights market for 2013 had to do so through the monthly processes.
- Congestion revenue rights awarded through the allocation process do not vary significantly from quarter to quarter. The small variation between calendar seasons reflects that the allocation process is based on historical load.

[183] For further details, please see the following: http://www.caiso.com/Documents/Annual2013CRRMarketReport.pdf.

Figure 8.4 Allocated and awarded congestion revenue rights (peak hours)

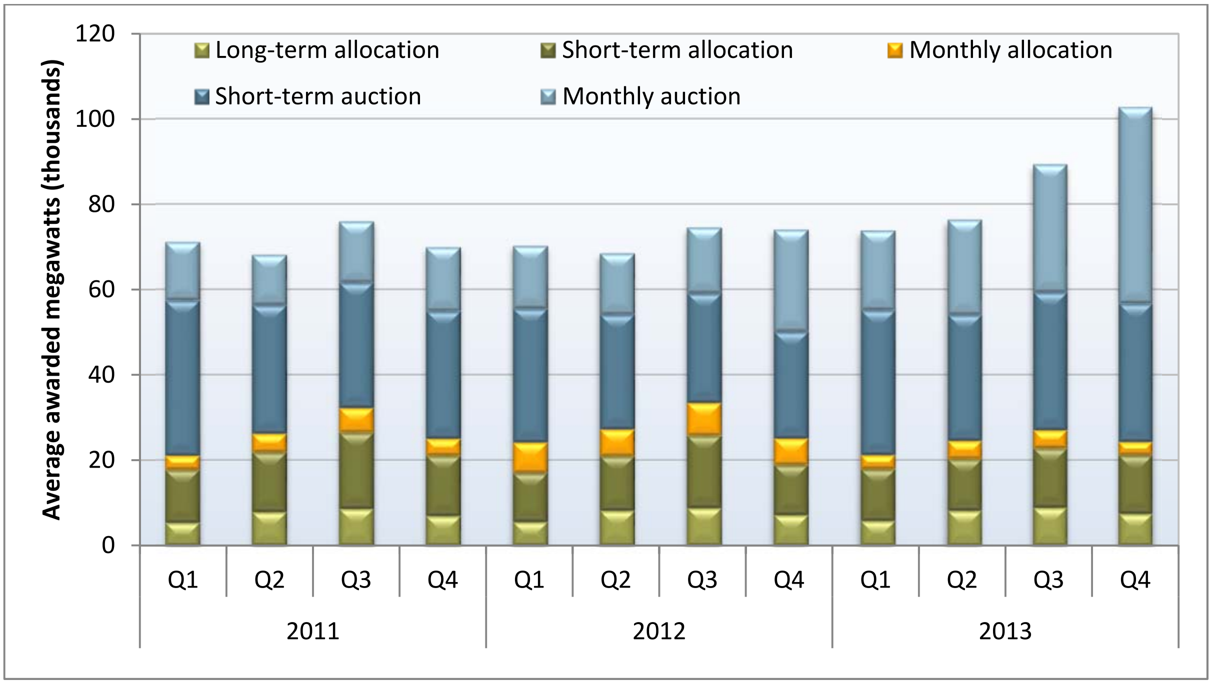


Figure 8.5 Allocated and awarded congestion revenue rights (off-peak hours)

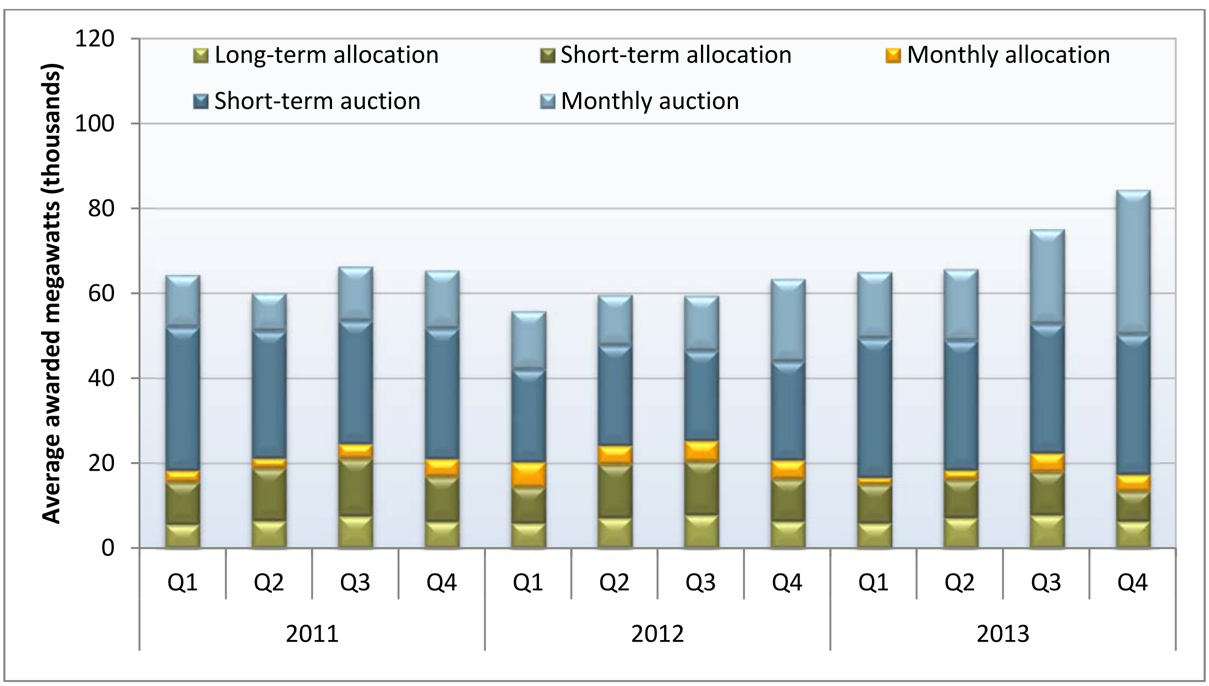


Figure 8.6 and Figure 8.7 provide a high level summary of the market clearing quantities and prices in the auctions for seasonal and monthly congestion revenue rights for each quarter over the last three years. Prices in these figures represent the price per megawatt-hour for each congestion revenue right. This is equal to the market clearing price divided by the total hours for which the right is valid.[184] This allows the seasonal rights to be grouped and compared with monthly rights.

Different general trends occurred for peak and off-peak hours in 2013. During peak hours, roughly 38 percent of 2013 awarded megawatts had a clearing price above $0.25/MWh, whereas during off-peak hours around 19 percent of 2013 awarded megawatts had a clearing price above $0.25/MWh. Figure 8.6 and Figure 8.7 show an increase in the average awarded megawatts in 2013 compared to previous years. This was in part related to an increase in the counter-flow positions.

Average monthly megawatts awarded with $0/MWh bids doubled in 2013 compared to 2012. Although the price of different congestion revenue rights varies widely, the price of most rights was at or above $0.10/MWh in 2013. The average monthly megawatts awarded above $0.25/MWh increased by around 68 percent for peak and by around 63 percent for off-peak congestion revenue rights in 2013 compared to 2012. There were two main reasons for the overall increase in the monthly megawatts awarded:

- An increase in bids submitted for the short-term and particularly monthly auction processes resulted in more awarded congestion revenue rights and cleared megawatts, most notably priced above $0.25/MWh.
- More congestion revenue rights in the counter-flow direction cleared. Therefore, this allowed more congestion revenue rights in the positive prevailing direction to also clear.

Although the price of different congestion revenue rights varies widely, the price of most off-peak rights was within ±$0.10/MWh, whereas the majority of on-peak rights were greater than $0.10/MWh. Moreover, there appears to be an on-peak trend towards greater awarded megawatts in clearing prices greater than $0.25/MWh. This trend began in the fourth quarter of 2012 and continued through 2013.

[184] Auction price is defined as auction cost, divided by the quantity megawatts and number of hours for which that right is valid. The same cost is represented for each awarded megawatt on the same path. For example, assume a monthly auction and a 10 MW monthly on-peak congestion revenue right is cleared with $20/MW price in the auction (total cost is $200=10 MW x $20/MW). If there are 400 peak hours in the month and the congestion revenue right was for 10 MW, the auction cost per megawatt hour would be $0.05/MWh ($200/400hrs/10MW = $0.05/MWh). This auction cost would be shown with a frequency of 10, representing each awarded megawatt.

Figure 8.6 Auctioned congestion revenue rights by price (peak hours)

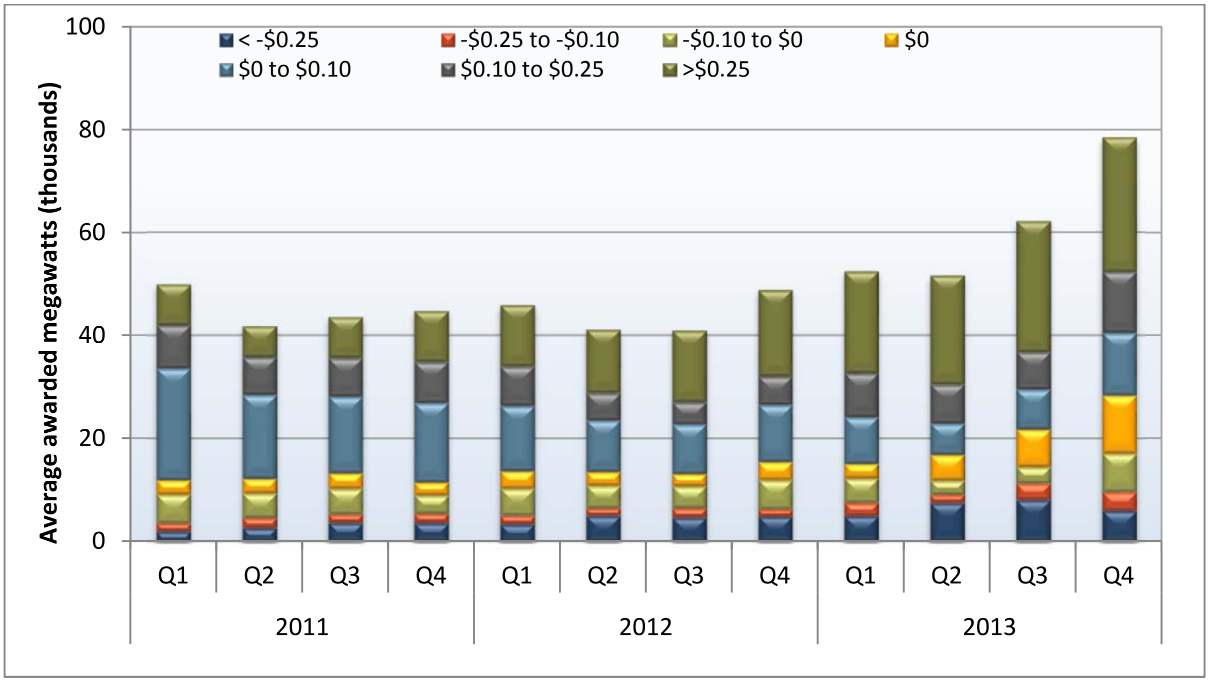
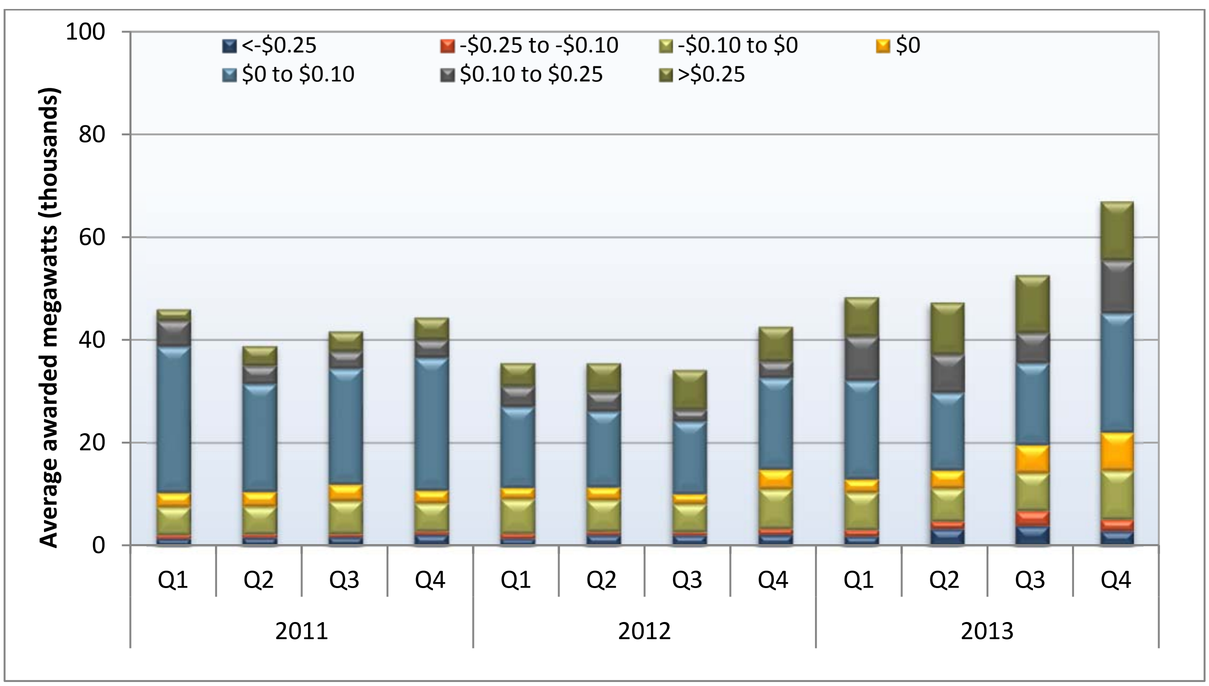


Figure 8.7 Auctioned congestion revenue rights by price (off-peak hours)



Congestion revenue right revenue adequacy

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

The market for congestion revenue rights is designed such that congestion rent collected from the day-ahead energy market is sufficient to cover payments to congestion revenue rights holders. This is referred to as revenue adequacy.[185] All revenues from the annual and monthly auction processes are included in the congestion revenue rights balancing account to help ensure revenue adequacy, if needed. Any shortfall or surplus in the balancing account at the end of each month is allocated to measured demand.

Congestion rents collected in the day-ahead market may not be sufficient to cover payments to congestion revenue rights holders. Revenue inadequacy is mainly due to differences between the network transmission model used in the congestion revenue rights process and the final day-ahead market model. In general, the day-ahead model is expected to be more restrictive than the congestion revenue right model because transmission changes unanticipated at finalization of the congestion revenue right model are more likely to reduce available transmission capacity than to increase it, as transmission flows are de-rated to account for outages and other unanticipated conditions. In addition, new nomograms not in place when the congestion revenue rights full network model is finalized may impose limits on transmission capacity in the day-ahead market.[186] Therefore, the quantity of congestion revenue rights released in the monthly and annual congestion revenue rights processes for a path may be higher than the actual transmission capacity available in the day-ahead market, increasing the potential for revenue inadequacy.

Figure 8.8 shows the revenues, payments and overall revenue adequacy of the congestion revenue rights market by quarter for the last three years.

- The dark blue bars represent congestion rent, which accounts for the main source of revenues in the balancing account.
- Light blue bars show net revenues from the annual and monthly auctions for congestion revenue rights corresponding to each quarter. This includes revenues paid for positively priced congestion revenue rights in the direction of expected prevailing congestion, less payment made to entities purchasing negatively priced counter-flow congestion revenue rights.
- Dark green bars show net payments made to holders of congestion revenue rights. This includes payments made to holders of rights in the prevailing direction of congestion plus revenues collected from entities purchasing counter-flow congestion revenue rights.

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

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

- The orange line shows the sum of monthly total revenue adequacy for the three months in each quarter when revenues from the auction are included.
- The red line shows total quarterly revenue adequacy when auction revenues are excluded.

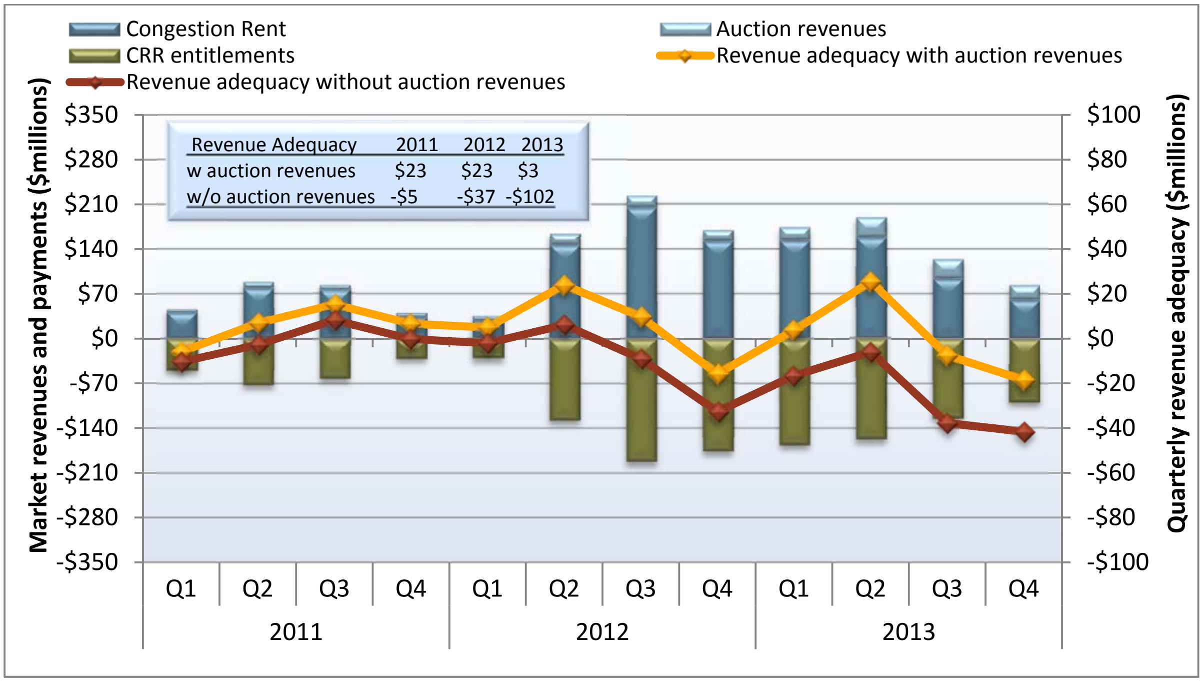
As seen in Figure 8.8, congestion revenue rights before auction revenues had significant levels of revenue shortfall in the second half of 2013. Shortfalls were due, in part, to the following differences between the network transmission model used in the congestion revenue rights process and the day-ahead market model:

- **Nomograms and constraints created due to a planned outage of the Devers-Palo Verde 500 kV line**: The Devers nomograms restrict flow through 115 kV to 230 kV transformers outside the ISO grid. Transfer through these transformers was not constrained in the congestion revenue right model until December.
    - **Palo Verde inter-tie:** This de-rate took the limit of the interface below the amount released in the seasonal congestion revenue right process for the fourth quarter. As a result, congestion revenue right revenue was inadequate in all congested hours, most notably in November.
    - **SLIC_2161499_DEVERS-VISTA_NG nomogram**: This nomogram led to revenue shortfalls of around $6 million in August, September and October.
- **6110_TM_BNK_FLO_TMS_DLO_NG nomogram**: In July, a revenue shortfall of around $11 million occurred on the 6110_TM_BNK_FLO_TMS_DLO_NG nomogram due to the difference between the value of the limit considered in the congestion revenue right model and the more restrictive limit used in the day-ahead market to account for anticipated loop flow.
- **7430_SOL-8_NO_HELMS_PUMP_NG nomogram**: This nomogram was intended to be an intermittent constraint that would not be enforced all the time in the day-ahead market. Therefore, the constraint was not initially implemented in the congestion revenue right model. However, further studies determined that the impact of the constraint on congestion revenue rights was significant enough to include it in the congestion revenue right model. The constraint was enforced beginning with the October 2013 monthly congestion revenue right process. Total revenue shortfall on this constraint was around $9 million in July, August and September.

In total for every quarter of 2013, revenues for congestion revenue rights were negative before taking into account auction revenues. With auction revenues included, revenues were positive for the first two quarters and negative for the remainder of the year.

The total cumulative revenue adequacy of the congestion revenue rights balancing account for 2013 was about $3 million, approximately a $20 million decrease from 2012. This represents only about 3 percent of total net revenues from the annual and monthly auctions for 2013.

Figure 8.8 Quarterly revenue adequacy



Profitability of congestion revenue rights

Each entity participating in the congestion revenue rights auction reveals its expectation of congestion costs through bid prices. Participants with actual generation, load or contracts tied to nodal market prices may assign an additional value to congestion revenue rights as a hedge against extremely high congestion costs. These participants may be willing to pay a premium above the expected value of congestion to mitigate this risk.

Profitability of prevailing flow congestion revenue rights. For prevailing flow congestion revenue rights, profitability depends on the initial purchase price, minus revenues received over the term of the right as the result of any congestion that occurs between the source and sink of the right. As previously noted, these rights are typically purchased by participants seeking a hedge against congestion costs associated with their expected energy deliveries, purchases or financial contracts.

Profitability of counter-flow congestion revenue rights. For counter-flow congestion revenue rights, profitability is determined by the payment received from the auction, minus payments made over the term of the right as the result of any congestion between the source and sink of the right. These counter-flow rights are typically purchased by financial traders willing to take the risk associated with the obligation to pay unknown amounts based on actual congestion in return for the initial fixed payment they receive for these rights.

Figure 8.9 through Figure 8.12 show the profitability distribution of congestion revenue rights for peak and off-peak hours in 2013.[187] The figures only include congestion revenue rights acquired through the auction process since these rights were valued through a market process. Each chart distinguishes between prevailing flow and counter-flow congestion revenue rights.

Results of these figures show the following:

- About 42 percent of the seasonal prevailing flow rights were profitable, while 26 percent of monthly rights were profitable. Overall, profits for seasonal prevailing flow rights averaged about $0.14/MWh, whereas profits averaged about $0.10/MWh for monthly rights.
- About 71 percent of all seasonal counter-flow rights had positive profits, while about 79 percent of monthly rights had positive profits. Profits for seasonal counter-flow rights averaged $0.15/MWh, while profits averaged about $0.25/MWh for monthly rights.

In the monthly auction, the most profitable and unprofitable congestion revenue rights were those impacted by unforeseen outages, and de-rates. Congestion on major transmission constraints in the third and fourth quarters caused congestion in the day-ahead market. This made some counter-flow rights unprofitable and some prevailing flow rights profitable. Overall, congestion revenue rights profitability was notably less in 2013 compared to 2012 on a per MWh basis.

[187] The congestion revenue rights profit is defined as the total congestion revenue rights revenues minus auction cost, divided by the quantity megawatts and number of hours for which that right is valid. The same profit is represented for each awarded megawatt on the same path. For example, assume a 10 MW monthly on-peak congestion revenue right cost $100 in the auction (10 MW x $10/MW). If this right received $900 in day-ahead congestion revenues this would represent a net profit of $800 over the life of the right. Since the congestion revenue right is valid for 400 hours and was for 10 MW, the profit per megawatt hour would be $0.20/MWh ($800/400hrs/10MW = $0.20/MWh). This profit would be shown with a frequency of 10, representing each awarded megawatt.

Figure 8.9 Profitability of congestion revenue rights - seasonal CRRs, peak hours

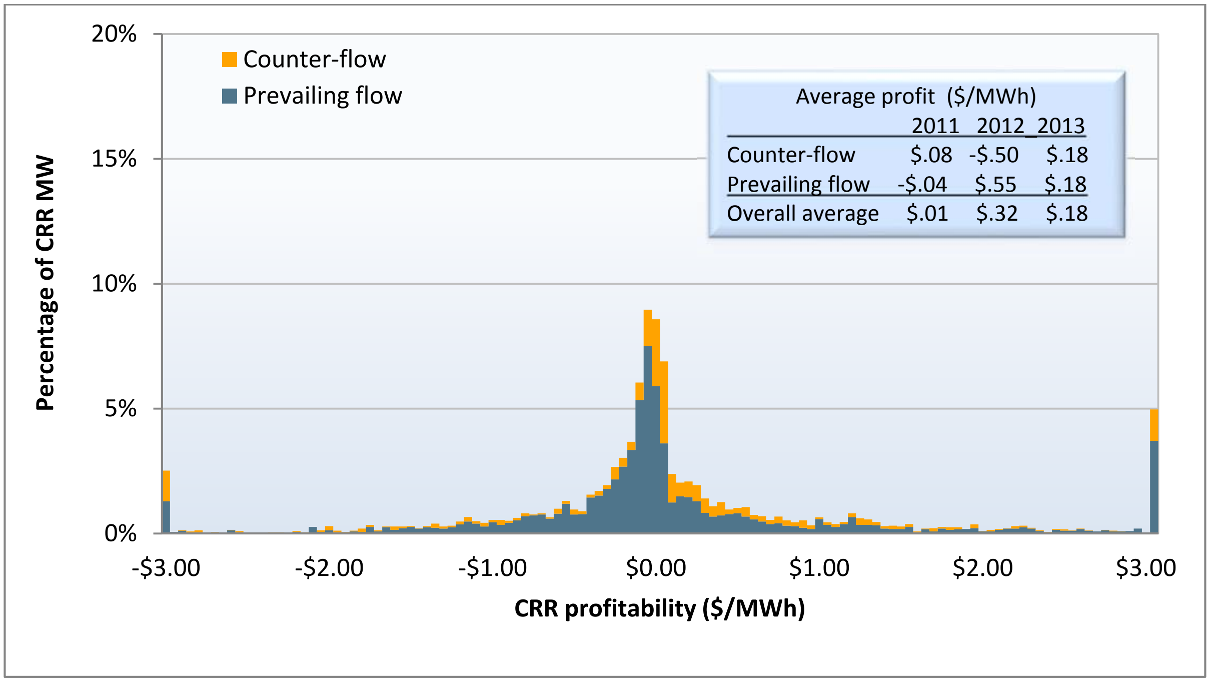


Figure 8.10 Profitability of congestion revenue rights - seasonal CRRs, off-peak hours

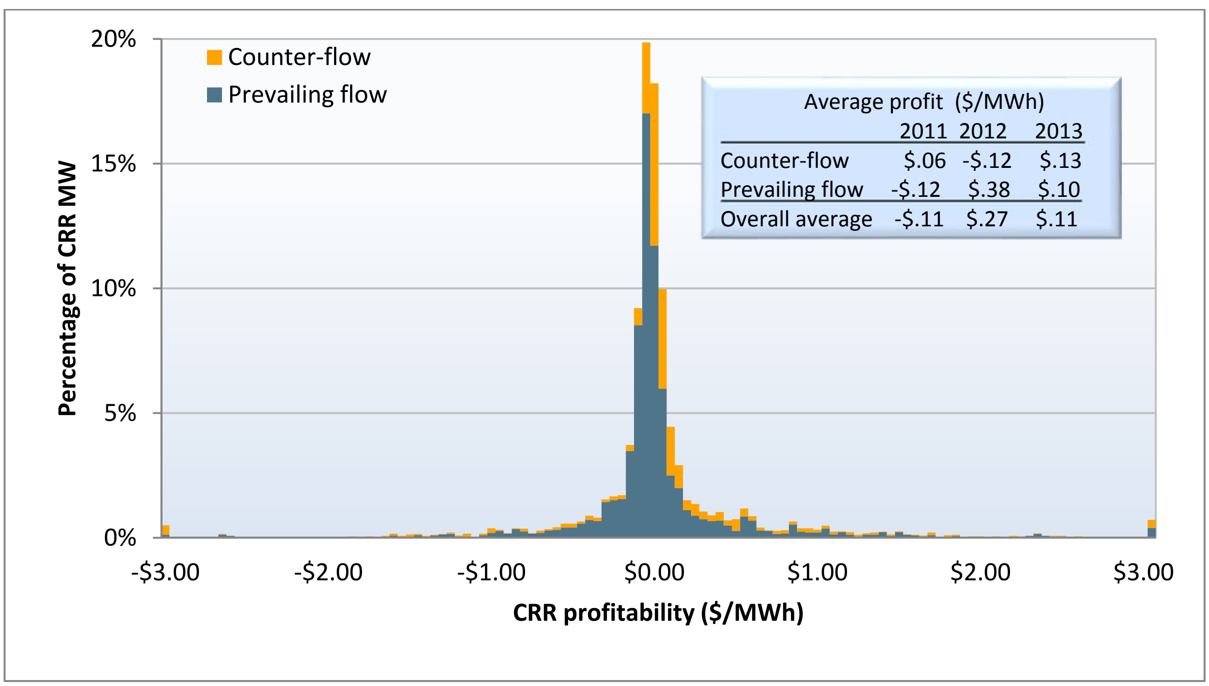


Figure 8.11 Profitability of congestion revenue rights - monthly CRRs, peak hours

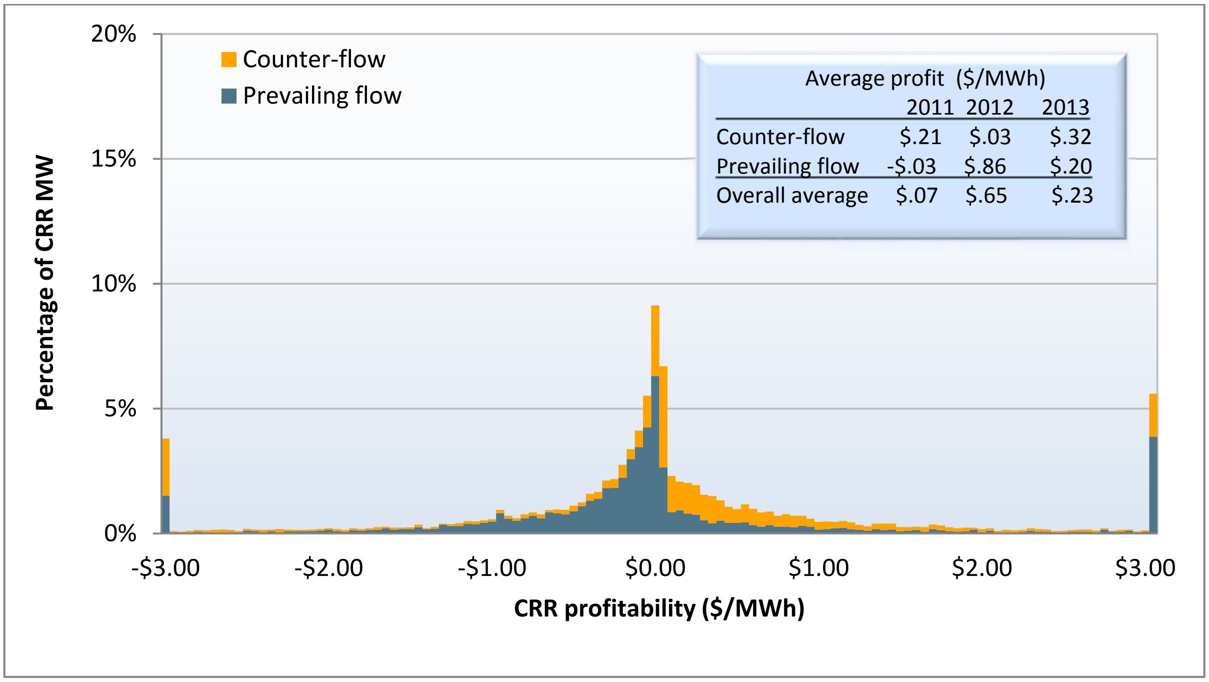
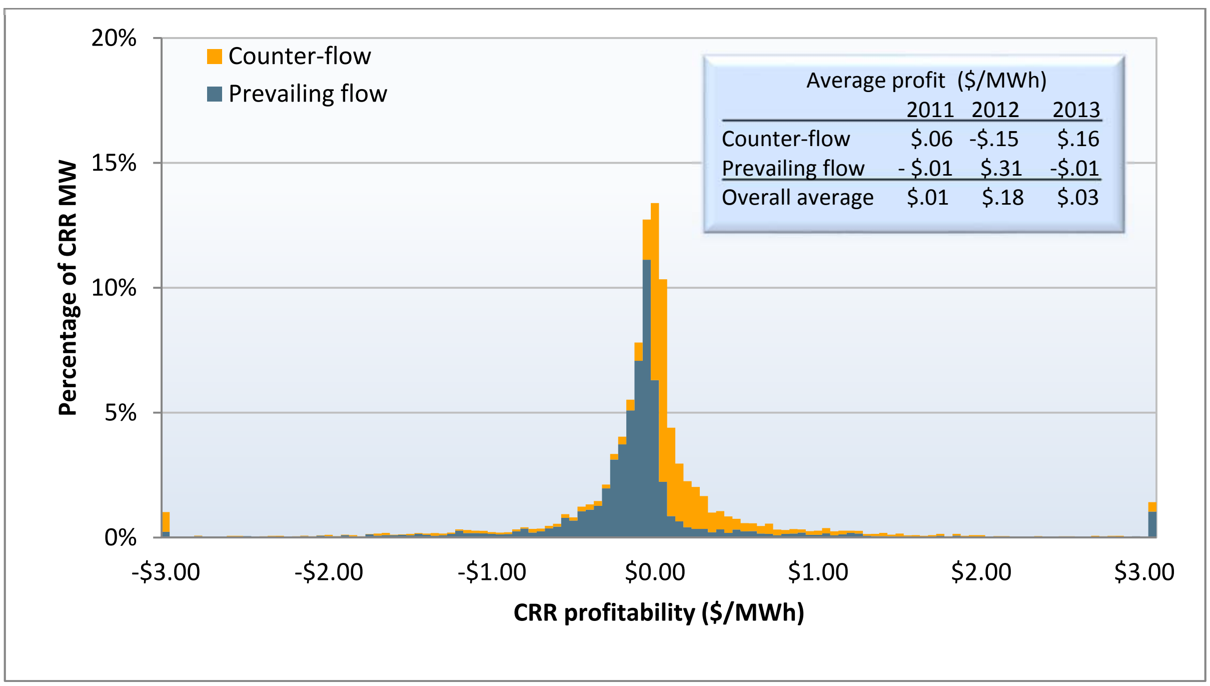


Figure 8.12 Profitability of congestion revenue rights - monthly CRRs, off-peak hours



Congestion revenue right settlement rule

The congestion revenue right settlement rule is an automated rule that limits the gaming opportunity where the value of a participant's congestion revenue rights holdings becomes increased by their convergence bidding activity in the day-ahead market. If a market participant's portfolio of convergence bids affects the flows on a congested constraint by more than 10 percent, then the ISO settlement compares the constraint's impact on the value of the market participant's congestion revenue rights.[188] If the constraint increases the value of the congestion revenue rights for a market participant, the ISO adjusts the payment by reducing the value of the congestion revenue rights. This settlement rule is not applied to convergence bids that affect load aggregation points or trading hubs, as the ISO deems the impact of a single market participant on congestion at the load aggregation point or trading hub level to be limited.

In total, the settlement rule rescinded congestion revenue rights payments of around $600,000 in 2011, $1.4 million in 2012, and $2.9 million in 2013. Total congestion revenue rights payments were $210 million in 2011, $504 million in 2012, and $528 million in 2013. Thus, the settlement rule affected just about 0.6 percent of the congestion revenue rights payments in 2013. This indicates that most participant convergence bidding positions did not affect congestion revenue rights positions above the threshold level.

[188] For detailed information, see the ISO Tariff section 11.2.4.6 on Adjustment of CRR Revenue.

9 Market adjustments

Given the complexity of market models and systems, all ISOs make some adjustments to the inputs and outputs of their standard market models and processes.[189] Market model inputs – such as transmission limits – may sometimes be modified to account for potential differences between modeled power flows and actual real-time power flows. Load forecasts may be adjusted to account for potential differences in modeled versus actual demand and supply conditions, including uninstructed deviations by generation resources. The ISO may need to modify market prices after the fact to correct for data errors or information system failures.[190]

In this chapter, DMM reviews the frequency of and reasons for a variety of key market adjustments, including:

- exceptional dispatches;
- modeled load adjustments;
- transmission limit adjustments;
- compensating injections made at inter-ties to account for loop flows;
- blocked dispatch instructions;
- aborted and blocked pricing runs in the real-time market;
- price corrections; and
- residual unit commitment adjustments.

Over the last few years, the ISO has placed a priority on reducing various market adjustments, and continues to work toward reducing market adjustments in 2014.

9.1 Exceptional dispatch

Exceptional dispatches are unit commitments or energy dispatches issued by operators when they determine that the market optimization results may not sufficiently address a particular reliability issue or constraint. This type of dispatch is sometimes referred to as an out-of-market dispatch. While exceptional dispatches are necessary for reliability, they create uplift costs not fully recovered through market prices, can affect market prices, and can create opportunities for the exercise of temporal market power by suppliers.

[189] At the California ISO, these adjustments are sometimes made manually based entirely on the judgment of operators. Other times these adjustments are made in a more automated manner using special tools developed to aid ISO personnel in determining what adjustments should be made and making these adjustments into the necessary software systems.

[190] Price correction is a tariff-defined process that is not an operator adjustment, but rather is an after-the-fact process separate from operational conditions.

Exceptional dispatches can be grouped into three distinct categories:

- **Unit commitments** — Exceptional dispatches can be used to instruct a generating unit to start-up or continue operating at their minimum operating levels. Almost all of these unit commitments are made after the day-ahead market to resolve reliability issues not met by unit commitments resulting from the day-ahead market model optimization.
- **In-sequence real-time energy** — Exceptional dispatches are also issued in the real-time market to ensure that a unit generates above its minimum operating level. This report refers to energy that would likely have cleared the market without an exceptional dispatch (i.e., that has an energy bid price below the market clearing price) as *in-sequence* real-time energy.
- **Out-of-sequence real-time energy** — Exceptional dispatches may also result in *out-of-sequence* real-time energy. This occurs when exceptional dispatch energy has an energy bid priced above the market clearing price. In cases when the bid price of a unit being exceptionally dispatched is subject to local market power mitigation provisions of the ISO tariff, this energy is considered out-of-sequence if the unit's default energy bid used in mitigation is above the market clearing price.

Decreased total energy from exceptional dispatch

Total energy resulting from all the types of exceptional dispatches described above decreased by over 50 percent in 2013 from 2012, as shown in Figure 9.1.[191] The percentage of total exceptional dispatch energy from minimum load energy accounted for about 79 percent of all energy from exceptional dispatches in 2013. About 15 percent of energy from exceptional dispatches in 2013 was from out-of-sequence energy, with the remaining 6 percent from in-sequence energy.

Total energy from exceptional dispatches, including minimum load energy from unit commitments, equaled 0.26 percent of system loads in 2013, compared to 0.53 percent in 2012. Thus, total energy from exceptional dispatches continues to account for a relatively low portion of total system loads.

Much of the decrease in total energy from exceptional dispatches was driven by a decrease in energy above minimum load. Uncompetitive bidding by some suppliers in 2012 was reduced or eliminated by the beginning of 2013 which led to more energy bid with prices below the locational marginal price.[192] This resulted in greater quantities of energy clearing at market prices, thus reducing the need for exceptional dispatch energy above minimum load to meet reliability. The overall decrease in exceptional dispatch energy also reflects a broader effort by the ISO to decrease the frequency and volume of exceptional dispatch through the use of other market tools where possible to address reliability concerns.

Although exceptional dispatches are priced and paid outside of the market, they can have an effect on the market clearing price for energy. Energy resulting from exceptional dispatch effectively reduces the remaining load to be met by the rest of the supply. This can reduce market prices relative to a case where no exceptional dispatch was made. However, most exceptional dispatches appear to be made to

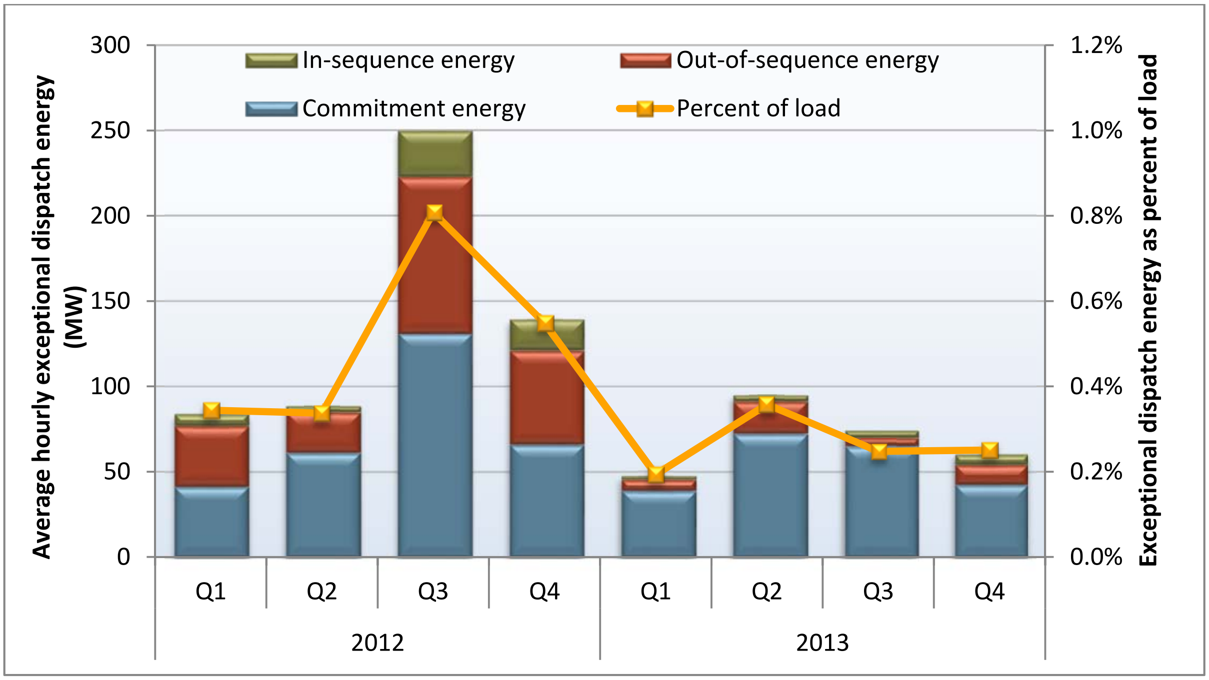
[191] All exceptional dispatch data are estimates derived from SLIC logs, Market Quality System (MQS) data, market prices, dispatch data, bid submissions, and default energy bid data. DMM's methodology for calculating exceptional dispatch energy and costs has been revised and refined since previous reports. Exceptional dispatch data reflected in this report may differ from previous annual and quarterly reports as a result of these enhancements.

[192] See DMM's 2012 *Annual Report on Market Issues and Performance*, Section 6.4: Market power mitigation in Southern California during July and August 2012, http://www.caiso.com/Documents/2012AnnualReport-MarketIssue-Performance.pdf.

resolve specific constraints that would make energy from these exceptional dispatches ineligible to set the market price for energy even if these constraints were incorporated in the market model.

For instance, as discussed later in this section, the bulk of energy from exceptional dispatches is minimum load energy from unit commitments. Energy from this type of exceptional dispatches would not be eligible to set market prices even if incorporated in the market model. In addition, because exceptional dispatches occur after the day-ahead market, energy from these exceptional dispatches primarily affects the real-time market. If energy needed to meet these constraints was included in the day-ahead market, prices in the day-ahead market would be lower.

Figure 9.1 Average hourly energy from exceptional dispatch



Exceptional dispatches for unit commitment

The ISO sometimes finds instances where the day-ahead market process did not commit sufficient capacity to meet certain reliability requirements not directly incorporated in the day-ahead market model. The ISO may then commit additional capacity by issuing an exceptional dispatch for resources to come online and operate at minimum load.

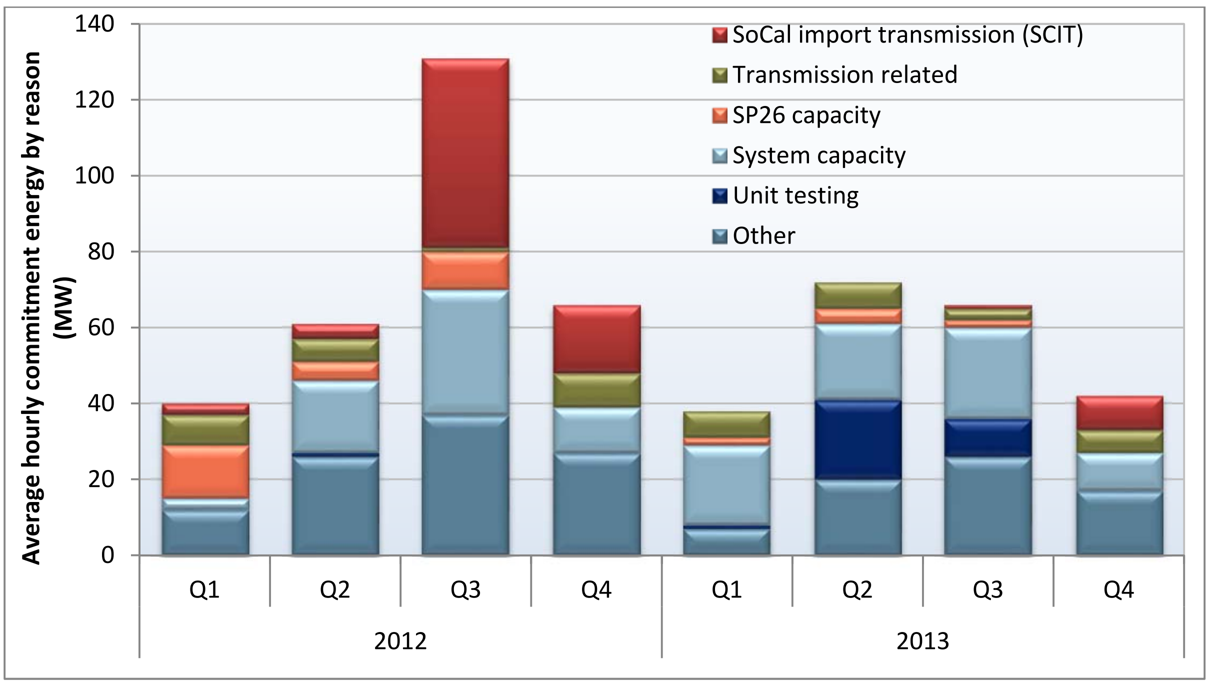
The frequency of exceptional dispatch for unit commitment was reduced significantly in 2010 largely as the result of the addition of new day-ahead market constraints, known as *minimum online constraints*.[193] These constraints require that a certain amount of capacity be committed in key areas to meet voltage requirements and other reliability criteria that cannot be directly incorporated in the power flow model used in the day-ahead market.

[193] For further discussion see, *2010 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2011, p. 75-77, http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf.

Minimum load energy from unit commitments made though exceptional dispatch fell by over 25 percent in 2013 compared to 2012. As shown in Figure 9.2, much of the reduction in minimum load energy from unit commitments occurred in the third and fourth quarters resulting from a decreased need to manage potential contingencies associated with the Southern California import transmission limit (SCIT). However, unit commitments associated with SCIT still accounted for about 20 percent of minimum load energy in the fourth quarter of 2013.

In addition, market conditions in 2013 were more competitive than those of 2012, which resulted in some reduction in additional unit commitments. Although minimum load energy from exceptional dispatch unit commitments fell in 2013, the level related to unit testing rose in the second and third quarters. However, this increase resulted from repeated testing of one large unit in the second quarter and testing of new generation resources throughout the spring and summer. A significant amount of minimum energy continued to result from unit commitments made for more general system contingencies and load uncertainty.

Figure 9.2 Average minimum load energy from exceptional dispatch unit commitments



Exceptional dispatches for energy

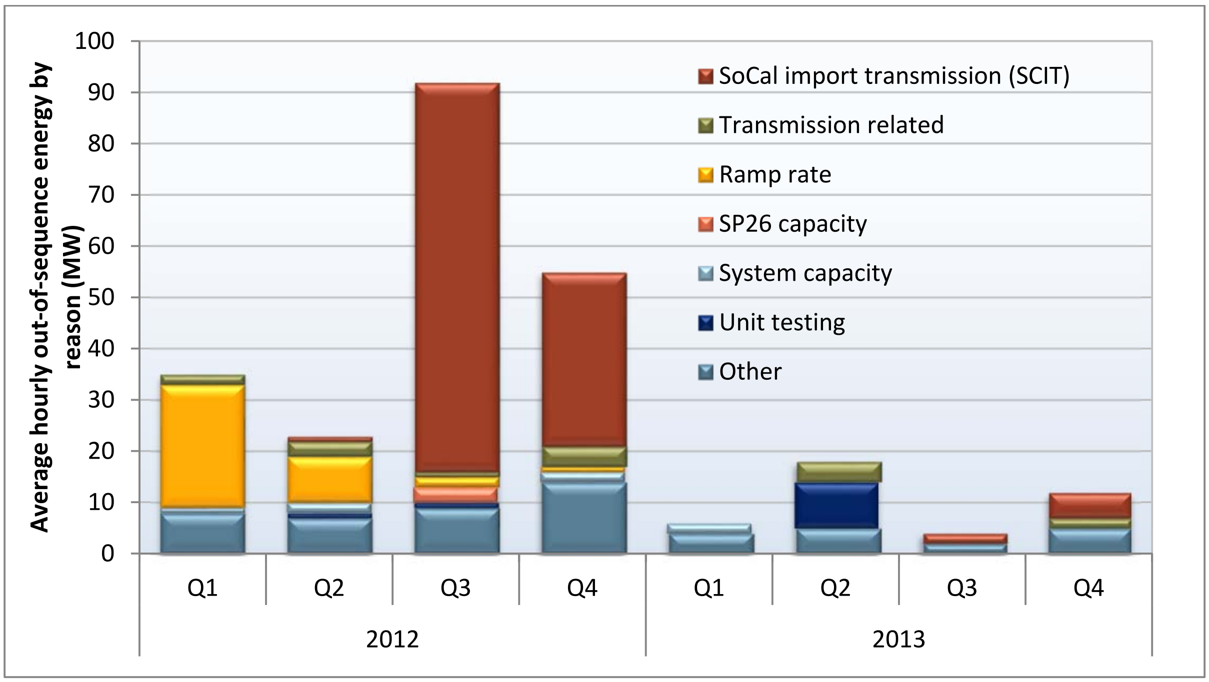
Energy from real-time exceptional dispatches to ramp units up above minimum load or their regular market dispatch level decreased by about 80 percent in 2013. As previously illustrated in Figure 9.1, most of this exceptional dispatch energy (about 70 percent) was out-of-sequence, meaning the bid price was greater than the locational market clearing price. This represents a 15 percent decline from 2012.

Figure 9.3 shows the decrease in out-of-sequence exceptional dispatch energy over the year in 2013, although levels related to unit testing increased in the second quarter. The increase in out-of-sequence energy from unit testing reflects repeated testing of one unit and testing of new generation resources. The decrease in out-of-sequence energy, as compared to 2012, was driven primarily by a decrease in exceptional dispatches to protect against contingencies related to the Southern California import transmission limit. Although the volume of out-of-sequence energy related to SCIT fell from an average hourly level of 28 MW in 2012 to just 2 MW in 2013, out-of-sequence energy relating to SCIT still accounted for 40 percent of all out-of-sequence energy in the second half of 2013 (Figure 9.3).

Most of these exceptional dispatches were to move resources above minimum operating levels to their minimum dispatchable level, at which they could be more quickly ramped up in the event of a contingency. The higher ramp capability at minimum dispatchable levels allows the ISO to manage reliability issues not adequately modeled in the ISO market software. These include 30-minute contingencies and other potential system conditions within the 30 to 60 minute time frame.[194]

The high level of out-of-sequence energy associated with this constraint in 2012 was largely the result of highly uncompetitive bidding of real-time energy by numerous units that were scheduled to operate at minimum load, and needed to be dispatched up to levels where they could ramp up more quickly in the event of contingencies related to the Southern California import transmission limit.

Figure 9.3 Out-of-sequence exceptional dispatch energy by reason



Exceptional dispatch costs

Exceptional dispatches can create two types of additional costs not recovered through the market clearing price of energy.

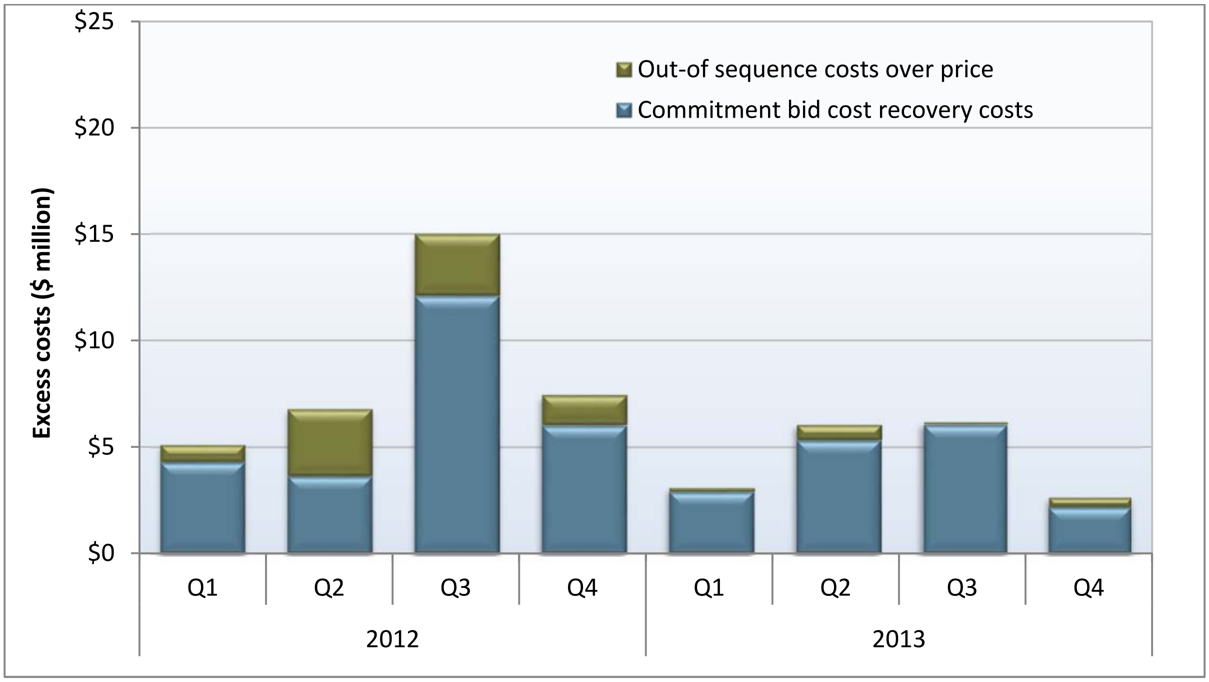
- Units committed through exceptional dispatch that do not recover their start-up and minimum load bid costs through market sales can receive bid cost recovery for any start-up and minimum load bid costs.

[194] Additional discussion of resource dispatchable minimum load is found in "Exceptional Dispatch and Residual Imbalance Energy Mitigation Tariff Amendment" in FERC Docket No. ER12-2539-000, August 28, 2012, at: http://www.caiso.com/Documents/August282012ExceptionalDispatch-ResidualImbalanceEnergyMitigationTariffAmendment-DocketNoER12-2539-000.pdf.

- Units being exceptionally dispatched for real-time energy out-of-sequence may be eligible to receive an additional payment to cover the difference in their market bid price and their locational marginal energy price.

Figure 9.4 shows the estimated costs for unit commitment and additional energy resulting from exceptional dispatches in excess of the market price for this energy. Commitment costs paid through bid cost recovery decreased from $26 million to $17 million, while out-of-sequence energy costs decreased from $8 million to $1.4 million.[195] Overall, these above-market costs decreased almost 50 percent from $34 million in 2012 to $18 million in 2013.

Figure 9.4 Excess exceptional dispatch cost by type



The role of local market power mitigation in limiting above-market costs of exceptional dispatch energy was greatly reduced in 2013. In 2012, local market power mitigation limited above-market costs from exceptional dispatch even as the amount of exceptional dispatch energy increased substantially in that year. Lower above-market costs from exceptional dispatch in 2013 reflect more competitive market conditions and the overall decrease in volume of exceptional dispatches. Additional discussion of local market power mitigation for exceptional dispatch is included in Section 7.3.2.

9.2 Load adjustments

In the hour-ahead and real-time markets, the ISO frequently adjusts real-time loads to account for potential modeling inconsistencies or inaccuracies. Some of these inconsistencies are due to changing

[195] The out-of-sequence costs are estimated by multiplying the out-of-sequence energy by the bid price (or the default energy bid if the exceptional dispatch was mitigated) minus the locational price for each relevant bid segment. Commitment costs are estimated from the real-time bid cost recovery associated with exceptional dispatch unit commitments.

system and market conditions, such as changes in load and supply, between the execution of the hour-ahead market and the real-time market. Other inconsistencies result from the fact that the hour-ahead market is based on a model that solves for 15-minute time intervals, while the real-time market actually dispatches units for 5-minute intervals.

Operators can manually adjust load forecasts used in the software through a *load adjustment*. These adjustments are sometimes made manually based entirely on the judgment of the operator informed by actual operating conditions. Other times, these adjustments are made in a more automated manner using special tools developed to aid ISO operators in determining what adjustments should be made and making these adjustments into the necessary software systems.

In December 2012, the ISO enhanced the real-time market software to limit load forecast adjustments made by operators to only the available amount of system ramp. Beyond this level of load adjustment, a shortage of ramping energy occurs that triggers a penalty price through the relaxation of the power balance constraint without achieving any increase in actual system energy. With this software enhancement, load adjustments made by operators are less likely to have an extreme effect on market prices.

Figure 9.5 shows the average hourly load adjustment profile for the hour-ahead, 15-minute pre-dispatch and 5-minute real-time markets during the first ten months of 2013 (January through October). Figure 9.6 shows the average load adjustments for each operating hour in these markets during the last two months of the year (November and December). The following is shown in these figures:

- During the first ten months of the year, hour-ahead market adjustments exceeded both the 15-minute and real-time for most of the day by 100 MW or more. The 15-minute pre-dispatch adjustment exceeded the 5-minute adjustments in all hours except during the morning and evening ramping periods.

- During the last two months of the year, load adjustments increased in all three markets. In particular, adjustments in the hour-ahead market reached 400 MW during the morning ramp and 700 MW during the evening ramp. The adjustments to the 5-minute market also increased in November and December, and were more consistent with the load adjustments to the hour-ahead market. This increase in adjustments occurred as the ISO operators increased ramping capacity to better meet system ramping needs during the steep morning and evening ramping periods. These adjustments increased particularly around the holidays, when sharp evening load ramps occurred.

Figure 9.7 highlights how load adjustments changed during peak hour ending 18 from month-to-month over the course of 2013.

- The use of load adjustments in all markets decreased in March and increased beginning in October.

- The load adjustments were highest in December for all markets, especially around the holidays. This is not uncommon as the ISO used load adjustments together with adjustments to the flexible ramp constraint to account for ramping needs in the steeper evening ramping period during the fall and winter months.

- Real-time load adjustments were negative in the months of April through July and well below the hour-ahead levels in all months except for October.

Figure 9.5 Average hourly load adjustments (January through October)

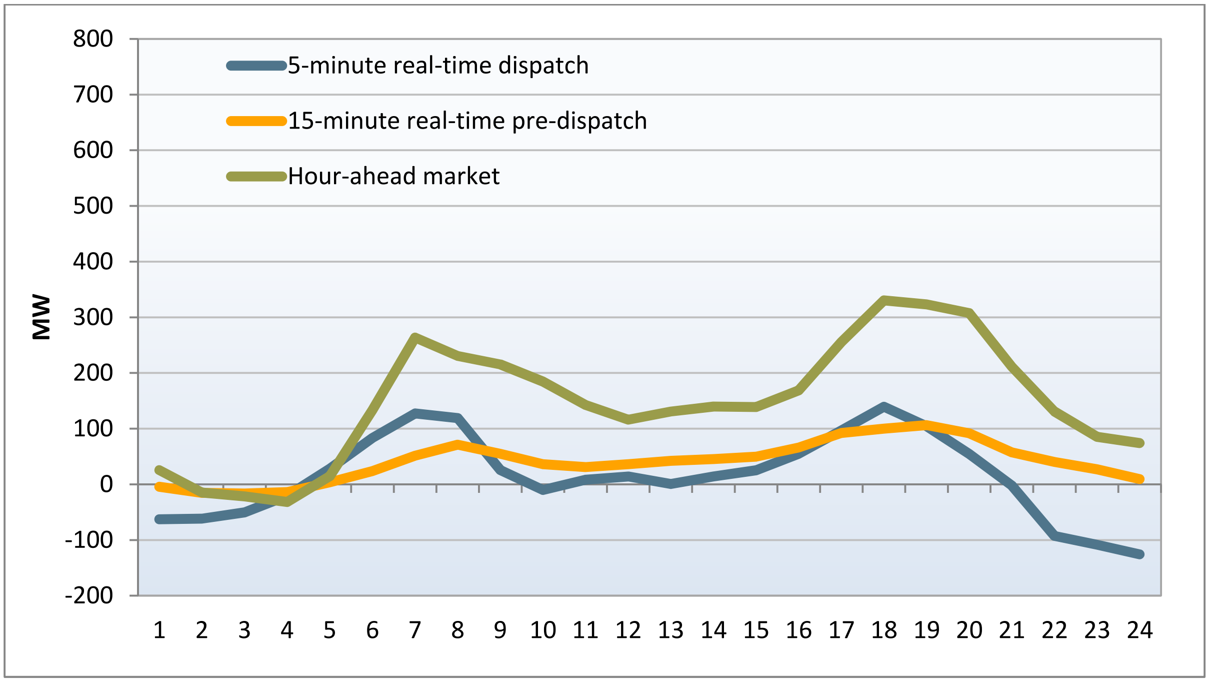


Figure 9.6 Average hourly load adjustments (November through December)

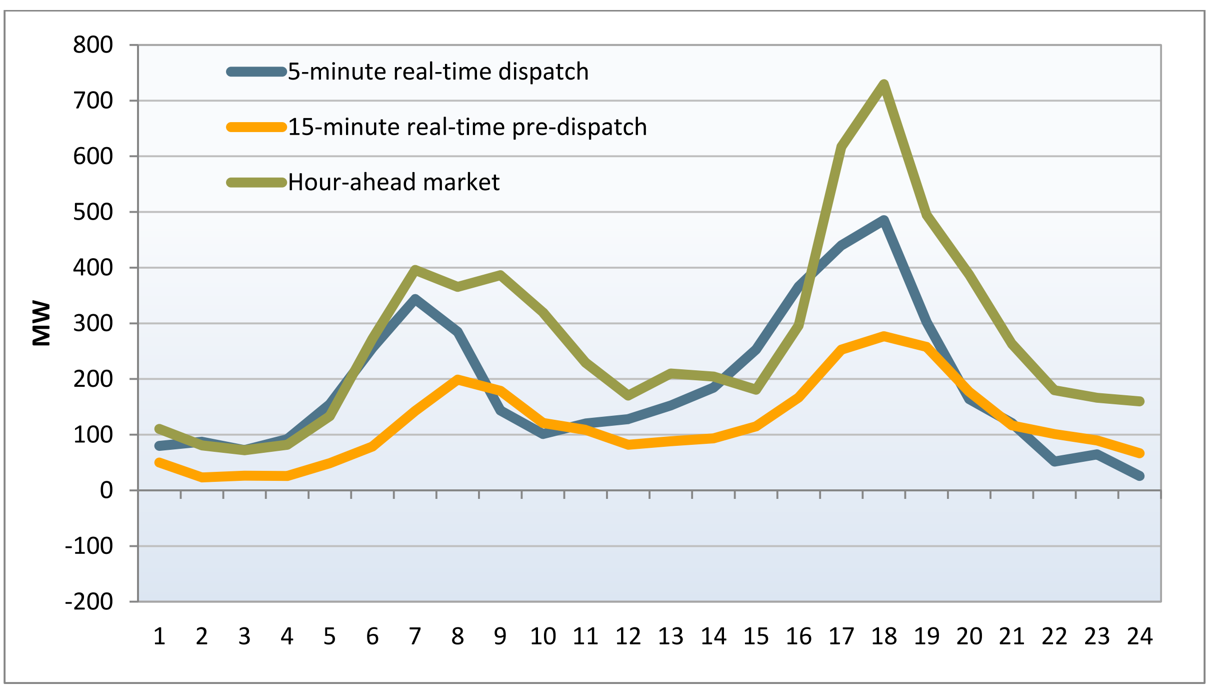
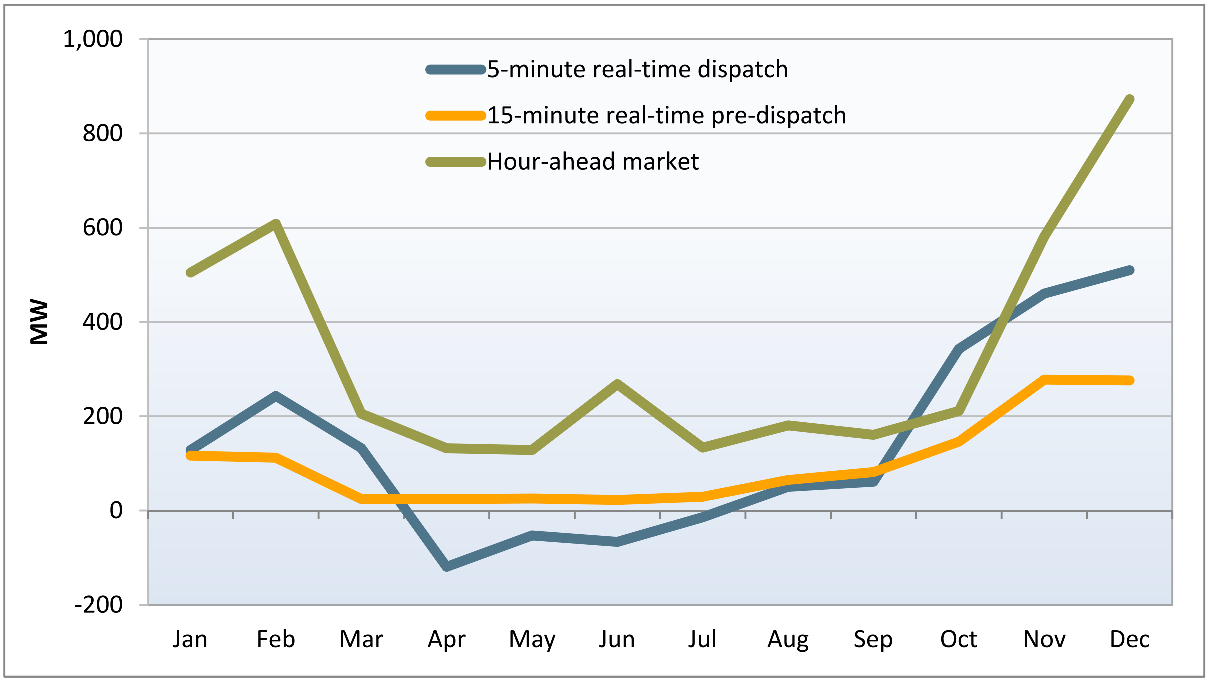


Figure 9.7 Average monthly load adjustments (hour ending 18)



9.3 Transmission limit adjustments

Actual flows on transmission lines can sometimes vary significantly from flows predicted by the network model. In the real-time market, operators track actual transmission line flows and may determine that the market model is not accurately reflecting the actual system flows. There are a variety of causes for these modeling inaccuracies. Unscheduled flows on major transmission paths – also known as *loop flows* – can originate due to differences in scheduled and actual power flows outside the ISO system.[196] Within the ISO system, differences in line flows can result from demand forecast errors and generating units deviating from their schedules, known as uninstructed deviations.[197]

In the real-time market, operators track actual transmission line flows and may determine that the market model is not accurately reflecting the actual flows. The ISO model may overestimate or underestimate transmission line flows. The operators will adjust the transmission limit incorporated in the market model depending on the nature of the inconsistency.

- There are times when the estimated power flow on a transmission line reaches the constraint limit incorporated in the market model. As a result, price congestion occurs on the line. After reviewing actual metered line flows, the operators may determine that the price congestion is not reflective of actual system conditions, and will therefore increase the line limit incorporated in the market model upwards to eliminate the inaccurate market congestion.

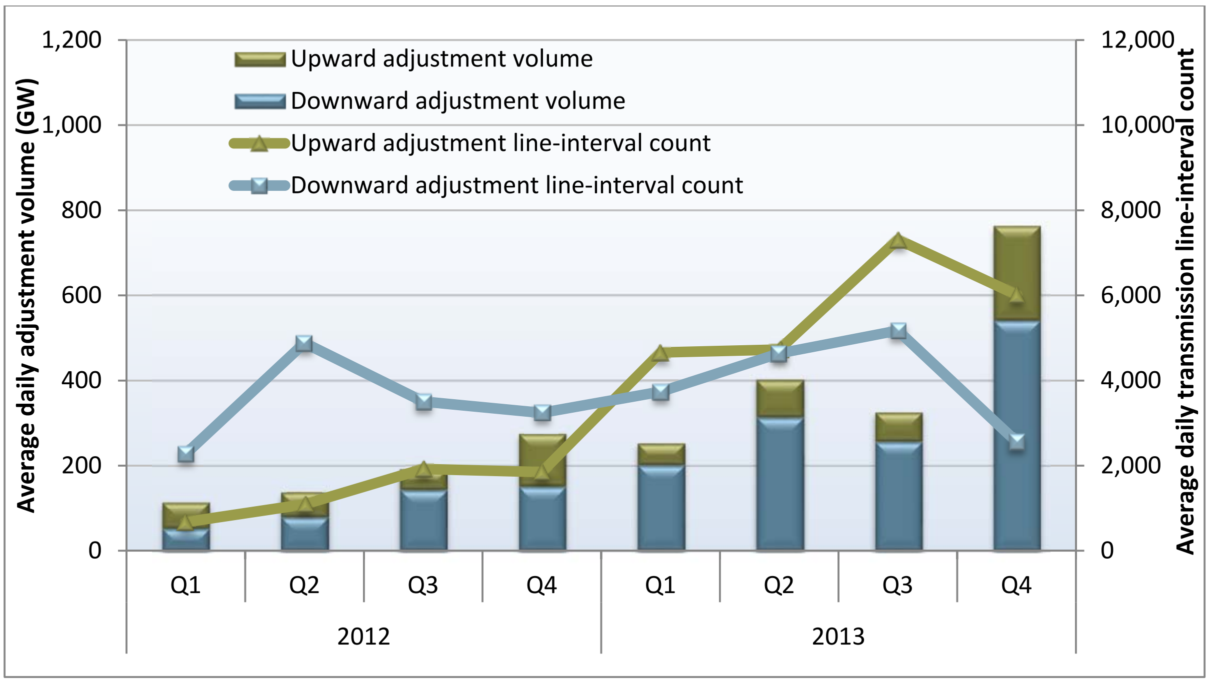
[196] The ISO attempts to model these flows at the inter-ties through a feature known as *compensating injections* (see Section 9.4).

[197] Differences also occur as a result of units generating below their minimum operating level due to start-up or shut-down profiles being left out of the market optimization.

- Alternatively, there are times when the estimated flow on a transmission line is below the constraint limit, but the operators may determine that the actual metered loads are indeed approaching or at the transmission limit. In this situation, operators will decrease the line limit in the market model downwards to force the model to account for the actual congestion. This triggers price congestion and causes the market model to manage the congestion by re-dispatching resources based on their bid prices and effectiveness at reducing congestion.

The ISO refers to such adjustments as *conforming* of transmission limits since the goal is to conform the limits in the market model to the actual level of flow being observed. Figure 9.8 shows the frequency operators have conformed transmission in either an upward[198] or downward direction, along with the average volume of these transmission adjustments.[199]

Figure 9.8 Average daily frequency and volume of internal transmission adjustments by quarter



The frequency of transmission adjustments increased by around 50 percent in 2013 compared to 2012. The main factor causing this increase in the frequency of transmission adjustments was that in 2013 the ISO enhanced the quantity and granularity of transmission nomograms.

198 Upward adjustments of 200 percent are excluded from these calculations. These adjustments were implemented as a business practice to un-enforce the nomograms in the market model beginning in the fourth quarter of 2012.

199 The frequency of transmission adjustments is measured by counting the number of intervals that each different line is adjusted. The ISO reports on transmission conforming in its monthly performance metric catalogue. Monthly transmission conforming information in 2013 can be found in the later sections of the monthly performance metric catalogue reports: http://www.caiso.com/Documents/Market%20performance%20metric%20catalog%202013.

The volume of transmission adjustments in both the upward and downward direction also increased in 2013 compared to 2012.[200] This increase was driven by a combination of the increase in the number of transmission constraints and the ISO's efforts to reduce use of exceptional dispatches. When a line shows signs of overloading but is not yet binding, the ISO operators can exceptionally dispatch a generator to prevent the line from overloading. As part of the ISO's efforts to reduce exceptional dispatches, the ISO operators conformed some line limits up and some line limits down to adjust the flows to prevent an overload by allowing the market software to adjust the flows.

9.4 Compensating injections

In the fall of 2012, the ISO made enhancements to the operational characteristics of compensating injections. These enhancements greatly improved the consistency of compensating injections throughout the day and carried over into 2013. However, on occasion, the performance of compensating injections declined in 2013, and the ISO has made adjustments to improve performance over the year. The performance declines typically occurred around model changes.

Background

In July 2010, the ISO re-implemented an automated feature in the hour-ahead and real-time software to account for unscheduled flows along the inter-ties. This feature accounts for observed unscheduled flows by incorporating *compensating injections* into the market model. These are additional injections and withdrawals that are added to the market model at various locations external to the ISO system.[201] Before implementing this feature, the ISO identified that if the net quantity of compensating injections – the difference between the injections and withdrawals added to the market model – is significantly positive or negative, this can create operational challenges due to the impact this has on the area control error (ACE).[202]

To avoid creating problems managing the area control error, a constraint was added to the software that limited the net impact of compensating injections to an absolute difference of no more than 100 MW. This limitation was imposed by applying a discount factor to the compensating injections calculated by the software as this absolute difference increases beyond this 100 MW threshold. This reduced the compensating injections at each location if the overall net system-level compensating injections exceeded this 100 MW threshold.

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

[200] When adjusting transmission in the upward direction, the goal is to alleviate false congestion. Therefore, the size of the upward adjustment is less important than a downward adjustment, as it is designed to eliminate congestion; the higher the number for an upward adjustment the more likely congestion will be eliminated. The size of a downward adjustment is important because the larger the adjustment, the bigger the potential market effect.

[201] The quantity and location of these compensating injections are calculated to minimize the difference between actual observed flows on inter-ties and the scheduled flows calculated by the market software. The software re-calculates the level of these injections in the real-time pre-dispatch run performed every 15 minutes. The injections are then included in both the 15-minute and 5-minute market runs.

[202] The ACE is a measure of the instantaneous difference in matching supply and demand on a system-wide basis. It is a critical tool for managing system reliability.

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

In 2012, the ISO took multiple steps to address this issue of compensating injections switching status. These changes included the following:

- As the net compensating injections approach a new threshold level (40 MW), they are gradually reduced to zero using a reduction factor.[203] Previously, when the compensating injections approached the threshold (100 MW), the software would immediately take the net compensating injections down to zero in the next interval.
- As the net compensating injections increase above a threshold level (40 MW) and remain below a higher threshold (2,000 MW), their system effect is gradually reduced using a reduction factor that reduces imports and increases exports or vice versa, in order to have a more gradual impact to the market flows.[204] Previously, both exports and imports were reduced by a single fixed parameter value in the next interval.

These changes greatly enhanced the performance of compensating injections at the end of 2012 and into 2013.

Analysis of 2013 results

During the summer, the ISO identified degraded performance of compensating injections as a result of database promotions, network model changes, and power flow tuning. Specifically, during several days in the summer, compensating injections varied frequently between the full, partial and off statuses. The ISO made software adjustments to make the compensating adjustments more consistent over the day and less variable.

Figure 9.9 shows the daily profile of the compensating injections prior to the enhancements performed by the ISO. The chart shows that the compensating injection status varied over the day. Figure 9.10 shows the daily profile of compensating injections on a more typical day when the tool was working correctly. As the figure shows, the status remained more consistent and less variable than before the enhancements. After the adjustments were made, the performance again improved considerably.

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

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

Figure 9.9 Compensating injection levels prior to enhancements (July 18, 2013)

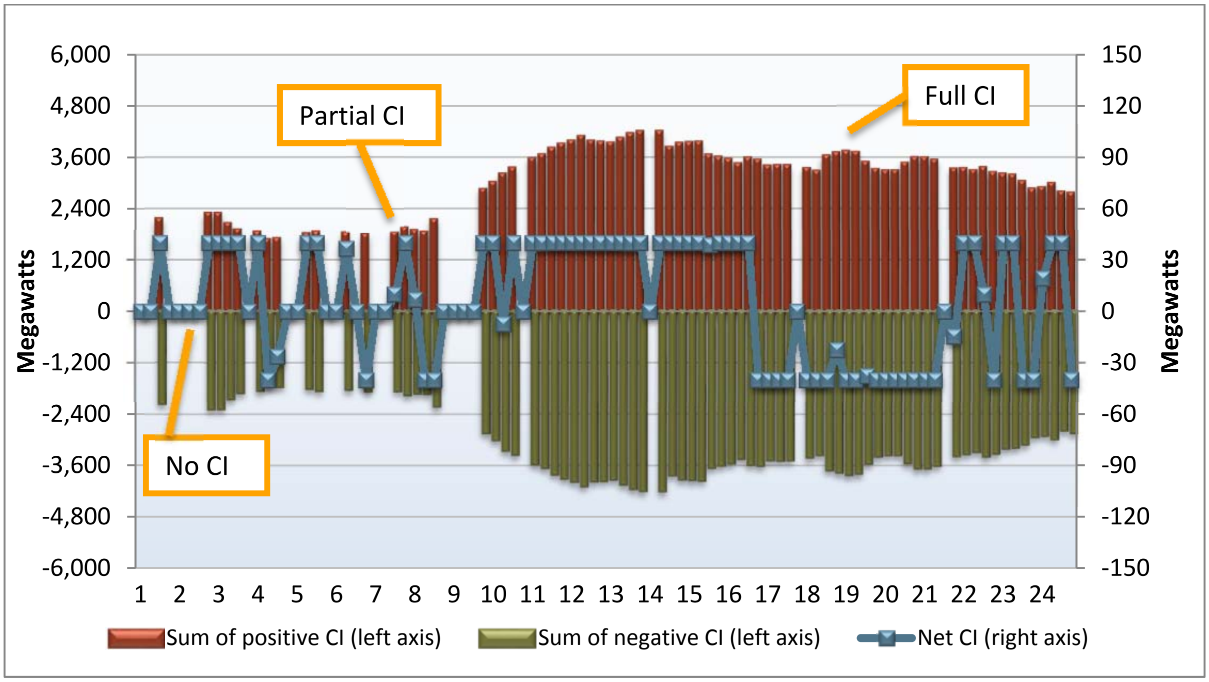
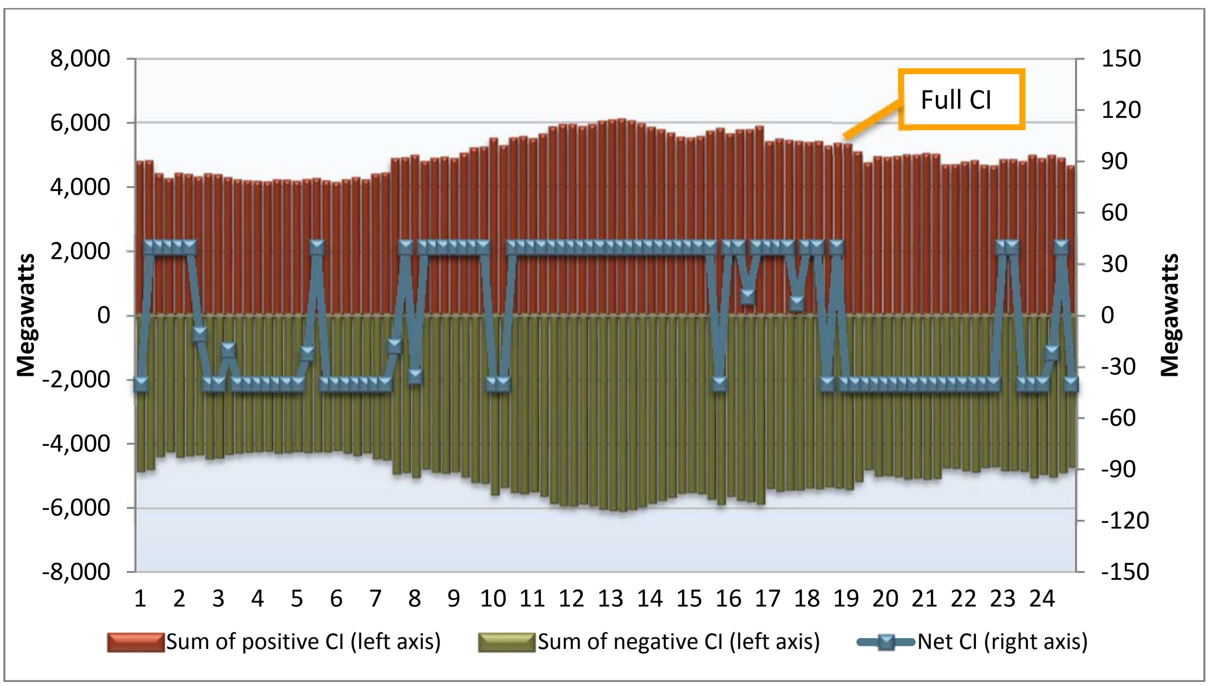


Figure 9.10 Compensating injection levels after enhancements (October 4, 2013)



Although these data indicate performance of compensating injections improved and became less volatile in 2013, the ISO has not yet performed an analysis of the impact that compensating injections have on individual constraints into and within the ISO system, as DMM has recommended. The ability of DMM or other ISO staff to perform analysis of these impacts is extremely limited, since the incremental impact of compensating injections on market flows is not explicitly calculated or stored by the market software. Review of ISO operator logs indicates that in some cases, compensating injections may make it more difficult for operators to manage unscheduled flows and can cause congestion to occur in the real-time market when actual flows are below constraint limits.

DMM continues to recommend that the impact of compensating injections on market flows and congestion on individual constraints should be routinely calculated, monitored and analyzed by the ISO. DMM has included this recommendation along with additional recommendations for monitoring and analysis that should be routinely performed when the ISO implements the first stage of its full network model initiative in the fall of 2014.

9.5 Blocked instructions

The ISO's real-time market functions using a series of processes. Imports and exports are dispatched through the hour-ahead scheduling process. The 15-minute pre-dispatch process is used to commit or de-commit short-start peaking units within the ISO and to transition multi-stage generating units from one configuration to another. Finally, the 5-minute dispatch process is used to increase or decrease the dispatch level of online resources within the ISO system.

During each of these processes, the market model occasionally issues commitment or dispatch instructions that are inconsistent with actual system or market conditions. In such cases, operators may cancel or *block* commitment or dispatch instructions generated by the market software.[205] This can occur for a variety of reasons, including the following:

- **Data inaccuracies.** Results of the market model may be inconsistent with actual system or market conditions as a result of a data systems problem. For example, the ISO takes telemetry data and feeds the telemetry into the real-time system. If the telemetry is incorrect, the market model may try to commit or de-commit units based on the bad telemetry data. The operators will act accordingly to stop the instruction from being incorrectly sent to market participants.
- **Software limitations of unit operating characteristics.** Software limitations can also cause inappropriate commitment or dispatch decisions. For example, some unit operating characteristics of certain units are also not completely incorporated in the real-time market models. For instance, the ISO software has problems with dispatching pumped storage units as the model does not reflect all of its operational characteristics.
- **Information systems and processes.** In some cases, problems occur in the complex combination of information systems and processes needed to operate the real-time market on a timely and accurate basis. In such cases, operators may need to block commitment or dispatch instructions generated by the real-time market model.

[205] The ISO reports on blocked instructions in its monthly performance metric catalogue. Blocked instruction information can be found in the later sections of the monthly performance metric catalogue report: http://www.caiso.com/Documents/Market%20performance%20metric%20catalog%202013.

Figure 9.11 Frequency and volume of blocked real-time inter-tie instructions

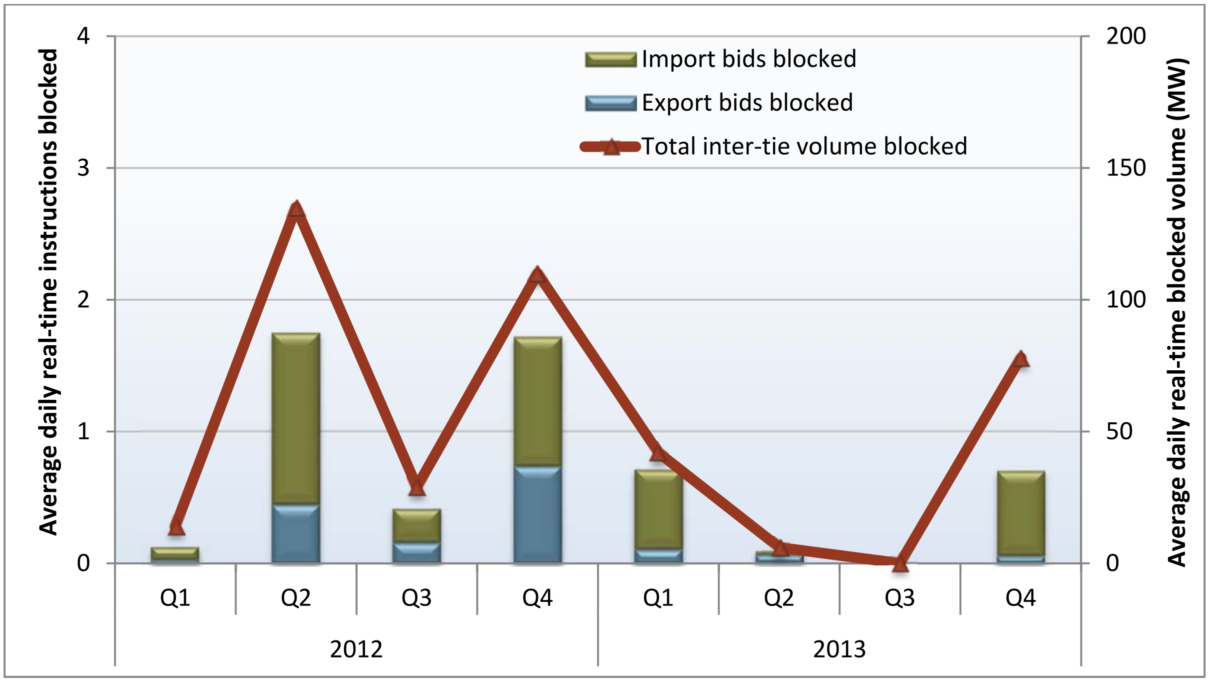
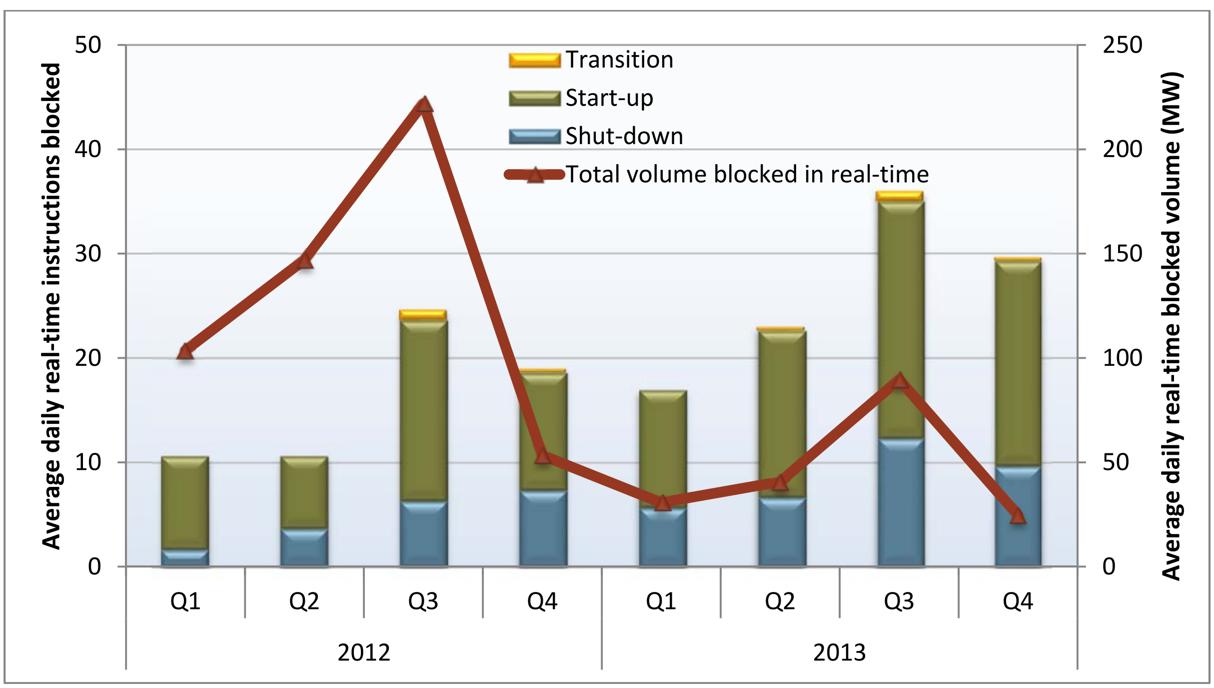


Figure 9.12 Frequency and volume of blocked real-time internal instructions



While the overall number of blocked instructions increased in 2013 compared to 2012, the change in blocked instructions decreased on the inter-ties and increased for internal units. The volume of blocked instructions was down in 2013 compared to 2012 on both inter-ties and for internal units. Figure 9.11 shows the frequency and volume of blocked dispatches on inter-ties. Figure 9.12 shows the frequency of blocked real-time commitment start-up and shut-down and multi-stage generator transition instructions for internal generators.

The average number of daily blocked inter-tie instructions in 2013 was about half of the blocked instructions in 2012. This decrease occurred mainly as a result of improvements in the market solution, lower network congestion and higher flexible ramping constraint values during ramping hours.

Blocked instructions for internal resources increased by over 60 percent in 2013 compared to 2012. The increase in blocked instructions for resources within the ISO system is mainly driven by about a 50 percent increase in blocked start-up instructions in 2013 compared to 2012. Moreover, blocked start-up instructions were the most common reason for blocked instructions at about 69 percent in 2013. Blocked shut-down instructions accounted for about 30 percent of blocked instructions within the ISO in 2013, with blocked transition instructions to multi-stage generating units accounting for only 1 percent for the same period.

Increases in transmission adjustments primarily caused the increase in blocked instructions for internal resources in 2013. This occurred because transmission adjustments sometimes caused the software to dispatch additional units not needed to address actual system conditions. In these cases, the ISO operators blocked the start-up of these extra units. In addition, the ISO software continued to have problems with dispatching pumped storage units as the model does not reflect all of its operational characteristics.

The ISO has been working on measures to decrease the need for blocked instructions. In 2013, the ISO operating engineers enhanced the granularity of existing nomograms. This enhancement included designing separate, but similar, nomograms to address certain planned outages. This change allowed ISO operators to better adjust transmission limits more accurately in accordance with current system conditions. This is intended to result in fewer exceptional dispatches and fewer blocked dispatches in real time.

9.6 Aborted and blocked dispatches

Operators review dispatches issued in the 5-minute real-time market before these dispatch and price signals are sent to the market. If the operators determine that the 5-minute dispatch results are inappropriate, they are able to block the entire real-time dispatch instructions and prices from reaching the market.

The ISO began blocking dispatches more frequently in 2011 as both market participants and ISO staff were concerned that inappropriate price signals were being sent to the market even when they were known to be problematic. These inappropriate dispatches would often cause participants to act inappropriately when considering actual and not modeled system conditions. Quite frequently, many of the blocked intervals eliminated the need for a subsequent price correction.

Operators can choose to block the entire market results to stop dispatches and prices resulting from a variety of factors including incorrect telemetry, inter-tie scheduling information or load forecasting data.

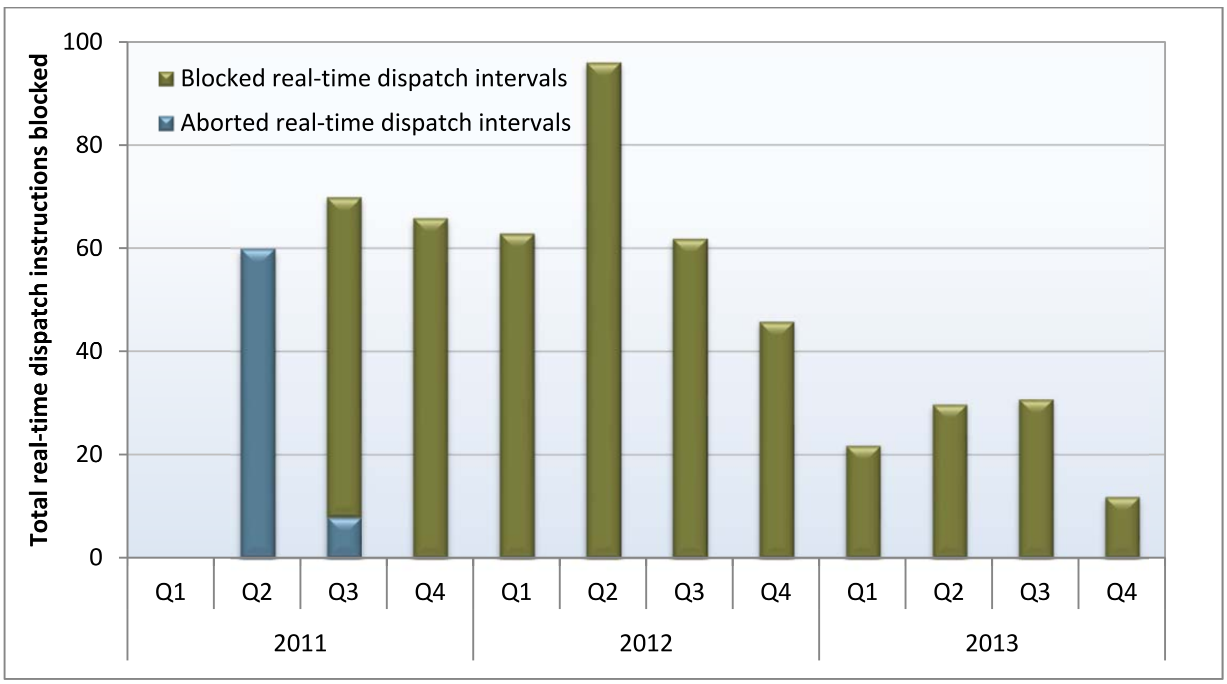
Furthermore, the market software is also capable of automatically blocking the solution when the market results exceed threshold values.[206]

In 2011, the ISO did not have a tool that allowed operators to block these dispatch and price signals, even if they knew that these were inaccurate. Instead, operators could only abort or cancel the entire 5-minute real-time dispatch signal. This eliminated all data associated with the interval, so that the market results could not be reviewed after the fact. Alternatively, operators could block the dispatch, but the associated prices for the blocked dispatch would be published, sending inaccurate price signals. The benefit of blocking compared to aborting was that blocking preserves the data.[207]

As a result, the ISO developed software functionality to block the dispatch and price signal and replace these with the previous 5-minute market solution. This new tool for blocking 5-minute interval results was implemented in late July 2011.

Figure 9.13 shows the frequency that operators aborted and blocked price results from the real-time dispatch process beginning in 2011 and through 2013. In August 2011, the ISO discontinued the option of aborting unreliable market results. This approach has been replaced with a blocking procedure which preserves the original market solution.

Figure 9.13 Frequency of aborted and blocked real-time dispatch intervals



[206] For example, if the load were to drop by 50 percent in one interval, the software can automatically block the results.

[207] DMM raised concerns with the ISO that the aborted results could not be reviewed for accuracy or were not sufficiently logged or tracked, and that the procedures around the abort process were not well defined. The block interval feature that was deployed in late July 2011, as well as an enhanced procedure, addressed DMM's concerns.

In 2013, the total number of blocked intervals dropped to about 35 percent of 2012 levels. This change is driven by the decrease in blocked dispatches triggered by ISO operators due to improved market software functionality.

9.7 Price corrections

The total frequency of intervals corrected and the volume of nodes corrected increased in 2013 compared to 2012. Corrections occurred more frequently because a single price node was improperly modeled for several weeks and the volume of price corrections increased significantly during the deployment of the September database upgrade. This section summarizes the frequency and category of price corrections over the last two years.

The tariff allows the ISO to perform price corrections for three distinct reasons:[208]

- invalid data input errors;
- software/hardware errors; and
- tariff inconsistencies.

Figure 9.14 and Figure 9.15 categorize price corrections, by interval and by node, respectively, using the following categorizations:

- **Data input errors** — This includes any price corrections due to incorrect data input that is not influenced by an ISO internal process, such as receiving inaccurate default energy bids. These are represented by the blue bars.
- **Software and hardware errors** — These are attributed to the market software functionality and are not related to the ISO internal process, and are represented by the red bars.
- **Results inconsistent with tariff** — This includes market results that are inconsistent with the ISO tariff and are represented by the yellow bars.
- **Process errors** — These are errors originating in an error or flaw in an internal ISO process. Such errors resulted in invalid market input data or in results inconsistent with the tariff, which are reasons for price corrections. These errors include incorrect actions of the dispatchers and incorrect model outages. These are represented by the green bars.

The total frequency of price corrected intervals increased from 2012 to 2013, both in terms of frequency of corrected intervals (Figure 9.14) and nodes (Figure 9.15). The increase in the corrections of intervals was driven by modeling issues of a single node for 50 days between October and November.[209] The frequency of corrections of nodes was driven by system-wide price corrections that occurred during the September database upgrade deployment.[210] The first half of 2013 was dominated by software error corrections, whereas the second half of the year were primarily process related corrections.

[208] The ISO corrects prices pursuant to tariff Section 35.

[209] The CLAP_INDIGO node was not properly mapped when the ISO relinquished operational control of the Devers-Mirage 115 kV line to SCE.

[210] Software related issues related to the DB66 promotion caused incorrect mapping of the market data which resulted in 201 intervals of state-wide price corrections on September 17 and 18. Further details can be found in the following price correction report: http://www.caiso.com/Documents/WeeklyPriceCorrectionReportSept16-22_2013.pdf.

Figure 9.14 Frequency of price corrections by category and interval in 2012 and 2013

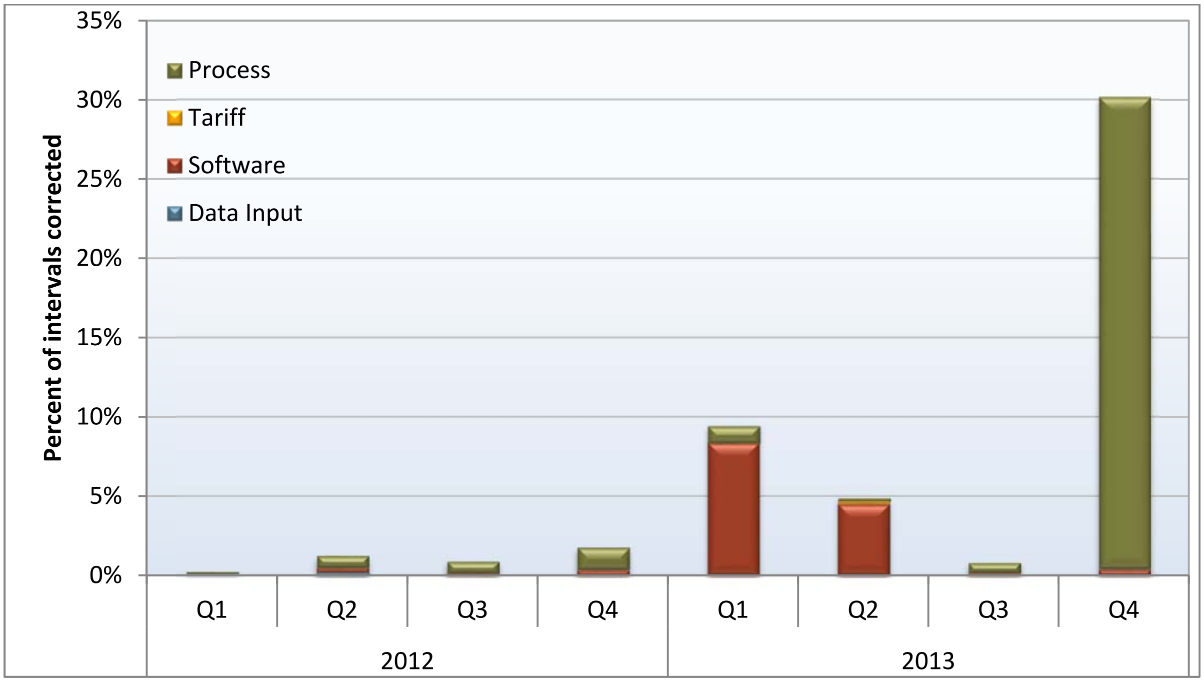
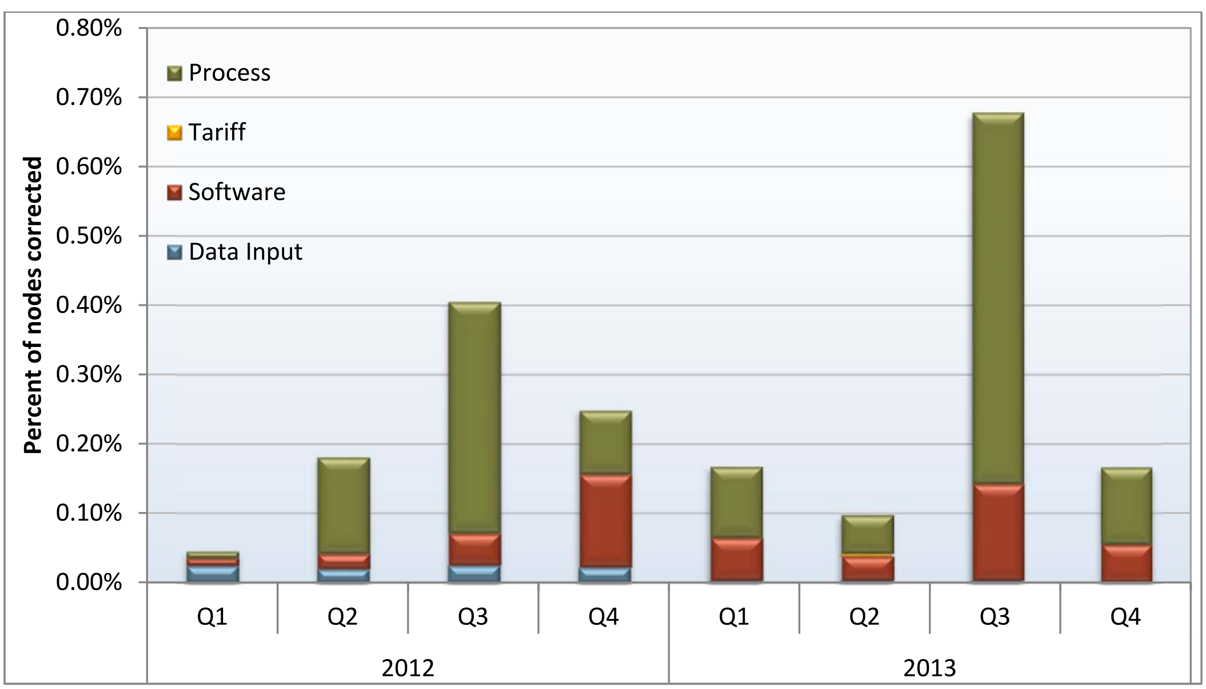


Figure 9.15 Frequency of price corrections by category and by nodal prices corrected in 2012 and 2013



The most frequent price correction category by both interval and node was process errors. This type of error jumped to 8 percent of intervals in 2013, up from 0.78 percent in 2012. Process errors occurred in 0.2 percent of nodes in 2013, up from 0.14 percent in 2012. The most significant process errors include the following categories: market application errors, model promotion errors, invalid outages and incorrect adjustments.

The second most frequent price correction category was related to software issues, representing 3.4 percent of the corrected intervals in 2013 up from 0.18 percent in 2012. On the nodal level, these corrections represented 0.07 percent of nodal corrections in 2013, up from 0.05 percent in the previous year. In 2013, most of the software errors occurred in the first and the second quarter, while in 2012 most of the intervals were corrected in the fourth quarter. In 2013, more intervals and more nodes were impacted by software problems.

DMM recognizes that price corrections are inevitable, given the growing complexity of the market software and the need for prices to reflect just and reasonable rates. DMM also recognizes the importance of price accuracy. While the ISO is improving the quality and accuracy of the prices, there appears to be room for improvement in the ISO processes that drive the need for price correction.

9.8 Residual unit commitment adjustments

As noted in Section 2.5, the purpose of the residual unit commitment market is to ensure that there is sufficient capacity online or reserved to meet actual load in real-time. The residual unit commitment market is run right after the day-ahead market and procures capacity sufficient to bridge the gap between the amount of load 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 more frequently and consistently in 2013 as compared to previous years.

As illustrated in Figure 9.16, residual unit commitment procurement appears to be driven in large part by the need to replace cleared net virtual supply bids which can offset physical supply in the integrated forward market. On average, cleared virtual supply (green bar) was more prevalent in 2013 than in 2012 (see Chapter 4 for further detail).

Operator adjustments to the residual unit commitment process (red bar) have also played a part in the growth of residual unit commitment procurement in 2013. In 2013, the average hourly adjustment to residual unit commitment procurement was about 300 MW, substantially above the average of 240 MW in 2012, but below the average of about 800 MW in the fourth quarter of 2012. Operator adjustments in the fourth quarter of 2013 were only 120 MW, on average, indicating that the use of this procedure declined by the end of the year.

The increase in the residual unit commitment requirement made by operators during 2013 was partly related to decreased reliance on exceptional dispatch, which increased the use of alternative means of ensuring adequate capacity and ramping in real time. Operators also make adjustments to accommodate changes in load area forecasts that were not factored into the ISO forecast. In addition, the ISO factors in forecasted variable generation, which can reduce the volume of operator adjustments.[211]

[211] On February 4, 2014, the ISO implemented a new Eligible Intermittent Resource Adjustment to account for wind and solar resources that self-schedule below their resource level forecast. This adjustment is automated in the residual unit commitment process.

Figure 9.16 Determinants of residual unit commitment procurement

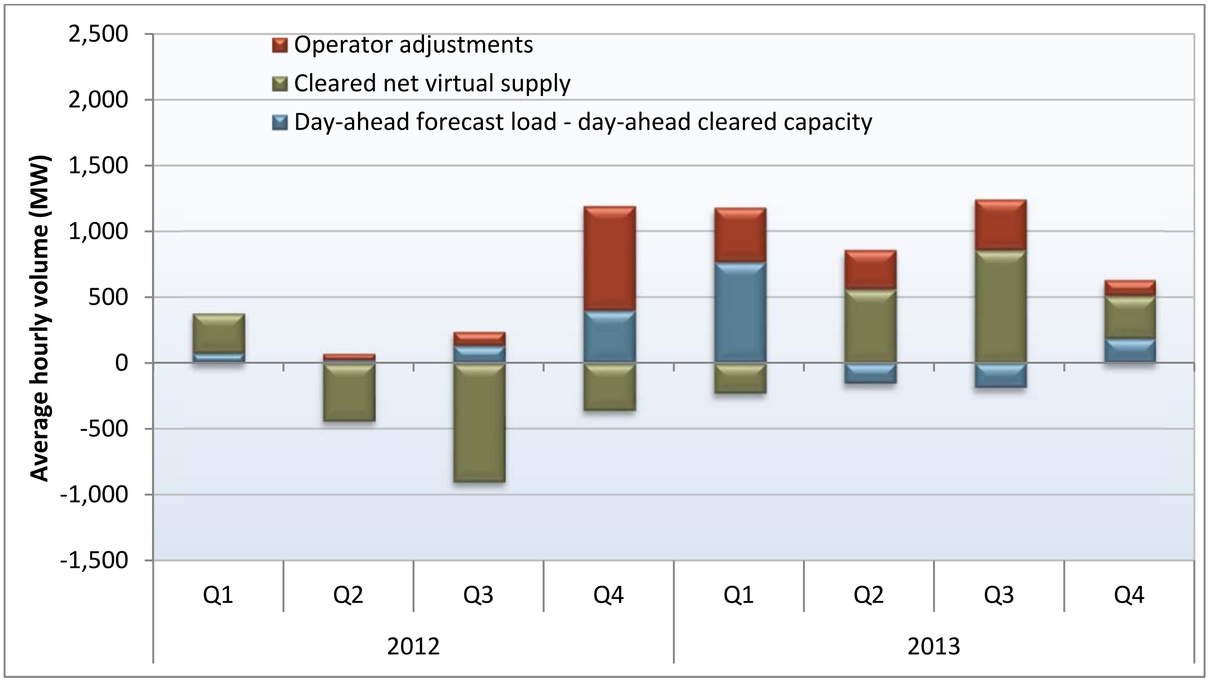


Figure 9.17 Average hourly determinants of residual unit commitment procurement (2013)

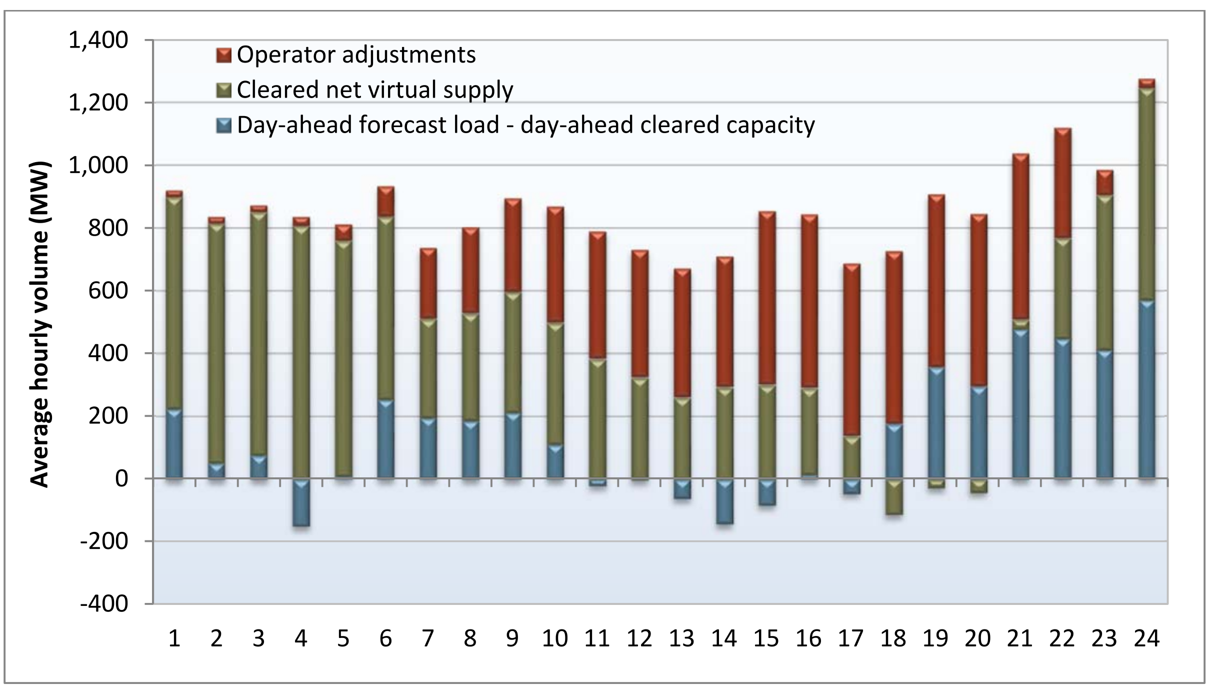


Figure 9.17 illustrates the average hourly determinants of residual unit commitment procurement. Operator adjustments were concentrated in the peak load hours of the day, peaking in hours ending 15 to 21. While adjustments were low in the off-peak hours, net virtual supply was a major driver of residual unit commitment procurement in these periods. Load differences were most pronounced in the evening hours.

10 Resource adequacy

California's wholesale market relies heavily on a long-term procurement planning process and resource adequacy program adopted by the CPUC to provide sufficient capacity to ensure reliability. The resource adequacy program includes ISO tariff requirements that work in conjunction with regulatory requirements and processes adopted by the CPUC and other local regulatory authorities.

This chapter analyzes the short-term effectiveness of the resource adequacy program in terms of the availability of resource adequacy capacity in the ISO market in 2013. This analysis focuses on the availability of these resources during the 210 hours with the highest system loads to provide an indication of how well program requirements are meeting actual peak loads. In 2013, this includes all hours with peak load over 38,724 MW. Key findings of this analysis include the following:

- During the 210 hours with the highest loads, about 94 percent of resource adequacy capacity was available to the day-ahead energy market and the residual unit commitment process. This is about equal to the target level of availability incorporated in the resource adequacy program design and a slight improvement to the availability in 2012 (91 percent).

- Capacity made available under the resource adequacy program in 2013 was mostly sufficient to meet system-wide and local area reliability requirements. However, due to the outage and retirement of the two SONGS units, the ISO relied on reliability must-run contracts with synchronous condensers at Huntington Beach Units 3 and 4 to improve local reliability.

- The aggregate output of solar resources during the 210 peak hours appears to be lower than their combined resource adequacy capacities (73 percent), and the aggregate output of wind resources during these hours was higher than their resource adequacy capacities (180 percent). For existing solar and wind units, resource adequacy capacities are typically based on resource performance over the prior three years. For new solar and wind units, resource adequacy capacities are based on monthly average production factor of all solar or wind units within the transmission access charge area in which the generating unit is located.

- Variable resources (including wind and solar) are currently used to meet a small portion of overall resource adequacy capacity requirements, but may be used to meet a growing portion of these requirements in future years. The CPUC is considering modifications to the current methodology for determining the resource adequacy rating of intermittent resources. This new methodology uses a probabilistic reliability modeling concept.[212]

With the urging of the ISO, the CPUC has adopted requirements for California's investor-owned utilities to procure flexible capacity in order to help meet the system net load changes. This represents a wider focus of the resource adequacy program from simply meeting peak system and local capacity needs to also include flexible capacity needs during ramping periods when renewable generation drops off. The ISO is developing the necessary protocols to determine requirements for flexible capacity, to count flexible resource adequacy showings, must-offer requirements, and to cure any shortfalls through backstop procurement.

[212] Details and assumptions of the new methodology can be found in the documents at: http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/Probabilistic+Modeling.htm.

10.1 Background

The CPUC resource adequacy provisions require load-serving entities to procure generation capacity to meet 115 percent of their forecast peak demand in each month.[213] The 115 percent requirement is designed to include the additional operating reserve needed above peak load (about 7 percent), plus an allowance for outages and other resource limitations (about 8 percent). This capacity must then be bid into the ISO markets through a must-offer requirement. Load-serving entities meet these requirements by providing resource adequacy showings to the ISO on a year-ahead basis due in October and provide twelve month-ahead filings during the compliance year.

Around half of the generating capacity counted toward resource adequacy requirements must be bid into the market for each hour of the month except when this capacity is reported to the ISO as being unavailable because of outages. This includes most gas-fired generation, with a total capacity of around 25,000 MW. If the market participant does not submit bids or report capacity as being on outage, the ISO automatically creates bids for these resources.

Imports represent around 9 percent of resource adequacy capacity. Beginning in January 2012, the ISO began to automatically create energy bids for imports in the day-ahead market when market participants fail to submit bids for this capacity and have not declared this capacity as unavailable. If an import is not scheduled in the day-ahead market, the importer is not required to submit a bid for this capacity in the hour-ahead market. If an import clears the day-ahead market and is not self-scheduled or re-bid in the real-time market, the ISO submits a self-schedule for this capacity.

The remaining generation resources that are counted toward the resource adequacy requirement do not have to offer their full resource adequacy capacity in all hours of the month. These resources are required to be made available to the market consistent with their operating limitations. These include:

- Hydro resources, which represent 13 percent of resource adequacy capacity.
- Use-limited thermal resources, such as combustion turbines subject to use limitations under air emission permits, which represent 8 percent of resource adequacy capacity.[214]
- Non-dispatchable generators, which include nuclear, qualifying facilities, wind, solar and other miscellaneous resources. These resources account for about 16 percent of capacity.

All available resource adequacy capacity must be offered in the ISO market through economic bids or self-schedules as follows:

- **Day-ahead energy and ancillary services market** — All available resource adequacy capacity must be either self-scheduled or bid into the day-ahead energy market. Resources certified for ancillary services must offer this capacity in the ancillary services markets.
- **Residual unit commitment process** — Market participants are also required to submit bids priced at $0/MWh into the residual unit commitment process for all resource adequacy capacity.

[213] As noted in Section 40.3 of the ISO tariff, load-serving entities are also required to procure generation capacity to meet capacity requirements for local capacity areas.

[214] Use-limited thermal resources generally have environmental, regulatory or technical restrictions on the hours they can operate, such as a maximum number of operating hours or a maximum number of start-ups and shutdowns in a month or a year. Market participants submit use plans to the ISO for these resources. These plans describe their restrictions and outline their planned operation.

- **Real-time market** — All resource adequacy resources committed in the day-ahead market or residual unit commitment process must also be made available to the real-time market. Short-start units providing resource adequacy capacity must also be offered in the real-time energy and ancillary services markets even when they are not committed in the day-ahead market or residual unit commitment process. Long-start units and imports providing resource adequacy capacity that are not scheduled in the day-ahead market or residual unit commitment process do not need to be offered in the real-time market.

10.2 Overall resource adequacy availability

Generation capacity is especially important to meet the peak loads of the summer months. However, it is also important that sufficient resource adequacy capacity be made available to the market throughout the year. For example, significant amounts of generation can be out for maintenance during the non-summer months, making resource adequacy capacity instrumental in meeting even moderate loads. With more intermittent renewable generation coming online, the need for sufficient ramping capacity is also becoming increasingly important throughout the year during many non-peak load hours.

In 2013, a high portion of resource adequacy capacity was available to the market throughout the year. Figure 10.1 summarizes the average amount of resource adequacy capacity made available to the day-ahead, residual unit commitment and real-time markets in each quarter of 2013. The red line shows the total amount of this capacity used to meet resource adequacy requirements.[215] The bars show the amount of this resource adequacy capacity that was made available during critical hours in the day-ahead, residual unit commitment, and real-time markets.[216]

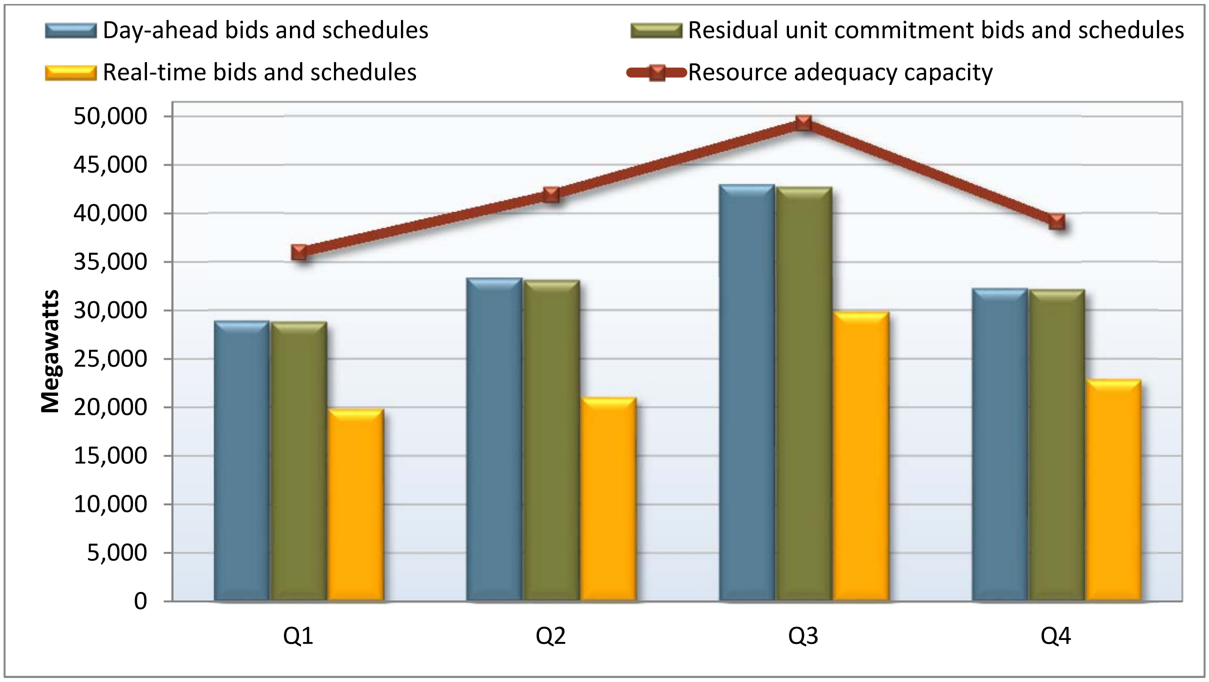
Key findings of this analysis include the following:

- The highest availability was during the third quarter, from July through September. During these months, out of the 49,300 MW of resource adequacy capacity included in this analysis, an average of around 43,100 MW (or about 87 percent) was available in the day-ahead market.
- The lowest level of availability was during the second quarter, during which about 80 percent of resource adequacy capacity was available to the day-ahead market.
- Over all months, almost all capacity offered in the day-ahead energy market was also available in the residual unit commitment process.
- Figure 10.1 also shows that a smaller portion of resource adequacy capacity was available to the real-time market. This is primarily because many long-start gas-fired units are not available to the real-time market if they are not committed in the day-ahead energy market or residual unit commitment process.

[215] The resource adequacy capacity included in this analysis excludes as much as a few thousand megawatts of resource adequacy capacity for which this analysis cannot be performed or is not highly meaningful. This includes resource adequacy resources representing some imports and firm import liquidated damages contracts, resource adequacy capacity from reliability must-run resources, resource adequacy requirements met by demand response programs, and load-following metered subsystem resources.

[216] These amounts are calculated as the hourly average of total bids and schedules made available to each of these markets during the resource adequacy standard capacity product *availability assessment hours* during each month. These are operating hours 14 through 18 during April through October and operating hours 17 through 21 during the remainder of the year.

Figure 10.1 Quarterly resource adequacy capacity scheduled and bid into ISO markets (2013)



10.3 Summer peak hours

California's resource adequacy program recognizes that a portion of the state's generation is only available during limited hours. To accommodate this, load-serving entities are allowed to meet a portion of their resource adequacy requirements with generation that is available only a portion of the time. This element of the resource adequacy program reflects the assumption that this generation will generally be available and used during hours of the highest peak loads.

Resource adequacy program rules are designed to ensure that the highest peak loads are met by requiring that all resource adequacy capacity be available at least 210 hours over the summer months of May through September.[217] The rules do not specify that these hours must include the hours of the highest load or most critical system conditions. Since participants do not have perfect foresight when the highest loads will actually occur, the program assumes that they will manage these use-limited generators so that they are available during the peak load hours.

Since the nodal market was implemented in 2009, DMM has evaluated the availability of resource adequacy during the 210 hours with the highest system loads to provide an indication of how well program requirements are meeting actual peak loads. In 2013, this includes all hours with peak load over 38,724 MW.

Figure 10.2 provides an overview of monthly resource adequacy capacity, monthly peak load, and the number of hours with loads over 38,724 MW during that period. Many of the highest load hours occurred during the heat waves at the end of June and early July, and at the end of August. The red and

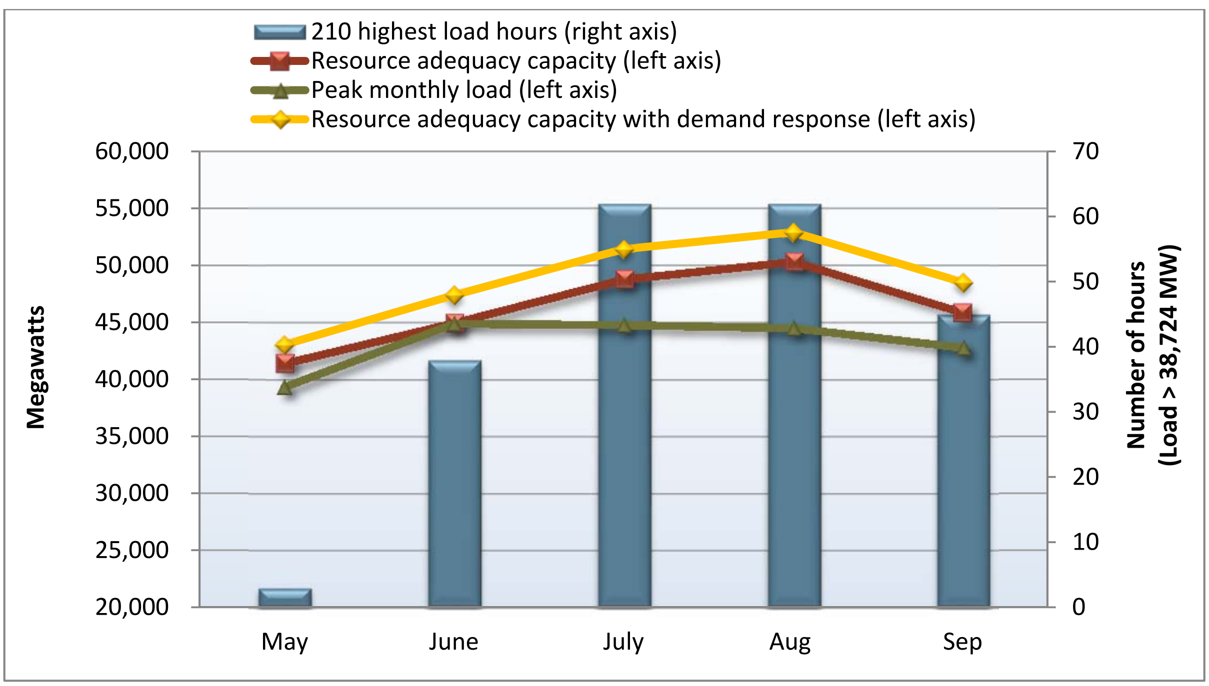
[217] The CPUC requires the resources be available 30, 40, 40, 60, and 40 hours during each of these months, respectively.

green lines (plotted against the left axis) compare the monthly resource adequacy capacity with the peak load that actually occurred during each of these months. The yellow line adjusts the resource adequacy capacity by demand response capacity.

Figure 10.3 shows the amount of capacity scheduled or bid in the day-ahead and real-time market during these 210 peak hours. These results are ranked in descending order of total resource adequacy megawatts bid or scheduled in each of the three markets listed below.[218] Figure 10.3 indicates the following:

- ***Day-ahead market*** — Bids and self-schedules for resource adequacy capacity in this market averaged about 90 percent of overall resource adequacy capacity, varying in individual hours from about 70 to 98 percent of resource adequacy capacity.
- ***Residual unit commitment*** — Resource adequacy capacity available to this process was 90 percent of overall resource adequacy capacity, just slightly less than the amount available to the day-ahead market.
- ***Real-time market*** — Bids and self-schedules for resource adequacy capacity in the real-time market averaged about 72 percent of overall resource adequacy capacity, varying in individual hours from about 60 to 86 percent. This primarily reflects the fact that many gas-fired units not committed in the day-ahead market are unavailable to start-up in real-time. A limited amount of imports and use-limited gas units are also not required to be offered in the real-time market when not scheduled in the day-ahead market.

Figure 10.2 Summer monthly resource adequacy capacity, peak load, and peak load hours (May through September 2013)



[218] Real-time bid amounts shown include energy bids and self-schedules for energy from resource adequacy capacity submitted to the real-time market and included in a day-ahead energy schedule.

Figure 10.3 Resource adequacy bids and self-schedules during 210 highest peak load hours

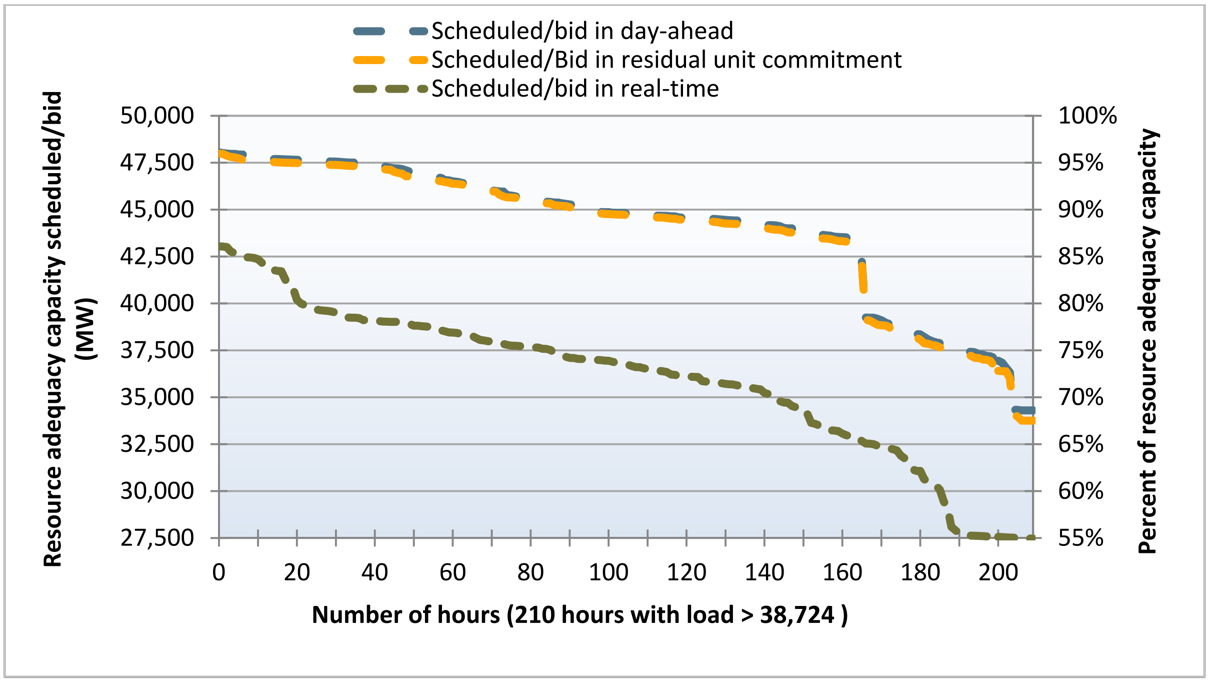


Table 10.1 provides a detailed summary of the availability of resource adequacy capacity over the 210 summer peak load hours for each type of generation. Separate sub-totals are provided for resources for which the ISO creates bids if market participants do not submit a bid or self-schedule, and resources for which the ISO does not create bids. As shown in Table 10.1:

- ***Resource adequacy capacity after reported outages and derates*** — Average resource adequacy capacity was around 48,849 MW during the 210 highest load hours in 2013. After adjusting for outages and derates, the remaining capacity equals about 94 percent of the overall resource adequacy capacity. This represents an outage rate of about 6 percent during these hours.

- ***Day-ahead market availability*** — For the 22,400 MW of resource adequacy capacity for which the ISO does not create bids, the total capacity scheduled or bid in the day-ahead market averaged around 83 percent of the available capacity of these resources after accounting for reported derates and outages. This compares to the 95 percent of the available capacity from the resources for which the ISO creates bids.

- ***Residual unit commitment availability*** — The overall percentage of resource adequacy capacity made available in the residual unit commitment process was just slightly less than that available to the day-ahead market.

- ***Real-time market availability*** — The last three columns of Table 10.1 compare the total resource adequacy capacity potentially available in the real-time market timeframe with the actual amount of capacity that was scheduled or bid in the real-time market. An average of about 86 percent of the resource adequacy capacity that was potentially available to the real-time market was scheduled or bid in the real-time market.

- ***Use-limited gas units*** — Around 3,600 MW of use-limited gas resources are used to meet resource adequacy requirements. Most of these resources are peaking units within more populated and transmission constrained areas that are only allowed to operate 360 hours per year under air permitting regulations. Market participants submit to the ISO use plans for these resources, but are not actually required to make them available during peak hours. About 87 percent of this capacity was available in the day-ahead market during the highest 210 load hours. In real-time, about 2,100 MW of this 3,600 MW of capacity was scheduled or bid into the real-time market.

- ***Nuclear units*** — Around 5,000 MW of nuclear capacity were used to meet resource adequacy requirements in 2011. However, both San Onofre Nuclear Generating Station units were unavailable since early 2012 and retired in June 2013. This was reflected in Table 10.1 which shows that the nuclear resource adequacy capacity decreased to around 2,800 MW in 2013.
- ***Imports*** — Around 4,500 MW of imports were used to meet resource adequacy requirements. About 97 percent of this capacity was scheduled or bid in the day-ahead market during the 210 highest load hours. Most of this capacity was self-scheduled or bid at competitive prices in the day-ahead market. As a result, about 89 percent of this capacity was also scheduled or bid into the real-time market. The availability of imports is discussed in more detail in Section 10.4.

The availability of wind, solar, qualifying facilities, and other non-dispatchable resources is discussed in more detail in Section 10.5.

Table 10.1 Average resource adequacy capacity and availability during 210 highest load hours

Resource type	Total resource adequacy capacity (MW)	Net outage adjusted resource adequacy capacity		Day-ahead bids and self-schedules		Residual unit commitment bids		Total real-time market resource adequacy capacity (MW)	Real-time market bids and self-schedules	
		MW	% of total RA Cap.	MW	% of total RA Cap.	MW	% of Total RA Cap.		MW	% of real-time RA Cap.
ISO Creates Bids:										
Gas-Fired Generators	25,604	24,678	96%	24,304	95%	24,304	95%	20,365	19,414	95%
Other Generators	845	729	86%	718	85%	718	85%	840	716	85%
Subtotal	**26,449**	**25,407**	**96%**	**25,022**	**95%**	**25,022**	**95%**	**21,205**	**20,130**	**95%**
ISO Does Not Create Bids:										
Use-Limited Gas Units	3,640	3,271	90%	3,152	87%	3,152	87%	2,392	2,112	88%
Hydro Generators	6,369	5,585	88%	4,866	76%	4,675	73%	6,369	4,808	75%
Nuclear Generators	2,830	2,404	85%	2,333	82%	2,333	82%	2,667	2,337	88%
Wind/Solar Generators	1,554	1,525	98%	871	56%	871	56%	1,554	1554*	100%
Qualifying Facilities	3,382	3,248	96%	2,874	85%	2,874	85%	3,337	2,804	84%
Other Non-Dispachable	107	106	99%	30	28%	30	28%	107	94	88%
Imports	4,518	4,518	100%	4,368	97%	4,368	97%	3,924	3,503	89%
Subtotal	**22,400**	**20,657**	**92%**	**18,494**	**83%**	**18,304**	**82%**	**20,350**	**15,658**	**77%**
Total	**48,849**	**46,064**	**94%**	**43,516**	**89%**	**43,326**	**89%**	**41,555**	**35,788**	**86%**

* Actual wind/solar generation is used as a proxy for real-time bids.

10.4 Imports

Load-serving entities are allowed to use imports to meet much of their resource adequacy requirement. There are roughly 11,000 MW of total import capability into the ISO system and net imports averaged about 8,300 MW during the peak summer months. Utilities used imports to meet around 4,500 MW, about 9 percent, of the resource adequacy requirements during the 210 highest load hours. This reflects a 15 percent decrease in the resource adequacy capacity from imports in 2013, compared to 2012.

Imports used to meet resource adequacy requirements are not required to originate from specific generating units or be backed by specific portfolios of generating resources. In addition, resource adequacy imports are only required to be bid into the day-ahead market. These imports can be bid at any price and do not have any further obligation if not scheduled in the day-ahead energy or residual unit commitment process.

DMM has expressed concern that these rules could in theory allow a significant portion of resource adequacy requirements to be met by imports that may have limited availability and value during critical system and market conditions. For example, resource adequacy imports could be routinely bid well above projected prices in the day-ahead market to ensure they do not clear and would then have no further obligation to be available in the hour-ahead market.

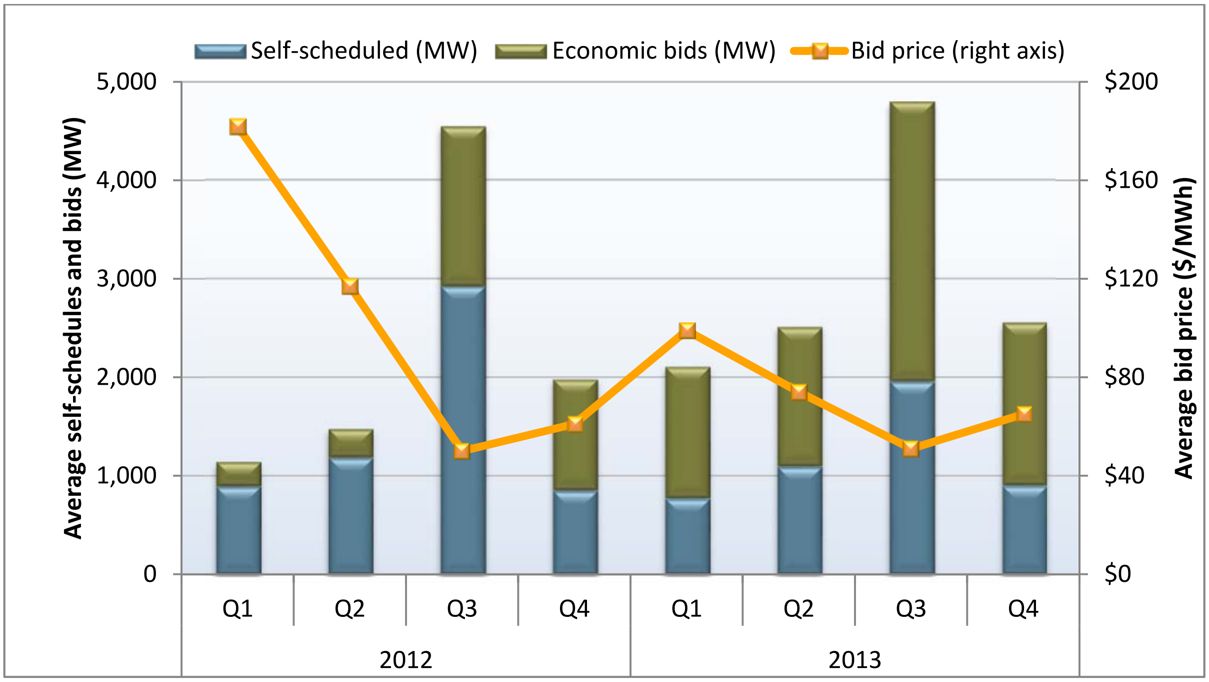
Before 2012, market participants self-scheduled a very large portion of resource adequacy imports in the day-ahead market, as noted in previous DMM annual reports. Most of the remainder of these imports was bid at relatively low prices. After 2012 the quantity and prices of economic bids for some resource adequacy imports started to increase. The trend of economic bidding continued further in 2013 as self-scheduled imports constituted around 39 percent of total bids in 2013 compared to 64 percent in 2012.

Figure 10.4 summarizes the bid prices and volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market, during peak hours, throughout the year. The blue and green bars (plotted against the left axis) show the respective average amounts of resource adequacy import capacity that market participants either self-scheduled (blue bar) or economically bid (green bar) in the day-ahead market. The gold line (plotted against the right axis) shows the average weighted bid prices for resource adequacy import resources for which market participants submitted economic bids to the day-ahead market.

Compared to 2012, the quantity of imports with economic bids in 2013 increased by around 120 percent, while the quantity of self-scheduled bids decreased by 35 percent. In every quarter of 2013, the quantity of economic bids was greater than the quantity of self-scheduled bids. Even though more economic bidding was used, day-ahead schedules from resource adequacy imports in 2013 were higher, by around 14 percent, than in 2012.

Figure 10.4 also shows that market participants submitted higher-priced economic bids in the first quarter of 2013. The weighted average of bid prices increased from $60/MWh in the final quarter of 2012 to $100/MWh in the first quarter of 2013. Even though this was a large movement in bid prices, this was lower compared to the average bid prices in the first quarter of 2012, which were about $180/MWh, and may be the result of more economics bids. Over the course of 2013, weighted average bid prices decreased. This is also a result of higher volumes of economic bids with lower bid prices.

Figure 10.4 Resource adequacy import self-schedules and bids (peak hours)



10.5 Intermittent resources

Intermittent resources include wind, solar, qualifying facilities and other miscellaneous non-dispatchable resources. Unlike conventional generation, the output of these resources is variable and, in some cases, cannot be dispatched. Consequently, the amount of resource adequacy capacity that these resources can provide is based on past output rather than nameplate capacity. The amount of resource adequacy capacity that each individual resource can provide is known as its *net qualifying capacity.*

The net qualifying capacity of wind and solar resources is based on the output that they exceed in 70 percent of peak hours (1:00 p.m. to 6:00 p.m.) during each month over the previous three years.[219] These amounts are adjusted upward by a factor that reflects the system-wide benefit that is assumed to result from a low covariance between the outputs of many individual intermittent generators. The CPUC is considering modifications to the current methodology for determining the resource adequacy rating of intermittent resources.

This analysis compares the following three measures of different types of intermittent resource capacity:

- The estimated amount of capacity from these resources used to meet 2013 resource adequacy requirements or the net qualifying capacity.

[219] This methodology sorts the generation from a specified period in a descending order and calculates the 70^{th} percentile of the observations of each month. The calculated value at the 70th percentile means that the generation is expected to be above the calculated value 70 percent of the time.

- The estimated values of the 70th percentile of the output of these resources during hours used to calculate the net qualifying capacity (weekdays from 1:00 p.m. to 6:00 p.m.).
- The estimated values of the 70th percentile of the output of these resources during the 210 highest load hours in 2013.

Figure 10.5 and Figure 10.6 show this comparison for wind and solar resources. As shown in Figure 10.5, in all three months, DMM's estimates of wind resources' output (at the 70th percentile) in the 210 highest load hours were higher their resource adequacy capacity.[220] In July and August of 2013, our estimate of wind resources' output in the hours used to calculate net qualifying capacity was less than their resource adequacy capacity by 12 and 5 percent, respectively. Output from wind resources in September, during both the highest load hours and net qualifying capacity hours, was about three times higher than their resource adequacy capacity.

Figure 10.6 shows a comparison of the same data for solar resources in July through September. Solar output in hours used to calculate net qualifying capacity was greater than the output in the 210 highest summer peak load hours in all three months. This was because more than 25 percent of the 210 highest summer peak load hours in 2013 were after 6:00 p.m. when solar generation is relatively low. Many of the highest load hours occurred during the heat waves, when evening and night temperatures can be higher than the day-time temperature on a normal summer day.

In all three months, the solar resources' output in both the hours used to calculate net qualifying capacity and the 210 highest load hours were less than their resource adequacy capacity. Actual solar output in the 210 highest summer peak load hours equaled about 73 percent of solar resource adequacy capacity during these months, down from 90 percent for the same months in 2012.[221]

Figure 10.7 provides a similar analysis for qualifying facilities and other miscellaneous non-dispatchable resources. The net qualifying capacity of qualifying facilities and other non-dispatchable resources is based on their average output during peak hours over the previous three years and is calculated for each month. An annual net qualifying capacity value is calculated based on their output during the summer months. This analysis shows the average actual output of these resources during these hours.

As shown in Figure 10.7, the output of these resources in July through September 2013 during hours used to calculate net qualifying capacity was less than their output in the 210 highest load hours. In all three months, resource adequacy capacity was higher than both net qualifying capacity output and actual output in the 210 highest load hours by 17, 20 and 14 percent, respectively.

[220] Note that the calculated 70th percentile refers to a minimum generation value. That is, generation is expected to be above this calculated value 70 percent of the time.

[221] Since the deadline for the 2013 annual resource adequacy plans was October 31, 2012, many solar generators that started commercial operations after the deadline were not included in the annual resource adequacy plans and therefore are not included in our analysis.

Figure 10.5 Resource adequacy capacity available from wind resources

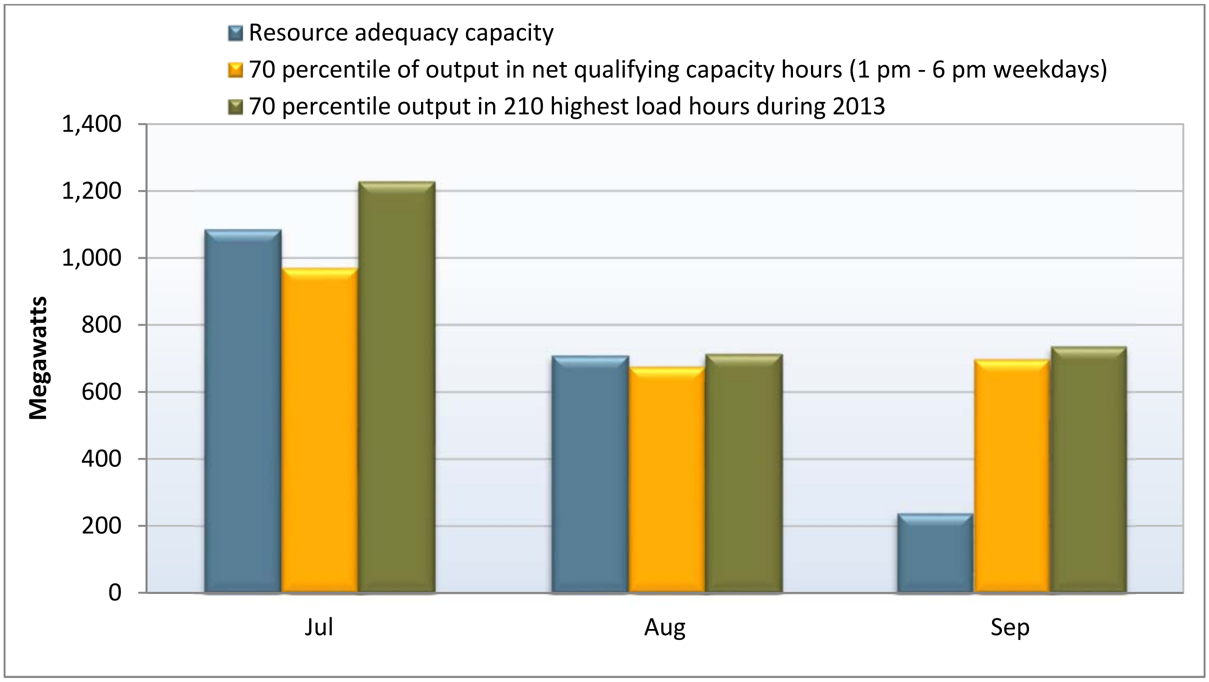


Figure 10.6 Resource adequacy capacity available from solar resources

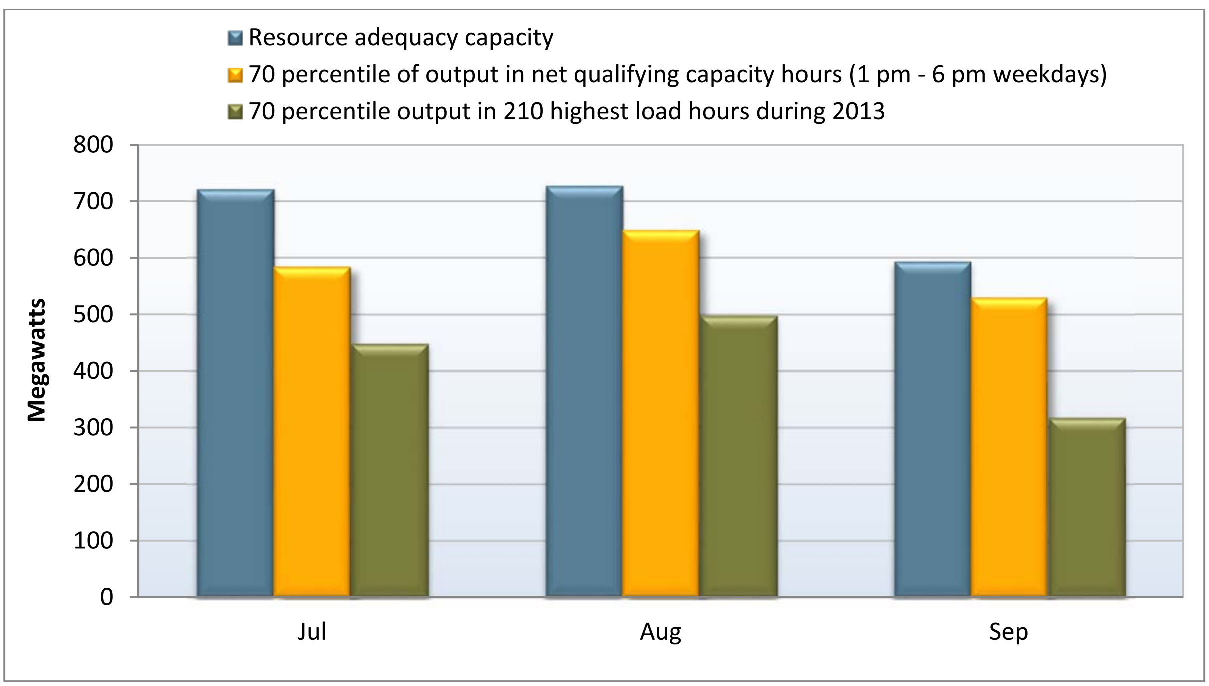
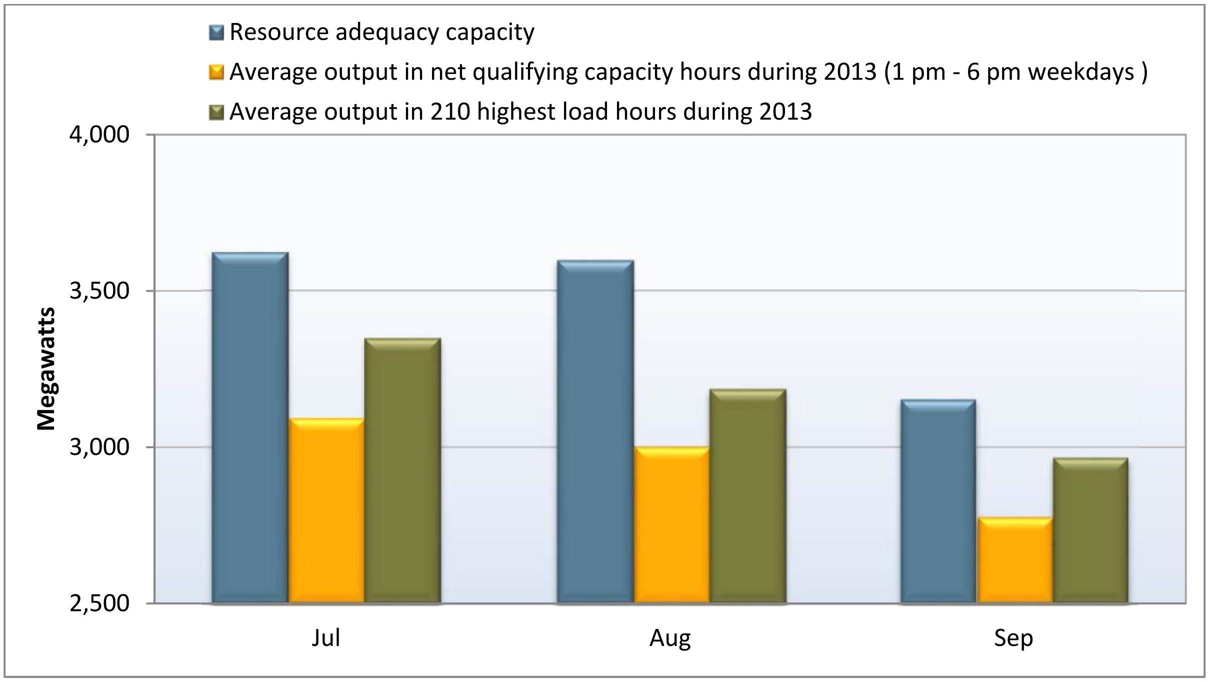


Figure 10.7 Resource adequacy capacity available from qualifying facility resources



10.6 Backup capacity procurement

The ISO tariff includes provisions allowing the ISO to procure any resources needed if capacity procured by load-serving entities under the resource adequacy program is not sufficient to meet system-wide and local reliability requirements. These provisions include both reliability must-run contracts and the capacity procurement mechanism.

Since load-serving entities procure most of the needed local capacity requirements through the resource adequacy program, the amount of capacity and costs associated with reliability must-run contracts have been relatively low over the past few years. However, these costs increased to $21 million in 2013 from $6 million in 2012. Most of this increase was the result of a reliability must-run agreement which placed synchronous condensers at Huntington Beach Units 3 and 4 into service in late June 2013 for the rest of the year. This agreement was put into place due to the outages of the SONGS units, which retired in June.

While reliability must-run payments increased notably, capacity payments related to the capacity procurement mechanism decreased. Capacity procurement mechanism costs decreased from $26 million in 2012 to only $2.7 million in 2013. 2013 costs were closer to 2011 costs which were only $1.5 million.

The high capacity procurement mechanism payments in 2012 were directly related to the outages of SONGS units 2 and 3, which were offline for almost all of 2012. The ISO took steps to avoid using the capacity procurement mechanism in 2013 to procure capacity to replace the SONGS capacity. These steps include converting Huntington Beach Units 3 and 4 to synchronous condensers for dynamic voltage support, installation of shunt capacitors at some substations for static reactive power support, reconfiguration of the Barre-Ellis 230 kV lines from 2 circuits to 4 circuits and further cooperation with local utilities on the use of demand response programs.

There were only two capacity procurement contracts in 2013. Morro Bay Unit 4 received capacity procurement mechanism payments as a result of an ISO study that identified the need for Morro Bay to support the Morro Bay-Midway 230 kV line outages and to protect for local contingencies. Huntington Beach Unit 2 received payments as a result of reliability concerns related to the two common Barre-Ellis towers.

Table 10.2 Capacity procurement mechanism costs (2013)

Resource	Local capacity area	CPM designation (MW)	Estimated cost	CPM designation dates
Morro Bay Unit 4	CAISO System	50	$640,815	2/22 - 4/22
Huntington Beach Unit 2	LA Basin	163	$2,088,642	9/1 - 10/30
		213	**$2,729,457**	

10.7 Availability payments and charges

The ISO tracks the availability of resource adequacy capacity during the availability assessment hours of each month.[222] A resource adequacy resource whose monthly availability is more than 2.5 percent below the monthly availability standard will be subject to a non-availability charge for the month. Resource adequacy capacity whose monthly availability is more than 2.5 percent above the monthly availability standard will be paid an incentive payment.

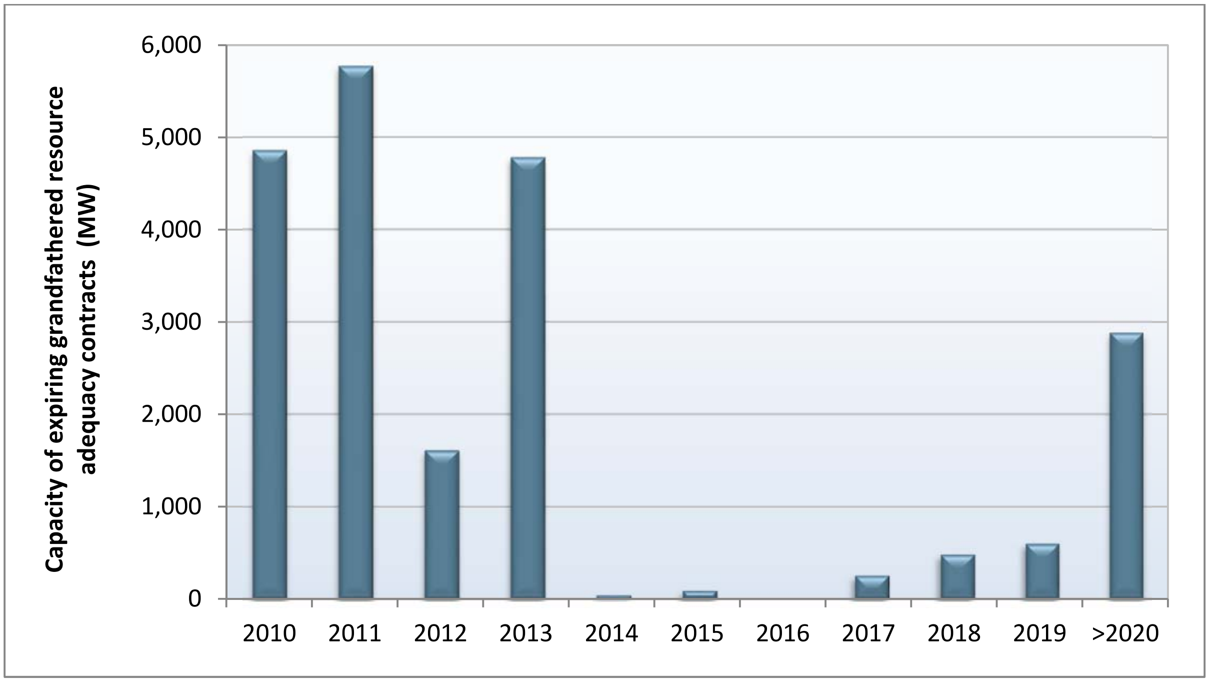
Resource adequacy non-availability charges were around $15 million, $32 million and $18 million in 2011, 2012 and 2013, respectively. More than half of these charges were paid by a group of 15 generators. Incentive payments were around $11 million, $18 million, and $14 million for the same period. The incentive payments were spread to many generators.

Many resource adequacy resources with historical capacity contracts are exempt (or *grandfathered*) from non-availability charges and availability payments until expiration of contracts that were signed prior to establishment of these charges.[223] Figure 10.8 shows the approximate capacity of expiring grandfathered resource adequacy contracts from natural gas-fired generators between 2010 and 2020.

[222] The resource adequacy standard capacity product availability assessment hours are operating hours 14 through 18 during April through October and operating hours 17 through 21 during the remainder of the year. For more details of non-availability charges and availability assessment hours, see tariff Sections 40.9.1 and 40.9.3.

[223] The ISO tariff section 40.9.2 (2) states that: "Capacity under a resource specific power supply contract that existed prior to June 28, 2009, and Resource Adequacy Capacity that was procured under a contract that was either executed or submitted to the applicable Local Regulatory Authority for approval prior to June 28, 2009, and is associated with specific Generating Units or System Resources, will not be subject to Non-Availability Charges or Availability Incentive Payments."

Figure 10.8 Capacity of expiring grandfathered contracts



While there has been a large amount of capacity exempt from non-availability charges in the past, the grandfathered contracts for much of that capacity has expired over the past few years. For example, approximately 5,000 MW of resource adequacy capacity has been exempt under grandfathered contacts that expired in 2013. By the end of 2013, most grandfathered contracts (totaling over 17,000 MW) had already expired. After considering the expired grandfathered capacity, DMM estimates that just over 5,000 MW of resource adequacy capacity remains grandfathered after 2013. The majority of this capacity will expire after 2020.

10.8 Resource adequacy developments

With the urging of the ISO, the CPUC has adopted requirements for California's investor-owned utilities to procure flexible capacity to help meet the system net load changes.[224] This represents a wider focus of the resource adequacy program from simply meeting peak system and local capacity needs to also include flexible capacity needs during ramping periods when renewable generation drops off. The ISO is developing the necessary protocols to determine requirements for flexible capacity, to count flexible resource adequacy showings, must-offer requirements, and to cure system-wide shortfalls through backstop procurement.

Flexible capacity will be differentiated from other capacity by an obligation to submit economic bids, as opposed to self-scheduling. The shift to adding flexible capacity is made with the expectation that it will result in a certain amount of capacity available for market dispatch and ramping. The current flexible resource adequacy requirements under development are derived from three hour ramping needs.

[224] Net load is made up of system load minus generation from wind and solar resources, and ramps up and down more frequently and more steeply than system load.

The design for implementing flexible resource adequacy requirements was approved by the ISO Board of Governors in March 2014. It will be a temporary framework for accounting for flexible capacity. In the near future, further developments will be needed, including methods to penalize noncompliance with flexibility requirements, a framework to standardize the obligations of capacity with grandfathered contracts and use-limited resources, and rules for new outage and substitution concerns that will come with flexible capacity needs.[225] The flexible resource adequacy proposal that was approved by the Board also included a commitment by the ISO to begin a new stakeholder process in 2016, separate from the reliability services initiative, to evaluate the results of the flexible resource adequacy framework, with the possibility of modifications or redesign as a result of that process.

[225] Some of these developments have been incorporated into the scope of the reliability services initiative that began development in January 2014. For more information, see: http://www.caiso.com/informed/Pages/StakeholderProcesses/ReliabilityServices.aspx.

11 Recommendations

DMM works closely with the ISO to provide recommendations on current market issues and new market design initiatives on an ongoing basis. This chapter summarizes DMM's recommendations on nine major current market design initiatives and issues:

- Re-design of the hour-ahead and 5-minute real-time markets.
- Flexible ramping product.
- Modeling enhancements to protect against contingencies.
- Procurement of flexible capacity multiple years in advance.
- Energy imbalance market.
- Expansion of network model to regional level.
- Compensating injections.
- Cost-based bids for gas-fired units.
- Transition cost bids for multi-stage generating units.

11.1 Re-design of the real-time market

Background

In June 2012, FERC approved Order No. 764, which is designed to remove barriers to the integration of variable energy resources by requiring transmission providers to allow adjustment of energy schedules between balancing areas every 15 minutes, rather than allowing only hourly scheduling on inter-ties. The ISO viewed Order No. 764 as an opportunity to implement real-time market changes that were not possible before the order. In addition to providing an improved scheduling framework for variable energy resources, the ISO also sought to address some of the fundamental market inefficiencies that led to high real-time energy imbalance offset costs and the suspension of virtual bidding on inter-ties.

In 2013, the ISO completed development of a proposal to re-design its real-time dispatch and scheduling process.[226] The ISO's proposed changes better integrate the process for dispatching and settling inter-tie transactions between the ISO and other balancing areas with the 5-minute process used to dispatch and settle resources within the ISO system. Currently, almost all inter-tie transactions consist of fixed hourly imports and exports established in the hour-ahead market. The ISO's current real-time market also includes a 15-minute process for real-time unit commitment and procurement of incremental ancillary services. Under the proposed changes, dispatches and prices produced by this 15-minute dispatch market will be financially binding for all internal generation and inter-tie transactions.

[226] For further information, please see the ISO's Draft Final Proposal posted on March 26, 2013: http://www.caiso.com/Documents/DraftFinalProposal-FERC-Order764MarketChanges.pdf.

The ISO's proposal was filed with FERC in late 2013 and accepted by the Commission in March 2014 with minimal required modifications. The changes are scheduled to go into effect May 1, 2014.

Recommendations

DMM worked closely with the ISO and stakeholders in developing these market design changes, which include several key modifications made to address concerns identified by DMM. We are very supportive of the final proposal and believe it represents a major improvement over the current market structure. Compared to the current hour-ahead market, dispatches and prices produced in the 15-minute process should be much more consistent with 5-minute market results. The following section provides more specific comments and recommendations by DMM on several aspects of this market design change.

Real-time imbalance offset costs

The proposed changes should significantly reduce revenue imbalances allocated to load through real-time imbalance offset charges by decreasing the difference in prices used to settle inter-tie transactions and 5-minute prices currently used to settle energy from resources within the ISO system. The ISO also anticipates that the network model expansions scheduled for fall 2014 will help reduce the impact of unscheduled flows created by other control areas on real-time imbalance offset costs (see Section 11.6). However, this model expansion will not occur until fall 2014, and experience from other ISOs indicates that it can be a difficult process to accurately model such unscheduled flows.

Therefore, DMM cautions that, despite the proposed market improvements, large real-time revenue imbalances could still occur if transmission limits are adjusted downward after the day-ahead market to account for unscheduled flows when congestion occurs. This creates offset costs by reducing the volume of energy flows in the real-time market over congested constraints. Thus, it will remain important for the ISO to continue efforts to improve modeling of flows in these two markets, so that the need to reduce flows in real time by adjusting constraint limits downward is reduced.

Virtual bidding

The ISO initially proposed to re-implement virtual bidding on inter-ties in conjunction with these market design changes. Virtual bids on inter-ties and internal locations within the ISO would all be settled at 15-minute prices. This eliminates the problem that led to high revenue imbalance costs and the suspension of virtual bidding on inter-ties in late 2011.[227]

However, as noted in our 2012 annual report, DMM cautioned that virtual bidding on inter-ties could inflate real-time revenue imbalances in the event that constraint limits need to be adjusted downward in the 15-minute process to account for unscheduled flows not incorporated in the day-ahead market model, as noted above. Thus, DMM recommended the ISO carefully consider this issue and that if virtual bidding on inter-ties is re-implemented that it be done in a very limited and gradual manner, contingent on the observed performance of this new market design.[228]

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[227] As described in DMM's 2011 annual report, this problem was created by the fact that virtual bids at inter-ties were settled on hour-ahead prices, while virtual bids at internal locations were settled at 5-minute prices. For further detail see the *2011 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2012, pp. 77-79: http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.

[228] See DMM's comments on virtual bidding under 764: http://caiso.com/Documents/DMMComments-FERC_Order764MarketChangesDraftFinalProposal.pdf.

In response to concerns by DMM and other entities, the ISO's final proposal was modified so that virtual bidding would not be re-implemented until 12 months after the start of the new 15-minute market. After this new market is implemented in spring 2014, DMM will work with the ISO to assess the impact virtual bidding on inter-ties may have in the context of this new market design and will provide recommendations prior to the re-implementation of inter-tie virtual bidding.

Scheduling of variable energy resources

The proposed changes allow variable energy resources to reserve hourly inter-tie transmission capacity to accommodate fluctuations in these resources' 15-minute schedules. Hourly transmission capacity reserved for variable energy resources will either become financially binding or released for other resources in the 15-minute market. However, this has the potential to displace other inter-tie supply resources with fixed hourly schedules.

Consequently, DMM recommended that the ISO retain the authority to utilize its own forecast of the output of a variable energy resource if schedules submitted by these resources appear to be systematically inaccurate and create detrimental market impacts. The ISO included this recommendation in its initial compliance filing for FERC Order 764. However, FERC's March 20, 2014, order on this filing required the ISO to either delete the tariff clause granting the ISO this authority or to establish specific criteria for triggering the automatic use of the ISO's forecast for a variable energy resource that has submitted inaccurate forecasts.

DMM believes that developing specific criteria for triggering the use of the ISO's forecast may alleviate some reliability concerns related to inaccurate variable energy resource forecasts. However, DMM does not believe this approach will effectively address the potential for variable energy resources to profit from strategically inaccurate forecasts intended to profit from systematic differences between the 15-minute and 5-minute markets.

Therefore, DMM is recommending the ISO create a new settlement rule to prevent variable energy resources from profiting from inaccurate forecasts. The rule would calculate the net revenues a resource received from inaccuracies in its 15-minute market forecast over an appropriately long period of time (e.g., several week or months). If a resource has positive net revenues from its forecast inaccuracies over this period the ISO should rescind payment of the net revenues.

DMM believes this type of settlement rule is more equitable and beneficial for all participants. This settlement rule would also avoid reliance on subjective determinations of whether forecast errors that are profitable for participants are intentional or not. Without such a settlement rule, the only course of action for the ISO is to rely on DMM to refer cases to FERC under behavioral market rules. FERC would then need to make a determination of whether forecast errors that are profitable for participants are intentional and violate FERC rules prohibiting false information and market manipulation.

11.2 Flexible ramping product

Background

The ISO is proposing to replace the flexible ramping constraint currently incorporated in the real-time market software with a flexible ramping product to be implemented in 2015. This product would be procured in both the day-ahead and real-time markets. DMM is supportive of this product as a more effective way of ensuring operational ramping flexibility than the current flexible ramp constraint.

The ISO's initial flexible ramping product proposal contains several provisions relating to market power mitigation. The current proposal includes a bid price cap of $250/MW, which is consistent with the existing caps on ancillary services. The ISO will also seek to procure substantial portions of capacity in the day-ahead market. This will help address potential temporal market power that may arise subsequently in the real-time market by securing a majority of the requirement under conditions where the market has more choices.

The flexible ramping product proposal also includes a provision that ensures all energy bid into the day-ahead and real-time markets is available to meet market requirements for this product. This will help ensure sufficient supply exists to meet the requirements by preventing physical withholding.

Recommendations

DMM believes that the best option for ensuring market efficiency and competitiveness would be to eliminate or revise the provision in the ISO's initial proposal allowing bids for flexible capacity up to $250/MW. No specific short-term marginal costs have been demonstrated or described that these bids would be used to cover. In addition, the ISO has also indicated that flexible ramping product could be procured regionally at some point.[229] This raises the potential that local and temporal market power could be exercised through capacity bids up to the $250/MW cap.

Consequently, DMM recommends the ISO consider reducing the bid cap to levels supported by actual marginal costs to providing capacity or eliminating the bidding altogether.[230] This is consistent with our recommendation to not allow separate bids for capacity as part of the contingency modeling enhancements discussed in the following section of this chapter.

The ISO has also left open the option to include a demand curve for flexible capacity product that would reduce the procurement as costs increase. This has the potential to reduce the risk of market power and increase efficiency overall and should continue to receive consideration.

11.3 Contingency modeling enhancements

Background

After a real-time transmission or major generation outage, flows on other transmission paths may begin to exceed their *system operating limit*. Under North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) standards, the ISO is required to return flows on critical transmission paths to its system operating limit (SOL) within 30 minutes when a real-time contingency leads to the system being in an insecure state. Under some conditions, the ISO currently uses exceptional dispatch and minimum online capacity constraints to position resources so that the ISO would have the ability to return critical paths to their operating limits within 30 minutes in the event of such a contingency.

[229] Even if the ISO does not procure regionally, one problem identified with the current flexible ramping constraint is that flexible capacity may be procured but be unavailable for dispatch due to internal constraints. This creates the potential for temporal market power even if the ISO does not procure regionally.

[230] Preliminary reasoning for this was presented at the Market Surveillance Committee meeting on July 2, 2013: http://www.caiso.com/Documents/Bidding-CapacityProducts-SpotMarkets-ISOPresentationJul2_2013.pdf.

Some stakeholders have objected to the use of exceptional dispatches and minimum online commitment constraints to help meet these reliability requirements since this approach does not incorporate resources' commitment costs into locational marginal prices. The ISO has identified these reliability requirements as one of the primary drivers of exceptional dispatches, and has placed a high priority on reducing the need for exceptional dispatches to meet these requirements. Meeting these requirements by constraints directly incorporated in the market model is also likely to allow these constraints to be met more efficiently by the overall market optimization.

The ISO has proposed an alternative modeling approach aimed at reducing the use of exceptional dispatches and minimum online capacity constraints. The modeling enhancements proposed by the ISO include the modeling of post-contingency preventive-corrective constraints and generation contingencies in the market optimization so the need to position units to meet applicable reliability criteria would be incorporated into the market model.[231] The ISO has noted that incorporating constraints in the market model should reduce exceptional dispatches, replace some minimum online constraints, provide greater compensation through locational marginal clearing prices, and may result in a separate capacity payment for resources (both generation and demand response) that help meet the reliability standards.

Recommendations

DMM is highly supportive of this initiative. The initiative directly addresses one of the recommendations in our 2011 annual report, in which we recommended that ISO monitor and seek to limit exceptional dispatches related to needs for online capacity and ramping capability to meet overall system and south of Path 26 needs.[232]

DMM believes one of the main additional benefits of this approach is that it will allow these reliability requirements to be met more efficiently, since they will be met by explicit constraints incorporated in the market model. This will allow requirements to be calculated in a more automated manner based on actual system conditions and then met by the least cost mix of resources as determined by the market software optimization.

DMM has worked with the ISO to incorporate these flow based corrective constraints into the current local market power mitigation process. Separate capacity bids could be used to exercise market power on these local constraints and there has been no demonstrated marginal cost that these bids would represent. Consequently, DMM recommends that no separate capacity bids be allowed as part of the contingency modeling enhancements until such time as marginal costs of providing capacity are demonstrated and appropriate market power mitigation measures developed for these costs.

11.4 Forward procurement of flexible capacity

Background

Under current market conditions, additional new gas-fired capacity does not appear to be needed to meet system-level capacity requirements at this time. However, a substantial portion of the state's

[231] *Contingency Modeling Enhancements Issue Paper*, March 11, 2013, http://www.caiso.com/Documents/IssuePaper-ContingecyModelingEnhancements.pdf.

[232] *2011 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2012, p. 200: http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.

15,000 MW of older gas-fired capacity is located in transmission constrained load pockets and is needed to meet local reliability requirements. Much of this capacity (or other new flexible capacity) may also be needed to provide the operational flexibility needed to integrate and back up the large volume of intermittent renewable resources coming online.

This older existing gas-fired capacity is increasingly uneconomic to keep available without some form of capacity payment and will need to be retrofitted or replaced to eliminate use of once-through cooling technology over the next decade. Under current market conditions, even relatively new gas-fired capacity without once-through cooling may be uneconomic to continue operating without significant revenues from capacity payments.

Investment necessary to maintain, retrofit or replace this existing capacity could be addressed through long-term bilateral contracting under the CPUC's long-term procurement and resource adequacy proceedings. To date, this process had proved effective at meeting system and local capacity requirements set by the ISO.

However, it is widely recognized that a potential gap exists between the state's current long-term procurement planning and the one year-ahead timeframe of the state's resource adequacy program.[233] Specifically:

- Until recently, neither of these processes incorporated any specific capacity or operational requirements for the flexible capacity characteristics that will be needed to integrate the large volume of intermittent renewable resources coming online in the next few years. The CPUC has taken the first step toward establishing flexible capacity requirements by establishing non-binding flexible capacity requirements for 2014 and mandatory requirements for 2015.
- The resource adequacy program and the capacity procurement mechanism in the ISO tariff are based on procurement of capacity only one year in advance. This creates a gap between the existing system and the multi-year timeframe over which some units at risk of retirement may need to be kept online to meet future system flexibility or local reliability requirements.

Another concern expressed by some policy makers and stakeholders is that the current long-term procurement and resource adequacy process is not sufficiently market driven and may therefore not result in development and selection of the most cost-effective alternative options for meeting resource needs, including demand-side options and new technologies.

Flexible capacity procurement proposal

The ISO continues to work with the CPUC, other local regulatory authorities and stakeholders to take a variety of steps to address this issue on a more comprehensive and longer-term basis.

In early 2014, the ISO completed a flexible capacity procurement proposal to establish requirements for flexible capacity and set the criteria for counting the amount of flexible capacity that can be provided by

[233] This gap was highlighted when the ISO was notified that a large combined cycle generating unit, not under a resource adequacy contract, was scheduled for retirement. The ISO determined that the unit was not needed in 2012, but that the unit is likely to be needed in the 2017-2018 timeframe. The ISO determined that the unit would be needed to provide flexible ramping capabilities to integrate the large volume of intermittent renewable resources coming online in the next few years, given the likely retirement of other existing gas-fired capacity subject to the state's once-through cooling regulations. See California Independent System Operator Corporation Petition for Waiver of Tariff Revisions and Request for Confidential Treatment, January 25, 2012: http://www.caiso.com/Documents/2012-01-26_ER12-897_Sutter_Pet_TariffWaiver.pdf.

different resources toward meeting these requirements. The proposal also gives the ISO the authority to procure additional capacity in the event these requirements are not met by load-serving entities.

The current flexible capacity proposal is widely viewed as being an interim solution and will provide the ISO and CPUC with additional experience and time to develop a more comprehensive set of provisions to ensure sufficient flexible capacity is available to the ISO markets. Numerous other key parts of the initiative have proven more difficult to find consensus on among stakeholders and the ISO. Thus, the design of key features, such as a market mechanism for procuring backstop capacity, was postponed. As noted in the recommendations provided in the following section, these features must be developed and implemented to ensure that the flexible capacity requirement provisions in the initial proposal ultimately provide the intended benefits.

Finally, it should be noted that the current flexible capacity proposal is also part of an overall package of initiatives designed to ensure procurement and availability of sufficient flexible capacity to meet system needs. Other elements include the following:

- Development of a flexible capacity product and contingency modeling enhancements that may provide additional market revenues to resources that are available and provide flexibility and reliability benefits in real-time, as discussed above in Sections 11.2 and 11.3.
- In addition, the ISO is seeking to develop a market-based backstop procurement mechanism, such as a residual capacity auction, that could provide a more efficient way of procuring any additional capacity needs and facilitating increased participation by smaller resources and non gas-fired alternatives.

Recommendations

DMM is supportive of a multi-year capacity procurement that includes flexible capacity requirements.

The ISO is developing several short-term products that may provide additional market revenues for resources providing flexibility in real-time. These include the flexible ramping product and the contingency modeling enhancements discussed in Sections 11.2 and 11.3. However, it is very unclear how often these constraints will be binding and, therefore, provide significant market revenues. As noted above, DMM has not identified any incremental costs of providing these products and is recommending that the market design not include separate capacity bids for these products until or unless any such costs have been quantified.

DMM does not believe that at this time it is possible to project the level of net revenues any unit may receive in an efficient spot market for flexible capacity and whether this would cover any incremental fixed cost of flexible capacity. However, DMM believes that the marginal costs of providing flexibility may in fact be relatively low, particularly relative to any additional fixed costs necessary to install flexible capacity. Under this scenario, it is entirely likely that efficient spot market prices would not cover these fixed costs – just as efficient competitive spot market energy revenues typically do not cover the fixed costs of new investment in energy capacity. Therefore, DMM believes it is prudent to continue development of a market design that includes provisions to ensure sufficient flexible capacity is built or maintained in advance on the timeline needed to bring new flexible capacity online.

DMM believes the ISO's recent flexible capacity proposal is a step in the right direction, but recommends that the ISO and CPUC should continue to work toward multi-year ahead flexibility requirements that ensure that all operational and market flexibility requirements can be met by capacity procured to meet these requirements. In prior reports and as part of other ISO initiatives, DMM has emphasized two major recommendations relating to this issue:

- **Flexible capacity requirements should be directly linked with operational ramping needs.** The ISO is developing a 5-minute flexible ramping product and corrective capacity constraint to be implemented in 2015. The ISO is also developing new model constraints that will result in resources being scheduled and compensated to help ensure sufficient additional capacity is available to respond to contingencies within 30 minutes. Any flexible capacity requirement established for a multi-year forward resource adequacy process or capacity market should ensure that day-to-day market requirements for these resource flexibility needs can be consistently met by the flexible capacity procured.

- **Flexible capacity procurement should be directly linked with a must-offer obligation for operational ramping products.** The ISO tariff should also include must-offer provisions ensuring that flexible capacity procured to meet forward requirements are actually made available in the ISO markets to meet operational and market needs. In some cases, market power mitigation or other economic provisions may be appropriate to ensure this capacity can be utilized to meet requirements for ISO market products or operational constraints developed to meet flexibility and reliability needs.

Consequently, DMM urges the ISO and CPUC to continue working toward a clear and orderly proposal to develop additional provisions and refinements to the flexible capacity procurement process. Provisions that DMM sees as being most important include the following:

- **Availability and performance incentives and penalties.** Incentive and penalty mechanisms should be developed for resources being utilized to meet flexible capacity requirements that do not meet the must-offer obligations for flexible resources. Penalties must be set high enough so that it is not more profitable to submit less flexible or reliable resources toward meeting flexible capacity requirements, and then simply pay any penalties incurred when must-offer obligations are not met.

- **Replacement requirements.** Large outages can severely restrict the amount of flexible capacity available to the ISO. Because the peak flexibility requirements are projected to occur during the traditional maintenance season, the need to replace capacity during an outage is likely to be acute. Thus, clear and effective requirements for replacing capacity during an outage are still needed.

- **Use-limited resources.** Currently, resource adequacy capacity with use limits (such as start-up and run hour limits due to air emissions) are allowed to be bid into the energy market only when the resource owners deem it to be the optimal time to offer these units. If these resources were bid in to the market at operating costs at all times they would quickly reach their use limits. The ISO's eventual goal is to develop an approach for incorporating these opportunity costs into the resource bids, so that these resources could be required to be bid into the market at all times. DMM is collaborating with the ISO on this effort, and believes the methods and mechanics of the calculations must be very open, direct and explicit before they are incorporated into any future proposal.

DMM also notes that the specific must-offer provisions and requirements used to define the three categories of resources incorporated in the ISO's proposal should be viewed as interim. The sufficiency and effectiveness of these initial provisions should be further analyzed and modified based on actual market and operational experience.[234] Experience during the initial year that these requirements are in effect should be helpful in understanding how the criteria for setting requirements may be refined.

The ISO's flexible capacity proposal contains no explicit provisions to mitigate market power. While DMM will monitor this issue over time, DMM notes that current flexible capacity requirements range from just over 7,000 MW in July to a high of about 11,000 MW in December, compared to total potential supply of about 31,000 MW.[235] DMM believes this is sufficient to ensure a competitive market for at least the next few years. In addition, DMM notes that the price at which the ISO may procure capacity through its backstop procurement authority (currently about $70/kW-year) constitutes an indirect form of market power mitigation in the bilateral market for flexible capacity.

11.5 Energy imbalance market

Background

The ISO completed development of its proposed design for the new energy imbalance market (EIM) in 2013, with implementation in the fall of 2014. The EIM will allow balancing authorities throughout the West to voluntarily participate in a real-time imbalance energy market operated by the ISO. The EIM will optimally dispatch resources within the ISO and EIM balancing authority areas' footprints to meet the combined real-time imbalance needs of both regions in the most cost effective manner. The energy imbalance market is designed to provide three main benefits:

- **Cost savings.** All EIM participants, including existing ISO market participants, will benefit from meeting their real-time imbalances from a larger pool of diverse resources.
- **Improved renewable integration.** The EIM will help integrate renewable resources by capturing the benefits of geographical diverse load and resources, which enables the output variation in one region to counterbalance variation in another.
- **Increased reliability.** The EIM will improve reliability by providing information that enhances operational awareness and responsiveness to grid conditions across its large footprint.

The energy imbalance market is scheduled to begin operation in October 2014 with two balancing authority areas operated by PacifiCorp with a total of about 10,000 MW of peak load which is primarily located in Oregon and Utah. NV Energy has also announced plans to join the EIM in 2015 with about 7,500 MW of peak load.

DMM worked closely with the ISO and members of its Market Surveillance Committee to ensure that this new market will offer benefits for current participants within the ISO, as well as entities outside the ISO, that will be participating in this new market as sellers or relying on it to meet their imbalance energy needs. DMM supports the general design outline in the ISO final proposal, which includes

[234] For example, DMM is concerned that a single 3-hour continuous ramping requirement may not ensure that shorter-term ramping requirements are met. These shorter-term requirements include those associated with the 5-minute flexible ramping product to be implemented in 2014, as well as new contingency modeling enhancements being developed to ensure sufficient additional capacity is available to respond to contingencies within 30 minutes.

[235] For further information, see: http://www.cpuc.ca.gov/NR/rdonlyres/B9A8BC3F-945B-4F50-A48D-52CFE687FF20/0/EffectiveFlexibleCapacityReportComplianceYear2014.xls.

numerous features made to protect current ISO market participants from potential uplift costs associated with the energy imbalance market.[236]

DMM will also collaborate with the ISO to develop the appropriate monitoring capabilities and identify actions that may be taken to mitigate any issues that arise following implementation of the energy imbalance market in October 2014.

Recommendations

The ISO's energy imbalance market proposal included the same local market power mitigation provisions that are applicable in the ISO's current real-time market. These provisions are only triggered when congestion occurs on a constraint within (but not between) the ISO or another EIM balancing area. DMM has noted that these provisions do not protect against market power on an EIM-wide level in cases where there may be one or two major suppliers in the EIM market.

Consequently, DMM recommended that the ISO consider additional market power mitigation provisions beyond those incorporated in the ISO's draft and final proposals. Specifically, DMM recommended the rules be modified so that bid mitigation tests and procedures would be triggered when congestion occurred into an EIM balancing authority area on an EIM scheduling constraint from the ISO or another EIM balancing area.

In response to concerns by DMM and other entities, the ISO's final tariff filing calls for additional market power mitigation procedures to be applied based on further analysis of potential supply and demand conditions in the EIM as these data become available. Under the ISO's filing, these additional mitigation measures could be applied in the market software if further study by the ISO indicates EIM-wide market power may exist and is approved by the Board of Governors.[237]

As noted in the ISO's filing, DMM is currently assessing the potential competitiveness of the initial two EIM balancing authority areas. DMM's proposed methodology and initial results of its analysis of EIM competitiveness have been presented to the ISO and its MSC for comment. Initial results include a tentative finding that DMM will not be able to conclude with a high level of confidence based on current data and experience that these initial two balancing authority areas will be competitive.[238]

DMM notes that this methodology and results can be refined as additional empirical information becomes available and modifications to EIM market structure take place. For example, after the first year that EIM is in operation, the same analysis included in the initial study can be performed using hourly data on actual hourly supply, demand and transfer capacity of the EIM. Based on such analysis, modifications would then be made to eliminate or relax mitigation when congestion occurs into an EIM balancing area.

[236] Memorandum from Eric Hildebrandt to ISO Board of Governors, re: Market Monitoring Report, October 31, 2013: http://www.caiso.com/Documents/DecisionEnergyImbalanceMarketDesign-DMM%20Memo-Nov2013.pdf.

[237] See *Tariff Amendments to Implement an Energy Imbalance Market*, California Independent System Operator Corporation, February 28, 2014, transmittal letter at pages 41-42: http://www.caiso.com/Documents/Feb28_2014_TariffAmendment_EnergyImbalanceMarket_ER14-1386-000.pdf.

[238] *EIM Market Power Mitigation*, presentation by Department of Market Monitoring, Market Surveillance Committee Meeting March 11, 2014: http://www.caiso.com/Documents/EnergyImbalanceMarketCompetitivenessAssessmentDiscussion-ISO_PresentationMar2014.pdf.

11.6 Network model expansion

Background

In early 2014, the ISO completed development of a proposal expanding the topology and inputs used to project actual power flows in the day-ahead and real-time models incorporated in the market software. By expanding the full network model to include other balancing areas, the ISO will also be able to reflect outages and other reliability parameters on those external systems and analyze how they may affect the ISO market.

The key feature of the final proposal is that the ISO's network model will be expanded to include the other balancing areas in the Western Electricity Coordinating Council area. This expanded model will be used to model the unscheduled electrical flows that will occur within the ISO balancing area caused by the load, generation, and interchanges forecast for other balancing areas in the western grid. The goal of this is to produce day-ahead and real-time schedules and prices that more accurately reflect actual system constraints and the impact schedules have on these constraints.

The proposal provides the opportunity for substantial reliability benefits under scenarios such as those that led to the major Southwest blackout on September 8, 2011. These modeling enhancements should also improve market efficiency by allowing better management of congestion, enforcement of reliability constraints in the ISO system impacted by unscheduled flows from other balancing areas, and more accurate prices for market transactions. This may help reduce real-time congestion imbalance offset costs that are incurred when unscheduled real-time flows create the need to reduce flows from schedules awarded in the day-ahead market.

Expanding the ISO's network model to a regional level that includes other balancing authority areas is also a key component needed to ensure the efficiency and future regional expansion of the ISO's energy imbalance market.

Recommendations

DMM strongly supports the ISO's final proposal to expand its network model. The ISO's initial proposal was modified significantly as the result of input from DMM, the Market Surveillance Committee and stakeholders.

Creating and testing an expanded network model is likely to be a difficult and complex task. Other ISOs have experienced serious challenges in improving the accuracy of their estimates of unscheduled flows. Consequently, both DMM and the MSC have recommended that the ISO analyze, validate, and benchmark the full network model before and after implementation to ensure this feature provides the intended benefits.

One potential limitation of the network model expansion is that the ISO may not have data on schedules outside the ISO that are complete, timely, or accurate enough to sufficiently project next-day base schedules used in the full network model. Even with this information, the accuracy with which unscheduled flows can be projected will depend on a variety of other modeling assumptions that must be made. For instance, assumptions must be made about which specific generation schedules in other balancing areas are unaffected by imports and exports to the ISO, and which are marginal, such that they will ultimately be increased or decreased as a result of additional incremental imports or exports with the ISO. Consequently, monitoring the impact that the expanded network model has on projections of unscheduled flow and congestion in the day-ahead and real-time market models – and modifying these models in response to this monitoring – will be critical.

The ISO has committed to performing a variety of studies as part of pre-implementation testing and to reporting on these results to stakeholders and the Board. DMM supports this approach, but also emphasizes that this pre-implementation testing be viewed as the first step in an ongoing process of monitoring, analysis, refinement and improvement of the full network model. DMM has provided specific recommendations relating to the metrics and analysis to be used by the ISO to assess the impacts of the expanded modeling functionality, and DMM is continuing to work closely with the ISO to monitor and enhance this new functionality before and after it is implemented in fall 2014.[239]

11.7 Analyzing compensating injections

In our 2011 annual report, DMM recommended that the ISO capture additional data elements needed to more effectively determine the impacts of compensating injections.[240] DMM believes analysis of the difference between modeled versus actual flows over longer time periods could provide insights into systematic patterns in unscheduled flows that might be incorporated into the day-ahead modeling process, rather than only the 15-minute and 5-minute real-time markets.

The performance of the compensating injection feature of the ISO software became much more consistent in late 2012 after a series of enhancements were made. However, DMM reiterates the recommendation that more data and analysis is required to allow for better understanding of the actual effectiveness of compensating injections in terms of improving estimated flows and congestion management on individual constraints within the ISO system. For instance, on multiple occasions the ISO has observed that compensating injections have had the effect of increasing modeled flows on internal constraints above metered flows, triggering congestion in the real-time market when actual flows were below actual limits.

DMM continues to recommend that the ISO systematically monitor for this potential scenario. To facilitate such monitoring, DMM has recommended that the ISO software and data explicitly calculate and report the impact that compensating injections are having on modeled flows on constraints within the ISO system which are at or near limits in real-time or the market model. DMM continues to include this recommendation as part of its broader recommendations on data and analysis requirements for the network expansion project.

11.8 Start-up and minimum load bids for natural gas units

Background

In 2011, DMM observed that the majority of bids for both start-up and minimum load costs for units under the registered cost option approached the current cap of 200 percent of fuel costs.[241] From early 2011 through 2012, DMM also identified a number of manipulative scheduling and bidding practices

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[239] Memorandum from Eric Hildebrandt to ISO Board of Governors, re: Market Monitoring Report, January 30, 2014: http://www.caiso.com/Documents/DepartmentMarketMonitoringReport-Memo-Feb2014.pdf.

[240] *2011 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2012, pp. 200-201: http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.

[241] *Quarterly Report on Market Issues and Performance*, November 8, 2011, pp. 41-44: http://www.caiso.com/Documents/QuarterlyReport-MarketIssues_Performance-November2011.pdf.

based in part on the ability of participants to submit high start-up and minimum load bid costs under the registered cost option.[242] These and other forms of manipulative behavior involving bid cost recovery payments for registered cost bids in excess of actual minimum load costs are described in a July 2013 FERC Order approving a settlement with J.P. Morgan concerning these practices.[243]

Consequently, DMM recommended that the ISO re-evaluate the appropriateness and effectiveness of the 200 percent cap. The ISO included this item as part of its commitment cost refinement stakeholder process initiated in 2012. This process was completed in 2013. As a result, the ISO lowered the cap for start-up and minimum load costs to 150 percent of start-up and minimum load costs, and included a non-fuel component for verifiable major maintenance costs.

Gas price issue

On February 6, 2014, a cold weather event leading to a rapid increase in gas prices highlighted the potential market impacts of the gas prices used by the ISO to calculate bids under the proxy cost option, which are based on gas prices traded two days prior to the operating day. This event also highlighted the potential impact of monthly fixed start-up and minimum load bids under the registered cost option selected by most gas-fired capacity in cases when a rapid increase in gas prices occurs.

Both these market features caused start-up and minimum load bids used by the ISO software to be significantly lower than market prices of natural gas. As a result, the ISO's market systems made resource commitments that reflected prices for minimum load energy from some units that may have been well below actual costs. In addition to creating less efficient unit commitments, this creates potential revenue inadequacy for some units.

To address this issue in the immediate future, the ISO requested, and the FERC granted, temporary waivers of its tariff to allow it to incorporate a more recent gas price forecast into its day-ahead market solution and settlement practices under certain conditions. The ISO plans to undertake a stakeholder process to explore refinements to its market rules to address this issue on a permanent basis.

Some stakeholders have suggested that the events of February 6, 2014, 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.

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[242] Proposal to modify market settlement rule to remedy the observed exploitation of the existing bid cost recovery tariff rules, California Independent System Operator Corporation, Tariff Revision and Request for Expedited Treatment, March 18, 2011: http://www.caiso.com/2b45/2b45d10069e0.pdf.

Proposed modifications to bid cost recovery rules to remedy the observed exploitative behavior that has resulted in excessive bid cost recovery payments beyond the expected outcome of a competitive market, California Independent System Operator Corporation, 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.

Exceptional Dispatch and Residual Imbalance Energy Mitigation Tariff Amendment in FERC Docket No. ER12-2539-000, August 28, 2012, at: http://www.caiso.com/Documents/August282012ExceptionalDispatch-ResidualImbalanceEnergyMitigationTariffAmendment-DocketNoER12-2539-000.pdf.

[243] Order Approving Stipulation and Consent Agreement, In Re Make-Whole Payments Docket Nos. IN11-8-000 and Related Bidding Strategies IN13-5-000 , (Issued July 30, 2013) pp.12-13: http://www.ferc.gov/EventCalendar/Files/20130730080931-IN11-8-000.pdf.

- 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 by one participant aimed at profiting from high minimum load bids under the registered cost option.[244] The lower 150 percent limit implemented in 2013 is seen as an important protective measure against other such practices.[245]

- Second, 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. After the fact 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.

11.9 Transition cost bids

DMM continues to recommend that the ISO revise the caps for transition cost bids for multi-stage generating units, as we first noted in our 2011 annual report. As noted in our 2012 annual report, DMM believes this will become increasingly important if the ISO requires additional resources to be modeled as multi-stage generating units. In March 2014, the FERC approved a 2013 filing by the ISO to require most units to be modeled as multi-stage generating units. Thus, DMM continues to re-iterate this recommendation.

Under the current tariff, transition cost bids submitted by participants are not required to reflect actual transition costs and are not subject to any cost verification. Rules limiting transition costs bids ultimately limit these bids based on the start-up costs submitted by the participant for *non-startable* configurations.[246] This requires participants to submit a value for something that is inherently

[244] Ibid.

[245] 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.

[246] See example on page 11 of Draft Final Proposal, *Changes to Bidding and Mitigation of Commitment Costs,* June 14, 2010: http://www.caiso.com/Documents/DraftFinalProposalonCommitmentCosts14-Jun-2010.pdf.

contradictory: start-up costs for a *non-startable* configuration. Participants are allowed to submit whatever value they want for the start-up costs for a *non-startable* configuration.

The ISO's rationale for adopting this approach was that "it provides MSG operators the freedom to accurately describe their transition costs while enabling the ISO to avoid onerous validation of costs for each transition."[247] However, DMM believes this makes limits on transition costs unenforceable in the event that a participant seeks to submit extremely high transition cost bids.

A second problem with the current tariff provisions governing transition cost bids for multi-stage generating units is that the entire transition cost bid submitted by the participant is scaled up or down each day based on the daily gas price index. This is appropriate since the transition cost bid is not required to be based on actual gas usage of transition between configurations. However, the ISO chose not to adopt a fuel cost-based approach for transition cost bids, on the theory that a large portion of transition costs were associated with fuel usage.

As the ISO implements new tariff provisions requiring more units to be modeled as multi-stage generating units, DMM believes the ISO should seek to modify the current rules governing transition cost bids to address these two issues. DMM continues to advocate an approach that is ultimately tied to actual verified fuel costs and any other verifiable incremental cost associated with transitioning from one configuration to another.

In practice, DMM's experience with specific units suggests that by far the main component of transition costs is fuel consumption, which may be relatively easy to estimate and verify. DMM suggests that rules be modified so that only the fuel component of transition costs is scaled up or down based on daily spot market fuel prices. Any verified non-fuel component of transition costs would remain fixed from day-to-day.

[247] Ibid, p.9.