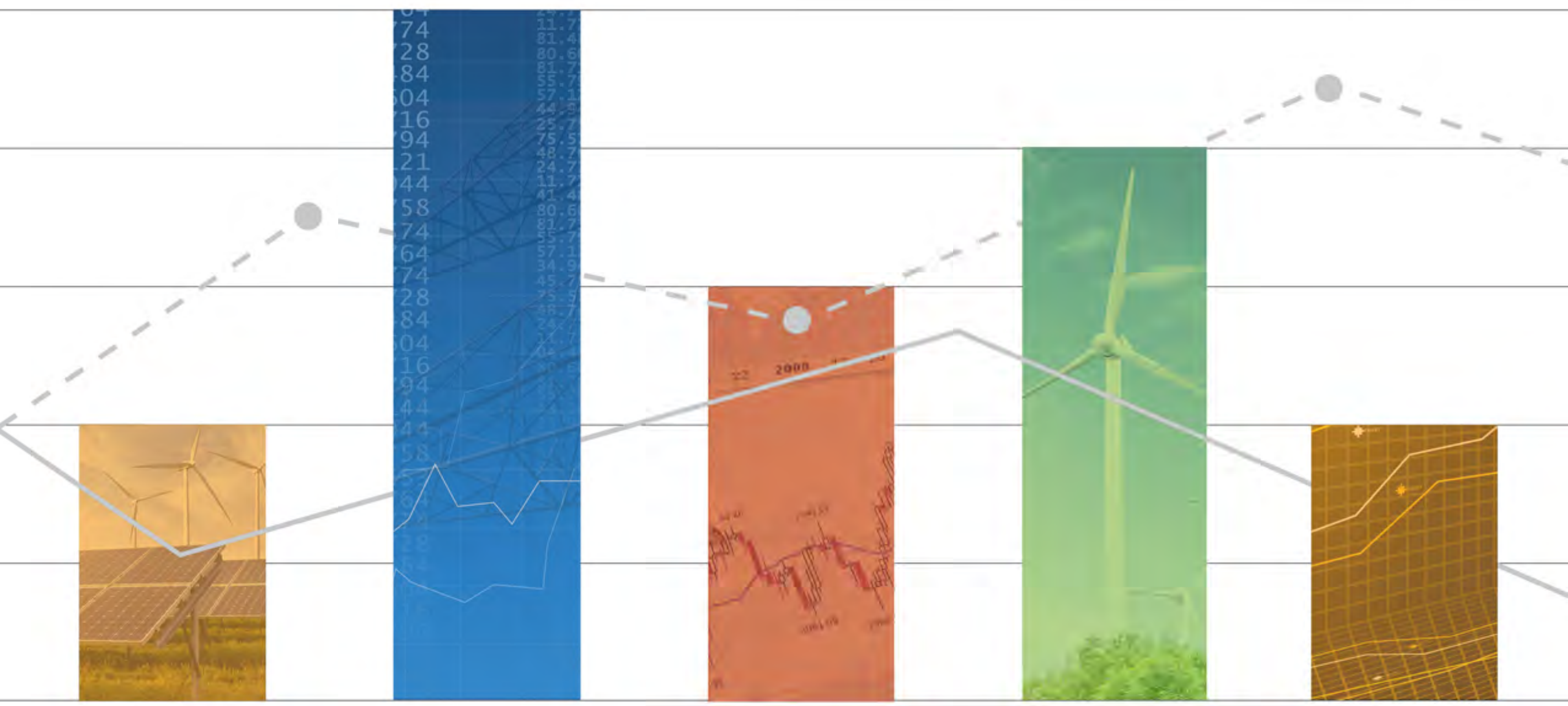
2015 ANNUAL REPORT ON MARKET ISSUES & PERFORMANCE



California ISO

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Executive summary

This report focuses on the performance of the ISO and energy imbalance markets, and finds that they continued to perform efficiently and competitively overall in 2015. Key highlights of market performance in this report by the Department of Market Monitoring (DMM) include the following:

- Total wholesale electric costs decreased by about 30 percent, driven primarily by a 40 percent decrease in natural gas prices compared to 2014. After controlling for the lower natural gas costs and changes in greenhouse gas prices, wholesale electric costs decreased by about 6 percent from 2014.
- Despite record low hydro-electric conditions, moderate loads and the addition of new generation (mostly solar) with about 950 MW of peak summer capacity helped to keep market prices low and highly competitive.
- Prices in the 15-minute and 5-minute markets were fairly stable in 2015, although there was an increase in frequency of negative prices compared to 2014. This trend was particularly notable in the first half of 2015 due to outage-driven congestion in the south-to-north direction on Path 15 in the spring. One of the contributing factors of negative real-time prices is the dramatic increase in solar production during the middle parts of the day.
- Overall prices in the ISO energy markets in 2015 were highly competitive, averaging close to what DMM estimates would result under highly efficient and competitive conditions, with most supply being offered at or near marginal operating costs.
- Average real-time prices tended to be lower than average day-ahead prices, continuing a trend that began in 2013. This trend is partly attributable to a drop in high real-time price spikes compared to prior years. This trend also reflects additional generation in real time not scheduled in the day-ahead market, particularly from wind and solar units.
- After implementation of 15-minute scheduling on inter-ties in May 2014, there was a significant decrease in the amount of economic inter-tie bids offered into the real-time market. This trend continued into 2015. Most economic real-time bids on the inter-ties continued to be hourly block bids in 2015. However, the share of 15-minute economic bids gradually increased over the year. Almost all 15-minute economic inter-tie bids were concentrated on only three inter-ties.

The energy imbalance market (EIM) continued to expand in 2015 with the addition of NV Energy in December 2015.

- Prices in the EIM during most intervals have been highly competitive and have been set by bids closely reflective of the marginal operating cost of the highest cost resource dispatched to balance loads and generation.[1]
- However, during a relatively small number of intervals, energy or flexible ramping constraints needed to be relaxed for the market software to balance modeled supply and demand. During

[1] Additionally, as of December 1, 2015, FERC ordered that participants in EIM offer their units into the market at or below each unit's default energy bid (153 FERC ¶ 61,206): https://www.ferc.gov/whats-new/comm-meet/2015/111915/E-5.pdf.

these intervals, the ISO has applied special price discovery measures approved by FERC to set prices based on the last dispatched bid price rather than penalty prices for various constraints.

- The price discovery mechanism effectively mitigated the impact of constraint relaxation on market prices, particularly during the first six months of 2015. Overall average prices in 2015 in the PacifiCorp areas remained at or below bilateral trading hub prices that were used to set prices prior to integration with the ISO. DMM uses these prices as a key indicator of the efficiency and competiveness of EIM performance.
- With the addition of NV Energy in December 2015, additional transfer capability was made available between the EIM areas and the ISO. This additional transfer capacity, along with improvements in EIM performance made over the course of 2015, has led to greatly improved performance in all EIM areas during December 2015 and the initial months of 2016. The amount of energy deemed delivered from EIM areas to the ISO increased substantially with the addition of NV Energy.
- NV Energy prices have consistently in line with bilateral trading hub prices. Although special price discovery provisions are in place within the NV Energy area for the first six months of implementation, these provisions have been triggered infrequently.

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

- Ancillary service costs totaled $62 million, or about 10 percent less than in 2014. The decrease is related to a decrease in ancillary services prices resulting from lower natural gas prices.
- Bid cost recovery payments remained unchanged at $92 million from 2014, and remained less than 1 percent of total energy costs in 2015. While overall payments remained unchanged, payments for units scheduled through the residual unit commitment process increased to over $15 million in 2015, up from $6 million in 2014. These costs were driven in large part by higher cost long-start units that were committed through the residual unit commitment during the warmest parts of the year, when loads were highest.
- Exceptional dispatches, or *out-of-market* unit commitments and energy dispatches issued by ISO grid operators to meet constraints not incorporated in the market software, increased from 2014 but remained relatively low overall. Total energy from all exceptional dispatches totaled about 0.2 percent of total system energy in 2015 compared to 0.16 percent in 2014. The above-market costs resulting from these exceptional dispatches decreased 15 percent to $9.3 million in 2015 from $11 million in 2014.
- Congestion on transmission constraints within the ISO system continued to remain low compared to prior years and had a limited impact on average overall prices across the system. Congestion was highest in the second quarter because of outage-related congestion on Path 15.
- Total real-time market revenue imbalance charges allocated to load-serving entities decreased significantly to $65 million in 2015 from $217 million in 2014. The charges associated with congestion fell to $50 million in 2015 from $107 million in 2014, and charges related to real-time energy imbalance costs decreased to $15 million in 2015 from $109 million in 2014. Much of this decrease in congestion costs was the result of lower overall congestion.

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

- About 950 MW of summer peak generating capacity was added in 2015 with about 93 percent of the new capacity coming from new solar generation.
- Energy from new solar resources is expected to continue to increase at a high 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.
- No new natural gas-fired generation was added in 2015.

Total wholesale market costs

The total estimated wholesale cost of serving load in 2015 was about $8.3 billion or just under $37/MWh. This represents a decrease of about 30 percent from wholesale costs of about $52/MWh in 2014. The decrease in electricity prices was mostly due to a corresponding decrease in wholesale natural gas prices of about 40 percent.[2] After normalizing for natural gas prices and greenhouse gas compliance costs, DMM estimates that total wholesale energy costs remained fairly stable, decreasing slightly by about 6 percent from $45/MWh in 2014 to about $42/MWh in 2015.[3]

A variety of factors had the effect of decreasing total wholesale costs. As highlighted elsewhere in this report, conditions that contributed to lower prices include the following:

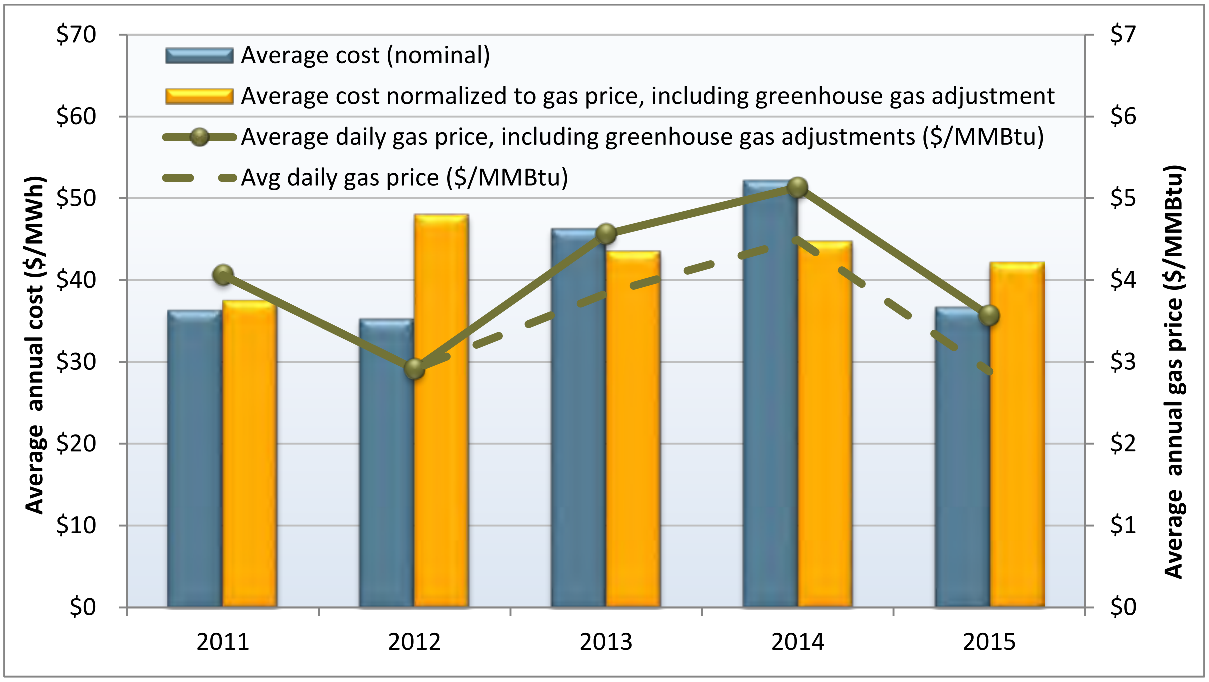
- Record solar generation and continued addition of new solar generating capacity, replacing more expensive generation;
- Continued low levels of congestion during most intervals; and
- Increased net virtual supply, which lowered average day-ahead prices and brought day-ahead prices closer to average real-time prices.

Figure E.1 shows total estimated wholesale costs per megawatt-hour of system load from 2011 to 2015. Wholesale costs are provided in nominal terms (blue bar), as well as after normalization for changes in average spot market prices for natural gas and greenhouse gas compliance costs (gold bar). The greenhouse gas compliance cost is added to natural gas prices beginning in 2013 to account for the estimated cost of compliance with California's greenhouse gas cap-and-trade program. The green line, representing the annual average of daily natural gas prices including greenhouse gas compliance, is included to illustrate the correlation between the cost of natural gas and the total wholesale cost estimate. The dashed green line excludes greenhouse gas compliance costs and is included for reference after 2012.

[2] For the wholesale energy cost calculation in 2015, an average of annual gas prices were used from the SoCal Gas Citygate and PG&E Citygate hubs.

[3] Greenhouse gas compliance costs are calculated by multiplying a load-weighted annual average greenhouse gas allowance price by an emission factor that is a measure of the greenhouse gas content of natural gas. Derivation of the emission factor used here, 0.531148, is discussed in further detail in Section 1.2.4. Gas prices are normalized to 2010 prices.

Figure E.1 Total annual wholesale costs per MWh of load (2011-2015)



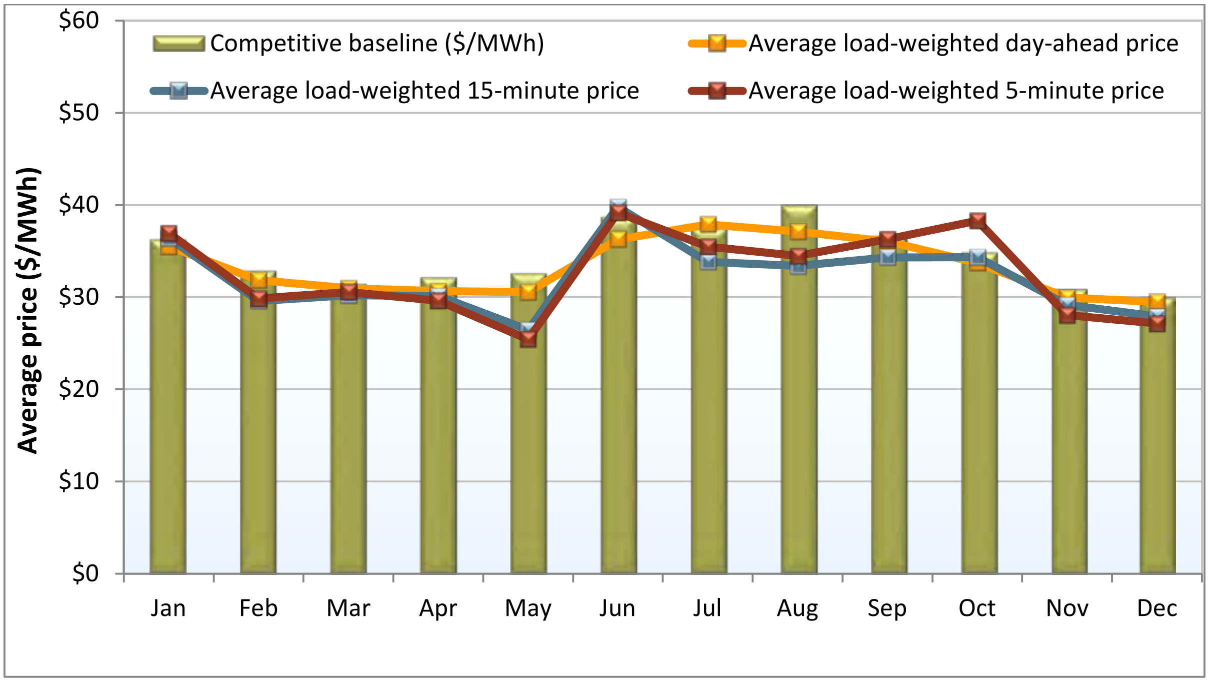
Market competitiveness

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, 15-minute 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 competitive baseline prices in most months in 2015. Day-ahead prices were noticeably lower than the competitive benchmark in May, June and August.

In the 15-minute and 5-minute real-time markets, average prices were also slightly lower than the competitive baseline in most months. Average 15-minute and 5-minute real-time prices were about $6/MWh lower during May and August, while 5-minute prices were about $3.50/MWh higher in October. Path 15 congestion and increased solar generation played a role in low May prices, while load forecast variability during July and August contributed to lower real-time prices. In October, a few days with higher than anticipated loads led to high average real-time prices.

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



Energy market prices

Energy market prices were lower in 2015 than 2014. This decrease was attributed primarily to a decrease in natural gas prices in 2015 where the average price of natural gas in the daily spot markets decreased by about 40 percent from 2014 levels at the main trading hubs in California. Figure E.3 and Figure E.4 highlight the following:

- Real-time energy prices tended to be lower than average day-ahead prices during most periods, which continued a trend that began in 2013. This can be partly attributed to additional generation in real-time that is not included in the day-ahead market, primarily from renewable resources.
- During the third quarter of 2015, price convergence declined between the day-ahead market and the 15-minute market, particularly in peak hours. Most real-time energy is settled based on prices in the 15-minute market.
- Average prices for the 15-minute market, upon which most real-time energy is settled financially, were lower than the day-ahead market prices. Prices in the 15-minute market averaged about $1.60/MWh lower than day-ahead prices.
- Prices in the 15-minute market tracked particularly far from day-ahead prices during peak hours in the third quarter of 2015. During this quarter, average 15-minute prices during peak hours were almost $4.90/MWh (or about 12 percent) less than day-ahead prices.
- Average quarterly 5-minute market off-peak prices in the fourth quarter were greater than the day-ahead market by about $1.40/MWh. Historically, the 5-minute market prices have been highly volatile, and have experienced periods of extreme positive and negative price spikes. However,

price variability in the 5-minute market now has a lower impact as less settlement occurs against the 5-minute real-time price.

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

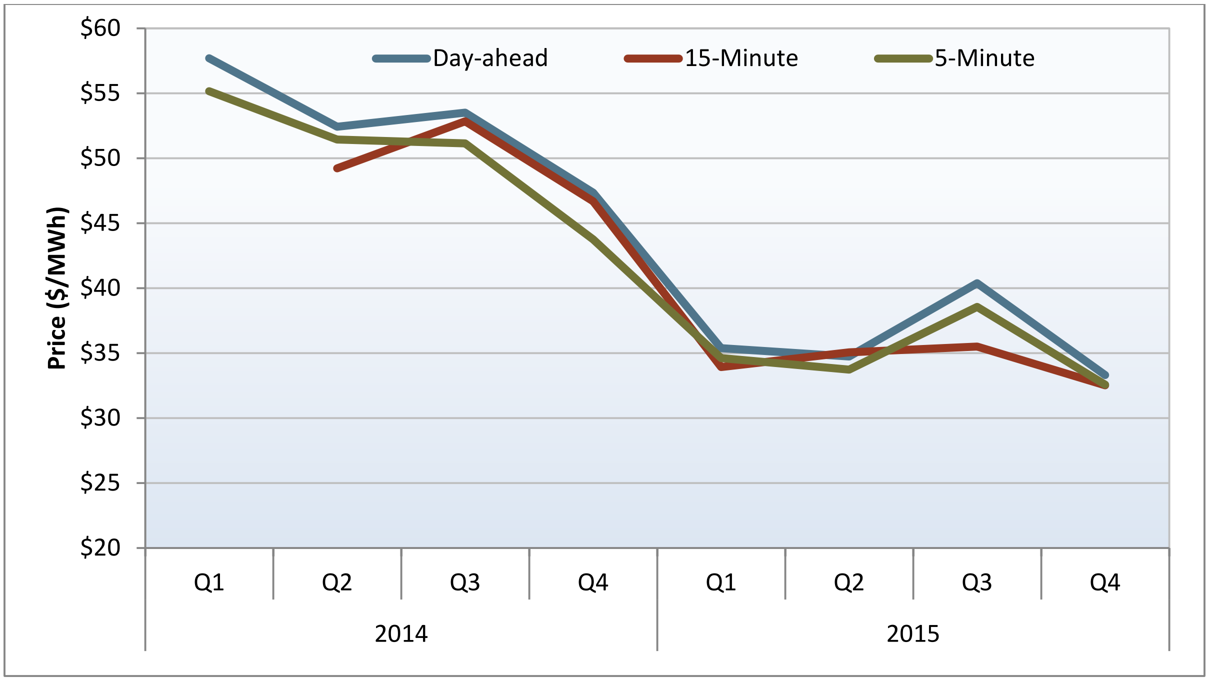
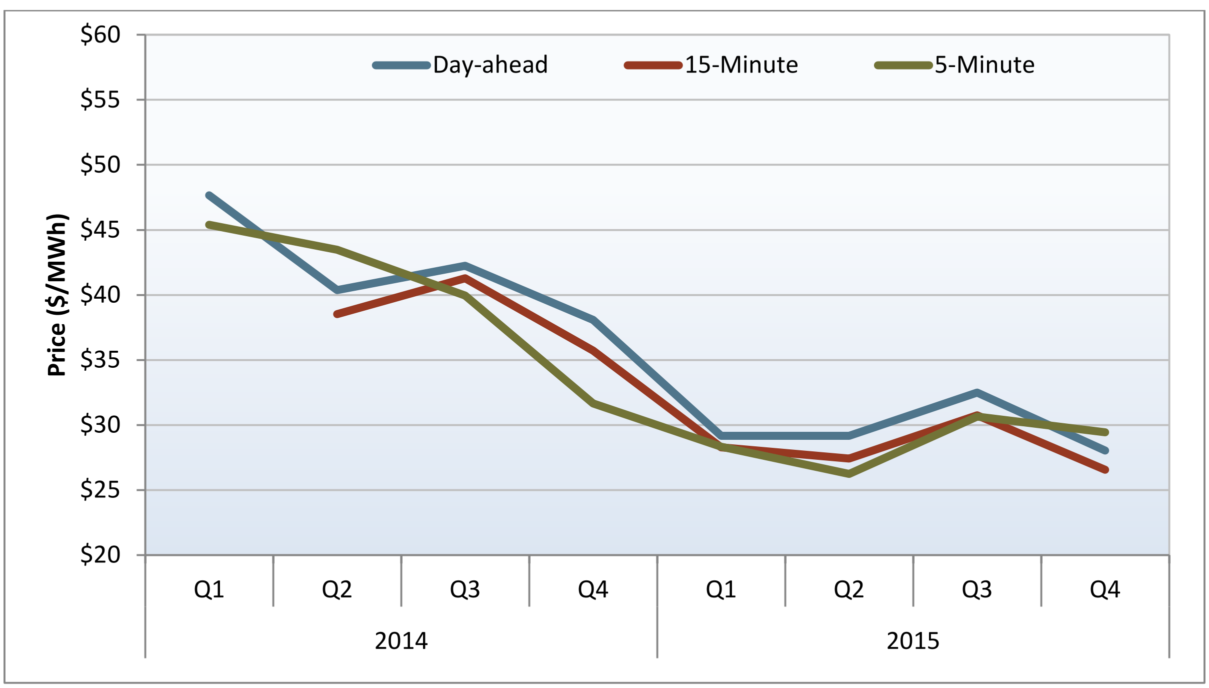


Figure E.4 Comparison of quarterly prices – system energy (off-peak hours)



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*, which was implemented in February 2011.

Convergence bidding allows participants to place purely financial bids for supply or demand in the day-ahead energy market. 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 real-time markets, which are dispatched based only on physical supply and demand.

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 on price differences at different locations due to congestion or between the day-ahead and real-time markets.

In 2015 convergence bidders continued a shift from virtual demand to virtual supply, which began in the latter half of 2013. Average hourly virtual supply clearing in the day-ahead market exceeded virtual demand by about 580 MW per hour in 2015, compared to an average of about 450 MW of net virtual supply last year. This trend reflects the change in prices that began in 2013, when average real-time prices began to be consistently lower than average day-ahead prices during most periods. The increase in virtual supply was driven in large part by an increase in net virtual supply bids submitted by marketers, which increased net virtual supply positions by about 100 MW per hour in 2015.

Total net revenues paid to entities engaging in convergence bidding, which included bid cost recovery charges allocated to virtual bids, were around $21 million in 2015, compared to about $26 million in 2014. Most of these net revenues resulted from virtual supply bids. However, financial entities and marketers also continued to place large volumes of offsetting virtual demand and supply bids at different locations during the same hour. Offsetting bids, which are designed to hedge or profit from congestion, represented about 55 percent of all accepted virtual bids in 2015.

Table E.1 compares the distribution of convergence bidding volumes and revenues among different groups of convergence bidding participants. These data show 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 around $14.5 million (almost half) of the total convergence bidding revenues in 2015.

The year-over-year decline in net revenues received by convergence bidders resulted in part from an increase in bid cost recovery payments from residual unit commitment costs allocated to virtual supply. The portion of these costs allocated to virtual supply rose to $7 million in 2015 from about $4 million in 2014. This was driven in large part by increases in long-start residual unit commitments, because of high levels of virtual supply on high load days in the summer. Further details on the increase in residual unit commitment can be found in Section 2.4.

Table E.1 Convergence bidding volumes and revenues by participant type (2015)

Trading entities	Average hourly megawatts			Revenues\Losses ($ millions)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	715	769	1,484	$0.5	$14.1	$14.6
Marketer	401	563	964	$0.9	$9.0	$9.9
Physical generation	70	170	240	-$0.5	$2.1	$1.7
Physical load	3	269	272	-$0.1	$2.6	$2.4
Total	**1,189**	**1,771**	**2,960**	**$0.8**	**$27.7**	**$28.6**

Local market power mitigation

The ISO day-ahead and real-time markets incorporate a transmission competitiveness evaluation and mitigation mechanism to address local market power. 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. This dynamic path assessment approach uses actual market conditions and produces a more accurate and less conservative assessment of transmission competitiveness than previous methods.

Most resources subject to mitigation submitted competitive offer prices, such that few bids were lowered as a result of the mitigation process. The number of units in the day-ahead market that had bids changed by mitigation averaged about 2.2 per hour in 2015, compared to 2.7 units per hour in 2014. The estimated impact of bid mitigation on the amount of additional energy clearing in the day-ahead market from units with mitigated bids was about 11 MW per hour in 2015 compared to about 17 MW per hour in 2014.

The frequency of bid mitigation in the real-time market in 2015 was lower when compared to 2014, averaging 1 unit with bids mitigated per hour in 2015 compared to 1.3 units per hour in 2014. The estimated impact of bid mitigation on the amount of additional real-time energy dispatched as a result of bid mitigation fell to about 6 MW per hour in 2015 from about 9 MW per hour in 2014.

Mitigation provisions that apply to exceptional dispatch for energy above minimum load reduced costs to $14,000 in 2015, down from $144,000 in 2014. This reflects the fact that exceptional dispatches were relatively low and bids mitigated were not significantly in excess of competitive levels.

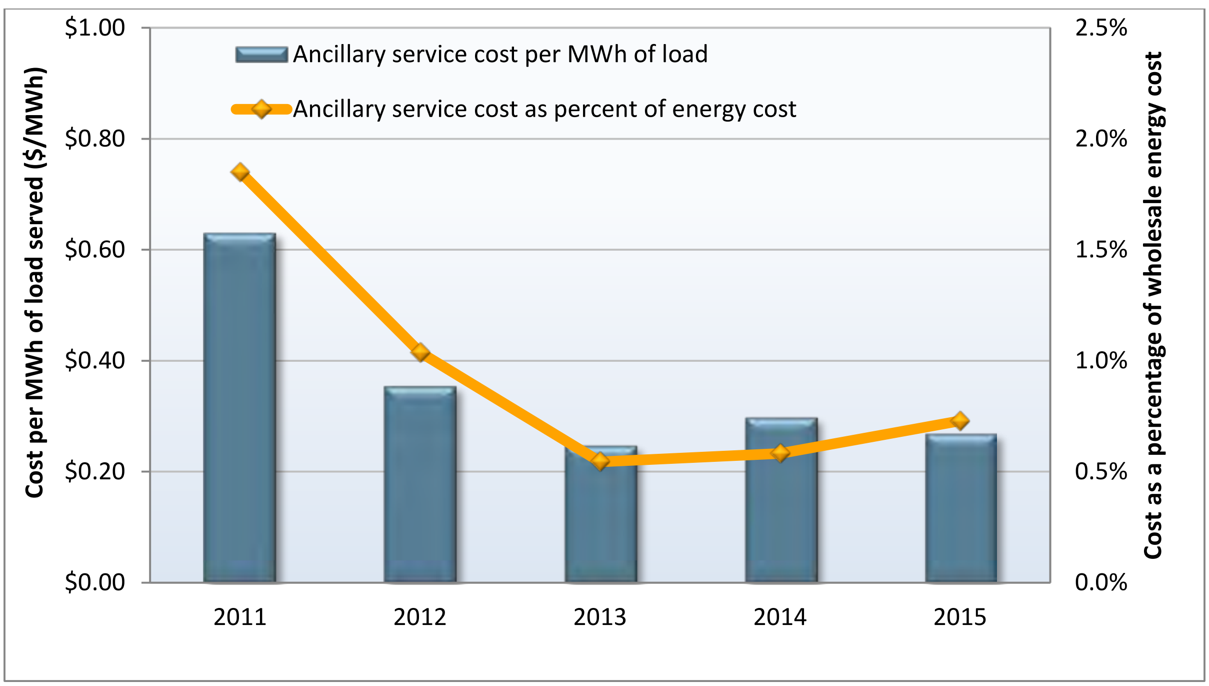
Ancillary services

Ancillary service costs totaled $62 million in 2015, representing a 10 percent increase from $69 million in 2014. The decrease is related to a decrease in ancillary services prices as a result of lower natural gas prices.

As shown in Figure E.5, ancillary service costs decreased to $0.27/MWh of load served in 2015 from $0.30/MWh in 2014. However, ancillary service costs as a percent of total wholesale energy costs increased slightly to 0.7 percent in 2015 from 0.6 percent in 2014. The simultaneous decrease in ancillary service costs per megawatt-hour of load and increase as a percent of wholesale energy costs is a result of wholesale energy costs decreasing more than ancillary service costs. This is likely related to decreased ancillary services provided by hydro-electric generation and imports, which were primarily replaced by higher cost natural gas capacity.

Ancillary service scarcity pricing events occurred in February, April, May and October. Scarcity pricing occurred in a total of nine intervals in the day-ahead market and 15 intervals in the 15-minute real-time market. This was the first time since implementation of scarcity pricing in December 2010 that scarcity events occurred in the day-ahead market. For the real-time market, the number of intervals with scarcity pricing decreased slightly compared to 2014, when they occurred in two intervals in the hour-ahead market and 14 intervals in the 15-minute market.

Figure E.5 Ancillary service cost as a percentage of wholesale energy cost



Exceptional dispatches

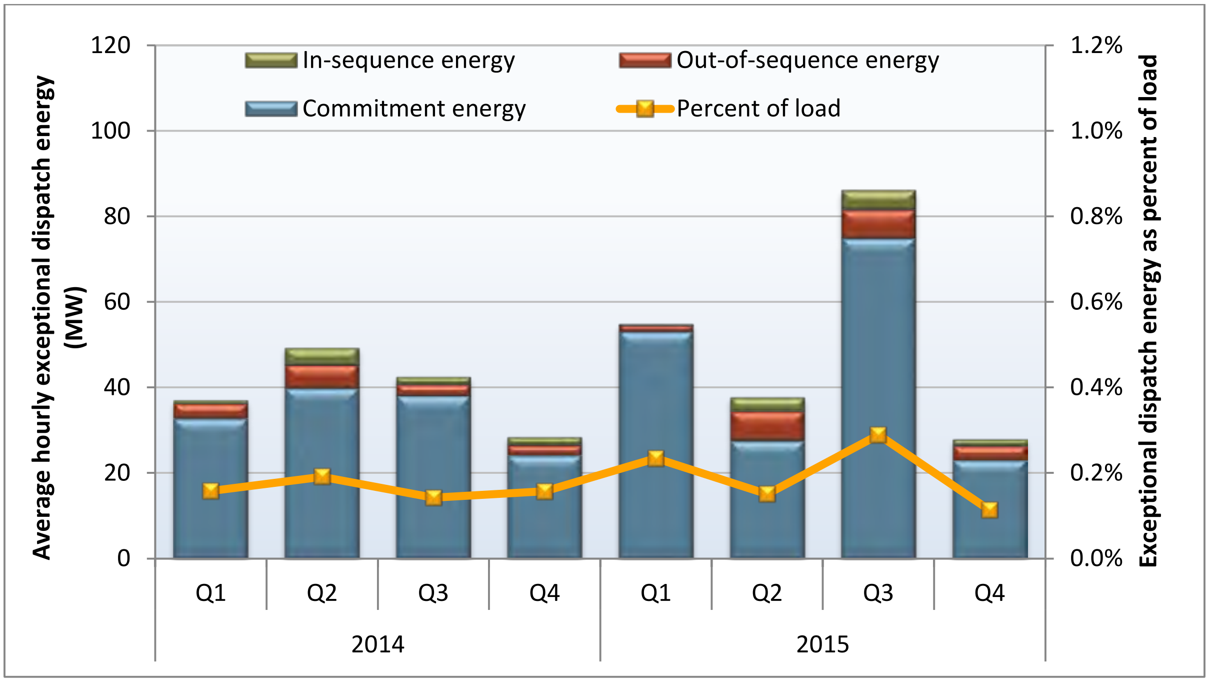
Exceptional dispatches are instructions issued by grid operators when the automated market optimization is not able to address particular reliability requirements or constraints. These dispatches are sometimes referred to as *manual* or *out-of-market* dispatches. Over the past several years, the ISO 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 increased in 2015, rising to 0.2 percent of system load in 2015 from 0.16 percent in 2014. While total energy from exceptional dispatches increased in 2015, total out-of-market costs from exceptional dispatches fell compared to 2014. This drop in out-of-market exceptional dispatch costs was driven by a decline in bid cost recovery payments associated with exceptional dispatch unit commitments. The following is shown in Figure E.6:

- Minimum load energy from units committed through exceptional dispatches averaged about 45 MW per hour in 2015, up from about 30 MW in 2014. The minimum load energy represents about 86 percent of energy from exceptional dispatches in 2015.
- Exceptional dispatches resulting in out-of-sequence real-time energy with bid prices higher than the market prices accounted for an average of about 5 MW per hour in 2015, up from 4 MW in 2014. This increase was driven primarily by load forecasting challenges in the third quarter and increased exceptional dispatch to manage transmission constraints.
- About 35 percent of the energy above minimum load from exceptional dispatches cleared in-sequence, which means that bid prices were less than the market clearing prices and were ultimately not classified as exceptional dispatches by the ISO.

The above-market costs of all exceptional dispatches, including commitment and energy, decreased to $9.3 million in 2015 from $11 million in 2014. Of these costs, approximately $1.2 million was related to exceptional dispatch energy above minimum load in 2015, compared to about $1 million in 2014.

Figure E.6 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:

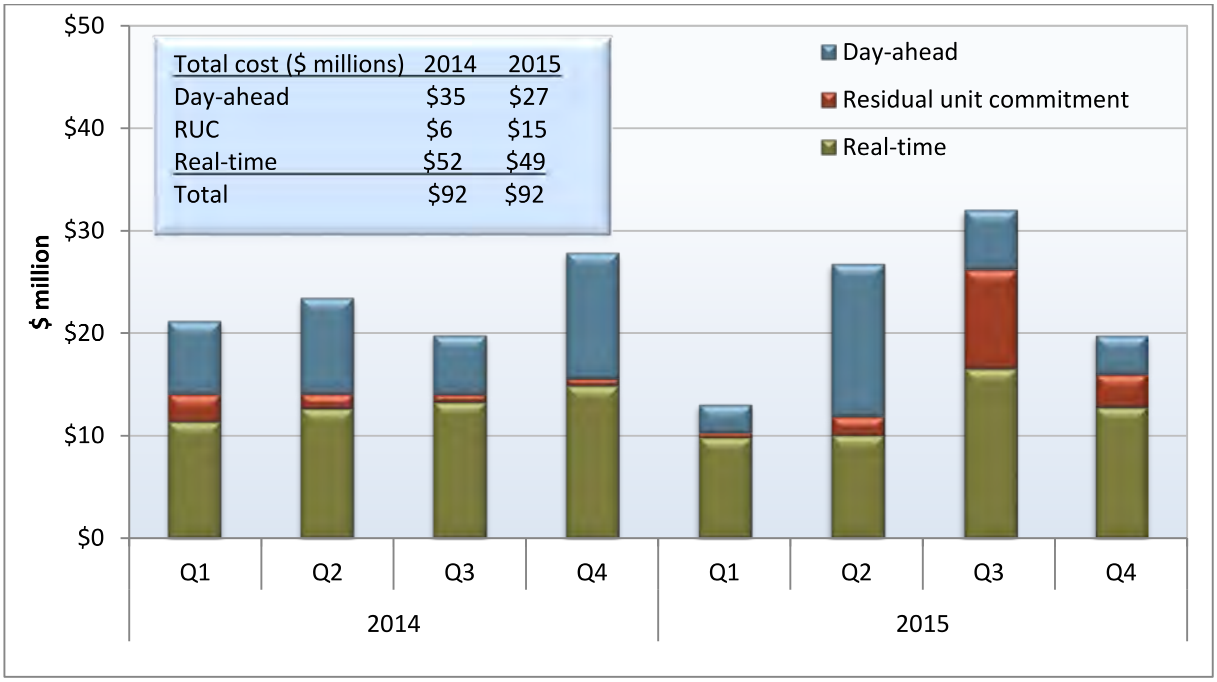
- Bid cost recovery payments;
- Real-time imbalance offset costs;
- Real-time exceptional dispatch costs; and
- Other reliability costs including reliability must-run and capacity procurement mechanism costs.

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.

Figure E.7 provides a summary of total estimated bid cost recovery payments in 2015. Bid cost recovery payments remained unchanged at $92 million from 2014, and remained less than 1 percent of total energy costs in 2015. While overall payments remained unchanged, payments for units scheduled through the residual unit commitment process increased to over $15 million in 2015, up from $6 million in 2014. These costs were driven in large part by higher cost long-start units that were committed through the residual unit commitment during the warmest parts of the year, when loads were highest.

Figure E.7 Bid cost recovery payments



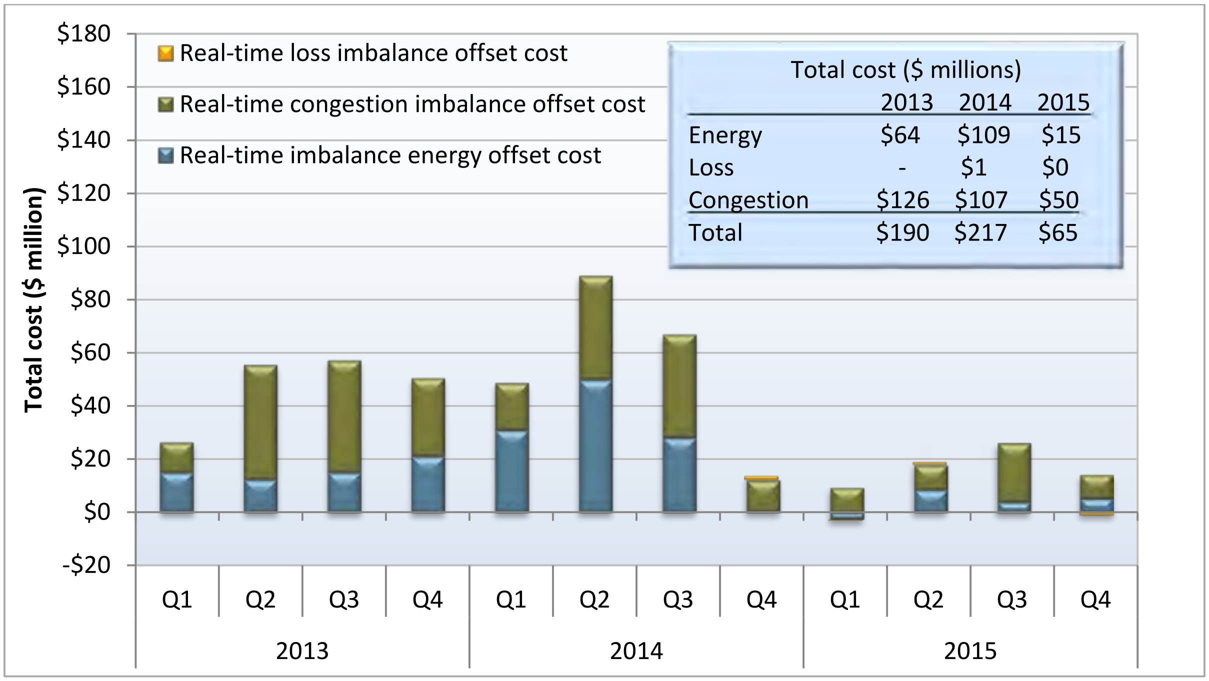
Real-time imbalance offset costs

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 real-time 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 three components. Any revenue imbalance from the energy component of real-time energy settlement prices is collected through the *real-time imbalance energy offset charge*. Any revenue imbalance from the congestion component of these real-time energy settlement prices is recovered through the *real-time congestion imbalance offset charge*. Until October 1, 2014, the ISO aggregated real-time loss imbalance offset costs with real-time energy imbalance costs. Following October 1, 2014, any revenue imbalance from the loss component of real-time energy settlement prices is collected through the *real-time loss imbalance offset charge*.

Total real-time imbalance costs for energy and congestion were about $65 million in 2015, compared to $217 million in 2014. As shown in Figure E.8, real-time imbalance congestion offset costs fell to $50 million in 2015 from $107 million in 2014. This decline is attributable in part to the resolution of an inter-tie metering error and transmission loss payback. The decrease in total imbalance offset costs was primarily attributable to a decrease in the real-time energy imbalance offset costs, which decreased from $109 million in 2014 to $15 million in 2015. Much of this decrease in congestion costs was the result of lower overall congestion.

Figure E.8 Real-time imbalance offset costs



Real-time exceptional dispatch costs

Real-time exceptional dispatch costs, also known as out-of-sequence costs, increased slightly from about $1 million in 2014 to around $1.2 million in 2015. The low increase in above-market costs from exceptional dispatch in 2015 generally reflect fewer exceptional dispatches subject to mitigation. Overall, the ISO goals to decrease the frequency and volume of exceptional dispatches appear to have influenced and sustained the low levels of 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 slightly to $26 million in 2015 from $25 million in 2014. These costs were primarily 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. This agreement was put into place due to the outages and retirement of the San Onofre Nuclear Generating Station units. These costs also include payments to Oakland Station Units 1, 2 and 3.

Capacity payments related to the capacity procurement mechanism decreased from almost $8 million in 2014 to under $1 million in 2015. In total, there were only two capacity procurement contracts in 2015. One of the contracts was related to transmission related reliability concerns and the second was related to load and weather conditions in the summer.

Congestion

This section provides a review of congestion and the market for congestion revenue rights in 2015. The findings include the following:

- Congestion on transmission constraints within the ISO system was low and had a limited impact on average overall prices across the system.
- The overall impact of congestion increased prices in the PG&E area above the system average by about $0.43/MWh (1.3 percent) in the day-ahead market and $0.86/MWh (2.6 percent) in the 15-minute market. Much of the impact in the PG&E area was related to Path 15 planned maintenance during most of the second quarter.
- Congestion decreased average day-ahead prices in the SCE area below the system average by about $0.28/MWh (0.9 percent), and decreased real-time prices by $0.55/MWh (1.8 percent).
- Prices in the SDG&E area were impacted the least overall by internal congestion. Average day-ahead prices in this area increased above the system average by about $0.20/MWh (0.6 percent) while real-time congestion decreased prices by about $0.19/MWh (0.6 percent).
- The frequency and impact of congestion was lower in 2015 than 2014 on most major inter-ties connecting the ISO with other balancing authority areas, particularly for inter-ties connecting the ISO to the Pacific Northwest and Palo Verde.
- Total day-ahead congestion rents fell 50 percent to $230 million in 2015 from $460 million in 2014. This dramatic decrease in day-ahead congestion contributed significantly to improvements in a variety of metrics related to congestion revenue rights.

Congestion revenue rights

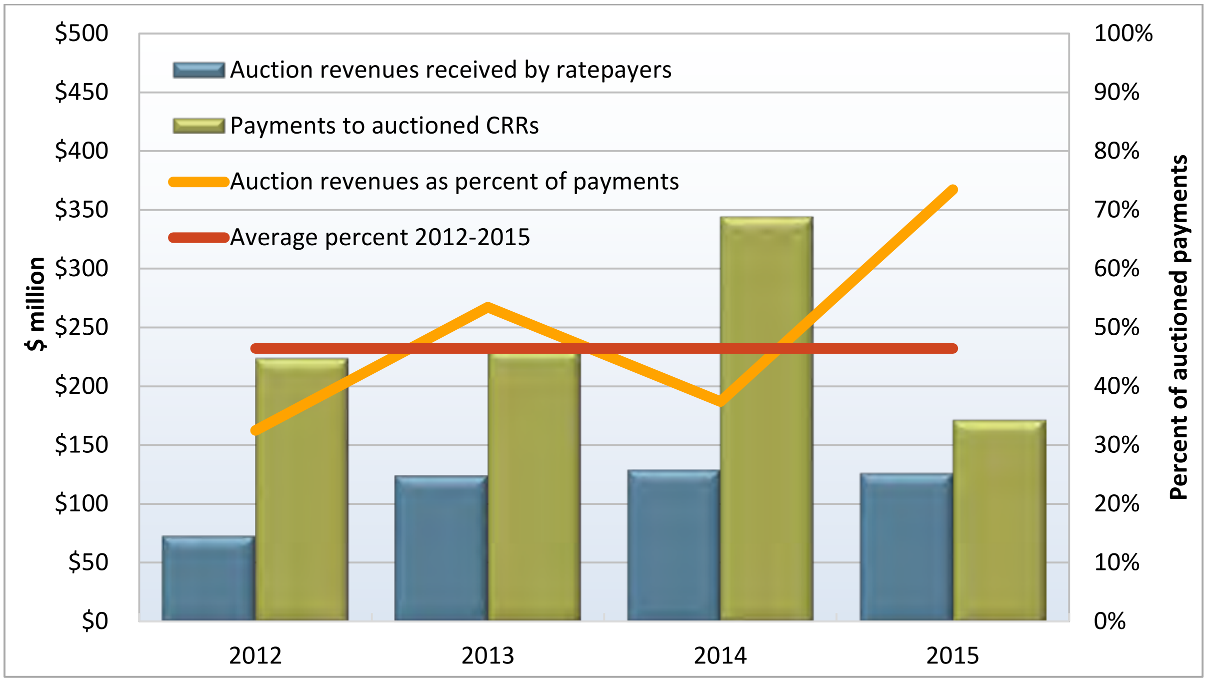
This report includes an analysis of the performance of the congestion revenue rights auction from the perspective of the ratepayers of load-serving entities. Key findings from this analysis include the following:

- Congestion revenue rights not allocated to load-serving entities that are sold in the auction consistently generate significantly less revenue than is paid to the entities purchasing these rights at auction. As shown in Figure E.9, from 2012 through 2015 ratepayers received about 45 percent of the value of their congestion revenue rights that the ISO auctioned.[4] This represents an average of about $130 million per year less in revenues received by ratepayers than the congestion payments received by entities purchasing these rights over the last four years.
- In 2015 this difference was lower ($45 million) due largely to much lower levels of congestion in the day-ahead market throughout the ISO system.
- As indicated in DMM's prior annual reports, entities purchasing congestion revenue rights are primarily financial entities not purchasing these rights as a hedge for any physical load or

[4] The large discrepancy between what congestion revenue rights sell for at auction and what they end up being worth is not unique to the California ISO. For a description of this phenomenon in PJM, see the PJM Independent Market Monitor's "2015 State of the Market Report for PJM" available at: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015.shtml.

generation. Thus, DMM recommends that the ISO and stakeholders reconsider the standard electricity market design assumption that ISOs should auction off transmission capacity in excess of the capacity allocated to load-serving entities.

Figure E.9 Ratepayer auction revenues compared with congestion payments for auctioned CRRs



Resource adequacy

California's wholesale market relies heavily on a long-term procurement planning process and resource adequacy program adopted by the California Public Utilities Commission 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 year was the first year that new flexible resource adequacy requirements and procurement were in place. Analysis of these new requirements in this report highlight the following:

- The total flexible resource adequacy requirement exceeded the actual maximum three-hour net load ramp in every month but January. However, because there are varying must-offer hours for the different flexible categories, the effective flexible resource adequacy requirement *during* the hours of the actual maximum net load ramp was often less than the ramping need.
- Collectively, load-serving entities procured more flexible capacity than required. This capacity exceeded the actual maximum three-hour net load ramp in every month. Procurement consisted mostly of gas-fired generation that qualified as Category 1 (base flexibility) capacity.
- Flexible resource adequacy capacity had fairly high levels of availability in 2015 even though there was not an incentive mechanism in place and resources could not provide substitute capacity during

outages or when a use-limitation was reached. Average availability ranged from 80 percent to 94 percent in the day-ahead market and from 84 percent to 92 percent in the real-time market.

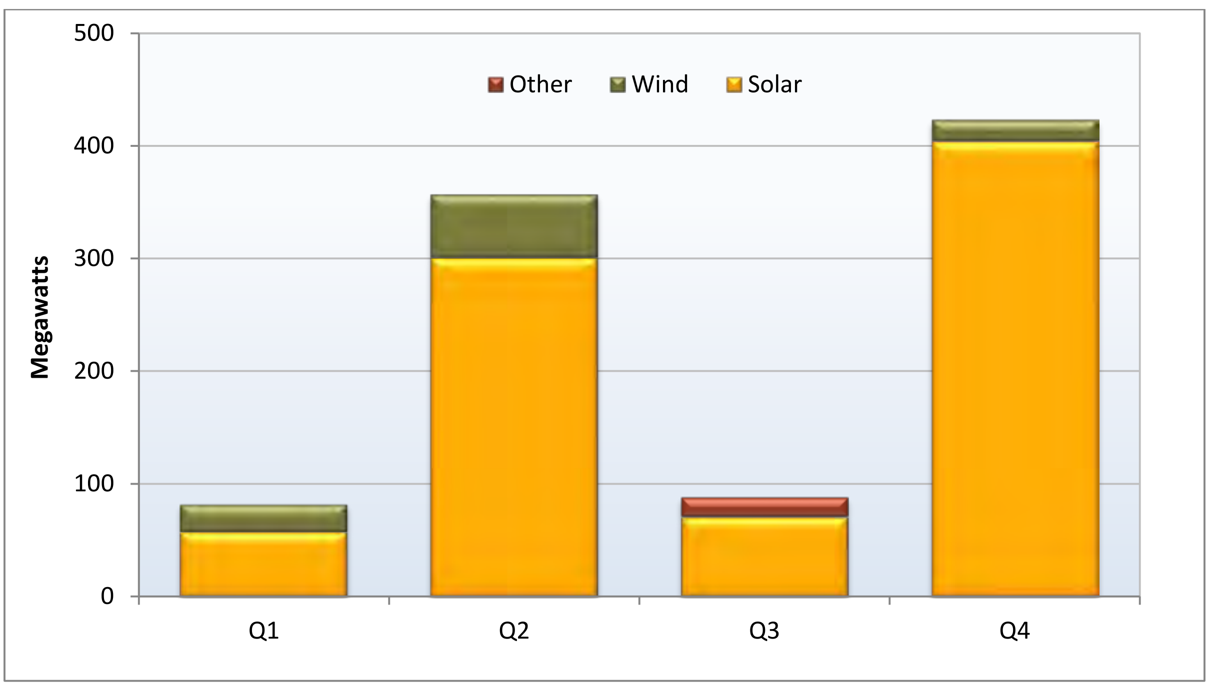
The CPUC and the ISO continue to refine and enhance the resource adequacy framework. Currently, the CPUC and ISO are developing protocols for determining requirements for flexible capacity, counting flexible resource adequacy showings, expanding replacement and substitution provisions, and resolving any shortfalls 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.10 summarizes the quarterly trends in summer capacity additions in 2015. Almost 1,700 MW of new nameplate generation began commercial operation within the ISO system in 2015, contributing to almost 950 MW of additional summer capacity. All of the new generation capacity was from renewable resources, primarily solar.

Figure E.10 Generation additions by resource type (summer peak capacity)



The ISO anticipates a continued increase in new nameplate renewable generation in the coming years to meet the state's goal to have 33 percent renewable generation by 2020 and 50 percent by 2030. While no new natural gas-fired capacity was added in 2015, over 1,000 MW of old natural gas generation was retired. Going forward, significant reductions in total gas-fired capacity may continue beyond 2015 due to the state's restrictions on using once-through cooling technology. The ISO has highlighted the need to back up and balance renewable generation with the flexibility of conventional generation resources to maintain reliability as more renewable resources come on-line.

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 2015 prices for gas and electricity show an increase in net operating revenues for hypothetical new combustion turbine gas units, compared to prior years, and reductions in net operating revenues for hypothetical new combined cycle units. In both cases, however, the 2015 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 2015 fell to an estimated $46/kW-year in Southern California, compared to potential annualized fixed costs of $165/kW-year.

Under current market conditions, additional new generic gas-fired capacity does not appear to be needed at this time. Net operating revenues for many – if not most – older existing gas-fired generators are likely to be lower than their going-forward costs. 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 on-line. However, this capacity must be retrofitted or replaced over the next decade to eliminate use of once-through cooling technology. This investment is likely to require some form of longer-term capacity payment or contracting.

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.

Congestion revenue rights

The performance of the congestion revenue rights auction in this report is assessed from the perspective of the ratepayers of load-serving entities. The analysis shows that congestion revenue rights not allocated to load-serving entities that are sold in the auction consistently generate significantly less revenue than is paid to the entities purchasing these rights at auction. From 2012 through 2015, ratepayers received about 45 percent of the value of their congestion revenue rights that the ISO auctioned.[5] This represents an average of about $130 million per year less in revenues received

[5] The large discrepancy between what congestion revenue rights sell for at auction and what they end up being worth is not unique to the California ISO. For a description of this phenomenon in PJM, see the PJM Independent Market Monitor's "2015 State of the Market Report for PJM" available at: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015.shtml.

by ratepayers than the congestion payments received by entities purchasing these congestion revenue rights over the last four years. In 2015 this difference was $45 million.

As indicated in DMM's prior annual reports, entities purchasing congestion revenue rights are primarily financial entities not purchasing these rights as a hedge for any physical load or generation. Thus, DMM recommends that the ISO and stakeholders reconsider the standard electricity market design assumption that ISOs should auction off transmission capacity in excess of the capacity allocated to load-serving entities.

If the auction revenue is expected to be less than the day-ahead market congestion revenue, then ratepayers should not want the ISO to auction off this extra transmission. Ratepayers would be better off directly receiving revenues from this transmission when congestion occurs in the day-ahead market, rather than receiving a lower price through the congestion revenue right auction process. Instead, it would be much more beneficial to allow ratepayers to collect these congestion revenues directly. DMM believes these results warrant reassessing the standard electricity market design assumption that ISOs should auction off transmission capacity that remains in excess of the capacity allocated to load serving entities.

The losses to ratepayers from the congestion revenue rights auction could in theory be avoided if load-serving entities purchased the rights at the auction from themselves. However, there are significant technical and regulatory hurdles making it difficult for load-serving entities to purchase these rights. Moreover, DMM does not believe it is appropriate to design an auction so that load-serving entities would have to purchase rights in order to avoid obligations to pay other congestion revenue rights holders. DMM believes it would be more appropriate to design the auction so that load-serving entities will only enter obligations to pay other participants if they are actively willing to enter these obligations at the prices offered by the other participants. With this approach, any entity placing a value on purchasing a hedge against congestion costs could seek to purchase this directly from the financial entities.

Virtual bidding

Virtual bidding on inter-ties was scheduled to be re-implemented in May 2015, one year after implementation of the 15-minute real-time market design. In April 2015, the ISO filed a report by DMM cautioning that reinstatement of virtual bidding on inter-ties coupled with the observed lack of liquidity for bidding on inter-ties could lead to decreased market efficiency. The ISO subsequently filed for a waiver to defer reinstatement of virtual bidding on inter-ties on May 1, 2015. [6]

FERC issued an order in September 2015 that found virtual bidding at inter-ties to be "unjust and unreasonable" under current market conditions and required the ISO to amend its tariff to eliminate virtual bidding on inter-ties.[7] To reinstate virtual bidding on inter-ties, the ISO would now need to file at FERC and demonstrate that this market feature would "function properly." DMM does not believe that the potential benefits of reinstating virtual bidding at inter-ties outweigh the potential market inefficiencies and other potential unforeseen issues that could result from virtual bidding at inter-ties.

[6] http://www.caiso.com/Documents/Apr3_2015_TariffWaiver_IntertieCB_ER15-1451.pdf

[7] See: http://www.caiso.com/Documents/Sep25_2015_Order_Request_Waiver_InstitutingSection206Proceeding_IntertieConvergenceBidding_EL15-98_ER15-1451_ER14-480.pdf.

Start-up and minimum load bids

The ISO completed a multiphase stakeholder process in early 2016 that resulted in ISO Board of Governors approval of several changes to the way that start-up and minimum load costs for natural gas units are calculated.[8] DMM has provided detailed comments on this initiative internally as well as through written comments submitted as part of the stakeholder process.[9]

DMM supports the ISO's overall proposal for commitment cost bidding improvements as a step forward in addressing a variety of important but difficult and controversial issues. However, DMM notes that this initiative incorporates several market design changes that are being made to accommodate various stakeholders. This could have the effect of reducing overall market efficiency and the flexibility of the gas-fired fleet at a time when the ISO will likely need to rely on a smaller but more flexible gas fleet to integrate the growing volume of renewable resources on the ISO system.

Opportunity cost bid adders. DMM is supportive of rule changes proposed by the ISO for use-limited resources, and notes that their effectiveness will depend on the details of the opportunity cost model process implementation. Use-limited resources include resources that have start and run limitations from environmental or other operational restrictions. The rule changes allow for units to include a calculated opportunity cost adder, which represents the opportunity cost a unit will forgo later by running and not being available in future potentially higher priced hours. DMM also recommends that the ISO complete development of a fully functional opportunity cost model and then utilize this model to work with stakeholders using actual unit and market data to identify any needed refinements prior to implementation.

Exemption for contractual limitations. The ISO has proposed to allow units to seek a three year exemption for contractual limitations incorporated in long-term contracts that have undergone extensive regulatory scrutiny and were entered prior to January 1, 2015. DMM continues to believe it is inefficient to treat contractual limitations as physical limitations in the market optimization, whether these contractual provisions are treated directly as physical unit operating constraints or indirectly through an opportunity cost adder. To the extent that these contractual limitations may reflect actual physical or environmental limits, it is more efficient and appropriate to incorporate these limits directly into unit operating constraints or opportunity cost bid adders.

The actual amount and location of capacity eligible for the proposed exemption, and the actual contractual limitations of these resources, will only be known with certainty after approval and implementation of the ISO's proposal. But some eligible resources may be in transmission constrained areas, and a significant amount of gas-fired generation could be eligible as well. Gas-fired generation eligible for this exemption could be problematic as the footprint will require increased flexibility from gas-fired generation as renewable generation grows.

Negotiated opportunity cost bid adders. The ISO's proposal offers a negotiated opportunity cost option to a potentially large set of resources. However, the proposed opportunity cost model will not include modeling of the most common type of multi-stage generating resource, a combined cycle unit, which may have a limit on the number of transitions between configurations. DMM has recommended the

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[8] *Commitment Cost Enhancements Phase 3 Draft Final Proposal*, February 17, 2016, http://www.caiso.com/Documents/DraftFinalProposal-CommitmentCostEnhancementsPhase3.pdf.

[9] *Comments on Commitment Cost Enhancements Phase 3 Draft Final Proposal*, Department of Market Monitoring, March 4, 2016:

http://www.caiso.com/Documents/DMMComments-CommitmentCostEnhancementsPhase3-DraftFinalProposal.pdf.

optimization tool now under development be expanded, if possible, to allow modeling of additional resource types if a significant number of units apply for opportunity cost adders.

Resource operating characteristics. The ISO is proposing to provide generators flexibility to submit lower values for three key unit characteristics used in the market software: maximum daily starts, maximum multi-stage generator daily transitions, and ramp rates. This represents a reduction of current tariff requirements concerning unit start-ups and ramp rates. When implementing this provision, DMM notes that exemptions should not be granted on the grounds that starting a unit up to twice a day may increase maintenance. ISO market rules are designed so that any incremental maintenance costs associated with starting up and operating a unit can be incorporated directly in commitment cost bids through major maintenance adders. To help manage this issue, the ISO will need to develop a process, guidelines and expertise to carefully evaluate any exemptions to the two start per day requirement.

Recovery of commitment costs that exceed the commitment cost bid cap. The ISO is proposing to add tariff provisions that will allow market participants to seek after-the-fact FERC approval of incurred actual commitment costs that exceed the commitment cost bid caps. The ISO would then reimburse the FERC approved costs through its bid cost recovery mechanism. DMM is supportive of providing a reimbursement mechanism, and has done analysis that indicates it would be used infrequently. Even though the proposal calls for FERC to assess any gas reimbursement filings by generators, DMM has encouraged the ISO to continue to work with stakeholders – and personnel with additional expertise in gas markets and procurement – to develop more specific guidelines, requirements and methodological details.

Market power mitigation

When congestion is not projected to occur in the 15-minute advisory market run, but does occur in the 15-minute or 5-minute binding runs, bid mitigation is not triggered. In DMM's prior reports, this is referred to as potential *under-mitigation*. Over the course of 2015, DMM continued to work with the ISO to develop software enhancements to effectively address the issue of potential under-mitigation in the real-time market. As a result of this effort, enhancements are being implemented in the 2016 spring and fall software releases to address the issue of potential under-mitigation. Both these modifications will make the current process more effective by integrating market power mitigation procedures more closely with the final software run used to determine final schedules and prices. These enhancements will increase the accuracy of mitigation in terms of applying mitigation during intervals when potential market power exists in the real-time market.

Flexible ramping product

DMM has worked with the ISO and the Market Surveillance Committee to develop a final version of a proposal for the flexible ramping product that will replace the flexible ramping constraint currently incorporated in the real-time market software. DMM is highly supportive of the ISO's final proposal for establishing a flexible ramping product. The proposal includes the following key details:

- Flexible ramping capacity prices will be set based on opportunity costs, rather than offers bid into the markets by generators.
- The flexible ramping product will not include a mechanism for day-ahead flexible ramping capacity procurement.

- Settlements will be based directly on market prices, rather than out-of-market uplift charges.
- Procurement of flexible ramping capacity will be based on a price-sensitive demand curve, rather than a solitary target.

DMM and the Market Surveillance Committee (MSC) have recommended that the ISO needs to thoroughly analyze the performance of the forecasting tool before it is implemented. The ISO also needs to track the performance of the methodology used to calculate ramp requirements after implementation and correct elements of the methodology that lead to poor projections of flexible ramping needs without long lags.

DMM believes that further refinements can be made to the initial cost allocation approach incorporated in the ISO's proposal to better align the allocation of flexible ramping costs with resources and performance that create demand for this product.[10] DMM is also supportive of further market design efforts that might allow the flexible ramping products to be effectively incorporated into the day-ahead market.

Contingency modeling enhancements

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 their system operating limits 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 on-line capacity constraints to position resources so that the ability is available to return critical paths to their operating limits within 30 minutes in the event of such a contingency.

The ISO has proposed an alternative modeling approach aimed at reducing the use of exceptional dispatches and minimum on-line capacity constraints. The modeling enhancements proposed by the ISO include modeling 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 in the market model.[11] DMM is supportive of this initiative, and believes one of the main benefits is the efficiencies gained from incorporating these requirements into the market model.

DMM also recommends updating the congestion revenue rights auction process for these constraints, and suggests excluding congestion prices from the post-contingency constraints in the congestion revenue rights settlement process. Thus, only transmission rights actually purchased would be paid for and all potential revenue inadequacy for congestion revenue rights would be eliminated from post-contingency constraints.

[10] *DMM Comments on Flexible Ramping Product Revised Draft Final Proposal*, January 15, 2016: http://www.caiso.com/Documents/DMMComments-FlexibleRampingProductRevisedDraftFinalProposal.pdf.

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

Resource adequacy

In 2014, the ISO completed a flexible capacity procurement proposal to establish flexible capacity requirements and set the criteria for counting the amount of flexible capacity that can be provided by different resources toward meeting these requirements. These flexible capacity rules are widely viewed as an interim solution and will provide the ISO and CPUC with additional experience and time to develop a more comprehensive set of provisions. The process of addressing flexible capacity needs and other issues related to the evolving framework of resource adequacy in the ISO are also being addressed through the CPUC's joint reliability plan proceeding.[12]

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 of the timeline needed to bring new flexible capacity on-line. The two major recommendations for this product should be that 1) the flexible capacity requirements should be adequate to meet actual operational ramping needs, and 2) the flexible capacity procurement should be directly linked with a must-offer obligation for operational ramping products.

The following sections summarize DMM's comments and recommendations on several ongoing initiatives relating to the resource adequacy program.

Resource operating characteristics. As discussed above, proposed changes in bidding rules that would allow market participants to bid resources, particularly flexible gas-fired resources, into the market according to contractual limitations rather than physical limitations could reduce available flexibility and jeopardize resource adequacy. Requirements that resources submit a minimum of two start-ups and two transitions per day, unless this exceeds their physical operating limits, was recommended by DMM and adopted by the ISO which helps to address these concerns. DMM further recommends that the ISO continue to assess how resource operating characteristics used in the market software may limit the ability of resources to actually provide the flexibility needed by the ISO system.

Reliability services initiative. The ISO is implementing an ISO Board approved initiative to encourage greater availability from resource adequacy resources.[13] The first phase of this initiative was completed in early 2015. DMM noted that, because the penalty for not meeting availability standards was set at 60 percent of the potential cost of procuring replacement capacity, it could be less costly for generating unit owners to pay the penalty rather than provide substitute capacity when supply conditions are tight. Consequently, DMM recommends that the ISO monitor this issue over time and adjust the penalty level so that it is sufficient to prevent this.[14]

As part of the second phase of this initiative, the ISO is working to improve the rules relating to the newly approved resource adequacy availability incentive mechanism (RAAIM).[15] While DMM views this mechanism as an improvement over the previous incentive mechanism (the *standard capacity product*), we still view the design of the mechanism as incomplete. DMM is recommending that the ISO incorporate an assessment of resources' performance when actually dispatched into its availability

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[12] For more information on the CPUC's joint reliability plan (JRP) see: http://www.cpuc.ca.gov/PUC/energy/Procurement/The_Joint_Reliability_Plan_Proceeding.htm.

[13] The proposal considered by the ISO Board can be found at: http://www.caiso.com/Documents/DraftFinalProposalAddendum-ReliabilityServices.pdf.

[14] Memorandum to ISO Board of Governors, from Eric Hildebrandt, Director, Market Monitoring, March 19, 2015, pp.6-7. http://www.caiso.com/Documents/Department_MarketMonitoringReport-Mar2015.pdf.

[15] http://www.caiso.com/informed/Pages/StakeholderProcesses/ReliabilityServices.aspx

incentive mechanism, rather than basing performance solely on whether or not a resource submitted a bid.

Flexible resource adequacy and must-offer obligation. The ISO continues to assess and improve the newly implemented flexible resource adequacy program as part of the flexible resource adequacy criteria and must-offer obligation initiative. While this program is in its first stages, DMM encourages the ISO and CPUC to consider modifying the current framework as the 2015 requirements and must-offer hours were insufficient in reflecting actual ramping needs.

The effectiveness of flexible resource adequacy requirements and must-offer rules hinge in part on the ability to predict the level of the maximum net load ramp as well as the time of day the ramp occurs over a year in advance, which can prove to be problematic. DMM is also concerned that a significant amount of procured flexible capacity in 2015 was from long-start or extra-long-start units that will not have a real-time obligation unless committed well in advance. DMM encourages the ISO and CPUC to consider whether flexible capacity from such resources should be limited in order to ensure the grid has sufficient real-time flexibility.

Non-resource specific resource adequacy imports. The ISO is currently assessing the ability of 15-minute inter-tie resources to be used to meet flexible resource adequacy requirements. Based on its initial assessment, the ISO proposed to allow 15-minute inter-tie resources that meet certain qualifications to provide flexible capacity.[16] These requirements include that imports be *resource specific* and must commit to providing firm energy to the ISO. Based on input from some stakeholders, the ISO is considering allowing non-resource specific resources to provide imported flexible capacity as well.

DMM is concerned that if imports are allowed to provide flexible capacity, additional criteria and even monitoring or reporting requirements may need to be developed to ensure that these imports are backed by available physical capacity that may be dispatched in the 15-minute market. Unlike resources within the ISO, the actual availability of resource specific imports cannot be directly monitored by the ISO. While resource adequacy imports are required to submit bids in the day-ahead market, if they are not dispatched, then they have no must-offer obligation in real-time.

DMM is recommending that the requirements and expectations relating to the physical availability of imports used to meet resource adequacy requirements be further discussed and clarified as part of this initiative. This is important since imports used to meet resource adequacy obligations are required to bid in the day-ahead market, but are not subject to any limits on bid price and do not have any must-offer obligation in real-time if not accepted in the day-ahead market.

[16] *Flexible Resource Adequacy Criteria and Must Offer Obligation – Phase 2 Straw Proposal,* December 11, 2015, pp.12-14. http://www.caiso.com/Documents/StrawProposal-FlexibleResourceAdequacyCriteria-MustOfferObligationPhase2.pdf.

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 2015. 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 2015.
- **Real-time market performance.** Chapter 3 provides an analysis of real-time market performance including information on 15-minute scheduling and pricing, the flexible ramping constraint and real-time bidding flexibility.
- **Energy imbalance market.** Chapter 4 highlights the performance of the energy imbalance market.
- **Convergence bidding.** Chapter 5 analyzes the convergence bidding feature and its effects on the market.
- **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 system and flexible resource adequacy programs in 2015.
- **Recommendations.** Chapter 11 highlights DMM recommendations on current market issues and new market design initiatives on an ongoing basis.

1 Load and resources

This chapter reviews key aspects of demand and supply conditions that affected overall market prices and performance. In 2015, wholesale electricity prices were driven lower by a 40 percent decrease in gas prices and a significant increase in supply from new solar generation. These factors offset the impact of higher peak loads and the lowest level of hydro-electric production since the ISO began operation in 1998.

More specific trends highlighted in this chapter include the following:

- The average price of natural gas in the daily spot markets in California decreased by about 40 percent from 2014. This was the main driver in the 30 percent decrease in the nominal annual wholesale energy cost per megawatt-hour of load served in 2015.
- Summer loads peaked at 47,257 MW, an increase of more than 2,000 MW from 2014 and the highest peak load observed in several years.
- Hydro-electric generation decreased by about 16 percent compared to 2014 and provided approximately 5 percent of total supply in 2015. This is the lowest level since the ISO began operation in 1998.
- Net imports decreased by about 2 percent in 2015. Imports from the Southwest decreased by about 3 percent, while imports from the Northwest remained roughly unchanged.
- Energy from wind and solar resources directly connected to the ISO grid provided more than 12 percent of system energy, compared to about 10 percent in 2014. Solar energy production increased by about 38 percent compared to 2014 and became the largest source of renewable power.
- About 950 MW of summer peak generating capacity was added in 2015, with almost 90 percent of this new capacity coming from solar generation.
- Demand response programs operated by the major utilities continued to meet about 5 percent of the ISO's overall system resource adequacy capacity requirements. During the summer, there was a significant increase in proxy demand response capacity registered into the ISO market, but only a fraction of this capacity was dispatched.
- The estimated net operating revenues for typical new gas-fired generation in 2015 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. These findings highlight 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 within the ISO remained almost the same in 2015 compared to 2014. Table 1.1 summarizes annual system peak loads and energy use over the last five years.

Table 1.1 Annual system load in the ISO: 2011 to 2015

Year	Annual total energy (GWh)	Average load (MW)	% change	Annual peak load (MW)	% change
2011	226,087	25,791	0.4%	45,545	-3.8%
2012	234,584	26,740	3.7%	46,847	2.9%
2013	231,800	26,461	-1.0%	45,097	-3.7%
2014	231,610	26,440	-0.1%	45,090	0.0%
2015	231,495	26,426	0.0%	47,257	4.8%

Average annual load remained almost unchanged in 2015 from the prior year. Overall, load has been relatively steady for the last several years. Even so, instantaneous peak load increased by almost 5 percent from 2014, and was the highest load in the last five years.

- Annual system energy totaled 231,495 GWh, about the same as in 2014.
- Summer loads peaked at 47,257 MW on September 10 at 5:00 p.m. — an increase of over 2,000 MW from 2014 and the highest peak load observed since 2010.

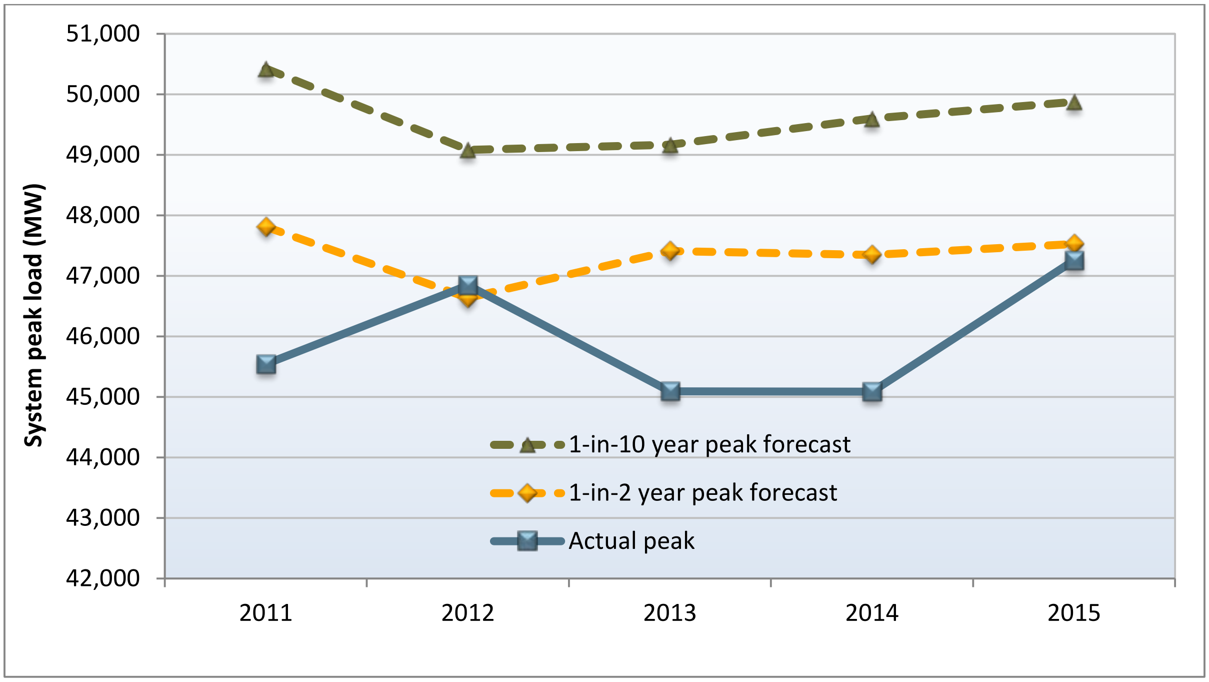
System demand during the single highest load hour often varies substantially year-to-year because of summer heat waves. The potential for heat-related peak loads creates a continued threat to operational reliability problems and drives many of the ISO's reliability planning requirements.

The peak load in 2015 was about equal to the ISO's 1-in-2 year load forecast (47,529 MW), and was about 5 percent lower than the 1-in-10 year forecast (49,879 MW) as shown in Figure 1.1. 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.

Load forecasting challenges during the summer

Challenges in load forecasting, which were likely related to a strong El Niño effect, impacted the market during the warm summer months when loads were highest. During the summer months, ISO forecasts tended to overestimate system load during the peak hours on many days. However, on days with the highest loads (>40,000 MW), the ISO day-ahead forecasts tended to significantly underestimate loads.

Figure 1.1 Actual load compared to planning forecasts



This pattern of forecasting errors tended to decrease real-time prices on most days, when load was overestimated, and contributed to very high real-time prices on days when the day-ahead load was underestimated. There were multiple days during the summer where this pattern resulted in high system-wide prices caused by frequent power balance constraint relaxations.[17] Forecasting uncertainty also led operators to at times increase residual unit commitment target levels and make exceptional dispatches to ensure reliability.

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 1.2). Table 1.2 summarizes the total amount of load used to set local reliability requirements within each of these local areas under the 1-in-10 year forecast. Most of the total peak system demand is located within two areas: the Los Angeles Basin (41 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 51 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.

[17] For instance, the real-time load on June 8 was over 3,000 MW higher than the ISO's day-ahead forecast during several peak hours, resulting in many power balance constraint relaxations.

- The Pacific Gas and Electric area accounts for almost 39 percent of total local capacity area loads under the 1-in-10 year forecast. Loads in the Greater Bay Area account for 54 percent of the potential peak load in the PG&E area.
- The San Diego Gas and Electric area is composed of a single local capacity area, which accounts for about 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. The proportion of load and generation located within the areas is shown in Table 1.2 and is an indication of the relative importance of results for different aggregate load and local capacity areas on overall market results.

Table 1.2 also 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.[18] 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.

Table 1.2 Load and supply within local capacity areas in 2015

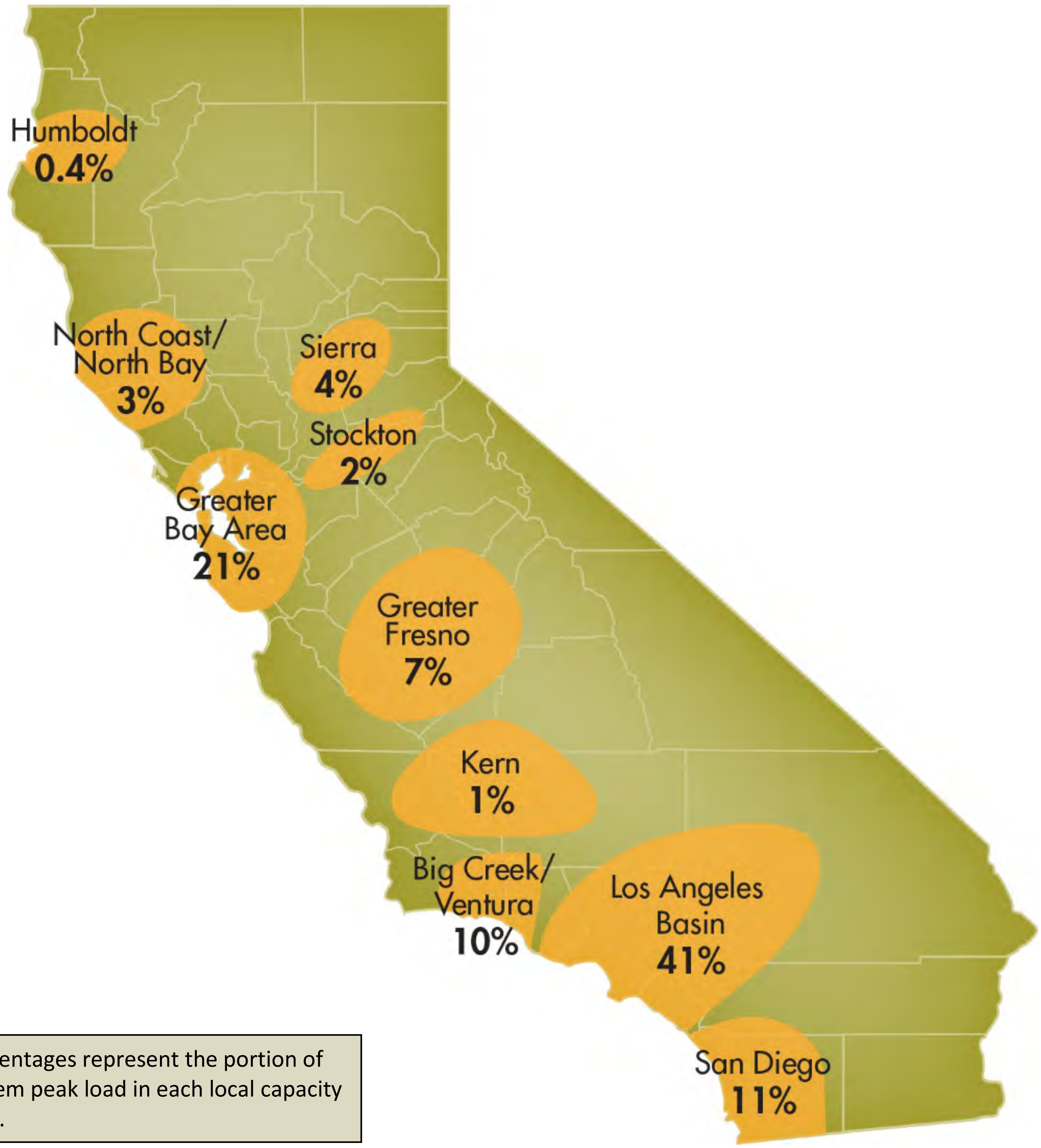
Local Capacity Area	LAP	Peak Load (1-in-10 year) MW	%	Dependable Generation (MW)	Local Capacity Requirement (MW)	Requirement as Percent of Generation
Greater Bay Area	PG&E	10,229	21%	7,505	4,367	58%*
Greater Fresno	PG&E	3,217	7%	2,848	2,439	86%*
Sierra	PG&E	1,961	4%	2,070	2,200	106%*
North Coast/North Bay	PG&E	1,458	3%	901	550	61%
Stockton	PG&E	1,105	2%	589	707	120%*
Kern	PG&E	731	1%	495	437	88%*
Humboldt	PG&E	195	0.4%	207	166	80%
LA Basin	SCE	19,970	41%	11,193	9,097	81%
Big Creek/Ventura	SCE	4,807	10%	5,363	2,270	42%
San Diego	SDG&E	5,407	11%	4,547	4,112	90%*
Total		**49,080**		**35,718**	**26,345**	

Source: *2016 Local Capacity Technical Analysis: Final Report and Study Results*, April 30, 2015. See Table 6 on page 22. http://www.caiso.com/Documents/Final2016LocalCapacityTechnicalReportApr302015.pdf.

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

[18] In addition, California's once-through cooling (OTC) regulations affect a significant proportion of capacity needed to meet requirements in four areas: Greater Bay Area, Los Angeles Basin, Big Creek/Ventura and San Diego.

Figure 1.2 Local capacity areas



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

1.1.3 Demand response

Demand response continues to play a 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 adjust 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.

Most demand response programs are currently dispatched and administered by the utilities that sponsor these programs, rather than by the ISO.[19] These programs are overseen by the CPUC. Independent demand response providers offer this resource through utility-sponsored programs, as do other non-utility entities. Most demand response provided directly to the ISO is pumping load, which is not associated with the utility demand response programs.[20]

In 2010, the ISO implemented a proxy demand resource product. This 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.

The total measured capacity of proxy demand response resources grew to almost 200 MW in 2015 from about 50 MW in 2014. Most of this increase occurred in mid-June when one participant registered multiple resources from an internally administered demand response program into the ISO market.

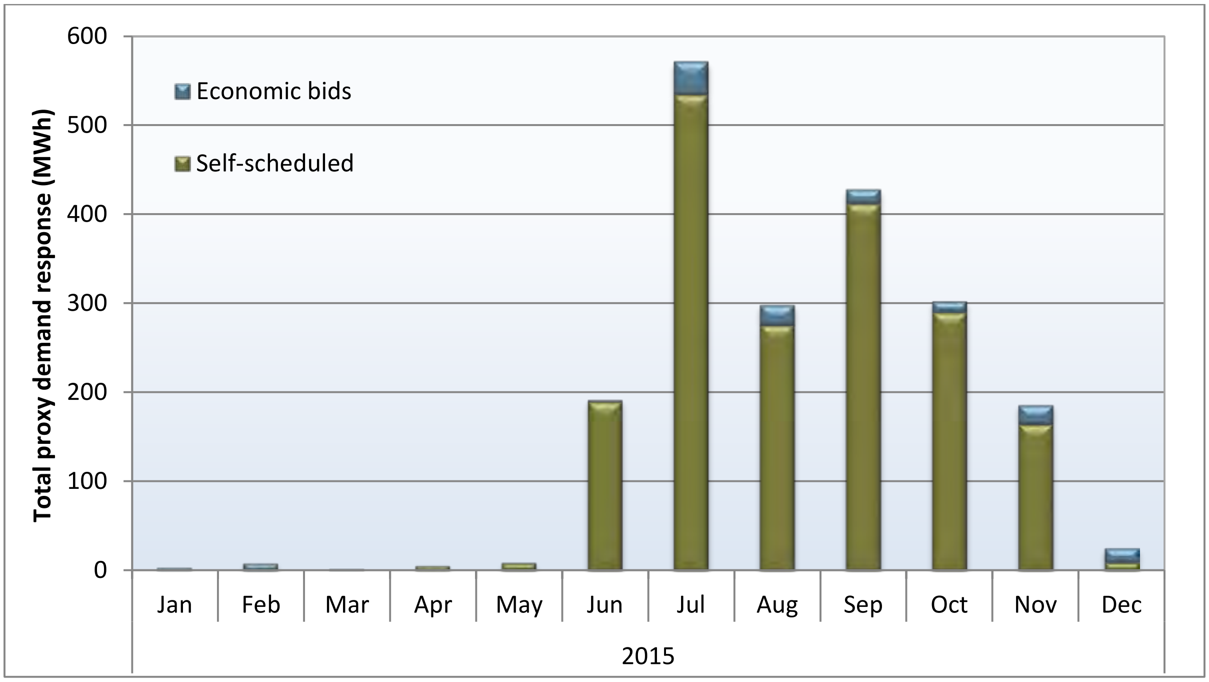
During 2015, 97 percent of proxy demand response was dispatched during peak weekday load hours (hours 15 through 19) between June and November. Figure 1.3 shows the total monthly volume of self-scheduled and price sensitive bids for proxy demand response in the real-time market. About 93 percent of proxy demand response bids in the real-time markets in 2015 were self-schedules. Total proxy demand response was most significant in July and September and occurred on several days with particularly high peak system loads.[21] Proxy demand resources were also dispatched frequently in the summer and fall months during peak weekday load hours. In comparison, these resources were dispatched only several times in 2014 and not at all in 2013.

[19] However, there was an increase in demand response bid in and dispatched by the ISO in 2015. This is discussed below.

[20] 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.

[21] Proxy demand response dispatches were highest on July 1, 2015, with almost 75 MWh dispatched during three consecutive peak load hours.

Figure 1.3 Proxy demand response self-schedules and bids



While almost 200 MW of proxy demand resource capacity was registered in 2015, only a fraction of this capacity was dispatched into the market. Table 1.3 shows the average hourly dispatch of proxy demand response during 291 peak load hours between June and November. During these hours, a monthly average of around 4 to 9 MWh of proxy demand response was dispatched, or around 3 to 5 percent of the monthly proxy demand resource capacity.

Table 1.3 Average hourly proxy demand response dispatched and frequency

Month	Number of days	Average hours per day	Average hourly dispatched (MWh)
June	14	3	4.2
July	22	3	9.0
August	18	3	4.8
September	20	3	6.5
October	16	2	8.0
November	19	2	4.7

The ISO also enabled reliability demand response resources to be dispatched by the ISO during a system emergency beginning in May 2014. When an emergency condition is declared, reliability demand response resources can enter the bid stack at prices between $950/MWh to $1,000/MWh. While no reliability demand response resources were registered or available for dispatch in the ISO market in 2014, many of these resources were integrated into the ISO market in 2015 with total measured capacity of almost 1,200 MW. Most of this increase occurred simultaneously with the increase of proxy demand resources in June. These resources participated directly in the ISO markets in 2015, but were not dispatched as the ISO did not declare a system emergency.[22]

In addition to the utility demand response programs, the ISO issues Flex Alerts when system conditions are expected to be particularly stressed. Flex Alerts urge consumers to voluntarily reduce demand and are communicated through press releases, text messages and other means. The paid media program that was funded by the utilities, under the authority of the CPUC, ended at the end of 2015. During 2015, the ISO declared a Flex Alert for June 30 and July 1 in response to reliability concerns related to high temperatures and higher than expected energy demand.[23]

Utility demand response programs

California's demand response consists of load management programs operated by the state's three investor-owned utilities. Historically, these programs were triggered by criteria set by the utilities and were not necessarily tied to wholesale market prices. Notification times required by the retail programs were historically not well coordinated with ISO market operations, which limited the programs' use and usefulness in the ISO markets. However, with the integration of a substantial portion of this capacity into the ISO's proxy demand response and reliability demand response resource programs, there is now a much stronger connection after the activation of these programs.

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.[24]

- ***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. For programs not yet integrated in the ISO's proxy demand response program, 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 because 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. Day-of demand response programs that are also proxy demand response resources can be dispatched through the ISO market systems.

[22] For more information, see: http://www.caiso.com/Documents/Mar28_2014_OrderAcceptingTariffRevisions-ReliabilityDemandResponse_ER11-3616_ER13-2192.pdf.

[23] See: http://www.caiso.com/Documents/CaliforniaISO_DeclaresFlexAlertForCalifornia.pdf.

[24] This includes resources that are in the reliability demand response resource program.

Table 1.4 summarizes total demand response capacity for each of the three major utilities during the peak summer month of August, as reported to the CPUC.[25] Protocols in effect since 2010 require utilities to report two measures of demand response capacity: *ex ante* and *ex post*.[26] *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 2015.

Each investor-owned utility uses demand response capacity to meet resource adequacy requirements. As shown in the bottom two rows of Table 1.4, demand response capacity used to meet resource adequacy requirements has tracked closely with estimates of actual demand response capacity reported in these years under the more advanced reporting protocols.

Estimated demand response capacity available in August was approximately equal to the resource adequacy requirements that the CPUC allowed these resources to meet. 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 1.4 Utility operated demand response programs (2011-2015)

Utility/type	2011 Estimated MW	2012 Estimated MW	2013 Estimated MW	2014 Estimated MW	2015 Estimated MW
Price-responsive					
SCE	287	962	706	790	690
PG&E	469	340	404	418	285
SDG&E	58	118	54	61	83
Sub-total	814	1,420	1,164	1,269	1,058
Reliability-based					
SCE	1,167	727	684	733	767
PG&E	253	282	332	313	334
SDG&E	8	2	0	0	1
Sub-total	1,428	1,010	1,016	1,046	1,102
Total	2,270	2,430	2,180	2,315	2,160
Resource adequacy allocation	2,421	2,598	2,582	2,299	2,401
With 15 percent adder	2,784	2,987	2,970	2,644	2,761

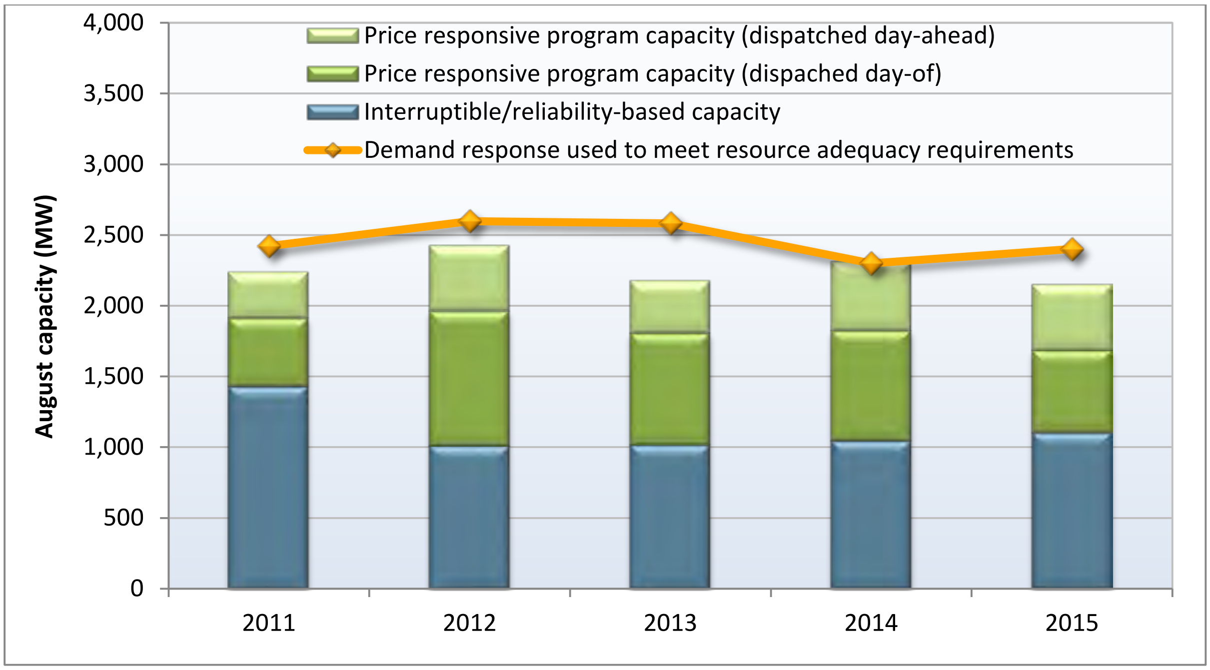
Figure 1.4 summarizes data in Table 1.4, but provides a further breakdown of the portion of price-responsive capacity that can be dispatched on a day-ahead and day-of basis. As shown in Figure 1.4:

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

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

- Price-responsive programs accounted for just under 50 percent of total demand response capacity in 2015, which has declined somewhat over the last few years as more stringent requirements have been imposed.
- Reliability-based programs also accounted for about 50 percent of the capacity from utility-managed demand response resources in 2015. Overall, capacity from reliability-based programs has increased slightly during the past few years.
- In 2015, price-responsive programs that can be dispatched on a day-of basis fell to 27 percent of all demand response capacity, down from about 34 percent in 2014.

Figure 1.4 Utility operated demand response programs (2011-2015)



1.2 Supply conditions

1.2.1 Generation mix

Natural gas and imports continued to be the largest sources of energy to meet ISO load in 2015. Because of low levels of precipitation and snowpack, hydro-electric generation continued to decrease in 2015 compared to the already low levels observed in 2014. Solar generation from resources directly connected to the ISO grid increased its overall share of generation to almost 7 percent.

Figure 1.5 provides a profile of average hourly generation by month and fuel type. Figure 1.6 illustrates the same data on a percentage basis. These figures show the following:

- The two largest sources of energy to meet ISO load in 2015 were natural gas and net imports, with about 40 percent of energy from natural gas generators and 28 percent from net imports. These percentages were roughly unchanged compared to 2014.
- Non-hydro renewable generation directly connected to the ISO system accounted for about 18 percent of total supply in 2015.[27] This represents an increase from about 16 percent in 2014, driven primarily by growth in generation from solar resources.
- Nuclear generation provided about 8 percent of supply in 2015, up slightly from about 7 percent in 2014.
- Hydro-electric generation continued to decrease in 2015 and provided approximately 5 percent of supply.

[27] 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.

Figure 1.5 Average hourly generation by month and fuel type in 2015

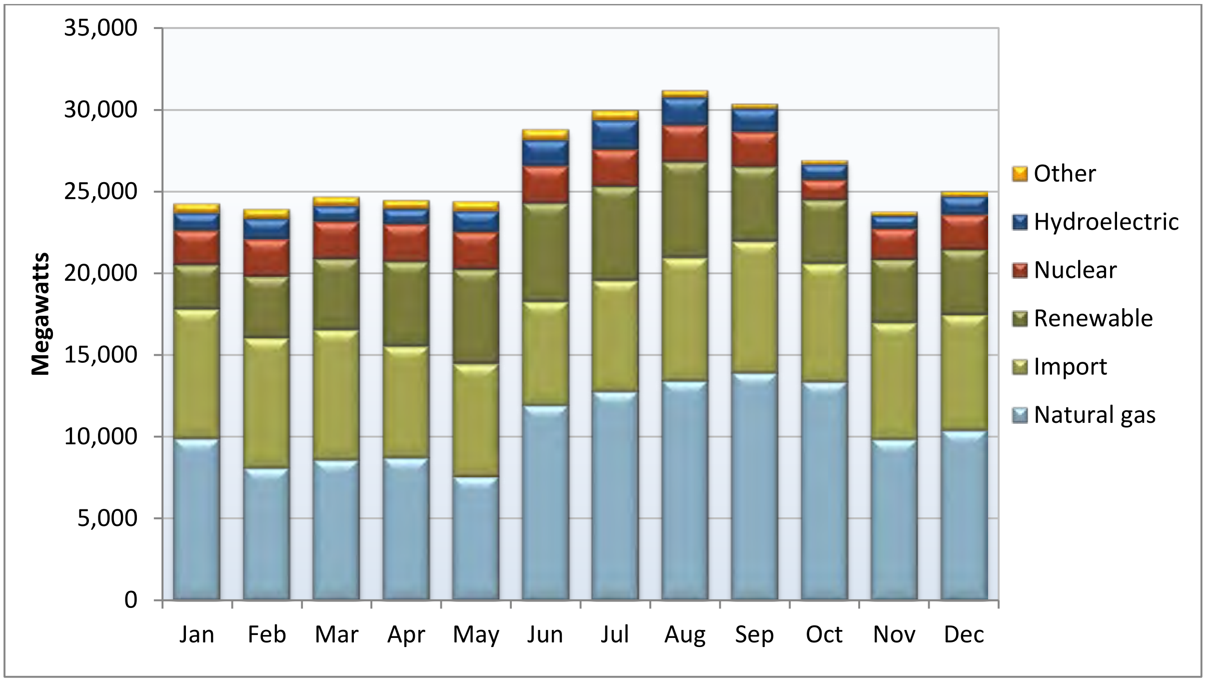
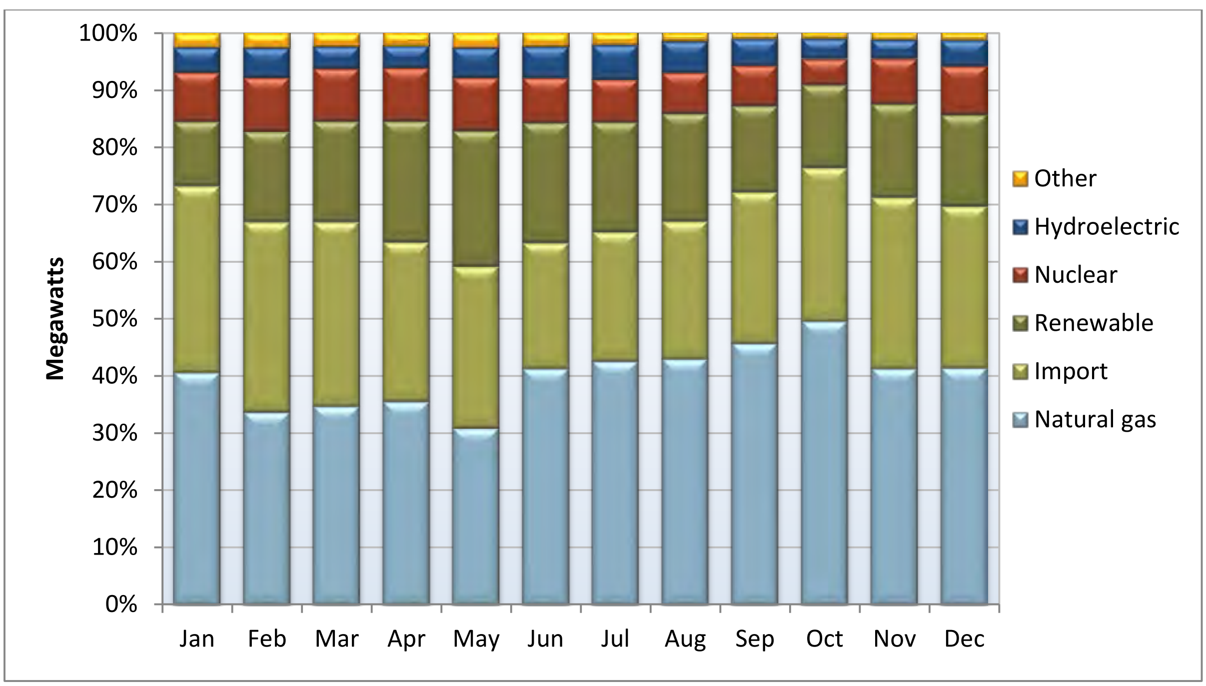


Figure 1.6 Average hourly generation by month and fuel type in 2015 (percentage)



Renewable generation

As noted above, about 18 percent of ISO load was met by non-hydro renewable generation directly connected to the grid. In addition, some of the imported energy was generated from renewable sources. DMM has limited access to the sources of most imports, with the exception of imports from tie generators. Tie generators are located outside the ISO balancing area but are under the direct control of ISO operators and are dispatched in a similar way to internal generators. Including these tie generators, about 19 percent of ISO load was met by non-hydro renewables in 2015.

Figure 1.7 provides a detailed breakdown of non-hydro renewable generation including tie generators. The following is shown in Figure 1.7:

- In 2015, solar power became the largest source of renewable energy for the first time since the ISO began operation in 1998. Overall output from solar generation increased by about 38 percent compared to 2014 and accounted for almost 7 percent of total supply in 2015. The increase was primarily driven by the addition of new solar resources.
- Generation from wind resources decreased slightly and contributed about 5 percent of total system energy.
- The overall output from geothermal generation increased by about 24 percent in 2015 and provided almost 5 percent of system energy. This increase occurred because a group of geothermal generators located outside of the ISO footprint became tie generators in late 2014.
- Biogas, biomass, and waste generation accounted for about 2 percent of system energy, a slight decrease compared to 2014.

Figure 1.8 compares average monthly generation from hydro, wind and solar resources. Because of the dramatic increase in solar generation and simultaneous decrease in hydro-electric generation, the amount of energy produced by solar exceeded hydro-electric generation for all months of 2015 except January. During the spring and summer months, wind generation also exceeded hydro-electric generation on an average hourly basis.

Wind production peaked in late spring when solar generation also approached peak output levels and system loads were moderate. During this period outages on Path 15 reduced the transmission capacity between Northern and Southern California. The combination of these conditions contributed to frequent negative prices reflecting near over-generation conditions during this period. This is described in further detail in Chapter 3.

Figure 1.7 Total renewable generation by type (2012-2015)

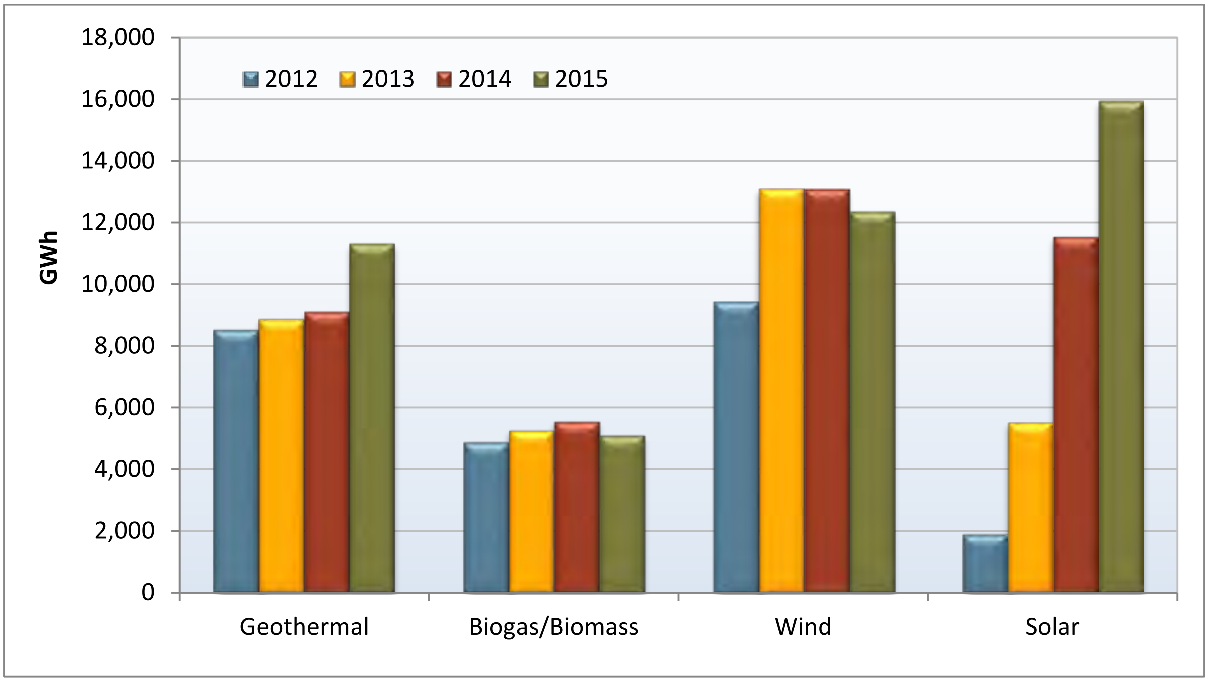
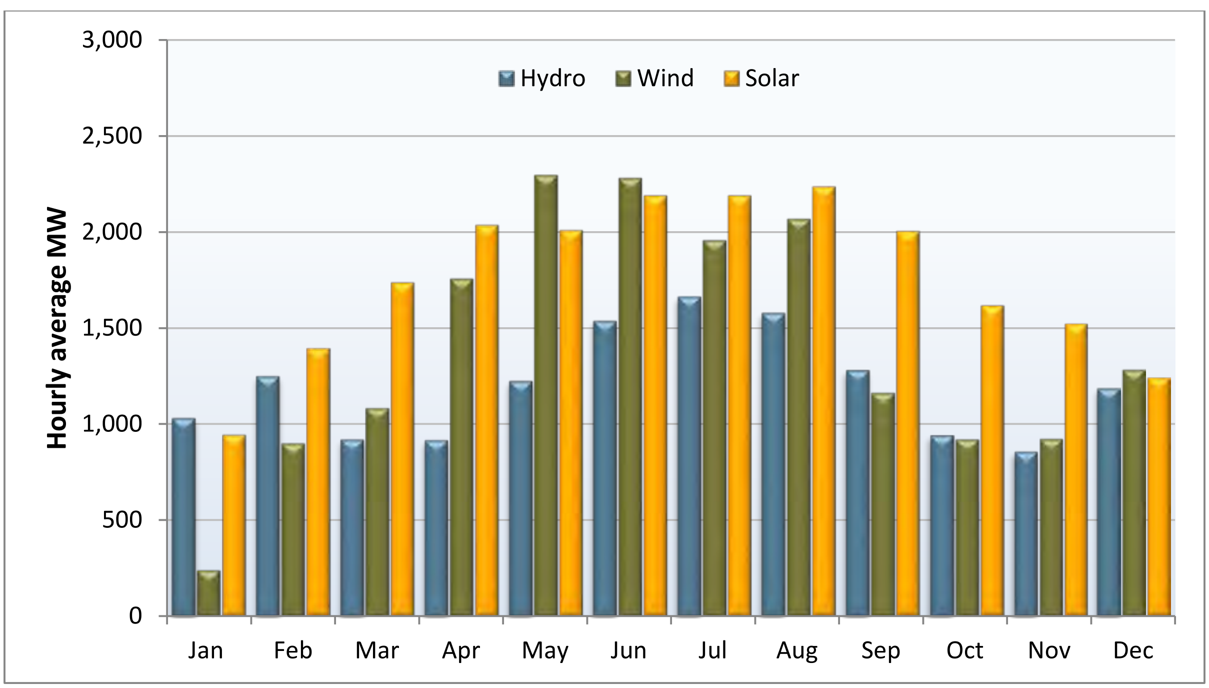


Figure 1.8 Monthly comparison of hydro, wind and solar generation (2015)



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.

Total hydro-electric production in 2015 fell below the already very low production levels in 2014. Hydro-electric generation in 2014 was the lowest since ISO began operation in 1998. In 2015, hydro-electric production decreased by an additional 16 percent. As seen in Figure 1.9, 2015 was the fourth consecutive year with decreasing hydro-electric generation. The yearly total hydro-electric generation was only about one third of the output four years earlier. Snowpack in the Sierra Nevada mountains, as measured on May 1, 2015, was only 3 percent of the long-term average, indicating much lower than average hydro conditions.[28]

Figure 1.10 compares monthly hydro-electric output from resources within the ISO system for each of the last three years. As in previous years, hydro generation in 2015 followed a seasonal pattern with the highest levels of generation in the late spring and early summer months. However, the difference between summer and winter production was smaller in 2015 compared to previous years. During the months of April through July, hydro production was 69 percent of production during the same period of 2014. For the rest of the year, the monthly generation levels were similar between 2014 and 2015.

Net imports

Net imports decreased by about 2 percent in 2015 compared to 2014.[29] Total net imports from sources in the Northwest remained roughly unchanged while net imports from the Southwest decreased by more than 3 percent. Figure 1.11 compares net imports by region for each quarter of 2014 and 2015. Net imports from the Northwest were lower than the previous year in all but the first quarter of 2015, while net imports from the Southwest were lower in all but the last quarter.

These changes in imports were likely driven by demand and supply conditions in the Pacific Northwest and the Southwest. Figure 1.12 shows the quarterly average day-ahead price difference for peak hours between Northern California (NP15) and the Northwest (Mid-C) as well as between Southern California (SP15) and the Southwest (Palo Verde). The increase in imports from the Northwest in the first quarter reflects that the price difference for the Northwest was higher compared to the first quarter of 2014, while the price difference for the Southwest decreased during the same time period. For the remaining three quarters of 2015, the price difference for the Northwest declined more than in 2014, and may have contributed to fewer imports during this period relative to the previous year.

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[28] 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.

[29] Net imports are equal to scheduled imports minus scheduled exports in any period.

Figure 1.9 Annual hydro-electric production (2006-2015)

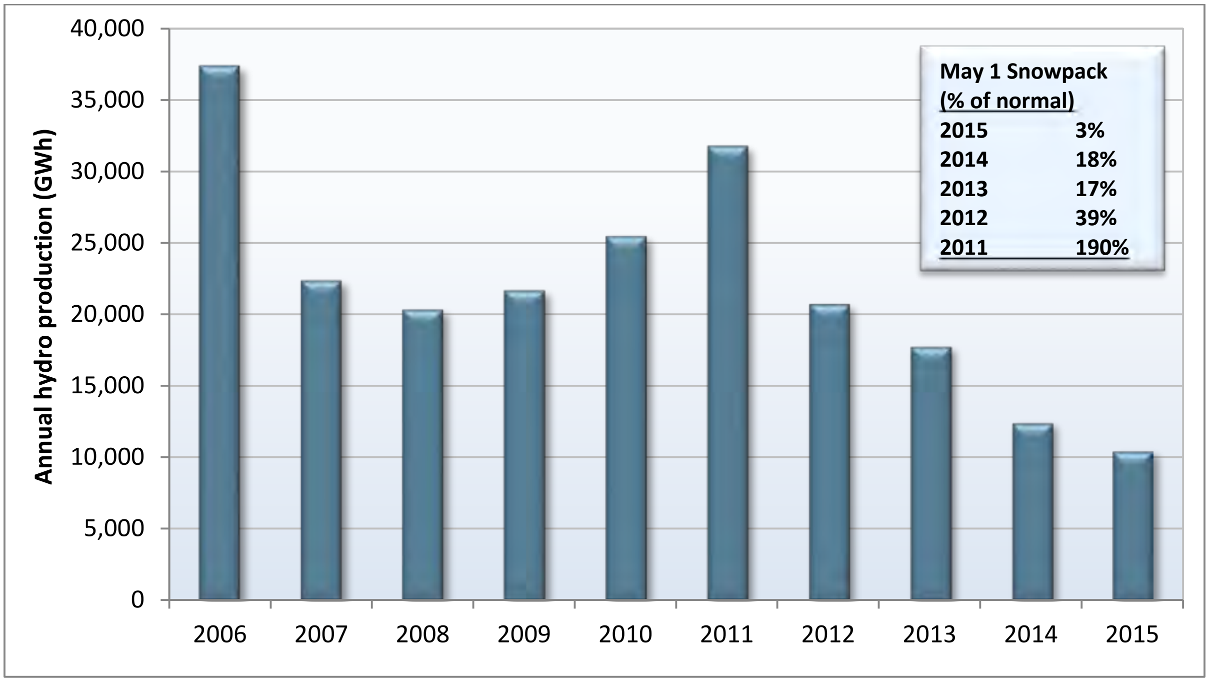


Figure 1.10 Average hourly hydro-electric production by month (2013-2015)

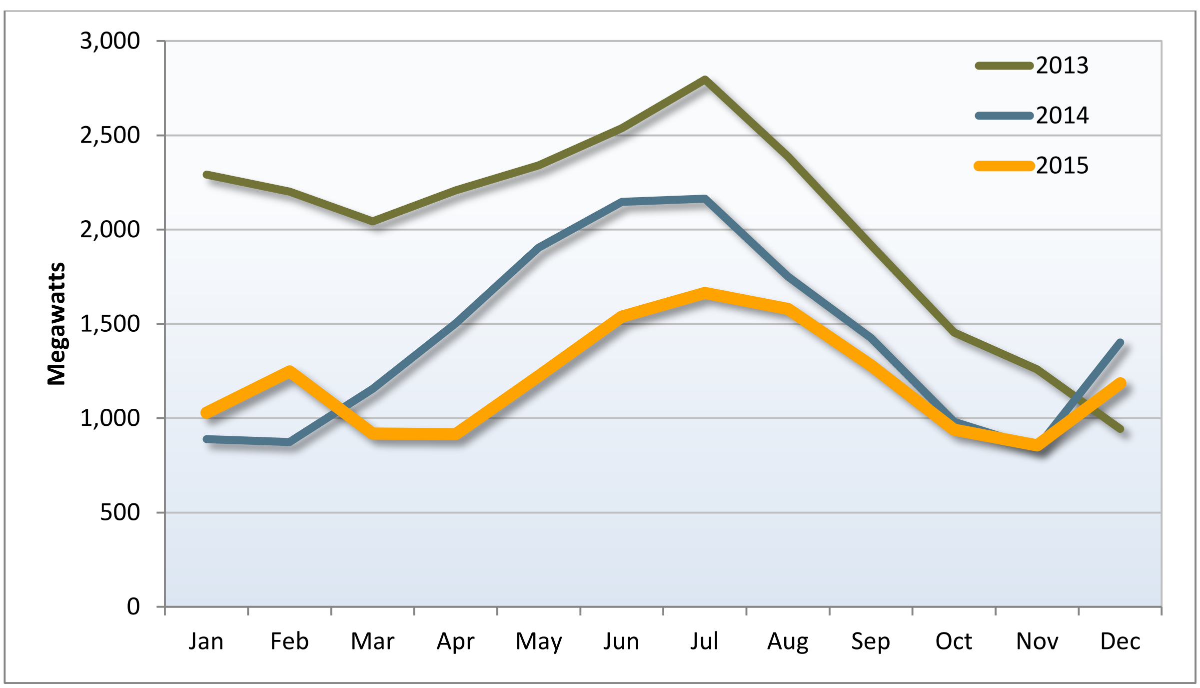


Figure 1.11 Net imports by region (2014-2015)

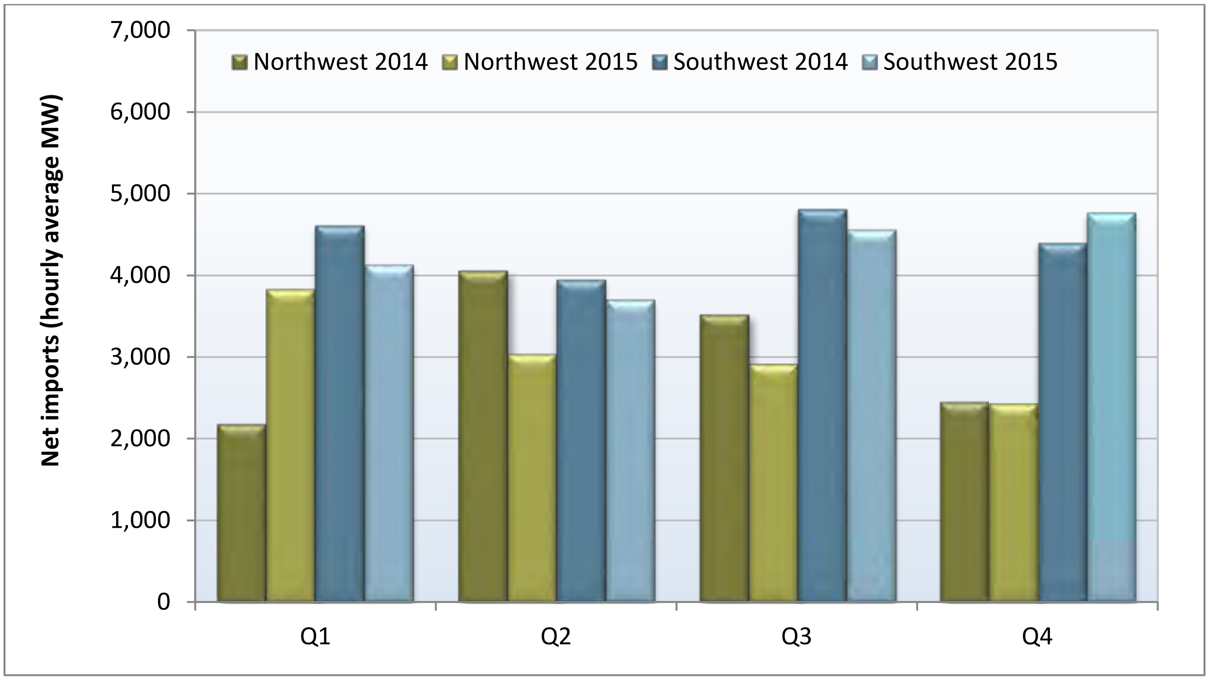
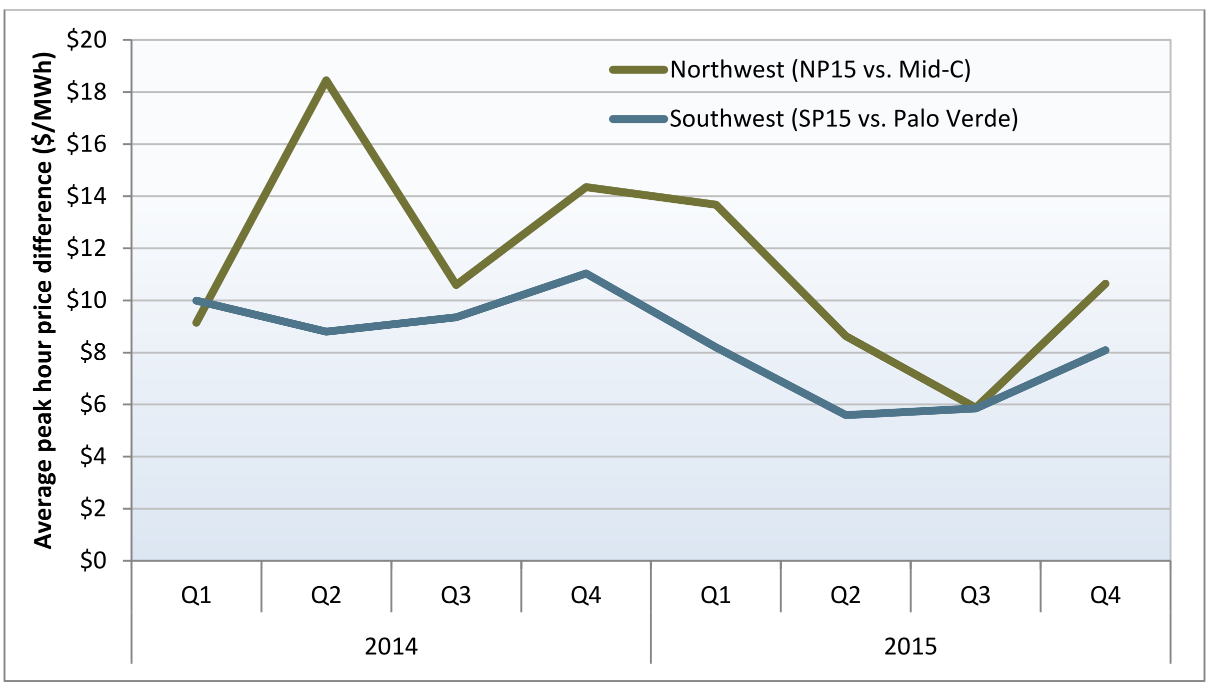


Figure 1.12 Average day-ahead price difference by import region – peak hours



1.2.2 Generation outages

The ISO implemented a new outage management system, known as WebOMS, in late February 2015. Prior to implementing WebOMS, outages were managed using the older SLIC system (Scheduling and Logging for ISO of California).

Along with implementing WebOMS, the ISO also changed the methodology for classifying generation outages into different categories. In the SLIC system, outages were grouped into four categories: planned, forced, ambient and normal.[30] In the new system, all outages are categorized as either planned or forced. An outage is considered to be planned if a participant submitted it more than 7 days prior to the beginning of the outage.

In addition, the new system includes a more granular list of subcategories indicating the reason for the outage. Examples of such categories are: plant maintenance, plant trouble, ambient due to temperature, ambient not due to temperature, unit testing, environmental restrictions, transmission induced, transitional limitations and unit cycling.

Because of the difference in categorization, it is difficult to make year-to-year comparisons for different types of outages between 2014 and 2015. At an aggregated level, the average total amount of generation outages in the ISO decreased slightly to about 11,000 MW in 2015 from about 11,500 MW in 2014.[31]

Figure 1.13 shows the monthly averages of maximum daily outages broken out by type during peak hours. For January and February, Figure 1.13 shows the average total level of outages from the SLIC system. 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 for maintenance, as maintenance is performed outside the higher summer load period.

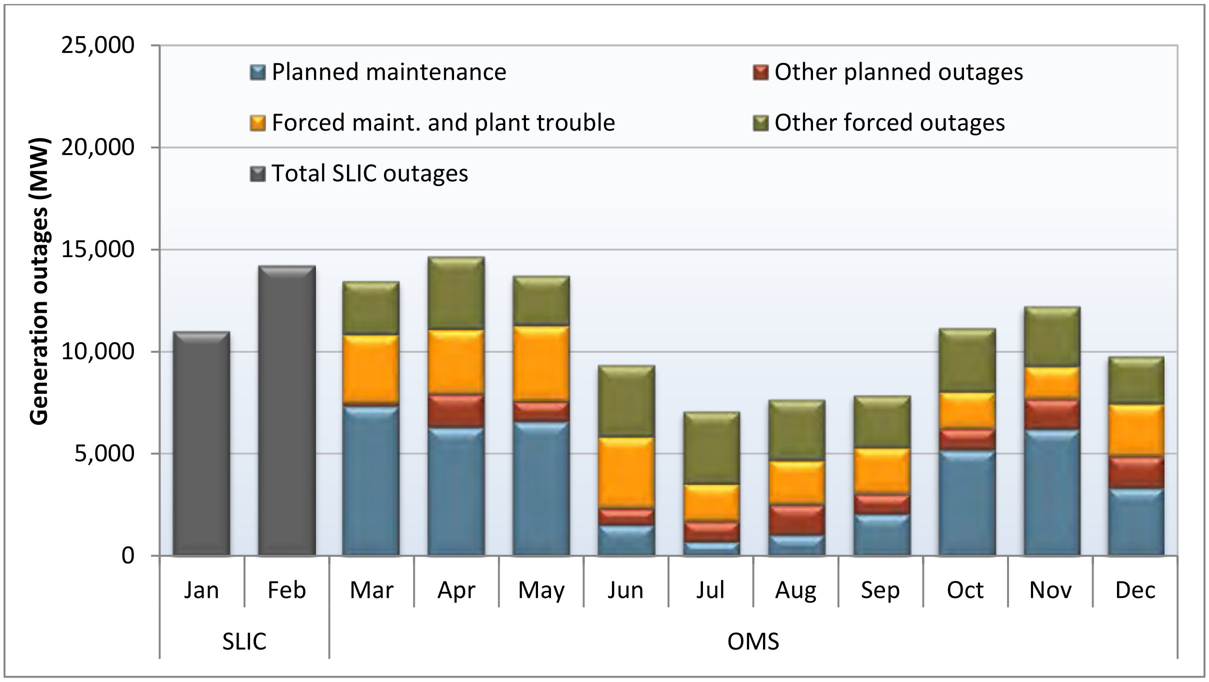
Outages for planned maintenance averaged about 4,000 MW during peak hours in March through December, and ranged from about 700 MW in July to more than 7,000 MW in March. Combined, all other types of planned outages averaged about 1,100 MW for March through December. Some common types of outages in this category were ambient outages (both due to temperature and not due to temperature) and plant trouble.

Among forced outages, about 2,600 MW were due to either plant maintenance or plant trouble. All other types of forced outages averaged almost 3,000 MW for March through December. This includes categories such as ambient due to temperature, ambient not due to temperature, environmental restrictions, unit testing and transitional limitations. Forced outages display less seasonal variation compared to planned outages.

[30] For more information about these categories, see the DMM *2014 Annual Report on Market Issues and Performance*, pp. 41-42: http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf.

[31] This average is calculated as the average of the daily maximum level of outages, excluding off-peak hours. Values reported here only reflect generators in the ISO balancing area and do not include outages from the energy imbalance market.

Figure 1.13 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. The average price of natural gas in the daily spot markets decreased by about 40 percent in 2015 from 2014 levels at the main trading hubs in California. The decrease in natural gas prices was the main driver causing the annual wholesale energy cost per megawatt-hour of load served in 2015 to decrease relative to 2014.

Figure 1.14 shows monthly average natural gas prices at key delivery points in Northern California (PG&E Citygate) and in Southern California (SoCal Citygate) as well as for the Henry Hub trading point, which acts as a point of reference for the national market for natural gas.

While natural gas prices in the West tend to follow national trends, price differences can occur that reflect gas pipeline congestion and differences in transportation costs. Figure 1.15 compares the yearly average natural gas prices at six major western trading points to the Henry Hub reference average for 2014 and 2015. In addition to PG&E Citygate and SoCal Citygate, Figure 1.15 includes Opal in Wyoming, Sumas in Washington, NoCal Border Malin in Oregon and the SoCal Border which represents deliveries at the California-Arizona border. The yearly average prices in 2015 remained close to the Henry Hub reference price at all six trading points. On average, the yearly price at the PG&E Citygate and SoCal Citygate exceeded the Henry Hub average by 14 percent and 6 percent, respectively. The lowest average price was at Sumas, which on average was 12 percent below the Henry Hub.

Figure 1.14 Monthly average natural gas prices (2012-2015)

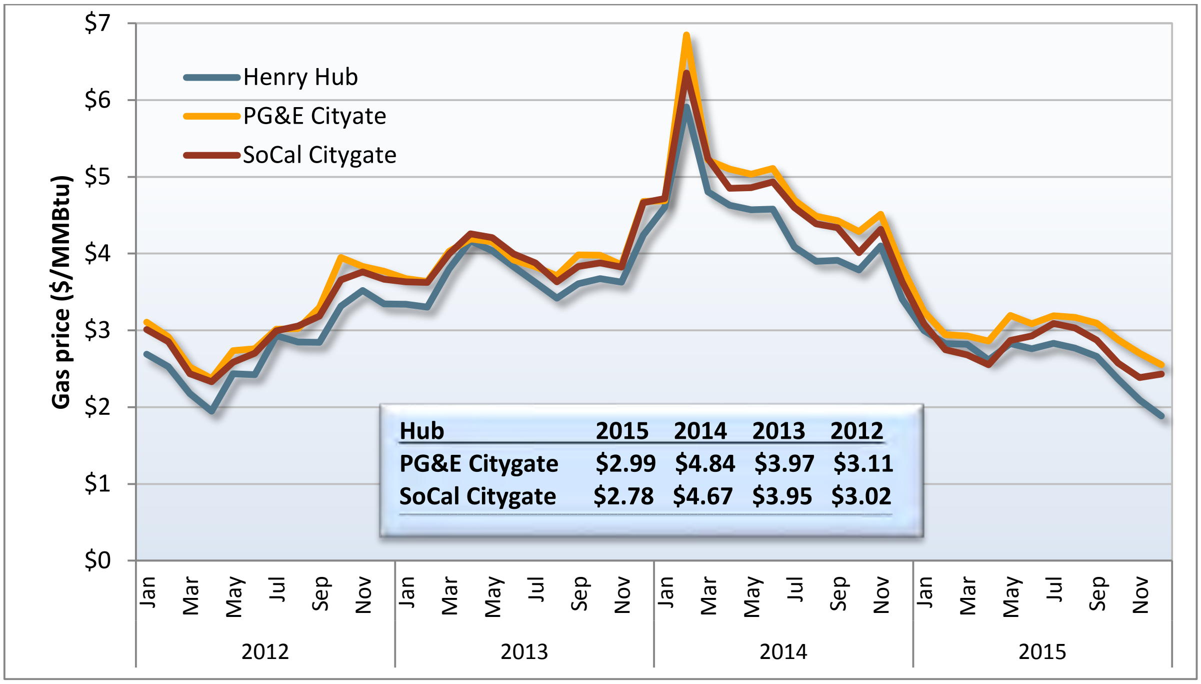
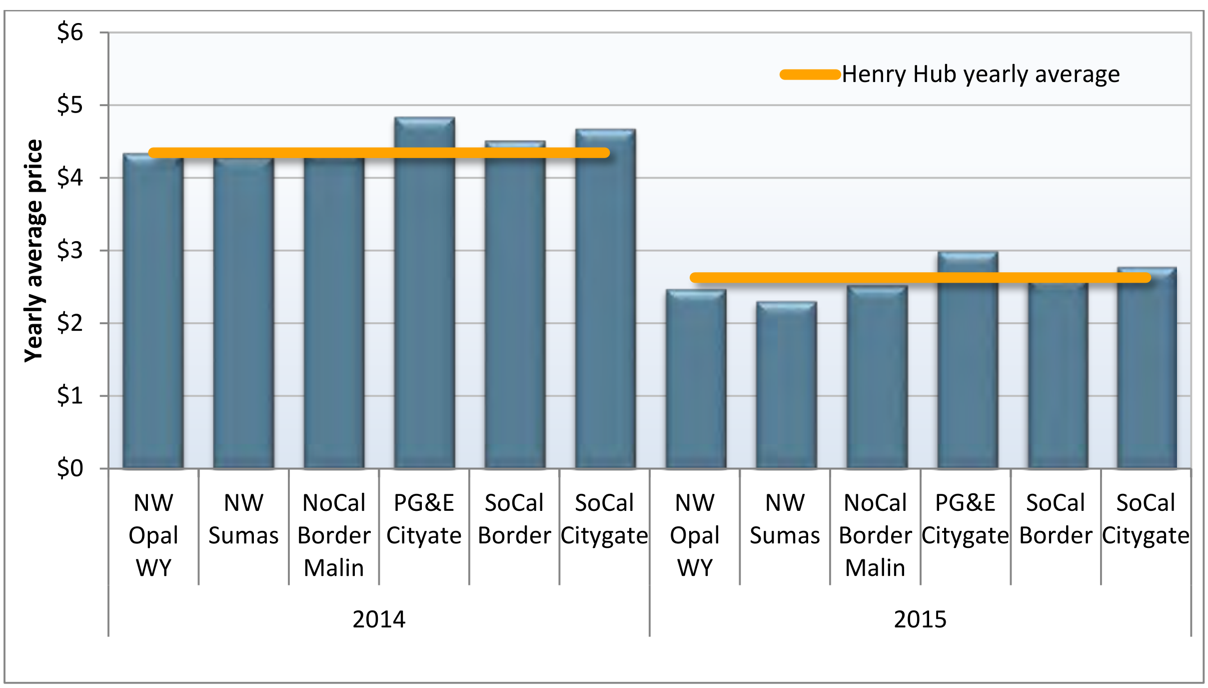


Figure 1.15 Yearly average natural gas prices compared to the Henry Hub



1.2.4 California's greenhouse gas allowance market

This section provides background on California's greenhouse gas allowance market under the state's cap-and-trade program, which was applied to the wholesale electric market beginning in 2013, and the impacts that greenhouse gas costs have on wholesale electric prices. A more detailed description of the cap-and-trade program and its impact on wholesale electric prices in 2013 was provided in DMM's 2013 annual report.[32]

Background

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 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.[33] The program includes an enforceable emissions cap that declines over time. Under the program, California directly distributes and auctions allowances, which are tradable permits equal to the emissions allowed under the cap.

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, but 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.

The second phase of the cap-and-trade program, which began on January 1, 2015, extended emissions compliance obligations to additional sources of greenhouse gas, including suppliers of natural gas. Under this second phase of cap-and-trade regulation, a natural gas supplier carries a greenhouse gas compliance obligation on the natural gas delivered to an electricity generator that is not itself responsible for the greenhouse gas content of the natural gas consumed to produce electricity. The retail tariffs of natural gas suppliers within the state of California were amended to reflect the cost of greenhouse gas compliance for some but not all consumers of natural gas by offering a lower transport rate to entities with their own greenhouse gas compliance obligation.

The ISO determined that the de minimis greenhouse gas natural gas transport cost difference was not significant enough to justify the establishment of gas price indices reflecting greenhouse gas compliance

[32] *2013 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2014, pp. 123-136: http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf.

[33] 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.

obligation status in the ISO markets in 2015.[34] The bidding rules enhancements, approved by the ISO Board on March 25, 2016, adds gas price indices reflective of greenhouse gas compliance status, a change justified by the significant difference in gas transport rates beginning April 1, 2016.[35]

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.[36] Generators, importers and others 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.[37] The total cap on emissions declined 2 percent annually through 2014 and will continue to decline 3 percent annually through 2020.

Allowances are available at quarterly auctions held by CARB and may also be traded bilaterally. In addition, contracts for future delivery of allowances 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, transition 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).[38]

In addition, all energy imbalance market transfers into the California ISO are deemed delivered to California for cap-and-trade program greenhouse gas compliance. Resource specific compliance obligations are determined by the ISO's optimization and are reported to participating resource scheduling coordinators for compliance. Further detail on greenhouse gas compliance in the energy imbalance market is provided in Section 4.5.

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

[34] See Bidding Rules Enhancements Revised Straw Proposal, pages 36 – 39, available here: http://www.caiso.com/Documents/RevisedStrawProposal_BiddingRulesEnhancements.pdf

[35] See California Public Utilities Commission, Rulemaking 14-03-003, issued October 23, 2015. Further information on this initiative is available here: http://www.caiso.com/informed/Pages/StakeholderProcesses/BiddingRulesEnhancements.aspx.

[36] 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.

[37] See the ARB offset credit issuance table for a list of projects that have been issued ARB offset credits: http://www.arb.ca.gov/cc/capandtrade/offsets/issuance/arb_offset_credit_issuance_table.pdf.

[38] 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%20Document%20Library/Market%20Instruments/BPM_for_Market%20Instruments_V39-clean.doc

index price is calculated as the average of two market based indices.[39] Daily values of the ISO greenhouse gas allowance index are plotted in Figure 1.16.

Figure 1.16 ISO's greenhouse gas allowance price index

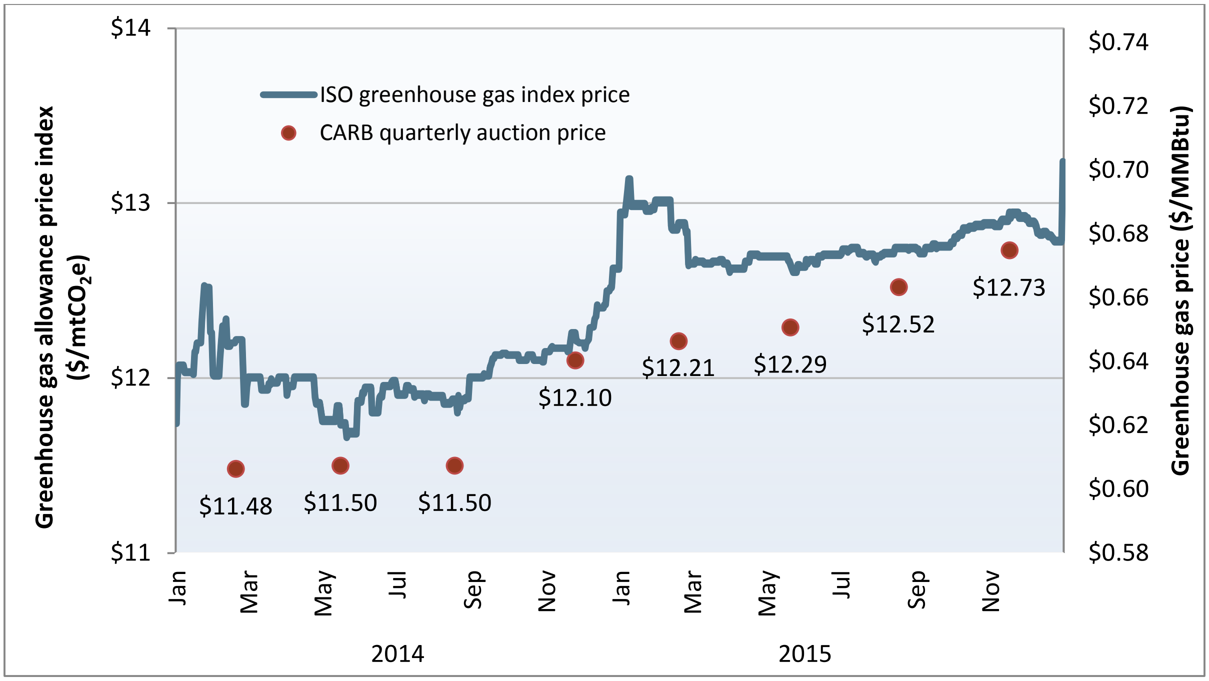


Figure 1.16 also shows market clearing prices in CARB's quarterly auctions of emission allowances that can be used for the 2014 or 2015 compliance years. The values displayed on the right axis convert the greenhouse gas allowance price into an incremental gas price adder, dollars per MMBtu, by multiplying the greenhouse gas allowance price by an emissions factor that is a measure of the greenhouse gas content of natural gas.[40] Thus, the blue line can be read from both the left and right hand axes.

As shown in Figure 1.16, the average cost of greenhouse gas allowances in bilateral markets was higher in 2015 than 2014, holding steady at a load-weighted average of $12.79/mtCO$_2$e in 2015. Allowance costs were stable at about $12/mtCO$_2$e throughout most of 2014. Thus, allowance costs were up almost 6 percent in 2015 compared to 2014. The ISO's greenhouse gas allowance price index exceeded clearing prices in the CARB's quarterly allowance auctions, but varied in a similar pattern, reflecting current market conditions.

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[39] The indices are ICE and ARGUS Air Daily. As the ISO noted in a market notice issued on May 8, 2013, the ICE index is a settlement price but the ARGUS price was updated from a settlement price to a volume weighted price in mid-April of 2013. For more information, see the ISO notice: http://www.caiso.com/Documents/GreenhouseGasAllowancePriceSourcesRevisedMay8_2013.htm.

[40] The emissions factor, 0.0531148 mtCO$_2$e/MMBtu, is the sum of the product of the global warming potential and emission factor for CO_2, CH_4 and N_2O for natural gas. Values are reported in tables A-1, C-1 and C-2 of Title 40 – Protection of Environment, Chapter 1 – Environmental Protection Agency, Subchapter C – Air Programs (Continued), Part 98-Mandatory Greenhouse Gas Reporting, available here: http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl.

The greenhouse gas compliance cost expressed in dollars per MMBtu in 2015 ranged from about \$0.65/MMBtu to \$0.70/MMBtu. This represents about one quarter of the average cost of gas during this period.

Impact of greenhouse gas program

A detailed analysis of the impact of the state's cap-and-trade program on wholesale electric prices in 2013 was provided in DMM's 2013 Annual Report.[41] Based on statistical analysis for changes in prices after the cap-and-trade program was implemented in January 2013, DMM estimated that greenhouse gas costs increased electric prices in the ISO market by about \$6/MWh in 2013.

DMM no longer uses this statistical approach for estimating the impact of greenhouse gas cost due to the difficulty of controlling for changes in other factors that also affect wholesale electric prices since the cap-and-trade obligations for electric generators went into effect in January 2013.

However, as noted above, greenhouse gas compliance costs in 2015 increased by about 6 percent relative to 2014, and averaged about 25 percent of the cost of gas. The \$12.79/mtCO_2e would represent an additional cost of about \$5.43/MWh for a relatively efficient gas unit.[42] The average price in 2014, \$12.04/mtCO_2e, would represent an additional cost of about \$5.12/MWh for the same relatively efficient gas resource.

1.2.5 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 new generation development.

Figure 1.17 summarizes trends in the addition and retirement of generation from 2006 through 2015.[43] Table 1.5 also shows generation additions and retirements since 2006, including totals across the 10 year period (2006 through 2015).

Figure 1.18 and Figure 1.19 show additional generation capacity by generator type. As the figures indicate, most of the additional generation capacity in 2015 was from solar generation.

Generation additions and retirements in 2015

About 950 MW of new summer peak capacity began commercial operation within the ISO system in 2015. About 400 MW of this capacity was installed in the PG&E area and about 550 MW came on-line in the SCE and SDG&E areas. On a nameplate basis, about 450 MW of wind capacity and more than

[41] *2013 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2014, pp. 123-136: http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf.

[42] 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: 0.0531148 mtCO_2e/MMBtu derived in footnote 40.

[43] Starting in 2011, capacity values are calculated summer peak values. The values in 2010 and before are nominal capacity values. For 2012 through 2015, 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.

1,200 MW of additional solar capacity came on-line in 2015. A more detailed listing of units added in 2015 is provided in Table 1.6.

More than 1,000 MW of summer peak capacity was retired in 2015. The retired resources were relatively old natural gas steam turbine generators located in the SCE and SDG&E areas.

Figure 1.17 Generation additions and retirements (2006-2015)

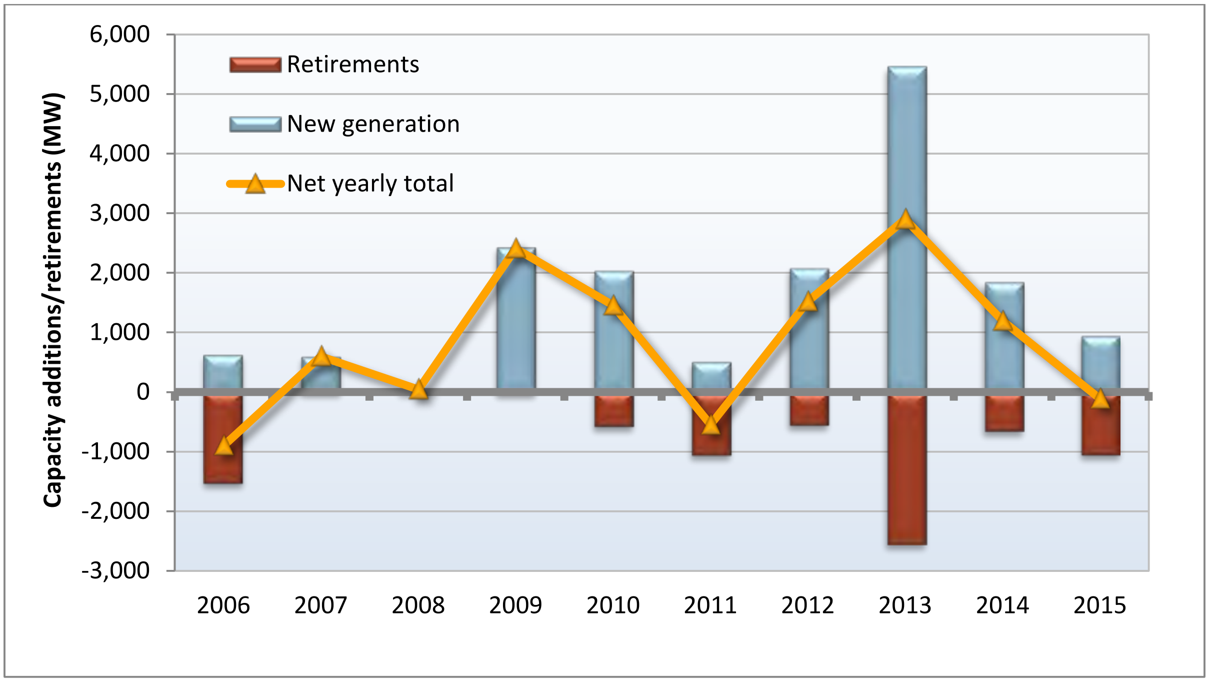


Table 1.5 Changes in generation capacity since 2006

	2006-2010	2011	2012	2013	2014	2015	Total through 2015
SCE and SDG&E							
New Generation	3,113	401	1,054	3,045	1,431	547	9,592
Retirements	(1,734)	(702)	(452)	(1,883)	(16)	(1,062)	(5,848)
Net Change	1,379	**(301)**	**602**	**1,163**	**1,415**	**(514)**	**3,744**
PG&E							
New Generation	2,642	115	1,033	2,411	426	401	7,029
Retirements	(416)	(362)	(114)	(674)	(650)	0	(2,216)
Net Change	2,226	**(247)**	**919**	**1,737**	**(224)**	**401**	**4,813**
ISO System							
New Generation	5,756	516	2,087	5,456	1,858	949	16,621
Retirements	(2,150)	(1,064)	(566)	(2,557)	(666)	(1,062)	(8,064)
Net Change	3,606	**(548)**	**1,521**	**2,899**	**1,192**	**(113)**	**8,557**

Figure 1.18 Generation additions by resource type (nameplate capacity)

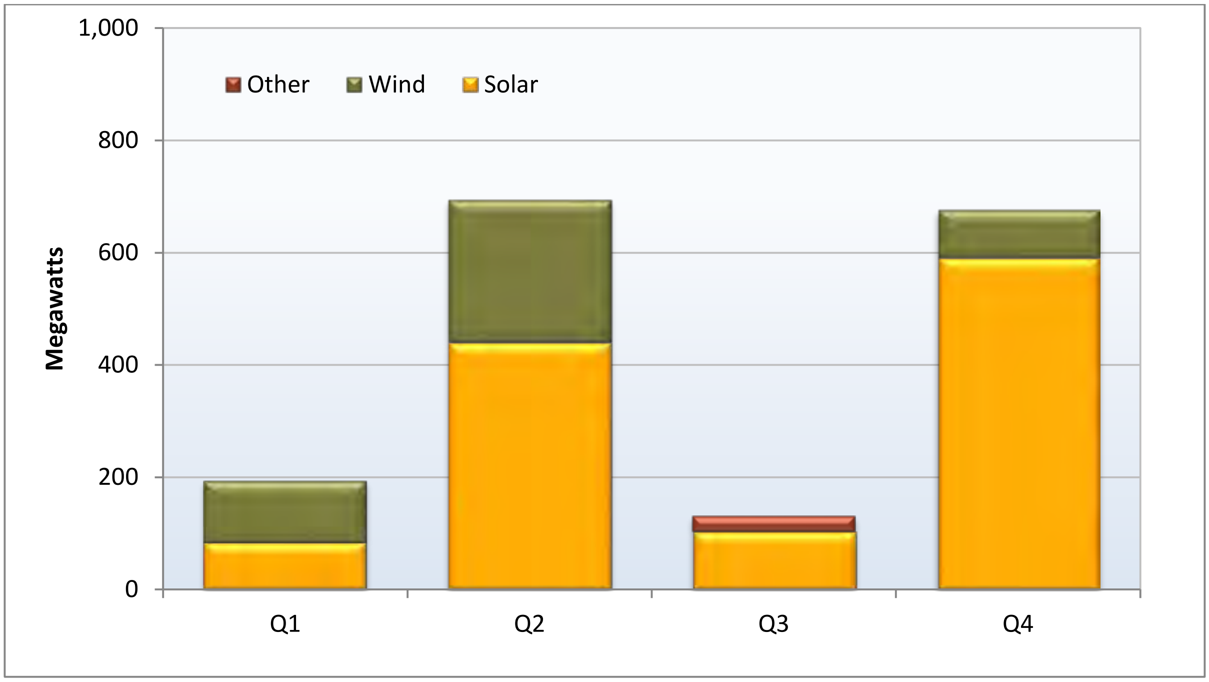


Figure 1.19 Generation additions by resource type (summer peak capacity)

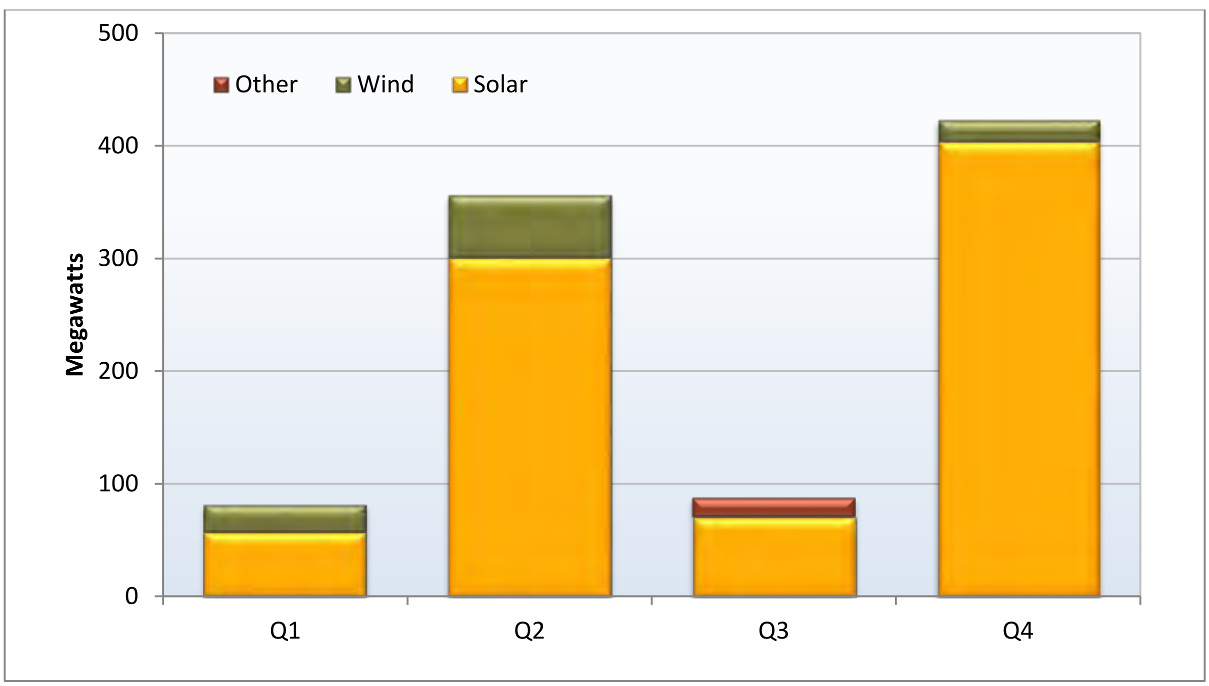


Table 1.6 New generation facilities in 2015

Generating unit	Unit type	Resource capacity (MW)	Summer capacity (MW)	Commercial operation date	Area
CID Solar*	Solar	20	14	9-Jan-15	PG&E
Wildwood Solar I*	Solar	20	14	19-Feb-15	PG&E
Vega Solar*	Solar	20	14	23-Mar-15	PG&E
Lost Hills Solar*	Solar	20	14	2-Apr-15	PG&E
South Kern Solar PV Plant*	Solar	20	14	7-Apr-15	PG&E
Blackwell Solar*	Solar	12	8	16-Apr-15	PG&E
Hollister Solar*	Solar	2	1	17-Apr-15	PG&E
2097 Helton*	Solar	2	1	1-May-15	PG&E
Merced Solar*	Solar	2	1	12-May-15	PG&E
Coronal Lost Hills*	Solar	20	14	15-May-15	PG&E
Corcoran 2*	Solar	20	14	20-May-15	PG&E
Corcoran City*	Solar	11	8	23-May-15	PG&E
Goose Lake*	Solar	12	8	23-May-15	PG&E
Mission Solar*	Solar	2	1	23-May-15	PG&E
Sun Harvest Solar*	Solar	2	1	28-May-15	PG&E
Shafter Solar*	Solar	20	14	4-Jun-15	PG&E
Atwell West*	Solar	20	14	11-Jun-15	PG&E
North Star Solar 1*	Solar	60	41	20-Jun-15	PG&E
Bakersfield 111*	Solar	1	1	28-Jul-15	PG&E
EE K Solar 1*	Solar	20	14	12-Aug-15	PG&E
SPI Anderson 2*	Biomass	27	17	9-Sep-15	PG&E
Fresno Solar West*	Solar	2	1	20-Oct-15	PG&E
Columbia Solar Energy II*	Solar	19	13	21-Oct-15	PG&E
Fresno Solar South*	Solar	2	1	21-Oct-15	PG&E
Morelos Solar*	Solar	15	10	25-Nov-15	PG&E
Quinto Solar PV Project*	Solar	108	74	30-Nov-15	PG&E
Citizen Solar B*	Solar	5	3	11-Dec-15	PG&E
Maricopa West Solar PV*	Solar	20	14	12-Dec-15	PG&E
Golden Hills A*	Wind	43	9	18-Dec-15	PG&E
Golden Hills B*	Wind	43	9	18-Dec-15	PG&E
Adera Solar*	Solar	20	14	23-Dec-15	PG&E
Hayworth Solar Farm*	Solar	27	18	23-Dec-15	PG&E
Woodmere Solar Farm*	Solar	15	10	23-Dec-15	PG&E
PG&E Actual New Generation in 2015		**648**	**401**		

Table continues on next page.

Generating unit	Unit type	Resource capacity (MW)	Summer capacity (MW)	Commercial operation date	Area
Rising Tree 1*	Wind	79	17	12-Jan-15	SCE
Rising Tree 2*	Wind	20	4	12-Jan-15	SCE
Little Rock C*	Solar	5	3	17-Jan-15	SCE
Phoenix*	Wind	11	2	26-Jan-15	SCE
Pumpjack Solar 1*	Solar	19	13	27-Jan-15	SCE
Golden Springs Building M*	Solar	2	1	1-Apr-15	SCE
Meridian*	Solar	1	1	13-Apr-15	SCE
Terra Francesca*	Solar	1	1	13-Apr-15	SCE
Golden Springs Building H*	Solar	2	1	22-Apr-15	SCE
Alamo Solar*	Solar	20	14	15-May-15	SCE
Kona Solar - Rancho DC #1*	Solar	2	1	2-Jun-15	SCE
Summer Solar North*	Solar	7	4	3-Jun-15	SCE
Victor Dry Farm Ranch A*	Solar	5	3	12-Jun-15	SCE
Victor Dry Farm Ranch B*	Solar	5	3	12-Jun-15	SCE
Solar Star 2 (Phase II)*	Solar	40	27	19-Jun-15	SCE
Rising Tree 3*	Wind	99	22	25-Jun-15	SCE
Solar Star 1 (Phase II)*	Solar	133	91	25-Jun-15	SCE
Adelanto Solar 2*	Solar	7	5	1-Jul-15	SCE
Catalina Solar 2*	Solar	18	12	22-Jul-15	SCE
Palmdale East*	Solar	10	7	31-Jul-15	SCE
AP North Lake Solar*	Solar	20	14	11-Aug-15	SCE
Adelanto Solar*	Solar	20	14	3-Sep-15	SCE
Tequesquite Landfill Solar Project*	Solar	8	5	9-Sep-15	SCE
Redcrest Solar Farm*	Solar	17	11	30-Oct-15	SCE
Sierra Solar Greenworks LLC*	Solar	20	14	30-Nov-15	SCE
Morgan Lancaster I*	Solar	2	1	9-Dec-15	SCE
McCoy Station (Phase I)*	Solar	99	68	16-Dec-15	SCE
Silver State South (Phase I)*	Solar	91	63	28-Dec-15	SCE
Desert Stateline (Phase I)*	Solar	110	75	31-Dec-15	SCE
ESJ Wind Energy (Phase I)*	Wind	155	34	4-Jun-15	SDG&E
Seville Solar One*	Solar	20	14	30-Dec-15	SDG&E
SCE and SDG&E Actual New Generation in 2015		**1,048**	**547**		
Total Actual New Generation in 2015		**1,696**	**949**		
Total Renewable Generation in 2015*		**1,696**	**949**		

Source: California ISO Interconnection Resources Department

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 are currently the primary mechanisms 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.[44] Costs used in the analysis are based on a study by the California Energy Commission (CEC).

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 1.20. The results show a decrease in net revenues in 2015 compared to 2014. The latest CEC reports of annualized fixed costs have also decreased from $176/kW-year to $165/kW-yr. The 2015 net revenue estimates for a hypothetical combined cycle unit in NP15 and SP15 both still fall substantially below $165/kW-yr.

Table 1.7 Assumptions for typical new combined cycle unit[45]

Technical Parameters	
Maximum Capacity	500 MW
Minimum Operating Level	150 MW
Startup Gas Consumption	1,400 MMBtu/start
Heat Rates	
Maximum Capacity	7,100 MBTU/MW
Minimum Operating Level	7,700 MBTU/MW
Financial Parameters	
Financing Costs	$89 /kW-yr
Insurance	$6.7 /kW-yr
Ad Valorem	$8.8 /kW-yr
Fixed Annual O&M	$43.7 /kW-yr
Taxes	$17.1 /kW-yr
Total Fixed Cost Revenue Requirement	**$165.2/kW-yr**

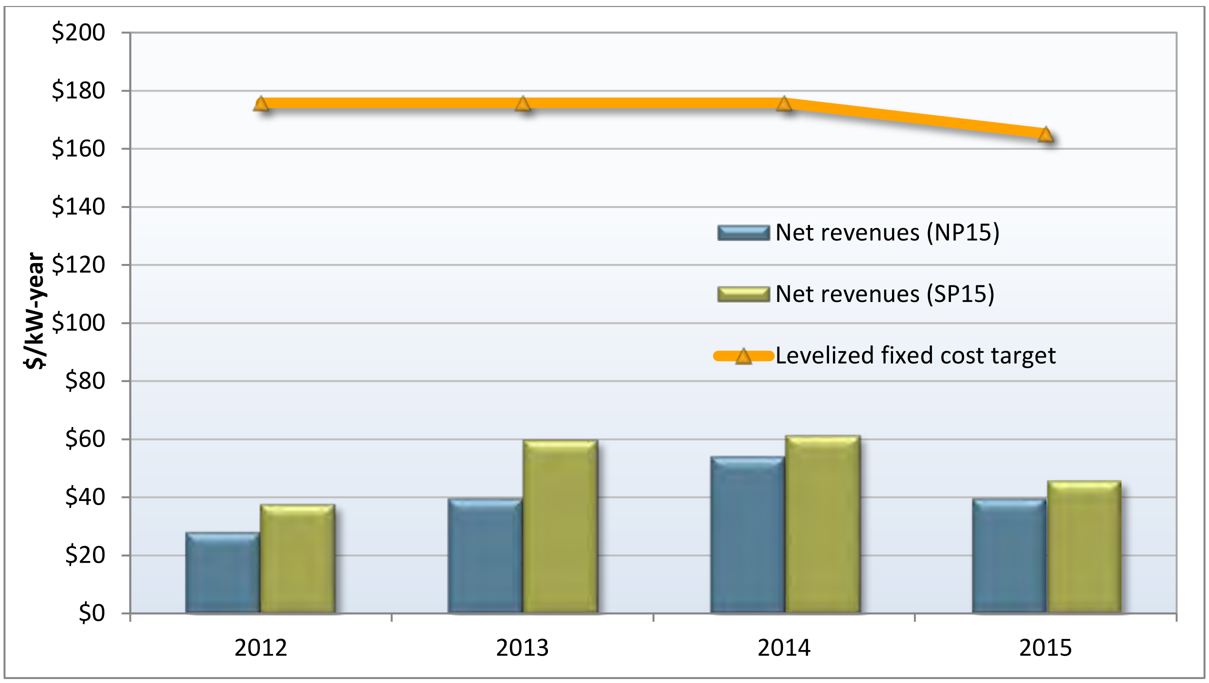
[44] A more detailed description of the methodology and results of the analysis presented in this section are provided in Appendix A.1 of DMM's *2009 Annual Report on Market Issues & Performance,* April 2010, which can be found at http://www.caiso.com/2777/27778a322d0f0.pdf.

[45] 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 2015 CEC Estimated Cost of New Renewable and Fossil-Fueled Generation in California, Final Staff Report: http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SF.pdf. 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 report.

Table 1.8 Financial analysis of new combined cycle unit (2012-2015)

Components	2012		2013		2014		2015	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	70%	75%	84%	83%	83%	84%	92%	93%
DA Energy Revenue ($/kW - yr	$118.95	$134.59	$286.19	$315.53	$325.36	$326.07	$251.35	$251.61
RT Energy Revenue ($/kW - yr)	$11.70	$11.62	$10.17	$10.14	$23.62	$22.08	$12.39	$9.45
A/S Revenue ($/kW – yr)	$0.37	$0.39	$0.03	$0.06	$0.08	$0.09	$0.04	$0.06
Operating Cost ($/kW - yr)	$103.01	$108.96	$256.78	$266.00	$295.03	$287.00	$224.16	$215.35
Net Revenue ($/kW – yr)	$28.02	$37.64	$39.62	$59.73	$54.02	$61.23	$39.62	$45.77
4-yr Average ($/kW – yr)	*$40.32*	*$51.09*						

Figure 1.20 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 1.21 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 an increase in net revenues for both the NP15 and SP15 areas in 2015 compared to 2014. This increase is attributable to the significant decrease in natural gas prices in 2015. As seen in Table 1.10, estimated operating costs decreased substantially from $59.46/kW-yr to $44.10/kW-yr in 2015 in the NP15 area. The low natural gas prices also led to lower wholesale energy prices, reducing the estimated energy revenues. However, the decrease in estimated operating costs exceeded the decline in energy revenues, resulting in a net revenue increase.

The CEC's estimate of annualized fixed costs for a hypothetical combustion turbine also decreased from $190/kW-year to $176/kW-year. Despite these changes, the estimated net revenues still fell well short of $176/kW-year.

Table 1.9 Assumptions for typical new combustion turbine[46]

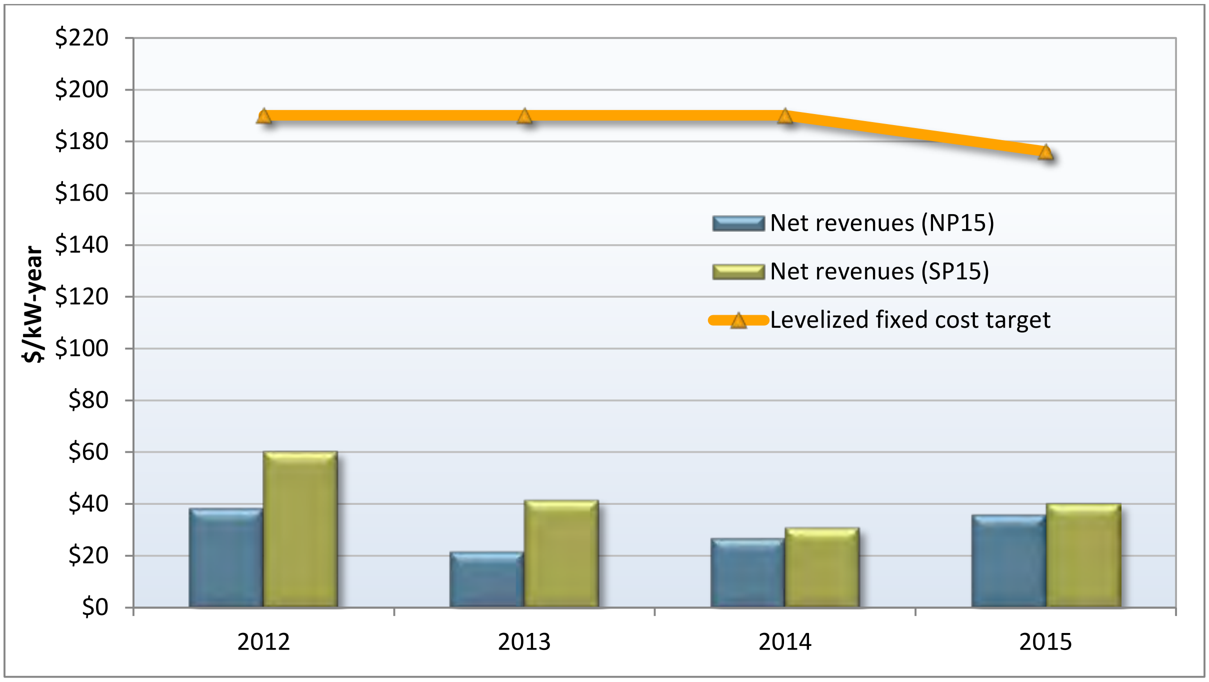
Technical Parameters	
Maximum Capacity	100 MW
Minimum Operating Level	40 MW
Startup Gas Consumption	280 MMBtu/start
Heat Rates (MBTU/MW)	
Maximum Capacity	9,300
Minimum Operating Level	9,700
Financial Parameters	
Financing Costs	$105.8 /kW-yr
Insurance	$8 /kW-yr
Ad Valorem	$10.6 /kW-yr
Fixed Annual O&M	$34.7 /kW-yr
Taxes	$17.1 /kW-yr
Total Fixed Cost Revenue Requirement	**$176.2/kW-yr**

Table 1.10 Financial analysis of new combustion turbine (2012-2015)

Components	**2012**		**2013**		**2014**		**2015**	
	NP15	**SP15**	**NP15**	**SP15**	**NP15**	**SP15**	**NP15**	**SP15**
Capacity Factor	5%	8%	8%	9%	10%	10%	11%	12%
Energy Revenue ($/kW - yr)	$48.78	$78.89	$58.48	$82.95	$85.48	$87.31	$78.56	$86.56
A/S Revenue ($/kW - yr)	$4.29	$5.04	$1.14	$1.34	$0.71	$0.86	$1.35	$1.92
Operating Cost ($/kW - yr)	$14.82	$23.62	$38.03	$42.85	$59.46	$57.26	$44.10	$48.31
Net Revenue ($/kW - yr)	$38.26	$60.32	$21.59	$41.45	$26.73	$30.91	$35.81	$40.17
4-yr Average ($/kW - yr)	*$30.60*	*$43.21*						

[46] 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 2015 CEC Estimated Cost of New Renewable and Fossil-Fueled Generation in California, Final Staff Report: http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SF.pdf. 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 report.

Figure 1.21 Estimated net revenues of new combustion turbine



Findings in this section 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 2015.

- Total wholesale electric costs decreased by about 30 percent, driven primarily by a 40 percent decrease in natural gas prices in 2015 compared to 2014. After controlling for the lower natural gas costs and changes in greenhouse gas prices, wholesale electric costs decreased by about 6 percent from 2014 and have remained very stable since 2013.
- Overall prices in the ISO energy markets in 2015 were highly competitive, averaging close to what DMM estimates would result under highly efficient and competitive conditions.
- Real-time energy prices tended to be lower than average day-ahead prices during most periods, continuing a trend that began in 2013. During the third quarter of 2015, price convergence declined between the day-ahead market and the 15-minute market, particularly in peak hours.
- After implementation of 15-minute scheduling on inter-ties in May 2014, there was a significant decrease in the amount of economic inter-tie bids offered into the real-time market. This trend continued into 2015. Most economic real-time bids on the inter-ties continued to be hourly block bids in 2015. However, the share of 15-minute economic bids gradually increased over the year. Almost all 15-minute economic inter-tie bids were concentrated on only three inter-ties.

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

- Ancillary service costs totaled $62 million, or about 10 percent less than in 2014. The decrease was primarily driven by a decrease in natural gas prices.
- Bid cost recovery payments remained unchanged at $92 million from 2014, and remained less than 1 percent of total energy costs in 2015. While overall payments remained unchanged, payments for units scheduled through the residual unit commitment process increased to over $15 million in 2015, up from $6 million in 2014. These costs were driven in large part by higher cost long-start units that were committed through the residual unit commitment during the warmest parts of the year, when loads were highest.
- Exceptional dispatches, or *out-of-market* unit commitments and energy dispatches issued by ISO grid operators to meet constraints not incorporated in the market software, increased from 2014 but remained relatively low overall. Total energy from all exceptional dispatches totaled about 0.2 percent of total system energy in 2015 compared to 0.16 percent in 2014. The above-market costs resulting from these exceptional dispatches decreased 15 percent to $9.3 million in 2015 from $11 million in 2014.
- Congestion on transmission constraints within the ISO system continued to remain low compared to prior years and had a limited impact on average overall prices across the system. Congestion was highest in the second quarter because of outages limiting south-to-north flows on Path 15 and an abundance of solar energy south of Path 15.
- Real-time market revenue imbalance charges allocated to load-serving entities decreased significantly to $65 million in 2015 from $217 million in 2014. The charges associated with congestion fell to $50 million in 2015 from $107 million in 2014. This decrease was driven largely by

lower overall congestion. Charges related to real-time energy imbalance costs decreased to $15 million in 2015 from $109 million in 2014. The decrease in real-time energy imbalance costs was driven primarily by a decrease in components of real-time energy imbalance energy cost which are offset by settlements elsewhere in the market. These factors contributed significantly to real-time energy imbalance costs in 2014.

2.1 Total wholesale market costs

The total estimated wholesale cost of serving load in 2015 was about $8.3 billion or just under $37/MWh. This represents a decrease of about 30 percent from wholesale costs of about $52/MWh in 2014. The decrease in electricity prices was mostly due to a corresponding decrease in wholesale natural gas prices of about 40 percent.[47] After normalizing for natural gas prices and greenhouse gas compliance costs, DMM estimates that total wholesale energy costs remained fairly stable for the third consecutive year, decreasing slightly by about 6 percent from $45/MWh in 2014 to about $42/MWh in 2015.[48]

A variety of factors had the effect of decreasing total wholesale costs. As highlighted elsewhere in this report, conditions that contributed to lower prices include the following:

- Record solar generation and the continued addition of new solar generating capacity, which replaces more expensive generation;
- Continued low levels of congestion during most intervals;
- Increased net virtual supply, which lowered average day-ahead prices and brought them closer to average real-time prices.

Figure 2.1 shows total estimated wholesale costs per megawatt-hour of system load from 2011 to 2015. Wholesale costs are provided in nominal terms (blue bar), as well as after normalization for changes in average spot market prices for natural gas and greenhouse gas compliance costs (gold bar). The greenhouse gas compliance cost is added to natural gas prices beginning in 2013 to account for the estimated cost of compliance with California's greenhouse gas cap-and-trade program. The green line, representing the annual average of daily natural gas prices including greenhouse gas compliance, is included to illustrate the correlation between the cost of natural gas and the total wholesale cost estimate. The dashed green line excludes greenhouse gas compliance costs and is included for reference for after 2012.

[47] For the wholesale energy cost calculation in 2015, an average of annual gas prices were used from the SoCal Gas Citygate and PG&E Citygate hubs.

[48] Greenhouse gas compliance costs are calculated by multiplying a load-weighted annual average greenhouse gas allowance price by an emission factor that is a measure of the greenhouse gas content of natural gas. Derivation of the emission factor used here, 0.531148, is discussed in further detail in Section 1.2.4. Gas prices are normalized to 2010 prices.

Figure 2.1 Total annual wholesale costs per MWh of load (2011-2015)

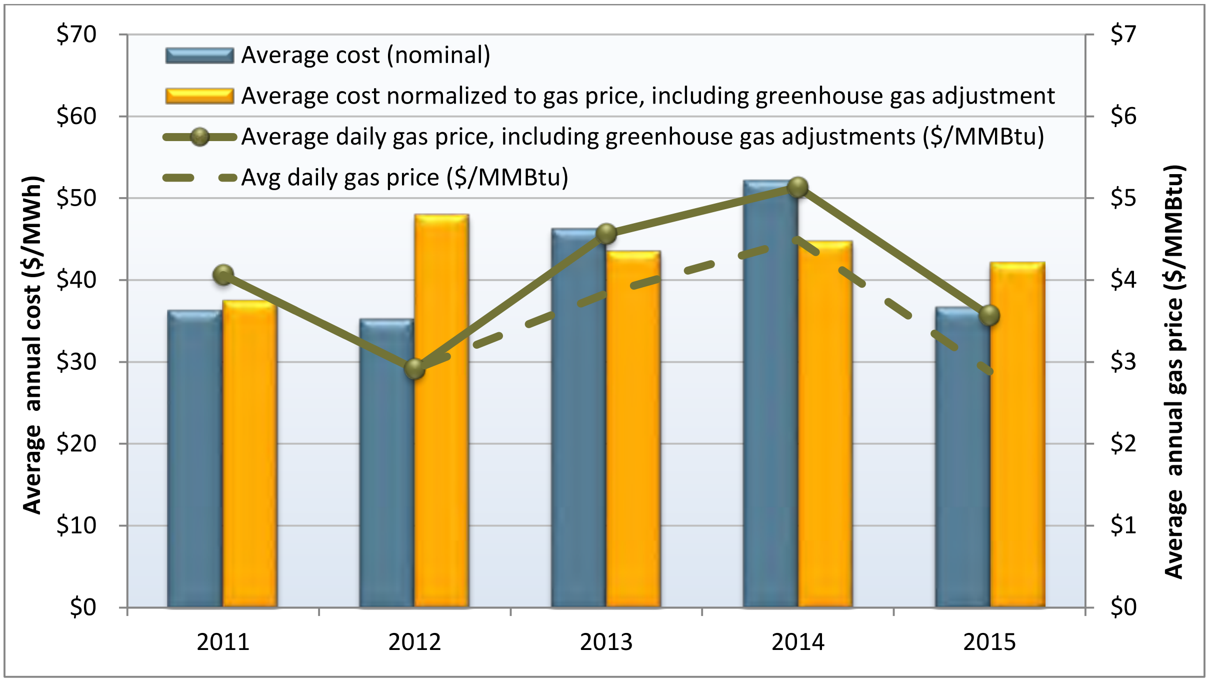


Table 2.1 provides annual summaries of nominal total wholesale costs by category from 2011 through 2015. Beginning in 2015, all total wholesale costs include costs incurred from EIM market operation, in addition to totals from the ISO. Starting in May 2014, total wholesale market costs are estimated based on prices and quantities cleared in each of the three energy markets: day-ahead, 15-minute and 5-minute real-time markets, which reflects the new market design implemented at that time. Prior to May 2014, costs were estimated based on prices and quantities cleared in the day-ahead, hour-ahead and 5-minute 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.[49]

As seen in Table 2.1, the decrease in total cost in 2015 was primarily due to decreases in energy costs, where day-ahead costs fell by more than $14/MWh, or roughly 30 percent, and real-time costs fell by more than $1/MWh, or 65 percent. The remaining components of the wholesale energy cost, which represent a relatively small portion of costs, also each modestly decreased from 2014.

[49] 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. This calculation was also updated to reflect the substantial market changes implemented on May 1, 2014. Following this period, both 15-minute and 5-minute real-time prices are used to calculate real-time energy costs. In addition, EIM costs were added to real-time energy costs beginning in 2015.

Table 2.1 Estimated average wholesale energy costs per MWh (2011-2015)

	2011	2012	2013	2014	2015	Change '14-'15
Day-ahead energy costs (excl. GMC)	$ 33.23	$ 32.57	$ 44.14	$ 48.57	$ 34.54	$ (14.03)
Real-time energy costs (incl. flex ramp)	$ 0.80	$ 0.99	$ 0.57	$ 1.98	$ 0.69	$ (1.29)
Grid management charge	$ 0.79	$ 0.80	$ 0.80	$ 0.80	$ 0.80	$ (0.00)
Bid cost recovery costs	$ 0.56	$ 0.45	$ 0.47	$ 0.41	$ 0.39	$ (0.02)
Reliability costs (RMR and CPM)	$ 0.03	$ 0.14	$ 0.10	$ 0.14	$ 0.12	$ (0.02)
Average total energy costs	**$ 35.42**	**$ 34.96**	**$ 46.08**	**$ 51.90**	**$ 36.54**	**$ (15.36)**
Reserve costs (AS and RUC)	$ 0.62	$ 0.37	$ 0.26	$ 0.30	$ 0.27	$ (0.04)
Average total costs of energy and reserve	**$ 36.04**	**$ 35.33**	**$ 46.34**	**$ 52.20**	**$ 36.81**	**$ (15.40)**

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.[50]

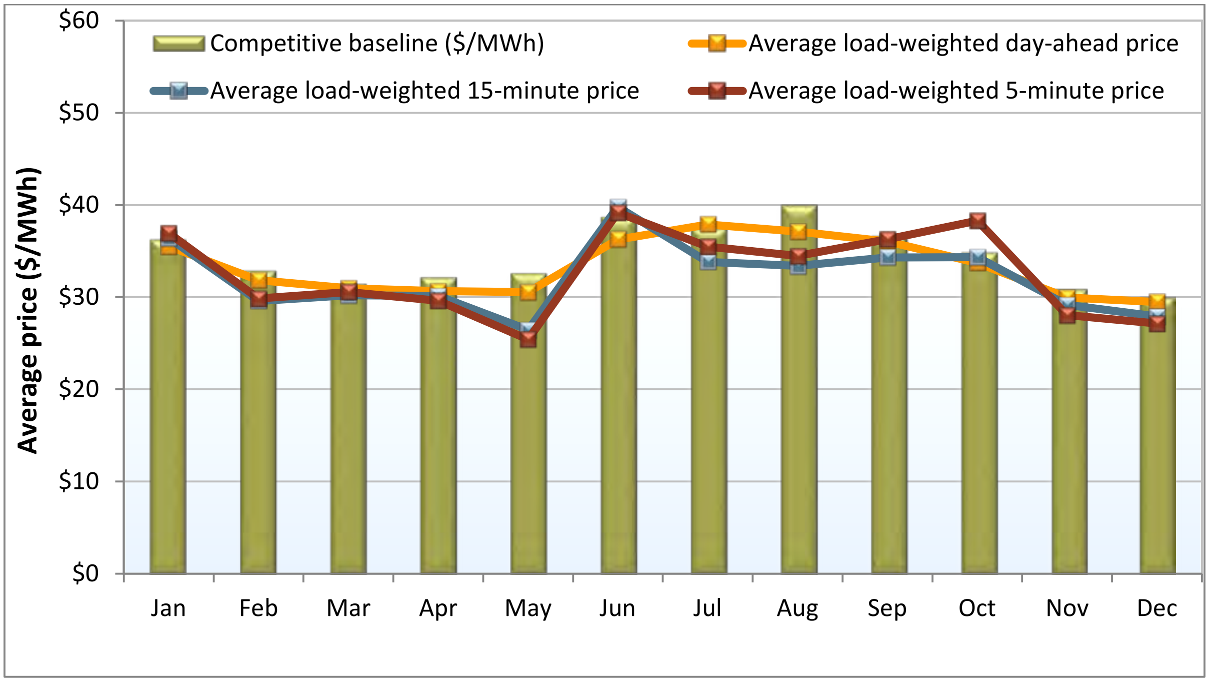
Figure 2.2 compares this competitive baseline price to load-weighted prices in the day-ahead, 15-minute and 5-minute real-time markets. When comparing these prices, it is important to note that baseline prices are calculated using the day-ahead market software under highly competitive conditions, which do 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 2015. Day-ahead prices were slightly lower than the competitive benchmark in most months, and about $2/MWh lower during the summer months.

In the 15-minute and 5-minute real-time markets, average prices were also slightly lower than the competitive baseline in most months. Average 15-minute and 5-minute real-time prices were about $6/MWh lower during May and August, while 5-minute prices were about $3.50/MWh higher in October. Path 15 congestion and increased solar generation played a role in low May prices, while load forecast variability during July and August contributed to lower real-time prices. In October, a few days with higher than anticipated loads led to high average real-time prices.

[50] 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, and is calculated using DMM's version of the actual market software.

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 energy prices to total average wholesale energy prices.[51] Total wholesale energy prices used in this analysis represent a load-weighted average price of all energy transactions in the day-ahead and real-time markets.[52] Thus, this analysis combines energy procured at higher day-ahead prices, as well as net energy sales in the 15-minute and 5-minute real-time markets at lower prices.

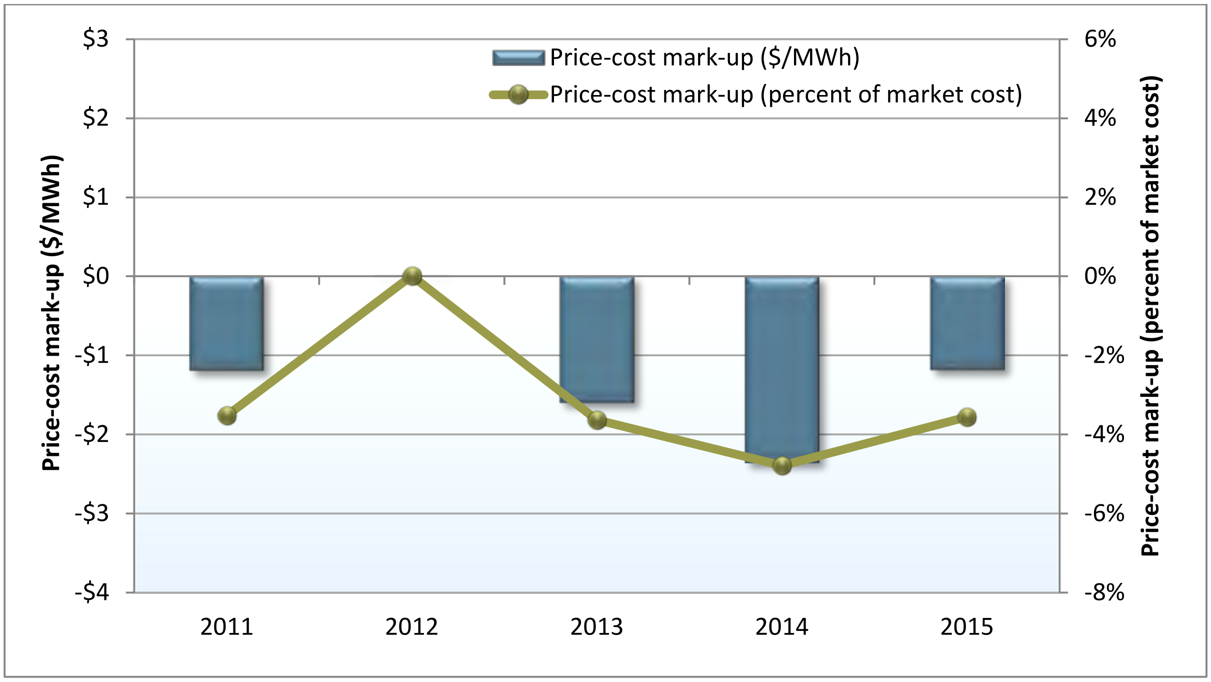
As shown in Figure 2.3, the overall combined average of day-ahead and real-time prices was about $1.19/MWh or about 3.6 percent lower than the competitive baseline price. This represents a slight increase in the price-cost mark-up in 2015 compared to 2014 and is consistent with the slightly negative price-cost mark-ups observed in the last several years. 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.[53] Overall, 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.

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

[52] The wholesale costs of energy are pro-rated calculations of the day-ahead, 15-minute and 5-minute real-time prices weighted by the corresponding forecasted load. Prior to May 2014, the calculation pro-rated day-ahead, hour-ahead and 5-minute prices weighted by the corresponding forecasted load.

[53] DMM is also working on a fix to account for actual renewable generation as opposed to day-ahead bid-in renewable generation that may also result in negative price-cost mark-ups. It does this by underestimating the actual supply of renewable generation, which increases the degree to which the competitive baseline calculation is higher than actual market costs.

Figure 2.3 Price-cost mark-up (2011-2015)



2.3 Energy market prices

This section reviews energy market prices by focusing on price levels and convergence. Key points highlighted in this section include the following:

- Average energy market prices were significantly lower in 2015 than 2014.
- Real-time market prices in both the 15-minute and 5-minute markets tended to be lower than day-ahead market prices during most periods in 2015.
- During the third quarter of 2015, price convergence declined between the day-ahead market and the 15-minute market, particularly in peak hours. Most real-time energy is settled based on prices in the 15-minute market.

Energy market prices were lower in 2015 than 2014, as seen in Figure 2.4 and Figure 2.5. This decrease was attributed primarily to a decrease in natural gas prices in 2015 where the average price of natural gas in the daily spot markets decreased by about 40 percent from 2014 levels at the main trading hubs in California.

Figure 2.4 and Figure 2.5 show the following:

- Real-time prices tended to be lower than average day-ahead prices during most periods, continuing a trend that began in 2013. This can be partly attributed to additional generation in real time that is not bid into the day-ahead market, primarily from renewable resources.

Figure 2.4 Comparison of quarterly prices – system energy (peak hours)

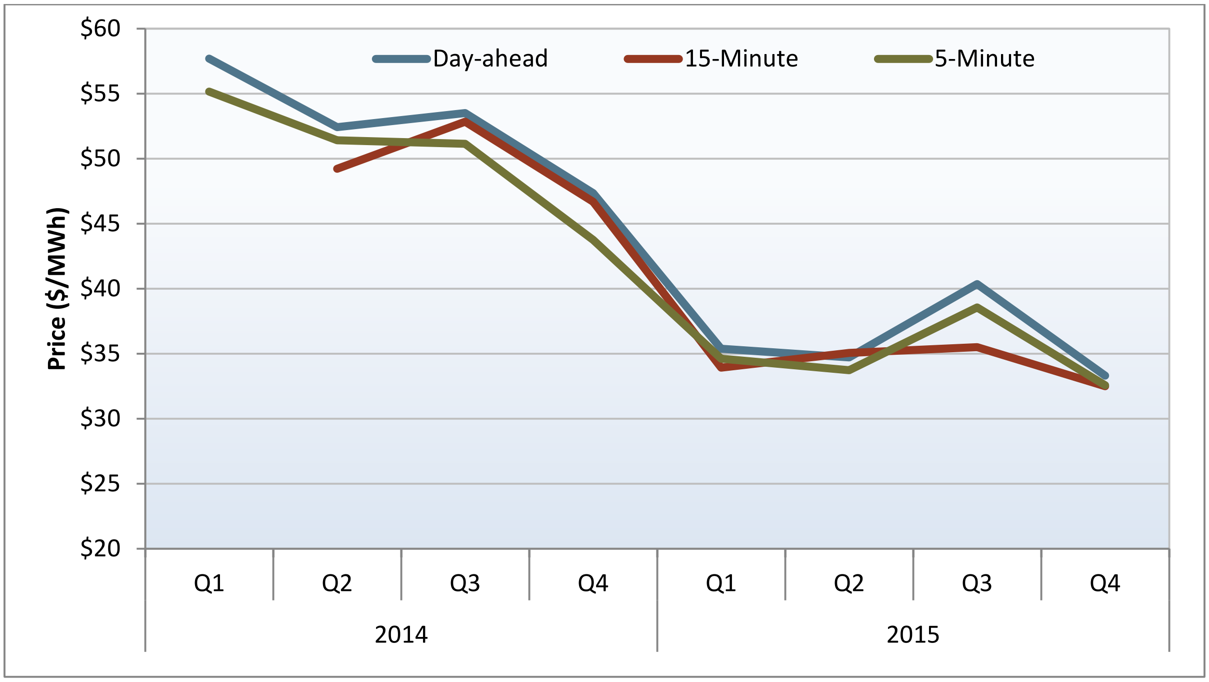
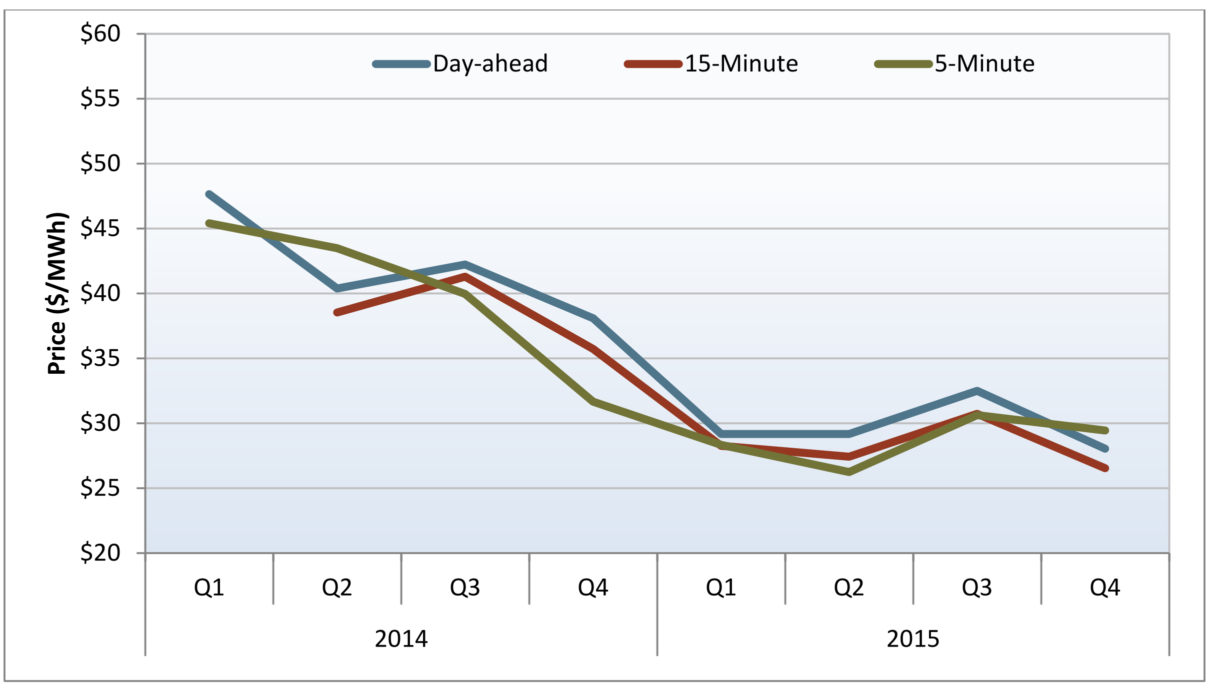


Figure 2.5 Comparison of quarterly prices – system energy (off-peak hours)



- Average prices for the 15-minute market, upon which most real-time energy is settled financially, were lower than the day-ahead market prices. Prices in the 15-minute market averaged about $1.60/MWh lower than day-ahead prices.
- Prices in the 15-minute market tracked particularly far from day-ahead prices during peak hours in the third quarter of 2015. During this quarter, average 15-minute prices during peak hours were almost $4.90/MWh (or about 12 percent) less than day-ahead prices.
- Average quarterly 5-minute market off-peak prices in the fourth quarter were greater than the day-ahead market by about $1.40/MWh. Historically, the 5-minute market prices have been highly volatile, experiencing periods of extreme positive and negative price spikes. However, price variability in the 5-minute market now has a lower impact as less settlement occurs against the 5-minute real-time price.

2.4 Residual unit commitment

The purpose of the residual unit commitment market is to ensure that there is sufficient capacity on-line or reserved to meet actual load in real time. The residual unit commitment market is run right after the day-ahead market and procures sufficient capacity 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.

The ISO in 2014 introduced an automatic adjustment to residual unit commitment schedules to account for differences between the day-ahead schedules of participating intermittent resource program (PIRP) resources and the forecast output of these renewable resources. This adjustment reduces residual unit commitment procurement targets by the estimated under-scheduling of bid-in renewable resources in the day-ahead market. In addition, ISO operators are able to increase the amount of residual unit commitment requirements for reliability purposes. These operator adjustments decreased slightly in 2015 when compared to 2014, though they were higher in the summer months.[54] 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 primarily from the second quarter of 2015 after staying at moderate levels through 2014.[55] Figure 2.6 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 increased to 539 MW per hour in 2015 from an average of 398 MW per hour in 2014.

While capacity procured in residual unit commitment must be bid into the real-time market, only a fraction of this capacity is committed to be on-line by the residual unit commitment process.[56] Most of the capacity procured in the residual unit commitment process is from units which are already

[54] See Section 9.5 for further discussion on operator adjustments in the residual unit commitment process.

[55] Values reported for 2014 exclude two days when market data was unavailable: October 15, 2014, and November 1, 2014.

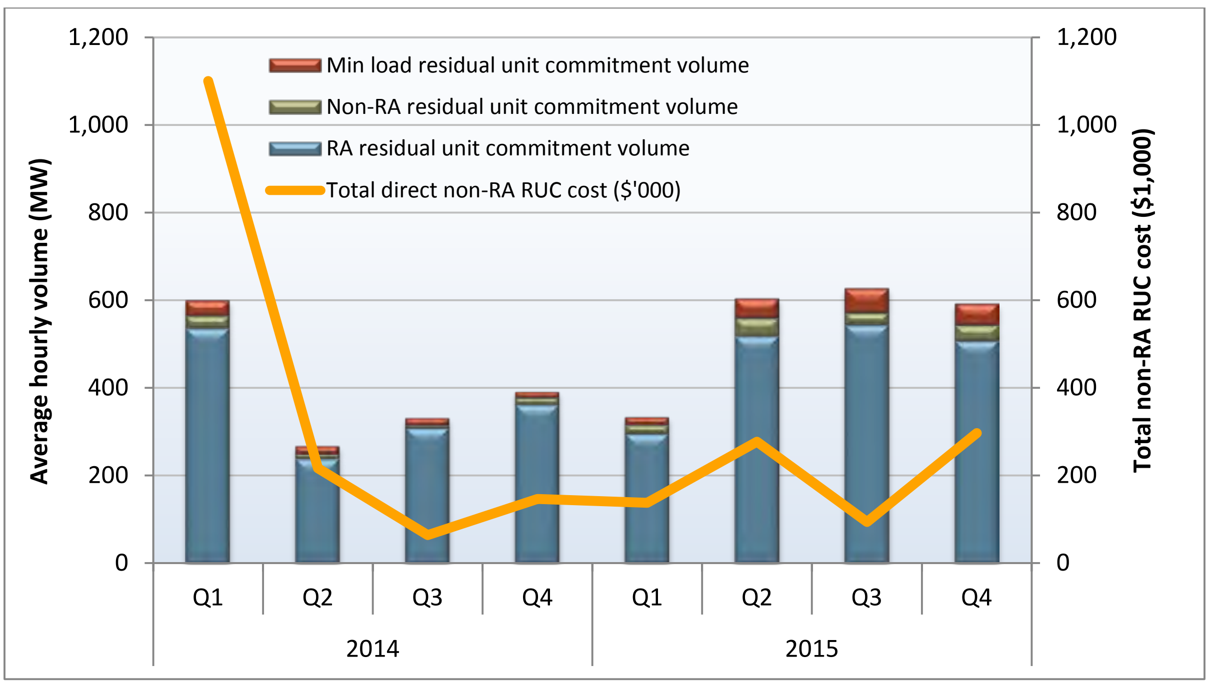
[56] Only the small portion of minimum load capacity from *long-start units*, units with start-up times greater than or equal to five hours, is committed to be on-line in real-time by the residual unit commitment process.

scheduled to be on-line 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 average hourly volume of residual unit commitment capacity was over 300 MW in each quarter of 2015, the capacity committed to start up and operate at minimum load averaged just 42 MW each hour. Only a small fraction (28 percent) of this capacity was from long-start units, which are committed to be on-line by the residual unit commitment process, except in the third quarter of 2015.[57] In the third quarter, the capacity committed to operate at minimum load averaged 57 MW each hour, of which long-start units accounted for 43 percent or 24 MW of the capacity committed to be on-line.

Most of the capacity procured in the residual unit commitment market does not incur any direct costs from residual unit capacity payments because only non-resource adequacy units committed in the residual unit commitment receive capacity payments.[58] As shown by the very small green segment of each bar in Figure 2.6, the non-resource adequacy residual unit commitment averaged about 30 MW per hour in 2015, about twice the volume in 2014. The total direct cost of residual unit commitment, represented by the gold line in Figure 2.6, was about $0.8 million in 2015, about 50 percent of the direct cost of $1.6 million in 2014.

Figure 2.6 Residual unit commitment costs and volume



[57] 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.

[58] Resource adequacy units receive bid cost recovery payments as well as payments through the resource adequacy process.

Some of the residual unit commitment capacity results in additional bid cost recovery payments, as discussed in Section 2.5. Units committed in this process in 2014 accounted for around $5 million in bid cost recovery payments, or just over 5 percent of total bid cost recovery payments. In 2015, these costs rose to about $15 million, or about 17 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 accounted for $10 million or about two-thirds of the residual unit commitment bid cost recovery payments after netting against real-time revenues. Short-start units accounted for about $5 million after netting against real-time revenues.

The increase in residual unit commitment bid cost recovery payments was primarily due to increased commitments that offset virtual supply. The next section explains bid cost recovery in further detail.

2.5 Bid cost recovery payments

Generating units in both the ISO and EIM 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.

Bid cost recovery rules were modified in May 2014. Before the changes, bid cost recovery payments were calculated by netting all daily bid costs and revenues from the day-ahead, residual unit commitment and real-time markets. For instance, if a unit was committed in the day-ahead market and required bid cost recovery payments, these payments would be adjusted by any positive net revenues received in the real-time market.

As of May 2014, the ISO no longer nets the costs and revenues between the day-ahead and real-time markets.[59] Instead, the ISO calculates the costs and revenues for day-ahead and real-time markets separately for each day. These changes were made to reduce incentives to self-schedule and increase incentives for suppliers to submit bids in the real-time market that reflect their actual marginal operating costs. DMM has not observed any increase in bid cost recovery payments as a result of this change.

Figure 2.7 provides a summary of total estimated bid cost recovery payments in 2014 and 2015 by quarter and by market. Bid cost recovery payments for units in the ISO and EIM totaled around $92 million, or below 1 percent of total energy costs, in 2015 and remain unchanged from 2014.

The decline in bid cost recovery payments resulted from a decrease in the portion associated with day-ahead payments, particularly during the first and fourth quarters. Day-ahead bid cost recovery payments totaled just $27 million in 2015 compared to $35 million in 2014. Payments in the first and fourth quarters of 2015 totaled under $6 million for day-ahead bid cost recovery. DMM estimates that units committed because of minimum on-line constraints incorporated in the day-ahead energy market accounted for about $19 million or around 22 percent of total bid cost recovery payments in 2015.

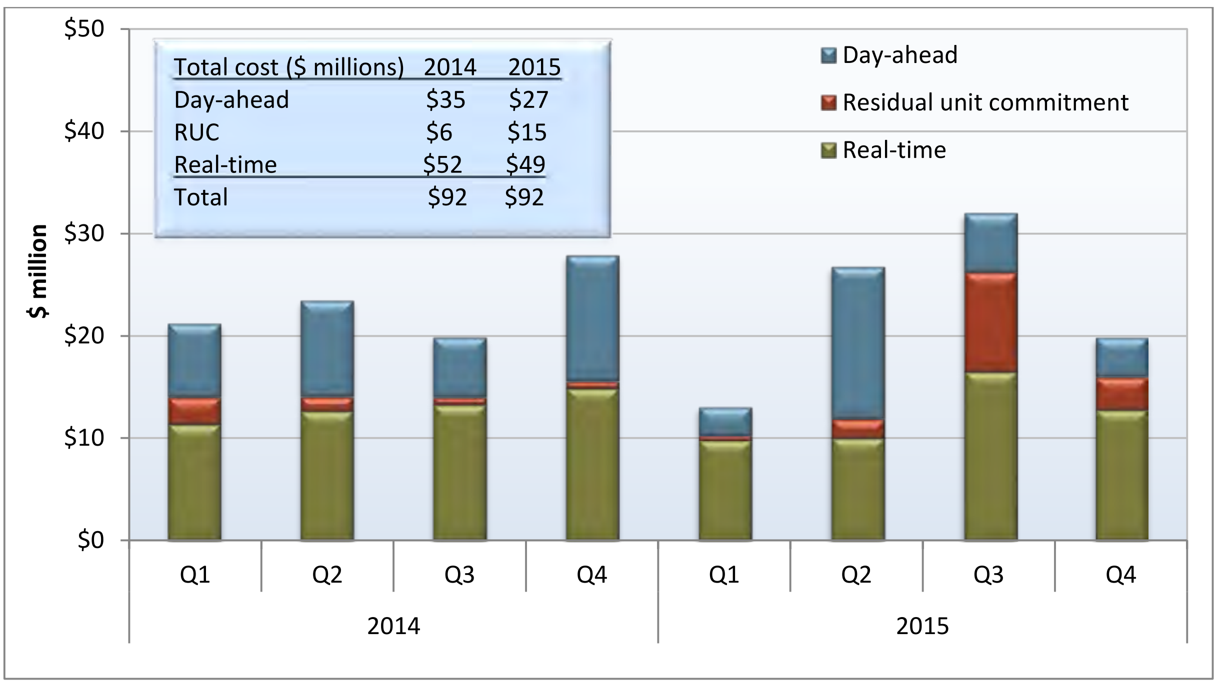
[59] The residual unit commitment and real-time markets are netted together.

These constraints are used to meet special reliability issues that require having units on-line to meet voltage requirements and in the event of a contingency.[60]

Bid cost recovery payments associated with real-time market dispatches accounted for $49 million in 2015 compared to $52 million in 2014. Bid cost recovery payments resulting from units committed though exceptional dispatches also played an important role in real-time bid cost recovery payments. DMM estimates approximately $15 million of the real-time bid cost recovery payments in 2015 was for units committed through exceptional dispatches. Payments for real-time bid cost recovery in EIM during 2015 totaled under $3 million, with more than $1 million accrued in February alone.

Bid cost recovery payments associated with units committed through the residual unit commitment process totaled about $15 million in 2015, a significant increase from $6 million in 2014, but still less than about $22 million in 2013. About $10 million of the bid cost recovery payments for residual unit commitment occurred during the third quarter of 2015. This was the result of high seasonal loads combined with large net virtual supply positions, which resulted in expensive long-start units being committed during this period. Fewer short-start units were available for residual unit commitment in the third quarter because they were committed through the market to meet high seasonal loads.

Figure 2.7 Bid cost recovery payments



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

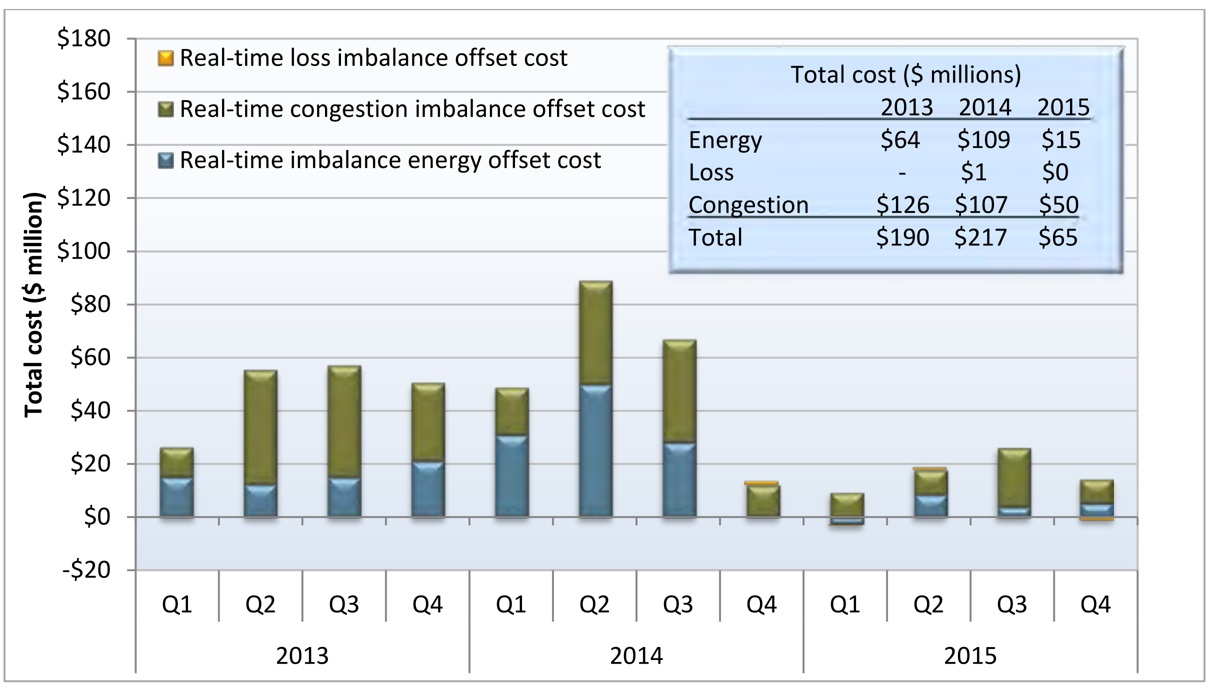
2.6 Real-time imbalance offset costs

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 in the real-time energy markets. Historically, this included energy settled at hour-ahead and 5-minute prices. The ISO implemented market changes related to FERC Order No. 764 on May 1, 2014, which included a financially binding 15-minute market. Following May 1, 2014, real-time imbalance offsets include energy settled at 15-minute and 5-minute prices. Within the ISO system, the charge is allocated as an uplift to measured demand (i.e., physical load plus exports).

The real-time imbalance offset charge consists of three components. Any revenue imbalance from the energy components of real-time energy settlement prices is collected through the *real-time imbalance energy offset charge* (RTIEO). Any revenue imbalance from the congestion component of these real-time energy settlement prices is recovered through the *real-time congestion imbalance offset charge* (RTCIO). Until October 1, 2014, the ISO aggregated real-time loss imbalance offset costs with real-time energy imbalance costs. Following October 1, 2014, any revenue imbalance from the loss component of real-time energy settlement prices is collected through the *real-time loss imbalance offset charge*.

Real-time imbalance costs for energy, losses and congestion totaled $65 million in 2015, compared to $217 million in 2014.[61] As seen in Figure 2.8, the decrease in total imbalance offset costs was attributable to a decrease in both the real-time energy and congestion imbalance offset costs. Real-time energy imbalance offset costs decreased to $15 million in 2015 from $109 million in 2014. Real-time congestion imbalance offset costs fell to $50 million in 2015 from $107 million in 2014.

Figure 2.8 Real-time imbalance offset costs



[61] Values reported here are the most current reported settlement imbalance charges, but are subject to change.

Real-time congestion offset costs

Congestion offset costs are caused by deviations between the congestion components of prices at which real-time load and generation are settled. Decreases in power flow limits between the day-ahead and the 15-minute real-time market can lead to real-time congestion offset costs as the ISO buys power at higher price locations and sells power at lower price locations to meet the lower real-time power flow limit on a constraint.

Real-time congestion offset costs totaled $50 million in 2015, and resulted primarily from unpredictable real-time conditions. Congestion offset costs incurred during July and August 2015 accounted for approximately $20 million, or about 40 percent of the annual total cost. In prior years, real-time congestion offset costs were driven higher by systematic and predictable congestion patterns stemming from unscheduled flows and market modeling differences.[62]

The ISO's efforts to address systematic modeling differences between the day-ahead and real-time markets, as well as lower overall levels of congestion, contributed to reducing real-time congestion imbalance costs in 2015 compared to previous periods. However, as the 2015 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

Real-time energy offset costs accounted for about 24 percent of total real-time imbalance offset costs in 2015. These costs totaled $15 million in 2015, or an 86 percent reduction from 2014.

Approximately one third of real-time energy offset costs in 2015 can be attributed to one day, June 8, 2015. On this day, real-time load was significantly higher than the day-ahead forecast. Multiple intervals of power balance constraint relaxations and corresponding high prices in the real-time markets resulted from higher than anticipated loads. Elevated real-time prices increase real-time energy offset when the quantities of settled generation and imports exceed the quantity of load and exports. These conditions likely affected the real-time energy offset costs on June 8.

The settlement values reported for the real-time energy imbalance offset include several components that are offset by settlement values elsewhere in the market or that may be subject to resettlement and thus are not true uplift costs. These components contributed significantly to real-time energy offset costs in 2014, but played a much smaller role in 2015.[63]

Real-time loss offset costs

Beginning on October 1, 2014, the ISO settled any revenue imbalance from the loss component of real-time energy settlement prices through the real-time loss imbalance offset charge. Previously, these offset charges were aggregated as part of the real-time energy imbalance costs. The real-time loss offset costs were negative in 2015, resulting in a small credit of about $400,000.

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[62] 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.

[63] Further details on the role of transmission loss obligation charges and other potential causes of real-time imbalance energy offset are outlined in the following DMM white paper: http://www.caiso.com/Documents/ReviewofReal-TimeImbalanceEnergyOffset-DMMWhitePaper.pdf.

3 Real-time market performance

This chapter provides key trends relating to performance of the real-time market. Highlights in this chapter include the following:

- Prices in both the 15-minute and 5-minute markets were fairly stable in 2015, although there was an increase in frequency of negative prices compared to 2014. This trend was particularly notable in the first half of 2015 due to congestion in the south-to-north direction on Path 15 in the spring.

- Extremely high and low prices in the 5-minute market had a relatively small impact on settlement prices since the 15-minute market was implemented in 2014. Real-time settlement prices are now weighted more heavily on prices in the 15-minute market, at roughly 80 percent, rather than the 5-minute market, at roughly 20 percent. Prices in the 15-minute market are much less susceptible to volatility from ramping limitations that can cause the dispatch of units with extremely high priced bids or a relaxation of the power balance constraint to balance load and supply.

- After implementing 15-minute scheduling on inter-ties in May 2014, there was a significant decrease in the amount of economic inter-tie bids offered into the real-time market. Economic bids refer to capacity that is offered into the market at various prices, rather than being self-scheduled. The portion of supply on inter-ties offered in the real-time market through economic bids continued to be relatively low in 2015. On average there were about 1,200 MW of economic import bids and about 400 MW of economic export bids in the real-time market in 2015.

- Most economic real-time inter-tie bids continued to be hourly block bids in 2015. These bids must be dispatched for the entire hour and cannot be dispatched during specific 15-minute intervals. However, the volume and proportion of 15-minute economic bids gradually increased over the year, reaching 37 percent for imports and 62 percent for exports in the fourth quarter. Almost all 15-minute economic inter-tie bids were concentrated on only three inter-ties.

- Flexible ramping payments were about $4 million for the year, compared to about $6.5 million in 2014. This decrease occurred despite an increase in payments from the addition of EIM generators, which are included in this total. The decrease is partly attributable to a decrease in the penalty price in January 2015 from $247/MWh to $60/MWh.

- The ISO implemented an automatic tool to calculate the flexible ramping requirement in late March 2015. When introduced, this new methodology resulted in increased volatility of the requirement between intervals, which may not have reflected actual ramping needs. In the second half of the year boundaries were placed on the limits of the tool to reduce volatility, which increased average flexible ramping requirements and, combined with other factors led to an increase in shortfalls as the year progressed.

- Participants submitted economic bids for only about one third of generation resources into the real-time market in 2015. The remaining two-thirds of real-time generation was submitted as self-schedules, or, in the case of wind and solar generation, were treated as self-schedules based on generation forecasts. Most natural gas capacity was economically bid (87 percent), while almost all nuclear and most imports (92 percent) were self-scheduled.

- Wind and solar generation participants submitted economic bids for about 20 and 25 percent of their generation in real-time, respectively, with all bids at negative prices. Most reductions for wind and solar generation were based on these negative economic bids. Total solar output was only reduced by about 1.2 percent due to real-time dispatches and curtailments in 2015, while wind output was decreased by only about 0.2 percent in the real-time market.

3.1 15-minute real-time bidding on the inter-ties

The ISO implemented 15-minute scheduling on inter-ties in May 2014, consistent with FERC Order No. 764. Along with this change, the ISO revamped its real-time market to include 15-minute settlement of both internal generation and inter-tie resources, while retaining the 5-minute market for balancing purposes.[64]

Following implementation of 15-minute scheduling on the inter-ties, there was a significant decrease in the amount of economic inter-tie bids offered into the real-time market. This trend continued into 2015. Figure 3.1 shows the hourly average level of economic bids and self-schedules for imports and exports in the real-time market. The figure further indicates whether the bids and self-schedules came from resources with or without day-ahead awards.[65] As seen in this figure, self-schedules from resources with day-ahead awards accounted for most of the real-time activity on the inter-ties since implementation of 15-minute inter-tie scheduling.

The volume of economic real-time inter-tie bids has remained at relatively low levels throughout 2015. On average there were about 1,200 MW of economic real-time import bids and about 400 MW of economic real-time export bids in 2015. The corresponding averages for May through December 2014 were about 1,200 MW for imports and about 300 MW for exports. Of the economic import bids, the percent without a day-ahead award increased to about 73 percent in 2015 from about 66 percent during May through December of 2014. About 99 percent of economic export bids were without day-ahead awards for both 2015 and May through December 2014.

Most real-time economic inter-tie bids have remained hourly block bids despite the introduction of 15-minute scheduling on the inter-ties. However, as shown in Figure 3.2, the share of 15-minute economic bids has gradually increased to about 30 percent of all bids, compared to only about 14 percent during May through December 2014. For economic export bids, the share of 15-minute bids increased from about 31 percent to almost 42 percent for the same time period. In the fourth quarter of 2015, the share of 15-minute economic bids reached 37 percent for imports and 62 percent for exports.[66]

Figure 3.3 shows the hourly average amount of 15-minute economic import and export bids by inter-tie, with each color representing a different scheduling coordinator. The figure shows that 15-minute economic inter-tie bids were concentrated on three inter-ties and submitted by a small number of participants. The majority of these participants were external balancing authority areas.

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[64] For more information about changes made to the 15-minute market in 2014, see DMM's *2014 Annual Report on Market Issues and Performance*: http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf.

[65] The classification is made by megawatt at the resource level. For example, if a resource has a 10 MW award from the day-ahead market and places a 20 MW economic bid in the real-time market, then 10 MW is considered to be with a day-ahead award and 10 MW is considered without a day-ahead award.

[66] Participants seldom used the hourly economic bid block option with a single intra-hour economic schedule change on the inter-ties.

Figure 3.1 Volume of import and export bids in the ISO real-time market

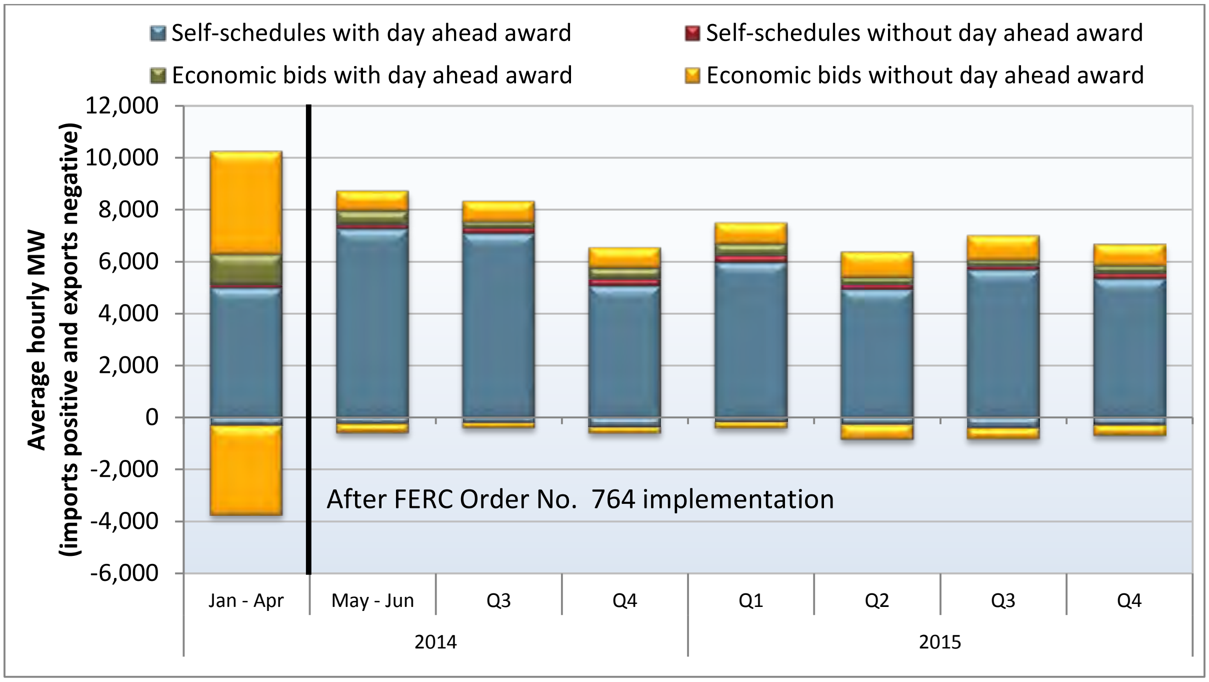


Figure 3.2 Economic import and export bids in the ISO by bidding option

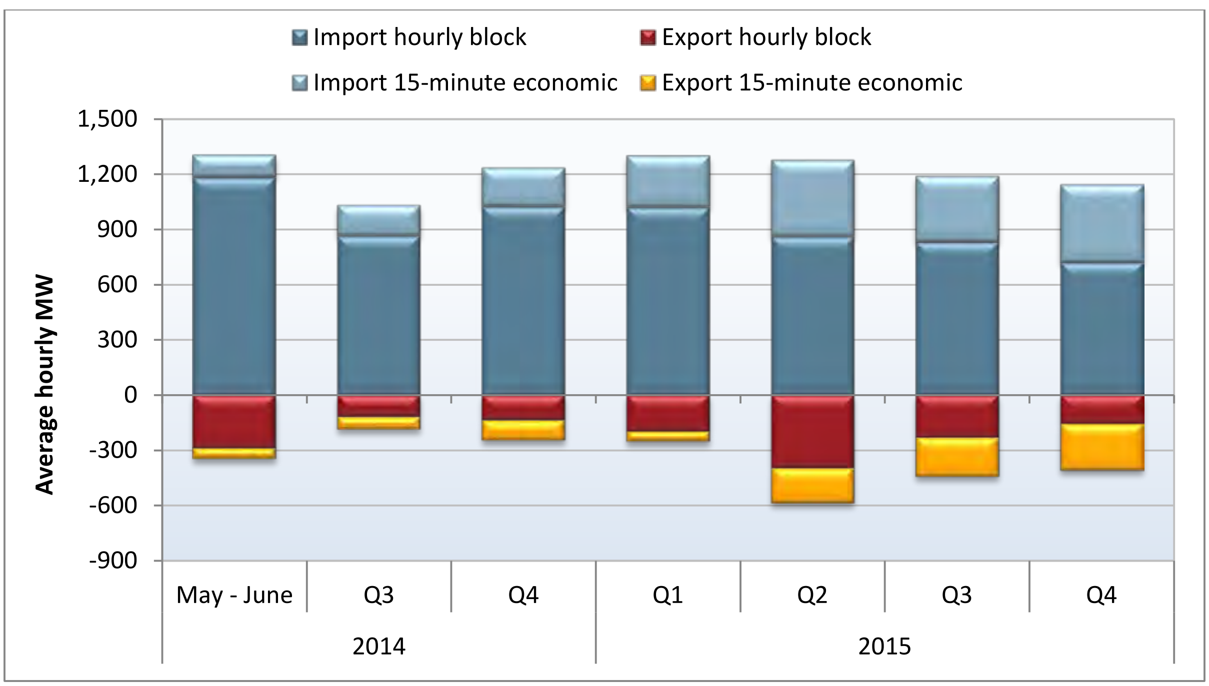
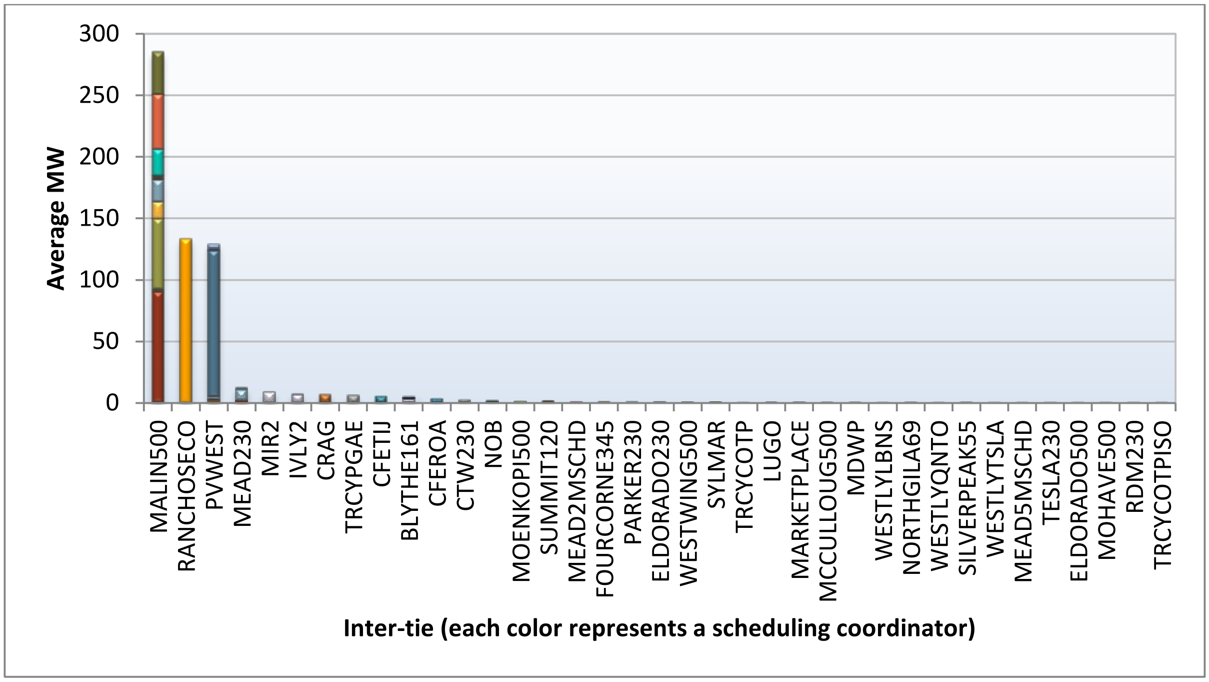


Figure 3.3 15-minute economic bids by inter-tie and scheduling coordinator (2015)



DMM published a report in April 2015 discussing how the lack of liquidity on the inter-ties in the 15-minute market would be problematic if convergence bidding on the inter-ties were to be reintroduced.[67] FERC issued an order in late September 2015 requiring the ISO to remove tariff provisions that provided for reinstatement of convergence bids at inter-ties.[68]

3.2 Real-time price variability

Since implementation of the nodal market in 2009, prices in the 5-minute real-time market have been volatile with brief periods of extremely high or low prices. These extreme prices frequently caused average 5-minute prices to diverge from average day-ahead prices. In many instances extreme prices resulted from modeling issues, causing the need to relax the power balance constraint in order to balance load and supply in the real-time market model, rather than signaling underlying supply and demand conditions.

Implementing the 15-minute market in 2014 reduced the impact of 5-minute market price variability on settlement prices because they are now weighted more heavily on prices in the 15-minute market (roughly 80 percent). The 15-minute market price is less volatile than the 5-minute price because there is a larger time horizon to ramp less expensive units to satisfy anticipated changes in load and supply, and to dispatch generation to avoid power balance constraint relaxations.

[67] The DMM report on potential issues with implementing convergence bidding on the inter-ties can be found here: http://www.caiso.com/Documents/DMMReport-ConvergenceBiddingonInterties.pdf. The analysis in the special report included bids by tie-generators, which are excluded from analysis in this section.

[68] For further details see: http://www.ferc.gov/CalendarFiles/20150925164451-ER15-1451-000.pdf.

In 2015, prices in the 15-minute and 5-minute markets continued to be fairly stable, with an increase in overall frequency of negative prices compared to 2014. This trend was particularly notable in the first half of 2015 due to Path 15 congestion in both real-time markets.

Prices in the 15-minute market rose above $250/MWh in around 0.3 percent of all intervals, and 5-minute market prices reached above $250/MWh in around 0.6 percent of all intervals. In 2014, prices in the 15-minute and 5-minute markets exceeded $250/MWh during 0.4 percent and 0.7 percent of all intervals, respectively.

Figure 3.4 shows the frequency of positive price spikes above $250/MWh in the 15-minute market. The frequency of price spikes above $750/MWh was most notable in the second quarter when they occurred in over 0.3 percent of 15-minute intervals, primarily due to scarcity events on June 8 when higher than anticipated loads occurred throughout the ISO system.

Figure 3.5 shows the frequency of positive price spikes above $250/MWh in the 5-minute market. While the overall frequency of 5-minute price spikes above $250/MWh was lower in 2015 than the previous year, the frequency of price spikes above $750/MWh increased in 2015. These high prices are primarily due to an increase in the frequency of power balance constraint relaxations during 2015, where market prices include the $1,000/MWh penalty price for the power balance constraint.

During 2015, negative prices occurred in the 15-minute market in about 2 percent of intervals. Figure 3.6 shows the quarterly frequency of negative price spikes in the 15-minute market. The frequency decreased significantly after the second quarter, from 4.7 percent to 0.6 percent in the third quarter and 1.2 percent in the fourth quarter. Most of the negative prices in the 15-minute market were between -$30/MWh and $0/MWh.

Figure 3.7 shows the quarterly frequency of negative price spikes in the 5-minute market. The overall frequency of negative prices in the 5-minute market was 4.3 percent in 2015, compared to 2.6 percent in 2014. This increase in negative real-time prices was driven in large part by south-to-north congestion on Path 15 in the spring, which decreased SCE and SDG&E prices. Lower loads and a high level of renewable generation, particularly from solar resources south of Path 15, further contributed to the congestion.

Figure 3.4 Frequency of positive 15-minute price spikes (ISO LAP areas)

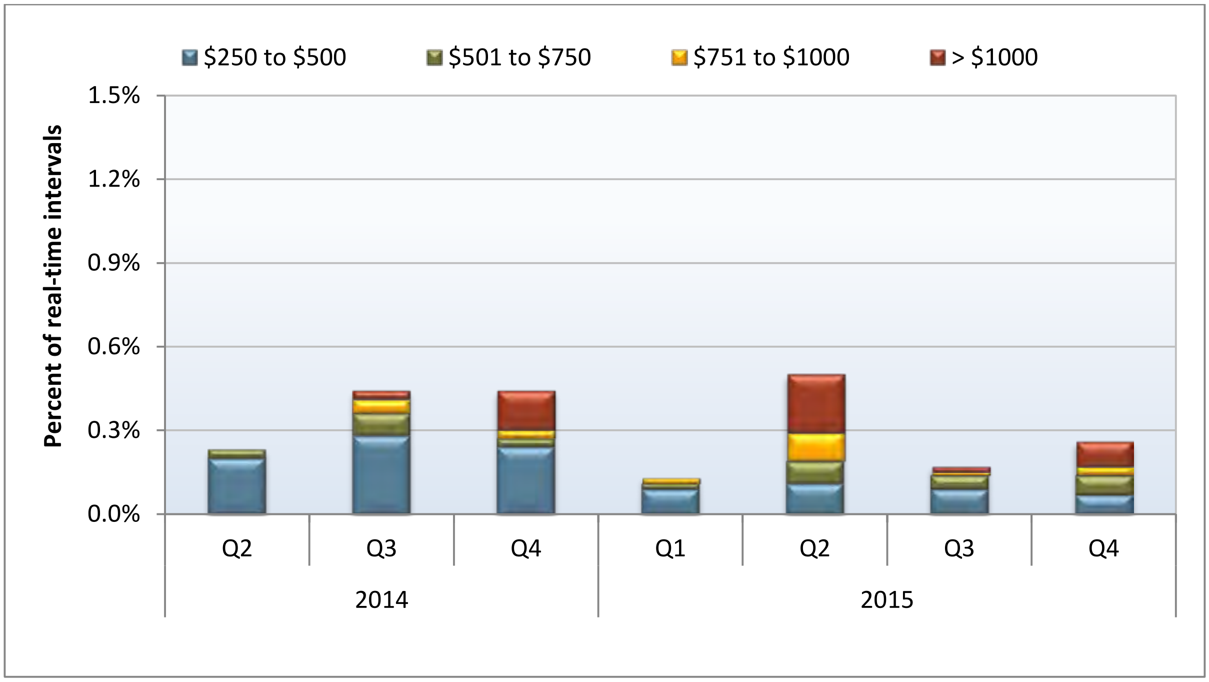


Figure 3.5 Frequency of positive 5-minute price spikes (ISO LAP areas)

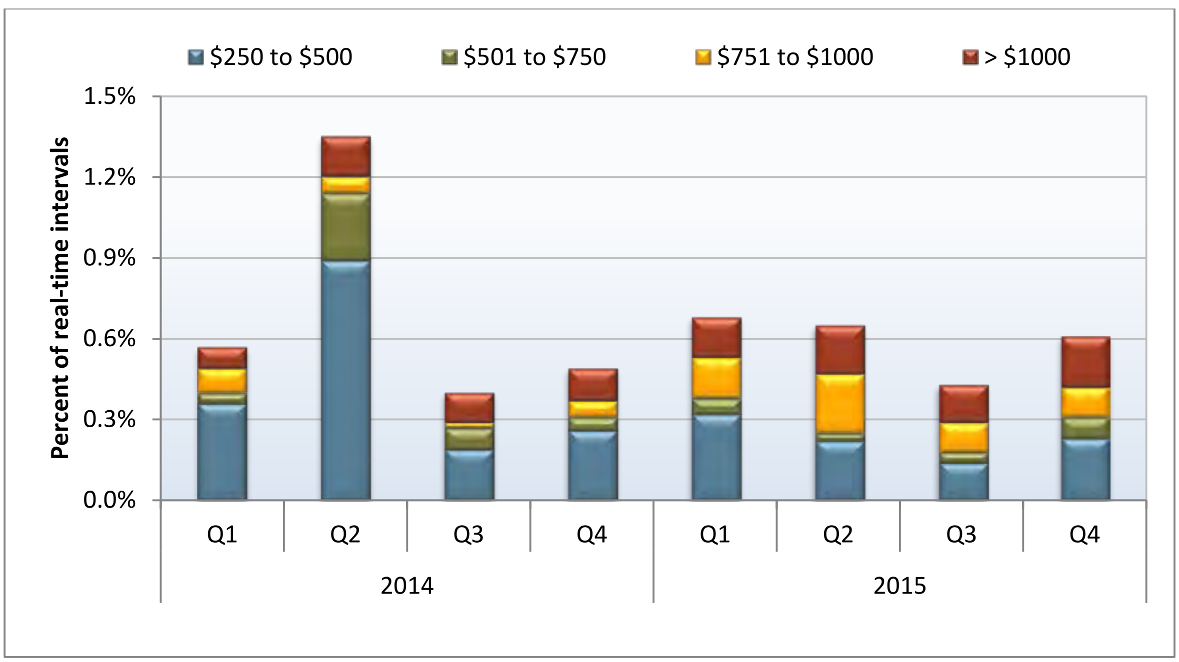


Figure 3.6 Frequency of negative 15-minute price spikes (ISO LAP areas)

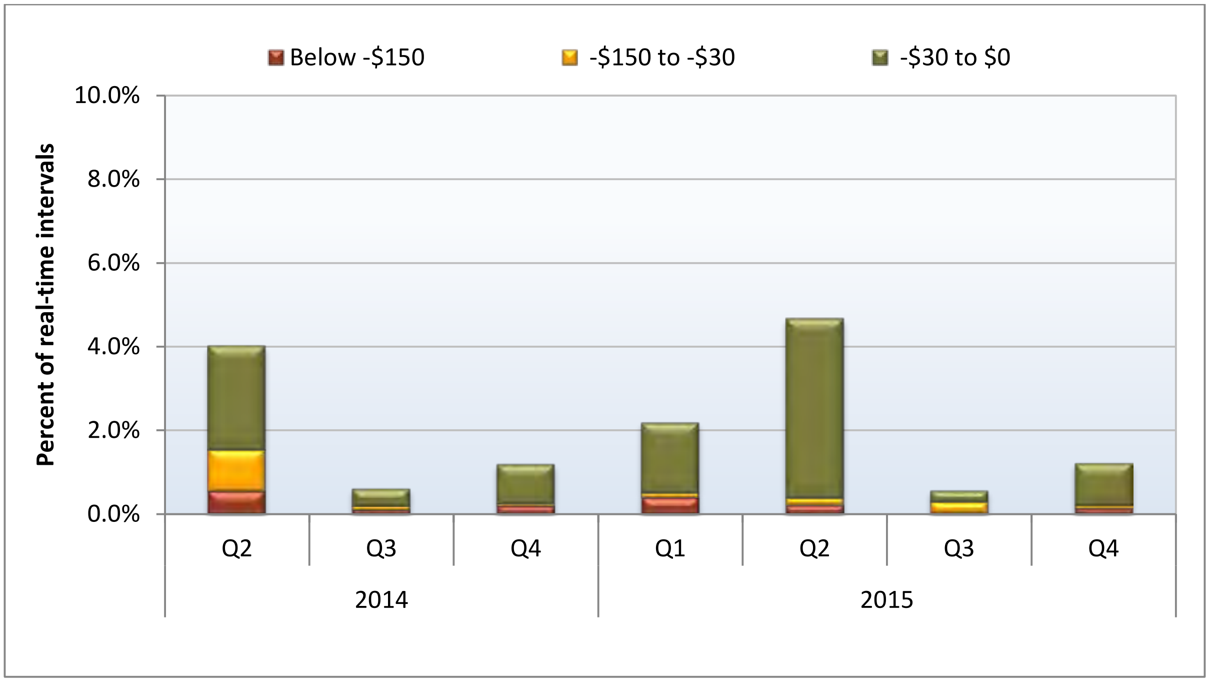
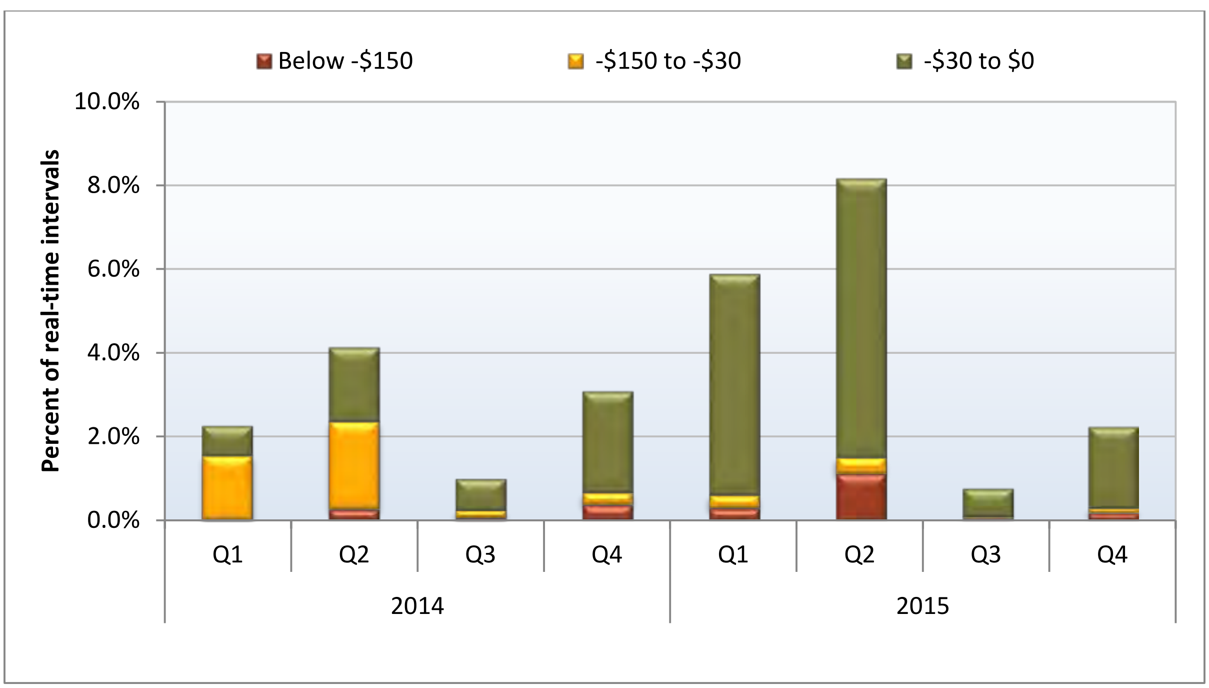


Figure 3.7 Frequency of negative 5-minute price spikes (ISO LAP areas)



3.2.1 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 and the bid floor is set at -\$150/MWh.[69] 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 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 by the market dispatching units offering these bid limits. Most intervals where prices reach bid limits are the result of relaxing the power balance constraint or transmission constraints.

When energy that can be dispatched in the real-time market is insufficient to meet estimated demand during any 15-minute or 5-minute interval, the system-wide power balance constraint is relaxed. This constraint requires dispatched supply to meet estimated load on a system-wide level in the real-time market. The power balance constraint is relaxed under two different conditions:

- When insufficient incremental energy is available for real-time 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/MWh for the first 350 MW relaxed.[70] After this, load and export schedules may be reduced at a penalty price of \$6,500/MWh in the scheduling run. In the pricing run, a penalty price of \$1,000/MWh is used. When the power balance constraint is triggered due to a shortage of generation relative to load, the \$1,000/MWh penalty price is included in the energy cost component of prices.
- When insufficient energy is available during downward real-time dispatch, the software relaxes this constraint in the scheduling run using a penalty price of -\$155/MWh for the first 350 MW relaxed. After this, day-ahead self-scheduled energy may be curtailed at the -\$1,000/MWh penalty price. In the pricing run, a penalty price of -\$150/MWh is used. When the power balance constraint is triggered due to insufficient energy for downward dispatch the -\$150/MWh penalty price is included in the energy cost component of prices.

Brief periods of power balance constraint infeasibilities do not necessarily pose a reliability problem. This is because the real-time market software is not a perfect representation of actual real-time conditions so the actual balance of system load and generation is not significantly impacted. When power balance relaxations occur more frequently or last for longer periods of time, an imbalance in load

[69] On May 1, 2014, the bid floor was lowered to a hard bid floor of -\$150/MWh from a soft bid floor of -\$30/MWh. This change was primarily intended to provide incentives for renewable generation to bid downward dispatch into the market economically. This change was also intended to eliminate inconsistencies between the scheduling run and the pricing run.

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

and generation can exist, resulting in units providing regulation service to provide additional energy needed to balance load 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 reductions in available ramping capacity, and thus cause relaxations of 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 resolve ramping limitations caused by congestion within the ISO system.[71]

Load bias limiter

Power balance constraint relaxation is modeled differently in the pricing run than in the scheduling run. Prior to the pricing run, the ISO software performs an additional test to see if operator load adjustments caused relaxation of the power balance constraint in the scheduling run. This functionality is called the load bias limiter. Specifically, the software compares the magnitude and direction of the power balance relaxation to the size and direction of the operator load adjustment for both shortage and excess events. If the operator load adjustments exceeded the quantity of the relaxation in the same direction, the size of the load adjustment is automatically reduced in the pricing run by a value slightly larger than the power balance constraint relaxation.

For instance, assume the grid operator had entered a 100 MW upward load bias for an interval. The load bias limiter is triggered if the power balance constraint is relaxed less than 100 MW during this interval. For instance, if the power balance constraint is relaxed by 70 MW in the scheduling run with the 100 MW of upward load bias in place, the load used in the pricing run is adjusted to reflect only 30 MW of upward load bias. This effectively limits the upward load bias in the pricing run to the amount of supply bids actually available to the market software given ramping and other constraints (100 MW bias - 70 MW relaxation = 30 MW of available supply).[72]

This results in a feasible market solution in the pricing run, so that the price is set by the highest priced supply dispatched rather than the $1,000/MWh penalty price for the power balance constraint.[73] The resulting price, from the unit entering the highest economic bid, is often significantly less than the $1,000/MWh penalty price.

The ISO implemented the load bias limiter as a real-time market software enhancement in December 2012. The purpose of this tool is to assist operators by automating adjustments to avoid extreme unintended market effects due to operator load adjustments that do not increase or decrease the actual supply of system energy. This tool was operational in the ISO real-time market throughout the year, but was not implemented into EIM until March 2015 when the ISO extended this tool to both the 15-minute

[71] 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 may be less expensive than the cost of relaxing the system constraint. Thus, the local constraint may be relaxed instead of the power balance constraint.

[72] If the relaxation exceeds the load bias or the load bias is in the opposite direction of the relaxation, the limiter feature does not apply in the pricing run.

[73] Because congestion usually happens on local or regional constraints, the load bias limiter feature may not be able to resolve the infeasibility. Thus, congestion-related power balance relaxations were not considered resolved by the load bias limiter in this analysis.

and 5-minute markets for the EIM balancing areas. However, the price discovery feature currently in effect in EIM, which sets prices to the price of the last dispatched resource when there is a power balance relaxation, makes the application of this tool duplicative in terms of the final price impact. See Section 4.3 for further information on the frequency and price impact of the load bias limiter for the EIM areas.

Figure 3.8 through Figure 3.11 highlight the frequency with which this mechanism resolved power balance relaxations in the ISO balancing area. The load bias limiter resolved almost 65 percent of the upward power balance relaxations that occurred in the scheduling runs in the 5-minute market during 2015, compared to about 80 percent in 2014. In 2015, this feature resolved about 30 percent of the downward power balance relaxations that occurred in the scheduling runs in the 5-minute market, compared to about 50 percent in 2014.

DMM has provided recommendations to the ISO on how the load bias limiter feature might be enhanced to better reflect the impact of excessive load bias adjustments on creating power balance shortages. Specifically, DMM has recommended considering the adjustment based on a combination of factors including the *change* in load bias from one interval to the next and the *duration* of an adjustment rather than solely the *absolute value* of any load bias.[74]

Power balance constraint relaxations

Before accounting for the load bias limiter, insufficient upward ramping capacity caused power balance constraint relaxations at about the same frequency as the previous year, while relaxations from insufficient downward ramping capacity decreased. After accounting for the load bias limiter, relaxations from insufficient upward ramping capacity increased in 2015. Path 15 congestion in the spring contributed to a significant increase in congestion-related power balance infeasibilities due to insufficient downward ramping capacity.

Figure 3.8 and Figure 3.9 show the frequency with which the power balance constraint was relaxed in the 5-minute market in each quarter since 2014.[75] As shown in Figure 3.8, excluding instances where the infeasibility was resolved by the load bias limiter, insufficient incremental energy caused constraint relaxations in almost 0.2 percent of 5-minute intervals in 2015, an increase from almost 0.1 percent in 2014. This figure also shows that in 2015, extreme congestion caused around 3 percent of the upward ramping capacity relaxations, compared to about 2 percent in 2014.

Insufficient downward ramping capacity relaxation frequency was much lower in 2015 compared to 2014. Unlike previous years, insufficient downward capacity resulted in power balance constraint relaxations only slightly more frequently than relaxations due to insufficient upward capacity. As shown in Figure 3.9, the constraint was relaxed because of insufficient downward capacity in about 0.5 percent of intervals in 2015, a decrease from almost 1 percent of intervals in 2014. However, congestion-related downward ramping relaxations significantly increased from 5 percent in 2014 to 64 percent in 2015. This trend was primarily a result of congestion on Path 15 in the second quarter.

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[74] The ISO has indicated that it intends to review and enhance the load bias limiter feature, with stakeholder feedback, in the coming months.

[75] The power balance constraint was relaxed due to insufficient upward ramping capacity during six intervals in the 15-minute market in the ISO system during 2015. These relaxations occurred during peak load hours in three intervals on June 8, two intervals on September 20, and one interval on October 13.

Figure 3.8 Relaxation of power balance due to insufficient upward ramping capacity

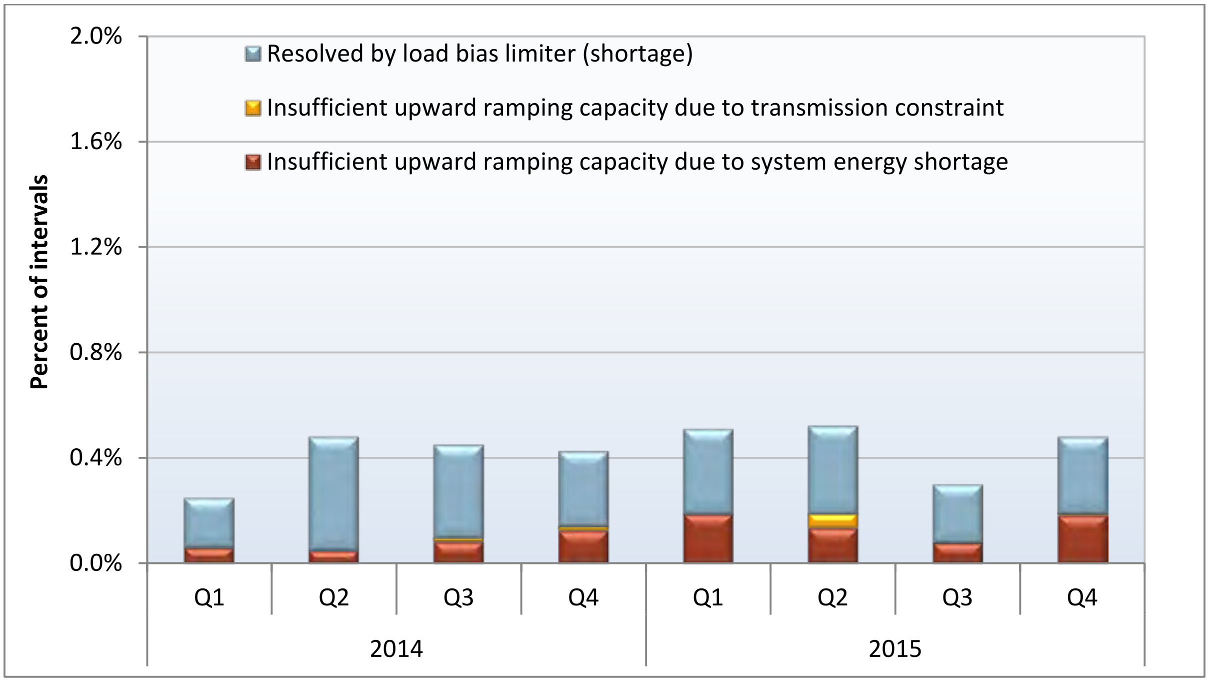


Figure 3.9 Relaxation of power balance due to insufficient downward ramping capacity

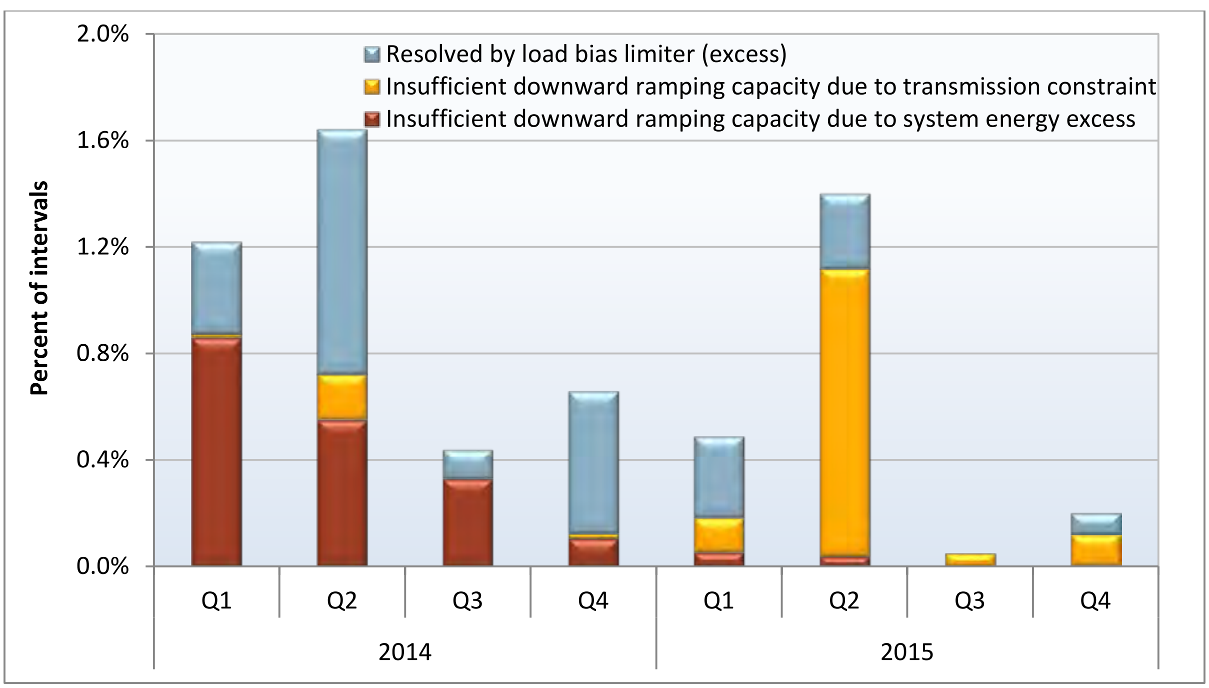


Figure 3.10 shows the percentage of intervals that the power balance constraint was relaxed in the scheduling run due to shortages of upward ramping during each hour in 2015. This figure also shows the average net load in each hour and the percentage of intervals the power balance relaxation was and was not resolved by the load bias limiter feature.[76]

As shown in Figure 3.10, shortages of upward ramping capacity caused the power balance constraint to be relaxed most frequently during the peak load hours of the day (hours 16 through 21). During these hours, shortages of upward ramping occurred in around 1 percent of intervals, down from about 1.2 percent in 2014.[77] This was almost four times more frequent than average shortages during all other hours.

Figure 3.11 shows the percentage of intervals that the power balance constraint was relaxed in the scheduling run due to shortages of downward ramping during each operating hour in 2015. This figure shows that the system power balance constraint was relaxed due to shortages of downward ramping capacity or excess energy primarily between morning and late afternoon hours when solar generation is highest.

Downward power balance relaxations occurred in almost 1 percent of intervals in the morning and afternoon hours (9 through 17). Excess energy during these hours is in part related to high renewable generation during south-to-north congestion on Path 15 in the spring. In particular, solar generation south of Path 15 further contributed to the congestion, which was the driver for most of the downward power balance relaxations in 2015.

As in prior years, most of the upward and downward ramping shortages were very short in duration. Similar to 2014, about 80 percent of upward ramping capacity shortages persisted for only one to three 5-minute intervals (or 5 to 15 minutes). About 70 percent of downward ramping capacity shortages lasted for only one to three 5-minute intervals in 2015, a slight increase from about 63 percent in 2014.[78]

[76] Net load is calculated during any interval as the system load less total renewable generation.

[77] The number in 2014 was based on hours ending 16 through 20.

[78] For additional information on impacts from power balance constraint relaxations and the load bias limiter in EIM please refer to Section 4.1 and Section 4.3, respectively.

Figure 3.10 Relaxation of power balance constraint due to insufficient upward ramping capacity by hour (2015)

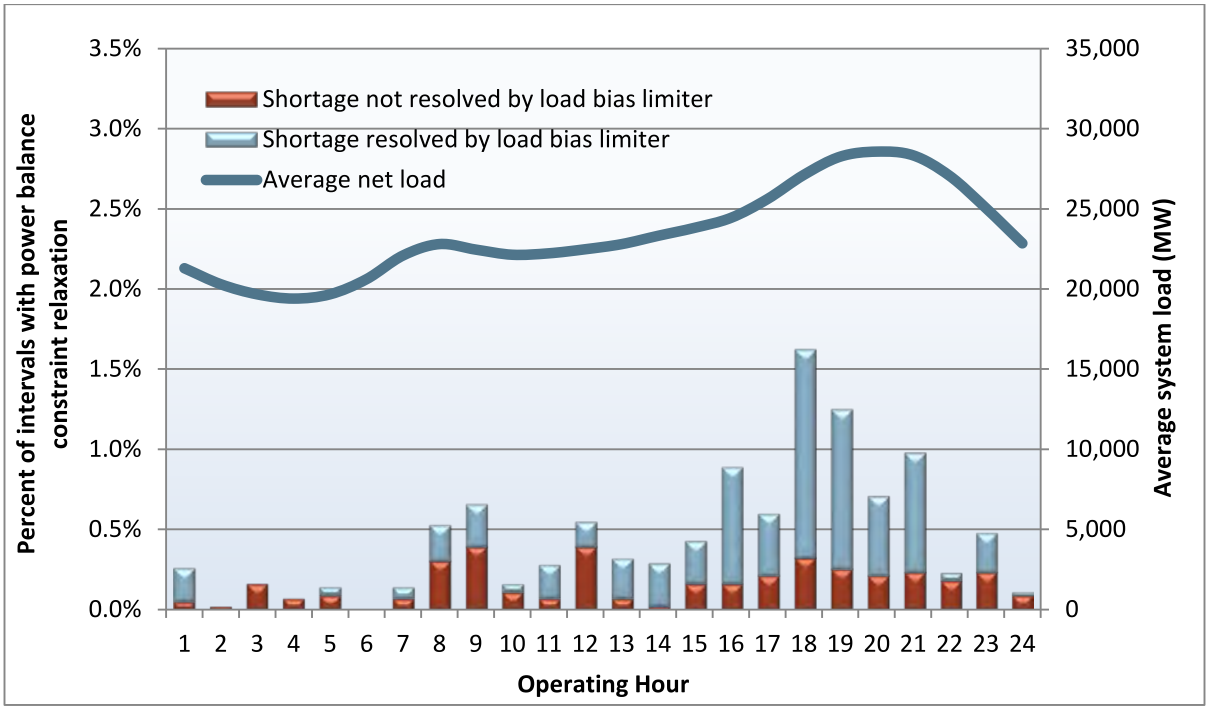
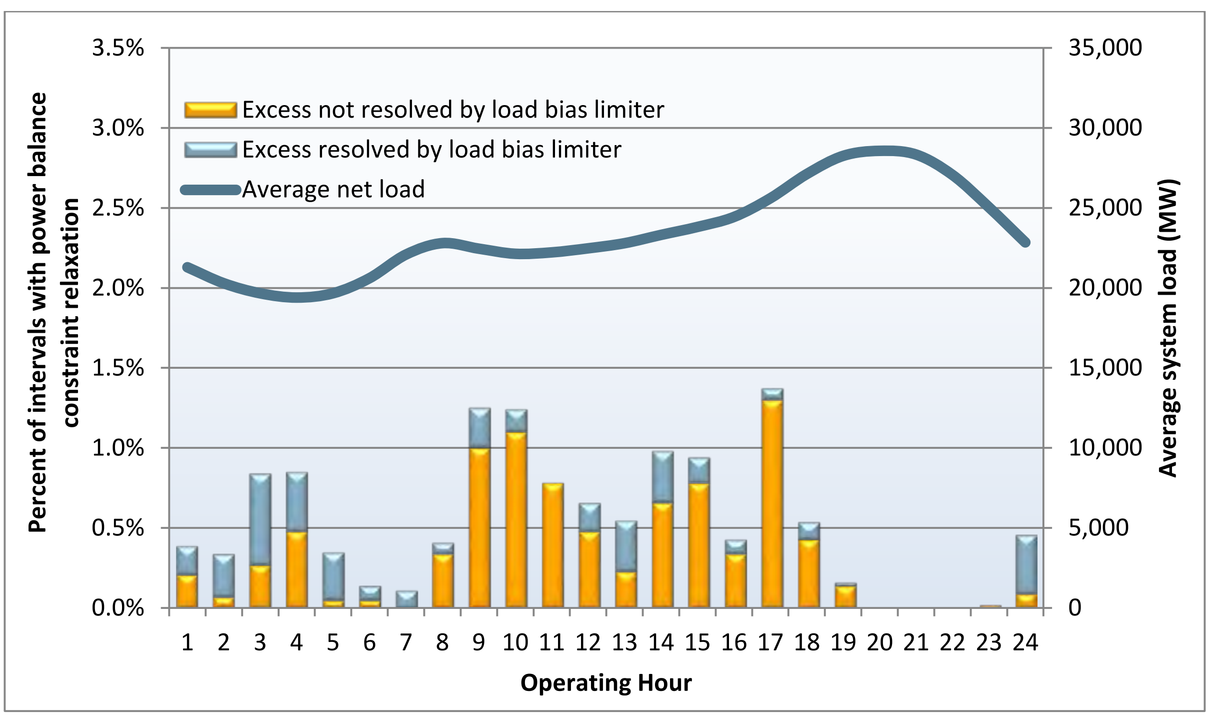


Figure 3.11 Relaxation of power balance constraint due to insufficient downward ramping capacity by hour (2015)



3.3 Flexible ramping constraint

This section provides information about the flexible ramping constraint and highlights key performance measures. These include the following:

- Total flexible ramping payments were about $4 million for the year compared to about $6.5 million in 2014. Total payments decreased despite a large increase from generation added in the EIM areas and additional flexible ramping requirements within the EIM areas.
- Payments made to generators in the ISO decreased to about $2 million in 2015 from about $6.4 million in 2014. This decrease was driven by a substantial decrease in the penalty price from $247/MWh to $60/MWh beginning in January 2015.
- Costs to procure flexible ramping capacity continue to be relatively low overall, and totaled about $0.08/MWh of load in PacifiCorp East, about $0.05/MWh of load in PacifiCorp West, and only about $0.01/MWh of load in the ISO.
- Most of the payments in 2015 were made to generators in the ISO and PacifiCorp East areas, with more total payments going to generators in PacifiCorp East beginning in the third quarter. About 58 percent of overall payments were made to gas-fired capacity and 23 percent to hydro-electric capacity, with most of the hydro-electric capacity payments to units inside the ISO.
- The ISO implemented an automated tool to calculate the flexible ramping requirement in late March 2015. When introduced, this new methodology resulted in increased volatility of the requirement between intervals, which may not have reflected actual ramping needs. In the second half of the year boundaries were placed on the limits of the tool to reduce volatility, which increased average flexible ramping requirements and, combined with other factors led to an increase in shortfalls as the year progressed.
- On average, the flexible ramping requirement was set to around 400 MW in the ISO, 83 MW in PacifiCorp East and 63 MW in PacifiCorp West in 2015. The requirements increased throughout the year, with a large increase occurring between the third and fourth quarters in all areas. This increase corresponded with increasing thresholds applied to the lower bounds of the requirements.

Background

The flexible ramping constraint included in the 15-minute market is designed to help ensure sufficient ramping capacity is available in the 5-minute market within each balancing area. If sufficient capacity is on-line, the ISO software does not commit additional resources in the system, and results in frequent low (and often zero) shadow prices for procured flexible ramping capacity. During intervals when there is not enough 15-minute capacity available for dispatch from committed units, the ISO software can commit short-start capacity or move multi-stage generation to a higher configuration. Flexible ramping capacity procured in the 15-minute market is paid based on the flexible ramping constraint shadow price.

The flexible ramping constraint relaxation pricing parameter, or penalty price, is $60/MWh in the scheduling and pricing runs of the 15-minute market.[79] Thus, the market software will dispatch units so that this constraint is met as long as the additional cost of procurement does not exceed $60/MWh. When this constraint is binding in the 15-minute market, the shadow price represents the marginal *opportunity cost* of not dispatching energy bids lower than local prices in order to maintain enough ramping capacity to meet the requirement.

When this constraint cannot be met and is relaxed in the pricing run, a shadow price is set at or near $60/MWh and the 15-minute energy price increases by $60/MWh. As discussed in Chapter 4, during much of the second half of 2015 average monthly prices in the PacifiCorp EIM areas have been driven up significantly by the relaxation of this constraint, particularly in PacifiCorp East. Beginning in late November 2015, the frequency and price impact of flexible ramping constraint relaxation in the PacifiCorp areas dropped sharply. This trend corresponded with an increase in available ramping capacity from several large generating units returning from extended outages, and also to the expansion of EIM in December to include the NV Energy area.

When the flexible ramping constraint is binding and feasible, DMM's review indicates that this does not generally have a significant upward impact on energy prices in the 15-minute market. A more detailed discussion is provided later in this chapter of how the flexible ramping constraint prices are being set in EIM areas.

Flexible ramping constraint requirement

The ISO implemented a tool to automatically calculate the flexible ramping requirement in both the ISO and EIM balancing areas in late March 2015. Prior to implementing this tool, the requirement was static for each hour and determined manually by ISO operators. The tool determines the flexible ramping requirement independently for each 15-minute interval based on the observed ramping need for that interval in the preceding 40 instances.[80] The requirements are bounded within predefined lower and upper thresholds. Because the requirement is based on relatively few observations, and because each interval is considered independently, the resulting ramping requirement was highly volatile in 2015, particularly in the second quarter, or was often set to either the lower or upper bound.[81]

Table 3.1 shows the average amount, range and volatility of the flexible ramping constraint requirements by quarter for the ISO and EIM balancing areas. Volatility is measured as the standard deviation of the percent change in the requirements between intervals. A higher volatility implies more frequent and/or larger changes in the requirement from one interval to the next. Further, the table shows the percent of intervals when the requirement was equal to the lower or upper bounds.

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[79] The penalty price was adjusted from $247 to $60/MWh on January 15, 2015. In EIM areas, when the energy power balance constraint must be relaxed in the scheduling run, the parameter for both the power balance and flexible ramping constraint are both set to $0/MWh in the pricing run so that energy prices can be set using the special price discovery feature temporarily in effect.

[80] Specifically, on weekdays it sets the requirement at the 95th percentile of the 40 observations. Weekend days are considered as separate observations from weekdays. On weekend days it uses the preceding 20 weekend days. For more details about how these calculations have evolved over 2015 see: http://www.caiso.com/Documents/FlexibleRampingRequirementDiscussion-ISO_Presentation-February2016.pdf.

[81] For a more detailed discussion about the implementation of the tool and the resulting increase in ramping requirement volatility see the *Q2 2015 Report on Market Issues and Performance*: http://www.caiso.com/Documents/2015_SecondQuarterReport-MarketIssues_Performance-August2015.pdf.

As shown in this table, the volatility of the flexible ramping requirements was very high in the second quarter, the first quarter for which the balancing area ramping requirement tool was in use. In late June, the ISO increased the lower thresholds in each of the balancing areas, which contributed to reduced volatility in the third and fourth quarters. However, volatility was still higher than prior to implementation of the tool, and the requirement was often set at either the upper or lower threshold. For example, the requirement was set at the upper threshold in 94 percent of intervals in PacifiCorp West during the fourth quarter.

Table 3.1 also generally shows that average flexible ramping requirements progressively increased in each of the balancing areas throughout the year. Overall, the average requirement for the ISO was almost 400 MW in 2015, which is similar to the yearly average for 2014. However, the average requirement was higher in the second half of 2015 compared to the first half. In the PacifiCorp East area, the average requirement for 2015 was about 83 MW, compared to only 35 MW during November and December of 2014. For the PacifiCorp West area, the average increased from 29 MW during November and December of 2014 to 63 MW on average in 2015. The requirement averaged 85 MW in the NV Energy area in December during its first month of EIM participation. These increases in average ramping requirements correspond to increases in the lower threshold of the requirement, and an increase in the frequency that requirements were set at upper thresholds.

Table 3.1 Flexible ramping requirement and volatility

BAA	Quarter	Requirement (MW)				Percent of intervals		
		Avg	Min	Max	Volatility	Req = Lower bound	Req = Upper bound	Req = bounds
CAISO	Q1*	373	300	450	4%			
	Q2	307	80	500	68%	37%	39%	75%
	Q3	448	300	500	14%	22%	69%	90%
	Q4	456	300	500	17%	9%	64%	72%
NV Energy	Q4**	85	80	100	8%	69%	24%	94%
PacifiCorp East	Q1*	33	30	40	5%			
	Q2	49	20	150	92%	61%	11%	72%
	Q3	112	80	150	18%	45%	36%	81%
	Q4	137	80	150	16%	2%	59%	61%
PacifiCorp West	Q1*	26	25	30	3%			
	Q2	44	10	100	114%	34%	39%	74%
	Q3	84	60	100	18%	35%	55%	90%
	Q4	99	62	100	5%	0%	94%	94%

** Excludes March 30-31 because of implementation of BARR tool.*

*** December only.*

Impacts on market dispatch and pricing

A sufficient amount of flexible capacity frequently gets committed by the market regardless of the flexible ramping requirement. In these intervals the flexible ramping constraint does not bind in the 15-minute market and the shadow price for the constraint is $0/MWh. This has been the case, particularly in the ISO area, for several years. However, in the EIM areas, most notably in the fourth quarter, this has not been the case.

Figure 3.12 shows the percent of 15-minute intervals where the flexible ramping constraint bound. The blue bars show intervals where the constraint bound but there was no shortfall in flexible ramping capacity. These are intervals when the constraint is not relaxed and shadow prices for the flexible ramping constraint are generally greater than $0/MWh but less than the $60/MWh penalty price. The red bars show intervals where the constraint needed to be relaxed in the scheduling run resulting in a positive shadow price, typically equal to the $60/MWh penalty price. As previously noted, during these intervals, the need to relax the flexible ramping constraint increases the 15-minute energy price by roughly $60/MWh.

The yellow bars in Figure 3.12 show the percent of 15-minute intervals where the flexible ramping constraint was relaxed in the scheduling run, but the shadow price was $0/MWh. This occurred in the PacifiCorp areas during the first and second quarters of 2015 for two reasons. Until early February, there were several software problems related to the flexible ramping credit and the relaxation parameter limits that prevented the flexible ramping constraint from binding in the pricing run. In addition, the penalty price for the flexible ramping constraint was set to $0/MWh in the pricing run for all intervals until mid-February.[82]

As seen in Figure 3.12, the flexible ramping constraint bound, but was not relaxed, much more frequently in the EIM areas than in the ISO. The portion of intervals during which the flexible ramping constraint bound also increased significantly towards the end of the year in all balancing areas. In the NV Energy area, the constraint bound during about 76 percent of 15-minute intervals in December, the first month of EIM operations in that area. The PacifiCorp East balancing area had the highest percentage of intervals with procurement shortfalls in the fourth quarter, where shortfalls occurred in about 11 percent of 15-minute intervals.

The average shadow value during intervals when the constraint was binding without a procurement shortfall in 2015 ranged from about $8/MWh in PacifiCorp West to about $11/MWh in the ISO and PacifiCorp East. This is significantly lower than the $27/MWh average shadow price during intervals when the constraint was binding without a procurement shortfall in the ISO in 2014.

When the flexible ramping constraint is binding but feasible, DMM's review indicates that this does not generally have a significant upward impact on prices within the EIM areas, but instead reflects the supply conditions within those areas. In the NV Energy area, for instance, resources providing flexible ramping capacity generally have marginal costs below system marginal prices. The flexible ramping constraint causes these lower cost resources to be dispatched at lower levels to provide additional 15-minute ramping capacity. In this situation, the shadow price for the flexible ramping constraint represents the difference between the market energy price and the bid price of the marginal unit being held back to provide additional 15-minute ramping capacity.[83] This shadow price reflects the relatively

[82] This occurred as a result of implementing the price discovery mechanism in the PacifiCorp areas. For this mechanism to work as intended, the penalty price for both the power balance and the flexible ramping constraint had to be set to $0/MWh when the power balance constraint was relaxed. However, due to software limitations, the penalty price for the flexible ramping constraint could not be set to $0/MWh in the pricing run only during intervals when the power balance constraint was relaxed. Therefore, due to this software limitation, the penalty price for the flexible ramping constraint was set to $0/MWh in the pricing run during all intervals. In mid-February, a software enhancement was implemented that allowed the penalty price for the flexible ramping constraint to be set at $0/MWh in the pricing run only during intervals when the penalty price for the power balance constraint is also set to $0/MWh.

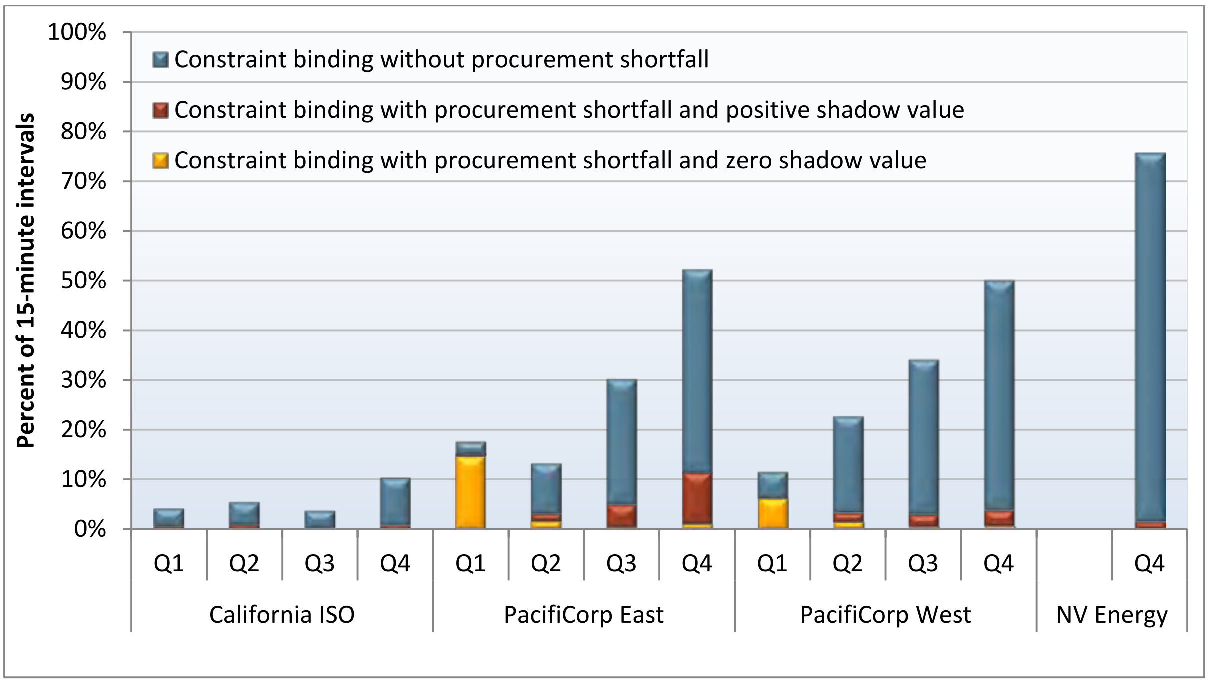
[83] For example, if the EIM area price is $35/MWh and the lowest priced energy bid being held back to provide flexible ramping capacity is $25/MWh, then the shadow price of the flexible ramping constraint is $10/MW for that EIM area.

low energy price of units providing flexible ramping capacity, but does not represent the degree to which this constraint is increasing the energy price.

Since the integration of NV Energy into EIM, prices in all EIM areas have been closely aligned with competitive system marginal prices throughout the ISO footprint, as well as prices at representative bilateral trading hubs.

In the ISO balancing area, units providing flexible ramping capacity tend to have higher marginal costs and therefore do not often have opportunity costs from providing available headroom as ramping capacity rather than providing energy. This often results in a $0/MWh shadow price for flexible ramping capacity in the ISO. When system conditions become tight in the ISO balancing area, the flexible ramping constraint may require units with lower marginal costs to withhold output, resulting in non-zero shadow prices. This tends to only occur during the morning and evening ramping hours in the ISO area, rather than throughout the day.

Figure 3.12 Percent of intervals with binding flexible ramping constraint (2015)



Flexible ramping procurement costs

Total payments to generators in the ISO and EIM areas for providing flexible ramping capacity in 2015 were about $4 million, a decrease from about $6.5 million in 2014.[84] However, because there were only two months of EIM operations in 2014, the 2014 and 2015 cost values are not directly comparable. When comparing payments to ISO generators only, total payments decreased to about $2 million in

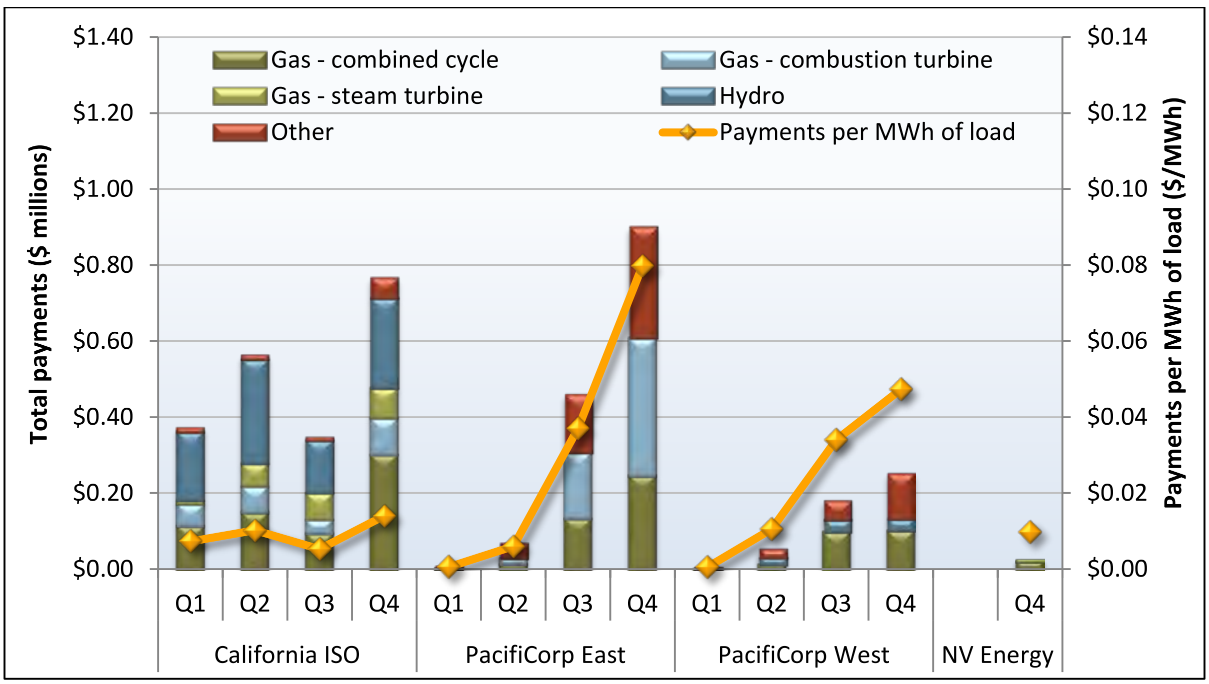
[84] The values presented are net payments after excluding rescissions for non-performance. However, secondary costs, such as bid cost recovery payments to cover the commitment costs and additional ancillary services payments, are not included in these calculations. Assessment of these costs is complex and beyond the scope of this analysis.

2015 from $6.4 million in 2014. This decrease is driven by a substantial decrease in the penalty price from $247/MWh to $60/MWh beginning in January 2015.[85]

As shown in Figure 3.13, most of the payments in 2015 were made to generators in the California ISO and PacifiCorp East areas.[86] Payments to generators in the PacifiCorp areas increased gradually over the year, in line with the increase in the percent of intervals where the constraint bound and the increase in average flexible ramping requirements. About 58 percent of payments were made to gas-fired capacity and 23 percent to hydro-electric capacity in 2015, with most of the hydro-electric capacity payments to units in the ISO area.

The gold lines in Figure 3.13 show the amount of payments made to generators for flexible ramping capacity per megawatt-hour of total area load. This metric shows that costs for flexible ramping capacity in the PacifiCorp areas per megawatt-hour of area load were significantly higher than in the ISO and NV Energy areas during the second half of the year. However, these costs are still relatively low overall, totaling only about $0.08/MWh of load in PacifiCorp East and about $0.05/MWh of load in PacifiCorp West in the fourth quarter. Flexible ramping costs totaled only about $0.01/MWh of load in the ISO and NV Energy areas during this same period.

Figure 3.13 Flexible ramping payments by fuel and balancing area (2015)



Most payments for flexible ramping capacity in the ISO occurred during the morning and evening peak hours, whereas payments to EIM generators were more evenly spread out over the day. This pattern can be seen in Figure 3.14 and Figure 3.15, which show the payments made to generators in 2015 by

[85] The motivation behind this decrease in the penalty price is explained in the following ISO technical bulletin: https://www.caiso.com/Documents/TechnicalBulletin-FlexibleRampingConstraintPenaltyPrice-FifteenMinuteMarket.pdf.

[86] The values for NV Energy represent December only.

hour for the ISO and PacifiCorp balancing areas, respectively.[87] The figures also show the hourly percent of 15-minute intervals that the constraint was binding.

Figure 3.14 Hourly flexible ramping constraint payments to ISO generators (2015)

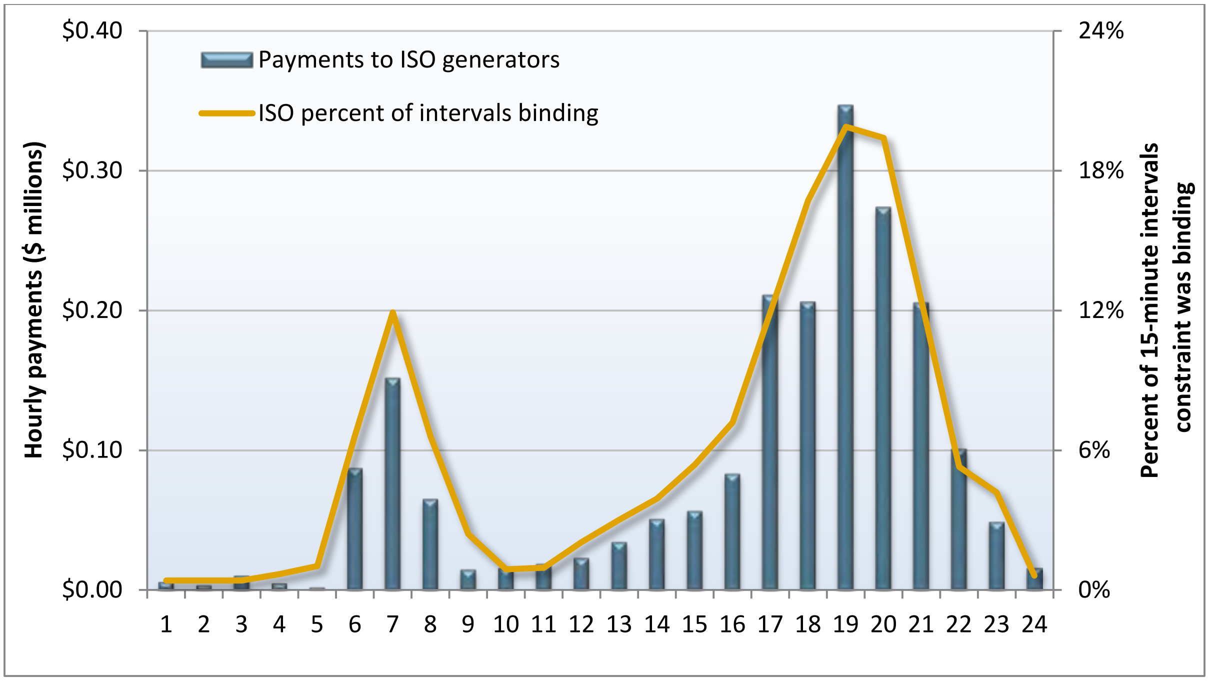
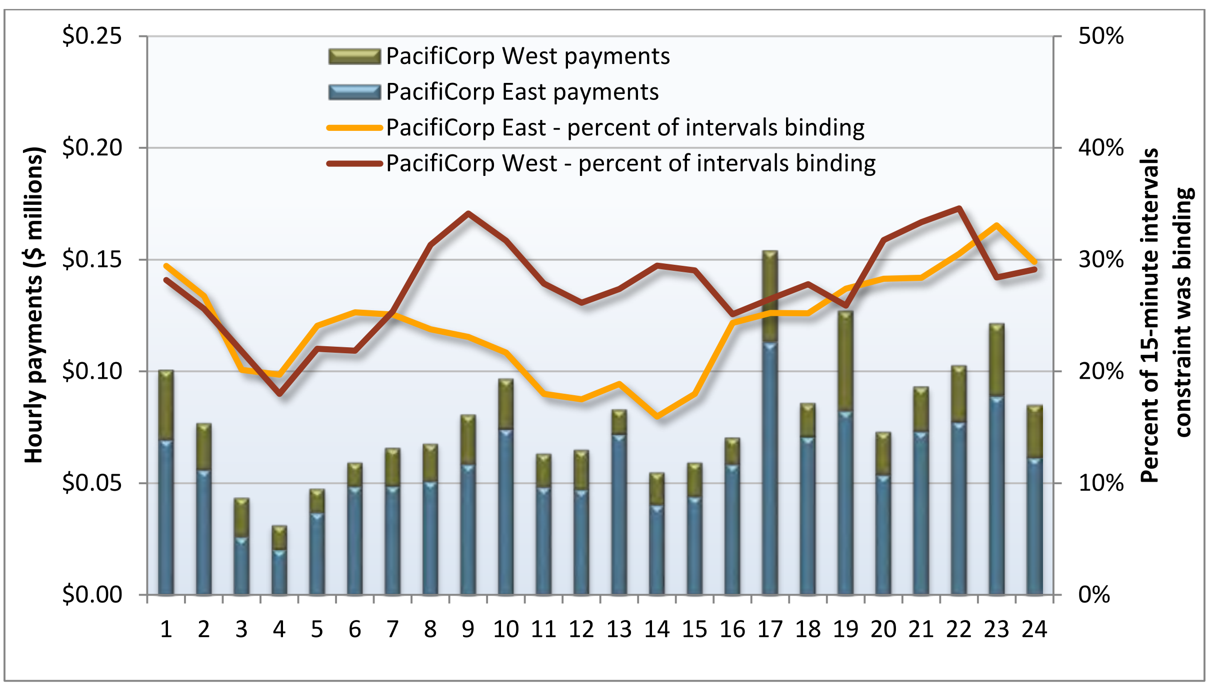


Figure 3.15 Hourly flexible ramping constraint payments to PacifiCorp generators (2015)



[87] The NV Energy balancing area is excluded from this analysis because only one month of data is available.

For the ISO, the constraint was most often binding during the morning and evening ramping periods and there is a clear correlation between the frequency with which the constraint is binding and the payments made. In the PacifiCorp balancing areas, the constraint was frequently binding during all hours of the day and the correlation between the frequency that the constraint is binding and payments made is less clear.

3.4 Bidding flexibility in real time

This section highlights the availability of economically priced bids, as opposed to self-schedules, in the real-time market. As more renewable generation is added to meet California state goals, economic bids provide flexibility that helps the market resolve surplus supply conditions without resorting to curtailment of self-schedules by the market software. Having sufficient economic bids also avoids prices being set by penalty parameters, or manual intervention by ISO operators to address over-generation conditions.

Analysis shows that participants submitted economic bids for only about one third of generation resources into the ISO real-time market in 2015.[88] The remaining two thirds of real-time generation was submitted as self-schedules, or, in the case of wind and solar generation, was treated as self-schedules based on generation forecasts.

Figure 3.16 shows the breakdown of economic bids in the real-time market compared with self-scheduled bids by resource type for 2015. Natural gas had the largest volume of economic generation bid into the real-time market and also had a high percentage of bid-in generation (87 percent) to self-scheduled generation (13 percent). However, it is important to note that this analysis does not account for other operational parameters, such as minimum run times, limitations on starts or transitions, or ancillary service awards, which may affect the ability of a gas resource to be effectively dispatched down over the time horizon needed to balance the real-time market.

Imports account for the highest share of real-time energy capacity, but only 8 percent of imports were bid into the real-time market economically.[89] Solar generation had more economic bids (26 percent) than wind (20 percent).[90] Imports, nuclear, wind and solar represented about 77 percent of real-time self-scheduled generation in 2015. The remaining 23 percent was primarily natural gas, hydro-electric, and geothermal generation, as well as other fuel sources including biogas, biomass and coal.

[88] This analysis focuses on the real-time energy bids that market participants submit to the ISO balancing area, and does not include bids in the energy imbalance market.

[89] This analysis only looks at real-time bid-in capacity relative to day-ahead schedules, and thus does not include new import bids in the real-time market as they would be incremental schedules compared to the day-ahead market. Imports also include consistent wheel-through generation with ISO analysis on bid flexibility. Exports are also not included in this analysis at this time.

[90] Like imports, solar and wind generation are compared to day-ahead schedules and are limited by how much was bid into the day-ahead market. This was done to remain consistent with ISO analysis. However, this analysis does not account for increases in generation forecasts or wind and solar generation that did not participate in the day-ahead market. Thus, this analysis likely overstates the real-time bidding flexibility, as a significant quantity of wind generation, and to a lesser extent solar generation, only participated in real-time and typically did not offer economic bids.

Figure 3.16 Average hourly real-time economic bids by generation type (2015)

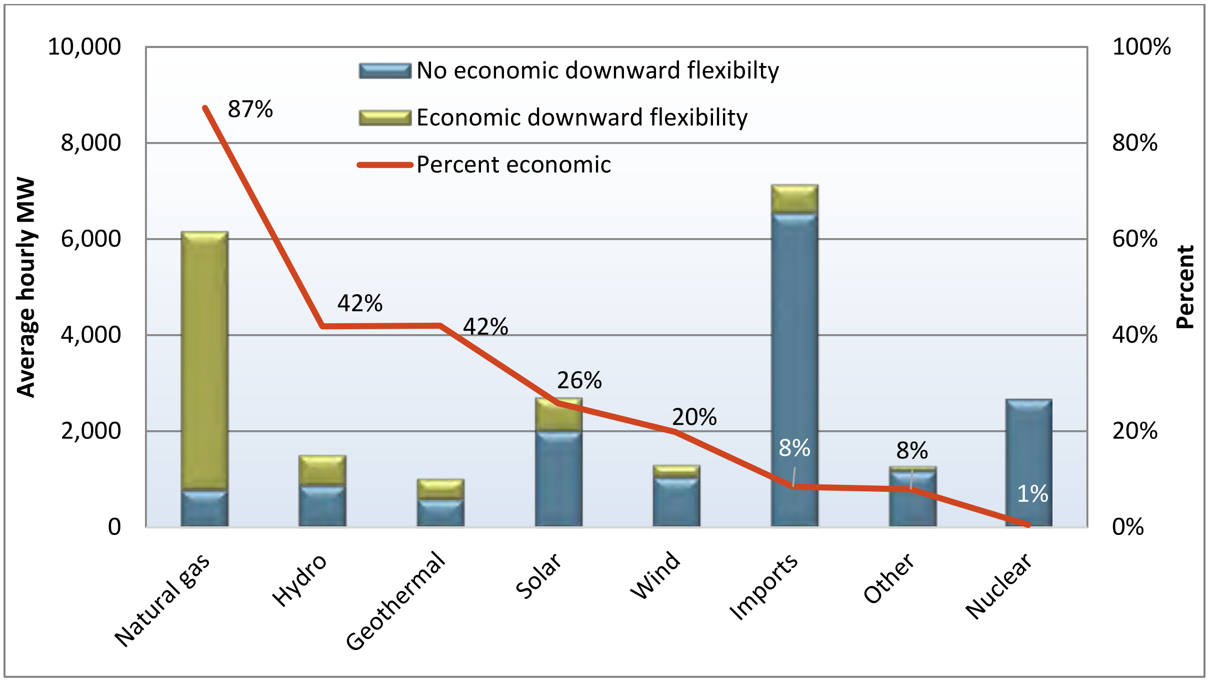


Figure 3.17 compares the average hourly ISO load curve to the average quantity of self-scheduled generation by type. As shown in this figure, self-scheduled generation averaged about 15,000 MW each hour in 2015, about 57 percent of load. Figure 3.18 shows the average hourly percentage of each type of self-scheduled generation relative to all self-scheduled generation.

Both charts show that imports represent the largest share (43 percent) of self-scheduled generation in the real-time market. As noted in Section 3.1, most real-time self-scheduled imports come from import schedules carried over from the day-ahead market. Nuclear generation was the second largest source of self-scheduled generation, accounting for an average of almost 18 percent. Wind generation averaged about 7 percent of self-schedules, and solar generation represented about 9 percent for the day and about 20 percent during hours ending 10 through 17. Both natural gas and hydro generation each only accounted for about 6 percent of real-time self-schedules.

Figure 3.17 Average hourly self-scheduled generation compared to load (2015)

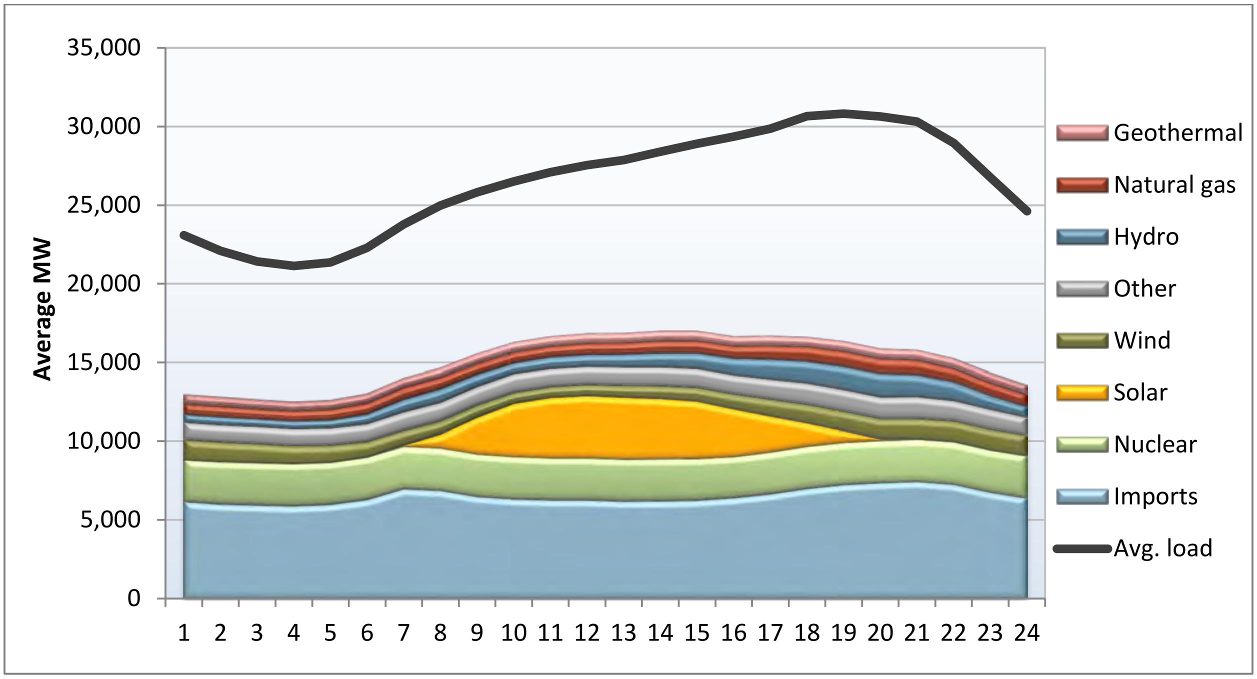


Figure 3.18 Hourly percentage of self-scheduled generation by type (2015)

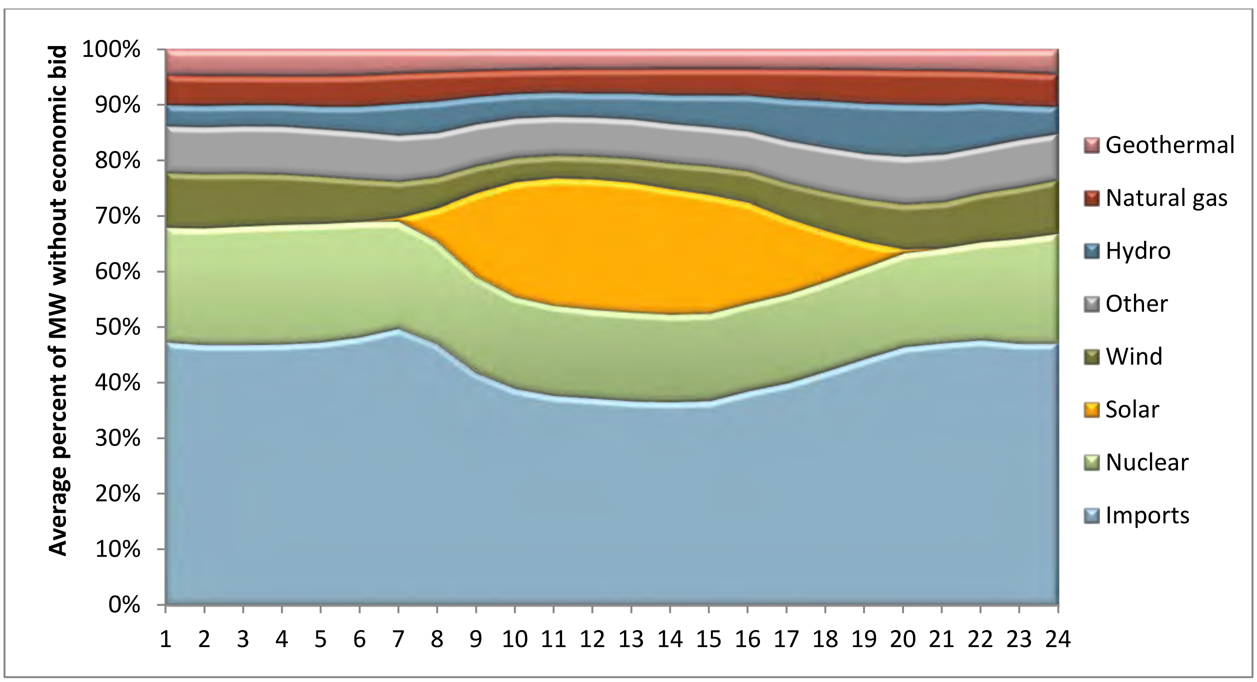
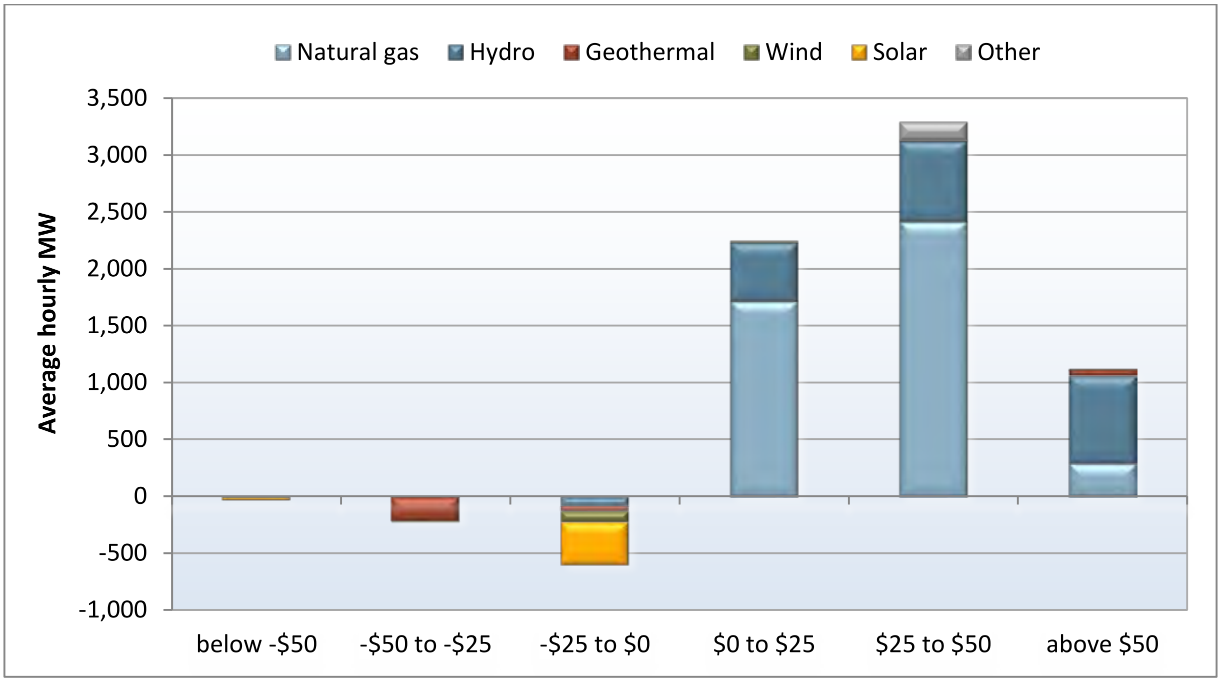


Figure 3.19 Real-time economic bids by bid range and resource type (2015)



When generators submit economic bids in the real-time markets, these bids can have either positive or negative offer prices. When the negative bids clear the market, these prices signal oversupply conditions and the ISO makes payments to generators to decrease their output. Almost all negative bids were submitted by renewable resources, including solar, wind and geothermal, in 2015.[91]

Figure 3.19 shows the ranges of bids submitted to the market by resource type in 2015. About 93 percent of natural gas-fired generation bid in below $50/MWh, which is consistent with the prevailing natural gas and greenhouse gas prices, resource heat rates and emissions factors. Hydro-electric generation varied from negative prices, which accounted for about 5 percent of total capacity bid into the market, to prices above $50/MWh.

Almost all negative bids submitted were for renewable resources, and these bids were generally between -$50/MWh and -$10/MWh, or the range of tax credits that these resources receive for each megawatt-hour of output. When output from these resources is decreased due to real-time market dispatch, these tax credits represent the opportunity cost of this lost production.

As noted in Section 3.2 above, the highest frequency of negative prices was in the second quarter in both the 15-minute and 5-minute markets. Most of these prices were set by renewable resources to resolve Path 15 congestion from Southern to Northern California.

Overall, wind and solar generation received only very infrequent downward dispatch instructions or curtailments from the ISO software. Most reductions in solar and wind generation in the ISO balancing

[91] These resources receive tax incentives and renewable energy credits that may be foregone when output is curtailed. Thus these credits and tax incentives can create negative marginal costs for renewable resources.

area in 2015 resulted from economic downward dispatch instructions corresponding to negative economic bids, rather than curtailments of self-schedules.

Table 3.2 shows the frequency of ISO software-based output reductions by month for solar and wind resources in 2015.[92] These reductions are measured as the difference between the ISO dispatch signal and the renewable generation forecast in the 5-minute market.[93] The table further breaks down the curtailment into downward dispatch based on participant bids as well as curtailment of self-scheduled generation. On average, DMM estimates that about 1.2 percent of solar generation was dispatched down in the real-time market in 2015, with the largest reductions occurring in May, at 3.2 percent.

The ISO software did not reduce output from wind resources as frequently as solar resources in 2015. Only about 0.2 percent of forecasted wind output was reduced in the real-time market, with the largest reductions occurring in April. The lower level of wind output reductions, relative to solar, occurred partly because solar generation was more effective at resolving Path 15 congestion in the second quarter and because wind resources tend to bid in at relatively lower prices.

Table 3.2 Volume of monthly ISO software-based reductions in solar and wind generation

Month	Solar			Wind		
	Economic downward dispatch	Non-economic curtailment	Total curtailment	% Economic downward dispatch	Non-economic curtailment	Total curtailment
Jan	1.1%	0.0%	1.1%	0.1%	0.0%	0.1%
Feb	1.5%	0.0%	1.5%	0.3%	0.0%	0.3%
Mar	2.0%	0.1%	2.1%	0.3%	0.1%	0.3%
Apr	2.0%	0.1%	2.1%	0.4%	0.1%	0.5%
May	3.2%	0.2%	3.4%	0.2%	0.1%	0.3%
Jun	0.8%	0.0%	0.8%	0.1%	0.1%	0.2%
Jul	0.4%	0.0%	0.5%	0.2%	0.0%	0.2%
Aug	0.6%	0.1%	0.6%	0.0%	0.0%	0.1%
Sept	0.3%	0.0%	0.3%	0.1%	0.0%	0.1%
Oct	0.4%	0.0%	0.4%	0.0%	0.0%	0.0%
Nov	1.2%	0.0%	1.3%	0.2%	0.0%	0.2%
Dec	1.1%	0.1%	1.2%	0.1%	0.1%	0.1%

In response to the increase in volume of downward dispatch for renewable resources, both DMM and the ISO reviewed wind and solar compliance with dispatch instructions. Solar resources complied with downward dispatch and curtailment instructions at a relatively high rate, whereas wind resources had a relatively low compliance rate for most of the year. Solar resources complied with 94 percent of instructions during the year, while wind resources complied with just 38 percent.[94]

[92] This metric does not attempt to capture instances where ISO operators manually curtailed renewable generation, only instances where the ISO software either dispatched economic bids down, or cut self-schedules because of violations of penalty parameters.

[93] This information includes only variable energy resources in the ISO balancing area that have corresponding forecast information. This covers the vast majority of wind and solar resources. The calculation also only takes the difference between the forecasted generation amount and the 5-minute dispatch when the ISO dispatch is below the forecasted generation level.

[94] Compliance indicates the percent of MWh of downward dispatch instructions where the meter data is adjusted accordingly.

Figure 3.20 Monthly compliance with ISO dispatch instructions – solar generation

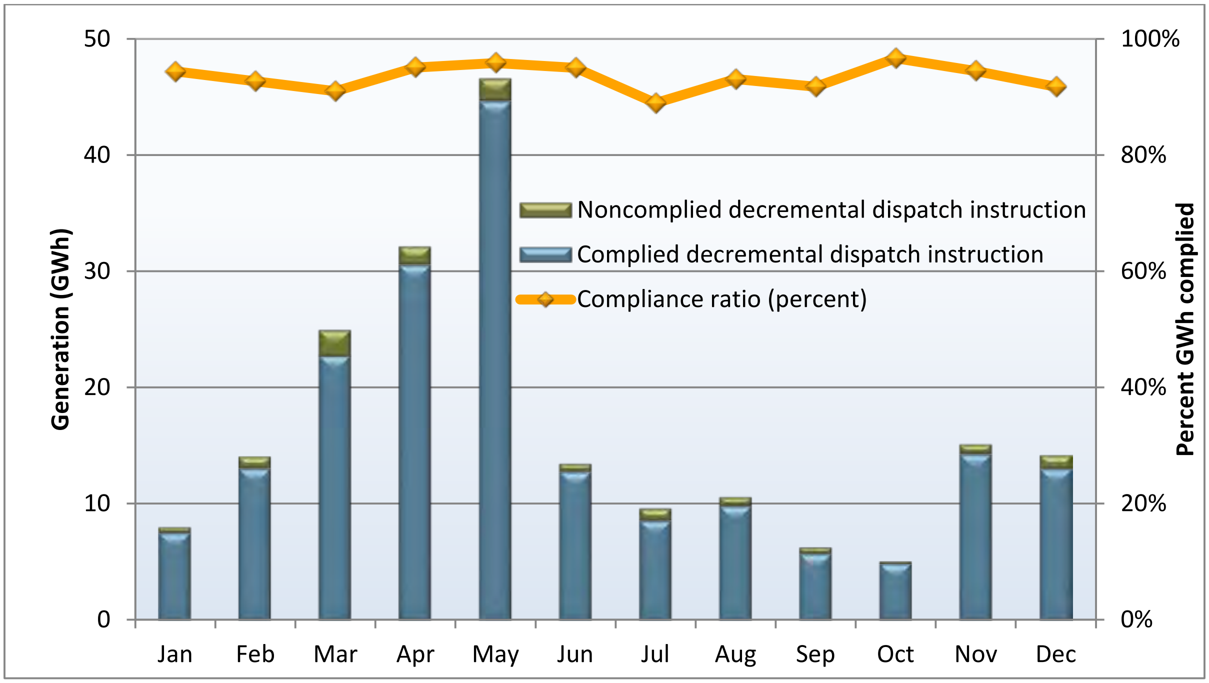


Figure 3.21 Monthly compliance with ISO dispatch instructions – wind generation

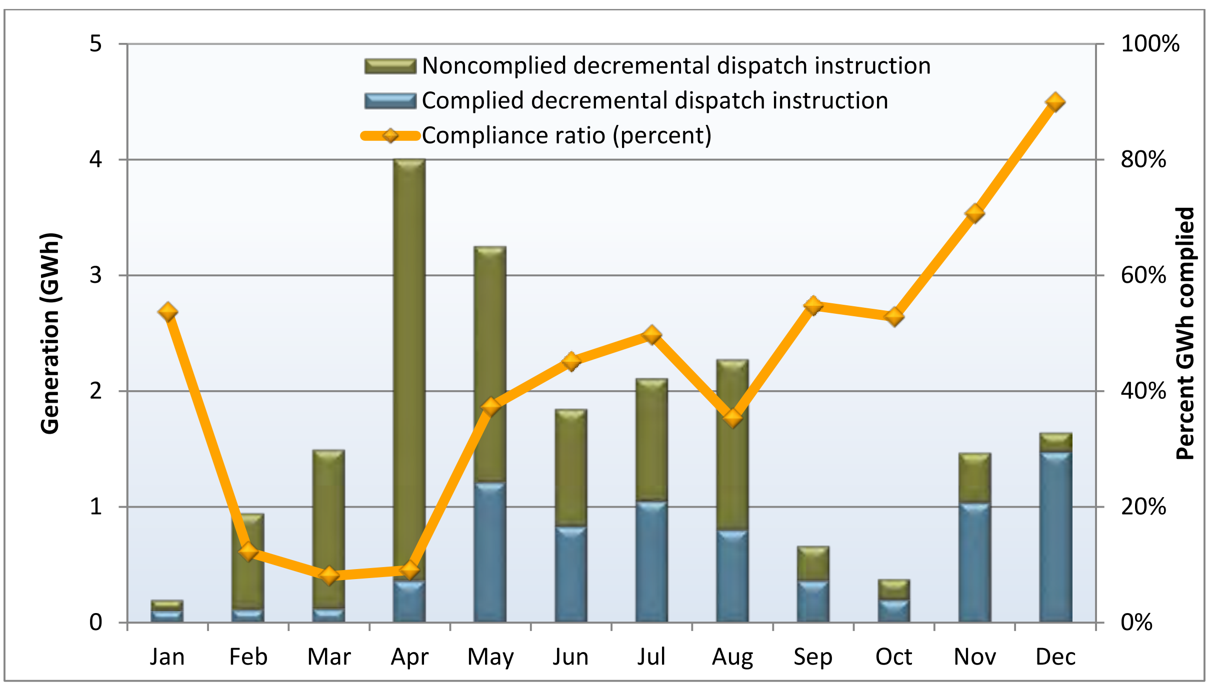


Figure 3.20 and Figure 3.21 show monthly solar and wind performance with downward dispatch and curtailment instructions during 2015, respectively. The blue bars represent the quantity of renewable generation that complied with dispatch and curtailment instructions. The green bars represent the quantity that did not comply with dispatch and curtailment instructions. The gold line represents the rate of compliance.

Where solar performance was fairly constant over the year, wind resources complied progressively better later in the year. Improvement in wind performance in the fourth quarter was due to a shift in concentration of downward dispatch instructions towards a single resource that historically complied well with dispatch instructions.

During 2015 the ISO reached out to market participants with poor performing solar and wind resources to better understand the circumstances regarding their performance. The market participants indicated that they intended to improve performance. The ISO continues to track compliance and will follow up with participants as necessary. Both the ISO and DMM expect that all market participants and resources follow ISO dispatch instructions.

4 Energy imbalance market

The energy imbalance market allows balancing authority areas outside of the ISO balancing area to voluntarily take part in the ISO real-time market. The EIM is designed to provide benefits from increased regional integration by enhancing the efficiency of dispatch instructions, reducing renewable curtailment and lowering the total requirements for flexible reserves. The EIM became financially binding with PacifiCorp becoming the first participant on November 1, 2014. NV Energy became the second participant in the EIM on December 1, 2015.

Key elements of EIM performance highlighted in this chapter include the following:

- Prices in the EIM during most intervals have been highly competitive and have been set by bids closely reflective of the marginal operating cost of the highest cost resource dispatched to balance loads and generation.[95]

- However, during a relatively small number of intervals, energy or flexible ramping constraints needed to be relaxed for the market software to balance modeled supply and demand. During these intervals, the ISO has applied special price discovery measures approved by FERC to set prices based on the last dispatched bid price rather than penalty prices for various constraints.

- The price discovery mechanism effectively mitigated the impact of constraint relaxation on market prices, particularly during the first six months after EIM launch. Overall average prices in 2015 in the PacifiCorp areas remained at or below bilateral trading hub prices that were used to set prices prior to integration with the ISO. DMM uses these prices as a key indicator of the efficiency and competiveness of EIM performance.

- With the addition of NV Energy in December 2015, additional transfer capability was made available between the EIM areas and the ISO. This additional transfer capacity, along with improvements in EIM performance made over the course of 2015, has led to greatly improved performance in all EIM areas during December 2015 and the initial months of 2016. The amount of energy deemed delivered from EIM areas to the ISO increased substantially with the addition of NV Energy.

- NV Energy prices have consistently in line with bilateral trading hub prices. Although special price discovery provisions are in place within the NV Energy area for the first six months of implementation, these provisions have been used infrequently.

- The EIM optimization minimizes costs of serving load in both the ISO and EIM including the greenhouse gas compliance cost for all energy deemed delivered to California. The EIM greenhouse gas price in each interval is set at the greenhouse gas bid of the marginal megawatt deemed delivered. Weighted average EIM greenhouse gas prices have been at or below estimated cost for an efficient gas resource in most months. This reflects the fact that during many intervals the marginal resource deemed delivered to California is a gas unit, while in some intervals the marginal unit is a hydro resource with no GHG compliance costs.

- In the early months of 2015, gas resources made up the majority of EIM energy deemed delivered to California. Hydro resources accounted for most EIM energy deemed delivered to California

[95] Additionally, as of December 1, 2015, FERC ordered that participants in EIM offer their units into the market at or below each unit's default energy bid (153 FERC ¶ 61,206): https://www.ferc.gov/whats-new/comm-meet/2015/111915/E-5.pdf.

following implementation of greenhouse gas bidding rule changes implemented as part of Phase 1 of EIM Year 1 Enhancements in November 2015.

Background

The energy imbalance market allows balancing authority areas outside of the ISO balancing area to voluntarily take part in the ISO real-time market. The EIM is designed to provide benefits from increased regional integration by enhancing the efficiency of dispatch instructions, reducing renewable curtailment and lowering the total requirements for flexible reserves. The EIM became financially binding with PacifiCorp becoming the first participant on November 1, 2014. NV Energy became the second participant in the EIM on December 1, 2015.

The EIM includes both 15-minute and 5-minute financially binding schedules and settlement. Energy imbalances between 15-minute schedules and base (pre-market) schedules settle at the 15-minute market prices, and energy imbalances between 15-minute schedules and 5-minute schedules settle at 5-minute market prices.

During the initial few months after EIM implementation in the PacifiCorp East and PacifiCorp West balancing areas, the amount of capacity available through the market clearing process was restricted and imbalance conditions in the market software were sometimes not reflective of actual economic and operational conditions. This caused the need to relax ramping and power balance constraints in the market software more frequently than expected to enable the market to clear. When the power balance constraint for an EIM area is relaxed, prices could be set using the $1,000/MWh penalty price for this constraint in the pricing run of the market model. The factors contributing to the need for constraint relaxation and steps being taken to address these issues have been addressed by the ISO as noted in its reports submitted to FERC.[96]

The ISO determined that many of these outcomes were inconsistent with actual conditions. Consequently, on November 13, 2014, the ISO filed with federal regulators special *price discovery* measures to set prices based on the last dispatched bid price rather than penalty prices for various constraints.[97] These measures were approved by FERC on December 1, 2014, and were extended through subsequent orders.

FERC also ordered that the ISO and the Department of Market Monitoring provide reports every 30 days during the period of the waiver that outline the issues driving the need for the EIM tariff waiver.[98] These waivers expired for PacifiCorp in March 2016 when the ISO implemented the available balancing capacity mechanism.[99] FERC also approved special transitional measures for NV Energy that allow for

[96] The ISO *Energy Imbalance Market Pricing Waiver Report*s can be found here: http://www.caiso.com/rules/Pages/Regulatory/RegulatoryFilingsAndOrders.aspx.

[97] For further details, see http://www.caiso.com/Documents/Nov13_2014_PetitionWaiver_EIM_ER15-402.pdf.

[98] The DMM filings can be found here: http://www.caiso.com/rules/Pages/Regulatory/RegulatoryFilingsAndOrders.aspx.

[99] The available balancing capacity mechanism will enhance EIM functionality by allowing the EIM to automatically recognize and account for capacity that participants have available to maintain reliable operations in their own balancing authority areas, thereby reducing the chance of an infeasibility based on false scarcity conditions. Further details can be found here: http://www.caiso.com/Documents/Aug19_2015_ComplianceFiling_EnergyImbalanceMarketEnhancements_AvailableCapacityAmendment_ER15-861_EL15-53.pdf.

price discovery during the first six months of NV Energy operation, and also required that the ISO file reports every 30 days during this period detailing market performance.[100]

4.1 Energy imbalance market performance

Prices in the EIM during most intervals have been highly competitive and have been set by bids closely reflective of the marginal operating cost of the highest cost resource dispatched to balance loads and generation.[101] However, during a relatively small number of intervals, energy or flexible ramping constraints needed to be relaxed for the market software to balance modeled supply and demand. During these intervals, the ISO has applied special price discovery measures approved by FERC's December 1, 2014 order. With these price discovery provisions, when the power balance is relaxed in an EIM area, prices are based on the last dispatched bid price rather than penalty prices for various constraints.

The price discovery mechanism effectively mitigated the impact of constraint relaxation on market prices, particularly during the first six months after EIM launch. Overall average prices in 2015 in the PacifiCorp areas remained at or below bilateral trading hub prices used to set prices prior to integration with the ISO. DMM uses these prices as a key indicator of the efficiency and competiveness of EIM performance. NV Energy prices were also close to the bilateral trading hub price range.

Figure 4.1 provides a summary of 15-minute and 5-minute prices within the EIM areas during 2015. This figure shows the average prices with special price discovery provisions (red bars) and prices that would have resulted without these provisions (gold bars). Figure 4.1 also compares these prices to the range of bilateral trading hub prices (grey region) and prices in the PG&E and SCE areas.[102]

As shown in Figure 4.1, average bilateral trading hub prices for PacifiCorp ranged between roughly $25/MWh and $26/MWh during 2015.[103] During the same time period, 15-minute prices in PacifiCorp East averaged just below $26/MWh in the 15-minute market, or about equal to the bilateral price range. Prices in the 5-minute market in PacifiCorp East averaged about $20/MWh, or about 19 to 23 percent less than bilateral prices. Prices in PacifiCorp West averaged about $25/MWh in the 15-minute market, at the lower end of the bilateral price range. PacifiCorp West 5-minute prices averaged about $21/MWh, or about 15 to 19 percent lower than bilateral prices.

Results for NV Energy were similar to PacifiCorp, although the EIM was active in the NV Energy area only during December. NV Energy prices in the 15-minute market averaged almost $25/MWh, or about 5 to

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[100] The FERC Order accepting the ISO Compliance Filing can be found here: http://www.caiso.com/Documents/Nov19_2015_OrderAcceptingComplianceFiling_EIMReadinessCriteria_ER15-861-004.pdf.

[101] Additionally, as of December 1, 2015, FERC ordered that participants in EIM offer their units into the market at or below each unit's default energy bid (153 FERC ¶ 61,206): https://www.ferc.gov/whats-new/comm-meet/2015/111915/E-5.pdf.

[102] The PG&E and SCE load settlement prices are an average of prices in the 15-minute market and the 5-minute market, weighted by each respective load imbalance in each respective market. Prices in the 15-minute market are weighted by the imbalance between day-ahead loads and forecast load in the 15-minute market. The 5-minute prices are weighted by the difference between forecast load in the 15-minute market and forecast load in the 5-minute market. This results in settlement prices that are weighted much more heavily on prices in the 15-minute market (about 80 percent) and less heavily on prices in the 5-minute market (about 20 percent).

[103] The bilateral trading hub price range is calculated using the range of index price results between the ICE and Powerdex indices. For PacifiCorp, the bilateral hub price represents a daily average of peak and off-peak prices for four major western trading hubs (California Oregon Border, Mid-Columbia, Palo Verde and Four Corners). The NV Energy bilateral hub price represents a daily average of peak and off-peak prices for two major western trading hubs (Mead and Mid-Columbia).

16 percent higher than the bilateral price range for NV Energy, while prices in the 5-minute market averaged about $23/MWh, just within the bilateral price range.

Figure 4.1 Average EIM annual prices with and without price discovery

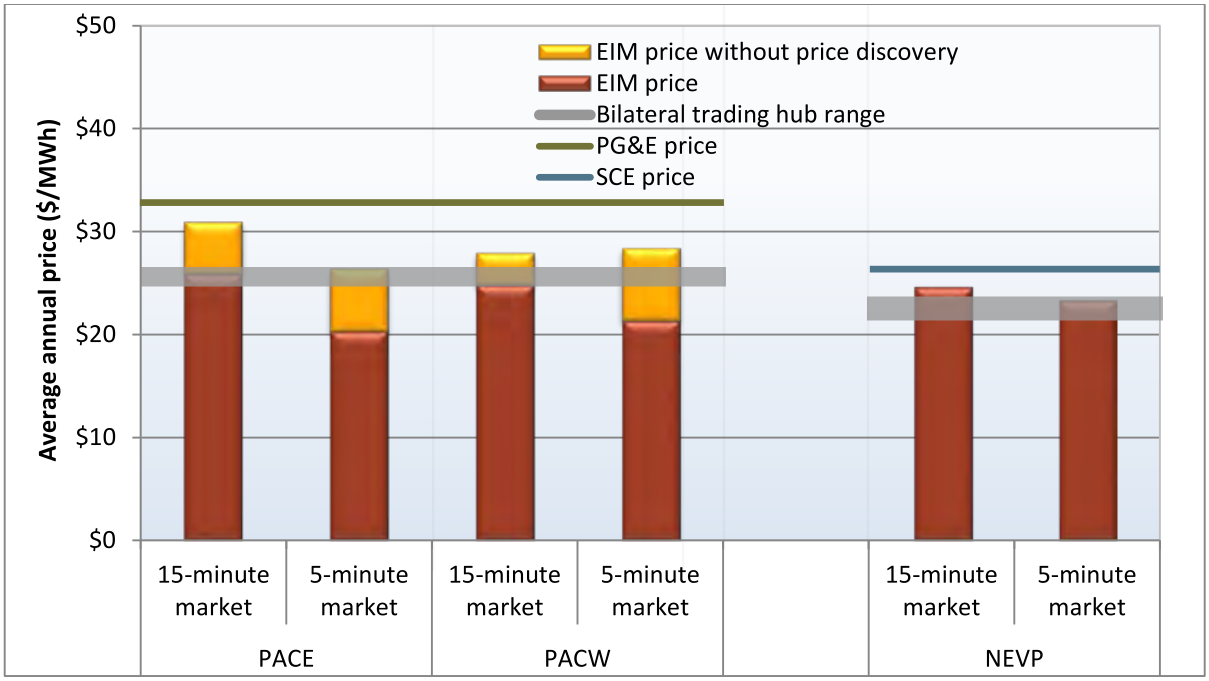

Figure 4.2 through Figure 4.7 provide summaries of the frequency of power balance constraint and flexible ramping constraint relaxations (blue and green bars), along with average prices with price discovery (gold line) and without price discovery (dashed red line). These figures also show the range of firm bilateral trading hub prices (gray region) for comparison to EIM market prices. Results for the PacifiCorp areas are shown on a monthly basis, while results are provided on a weekly basis for the NV Energy area covering the period after NV Energy joined EIM on December 1, 2015.[104]

A detailed description of the methodology used to calculate counterfactual prices that would result without price discovery has been provided in prior reports.[105] The ISO implemented the load bias limiter feature for EIM on March 20. Adjusted prices thereafter reflect intervals when the power balance constraint was relaxed in the scheduling run, but this software feature would have been triggered if price discovery was not in effect. Section 4.3 of this chapter provides additional detail on the impact of the load bias limiter feature on prices if price discovery was not in effect.

Several noteworthy trends occurred during the year across the PacifiCorp areas. During the first few months after PacifiCorp joined EIM, price discovery significantly influenced market prices because of increased levels of power balance constraint relaxations. With the price discovery provisions in place, EIM market prices were roughly equal to regional bilateral trading prices.

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[104] The first week and the last week included in Figure 4.6 and Figure 4.7 include observations from fewer than 7 days.

[105] *Report on Energy Imbalance Market Issues and Performance*, Department of Market Monitoring, April 2, 2015, p.6. http://www.caiso.com/Documents/Apr2_2015_DMM_AssessmentPerformance_EIM-Feb13-Mar16_2015_ER15-402.pdf.

During the summer months, there was better convergence between the EIM prices with and without price discovery as the frequency of power balance constraint relaxations declined. During this period, prices tended to be below the bilateral trading hub price range.

Finally, in the last several months of 2015, particularly in PacifiCorp East, convergence continued to be good between prices with and without price discovery; however, frequent relaxation of the flexible ramping constraint elevated 15-minute prices above bilateral trading hub prices. Figure 4.2 through Figure 4.7 highlight these trends.

Figure 4.2 and Figure 4.3 show that flexible ramping constraint relaxations increased between September and November in the 15-minute market in PacifiCorp East and West. This resulted in 15-minute EIM prices above the upper bound of bilateral trading hub prices. DMM believes that this trend occurred because of high increased flexible ramping requirements in conjunction with a reduction of available ramping capacity from generation outages. According to the ISO, other factors contributing to this trend included a software defect and data alignment issues.

Figure 4.2, Figure 4.3, and Figure 4.6 show that during the year the power balance constraint was relaxed infrequently in the 15-minute market in EIM. Although power balance constraint relaxations were higher in PacifiCorp East during the first two months of the year, at around 4.2 percent of 15-minute intervals, all monthly frequencies thereafter were less than 2 percent of all 15-minute intervals. For NV Energy, the power balance constraint was not relaxed during any interval in the 15-minute market during December after inclusion into EIM.

Figure 4.4, Figure 4.5 and Figure 4.7 provide the same information on prices and constraint relaxations in the 5-minute market. As shown in Figure 4.4, power balance constraint relaxations and divergence between prices with and without price discovery decreased during the year for PacifiCorp East. Unlike the results in the 15-minute market, 5-minute prices in both PacifiCorp areas were consistently below the lower bound of bilateral trading hub prices during the year. In NV Energy, 5-minute prices were at or below the bilateral trading hub average for much of December.

Overall, the price discovery mechanism approved under FERC's December 1, 2014, order effectively mitigated the impact of constraint relaxation on market prices, particularly during the first six months after EIM launch.

Figure 4.2 Frequency of constraint relaxation and average prices by month PacifiCorp East – 15-minute market

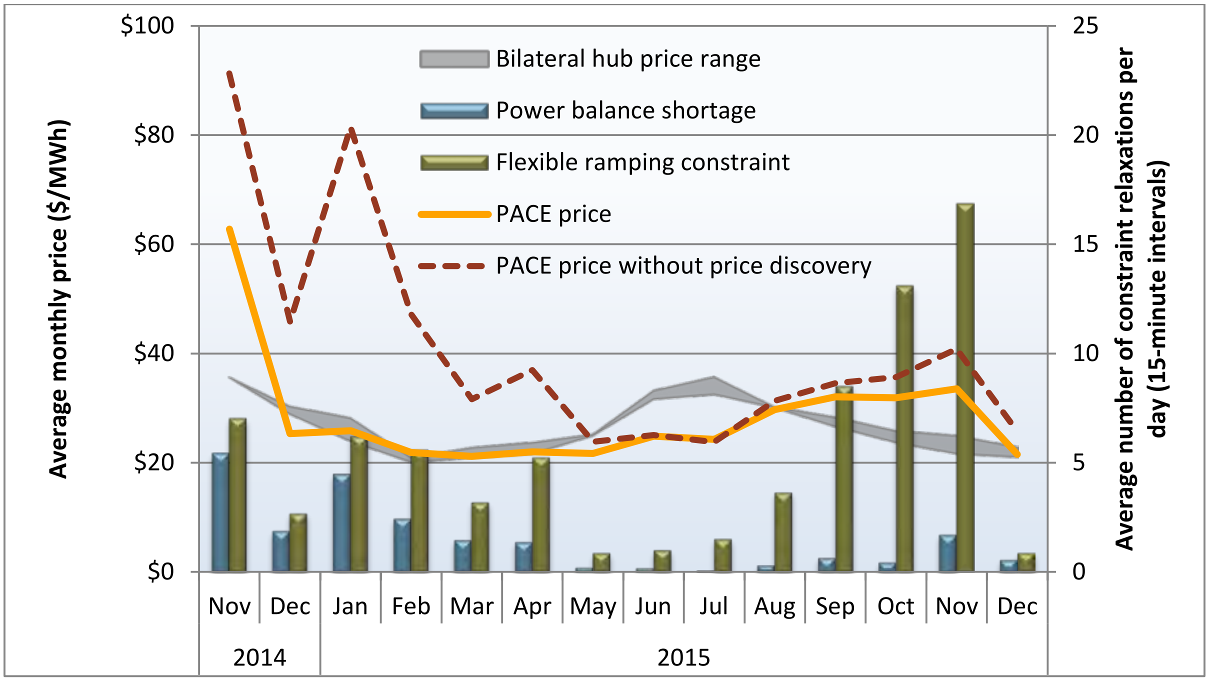


Figure 4.3 Frequency of constraint relaxation and average prices by month PacifiCorp West – 15-minute market

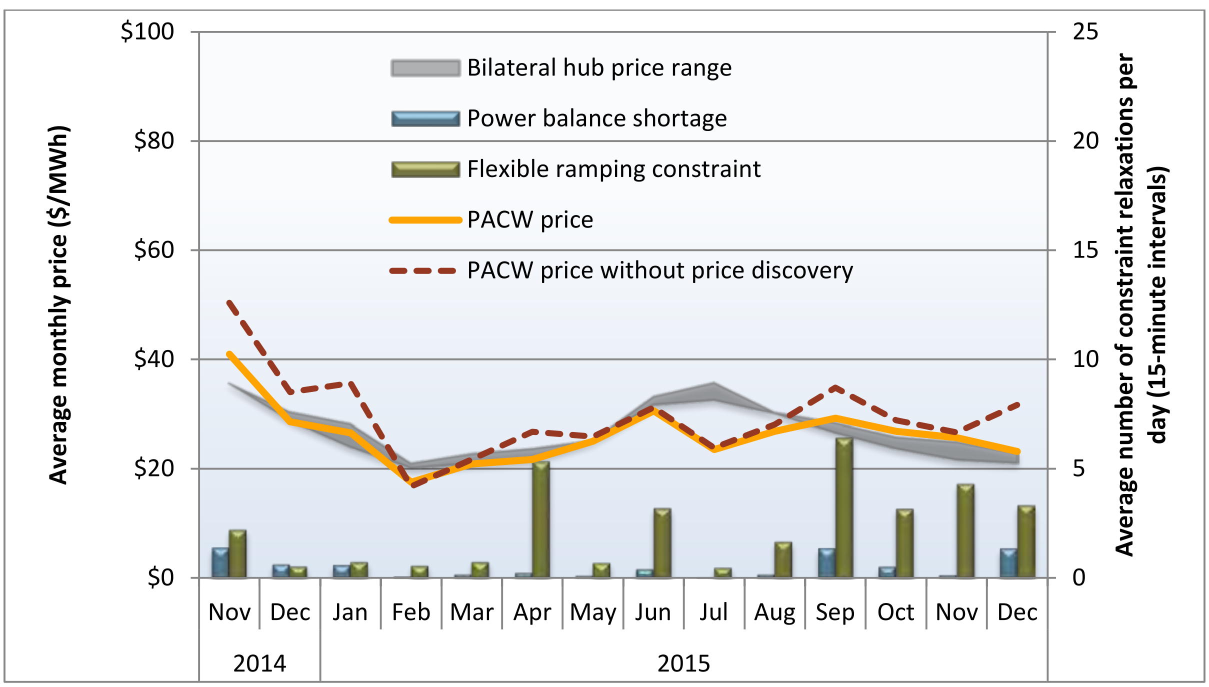


Figure 4.4 Frequency of constraint relaxation and average prices by month PacifiCorp East – 5-minute market

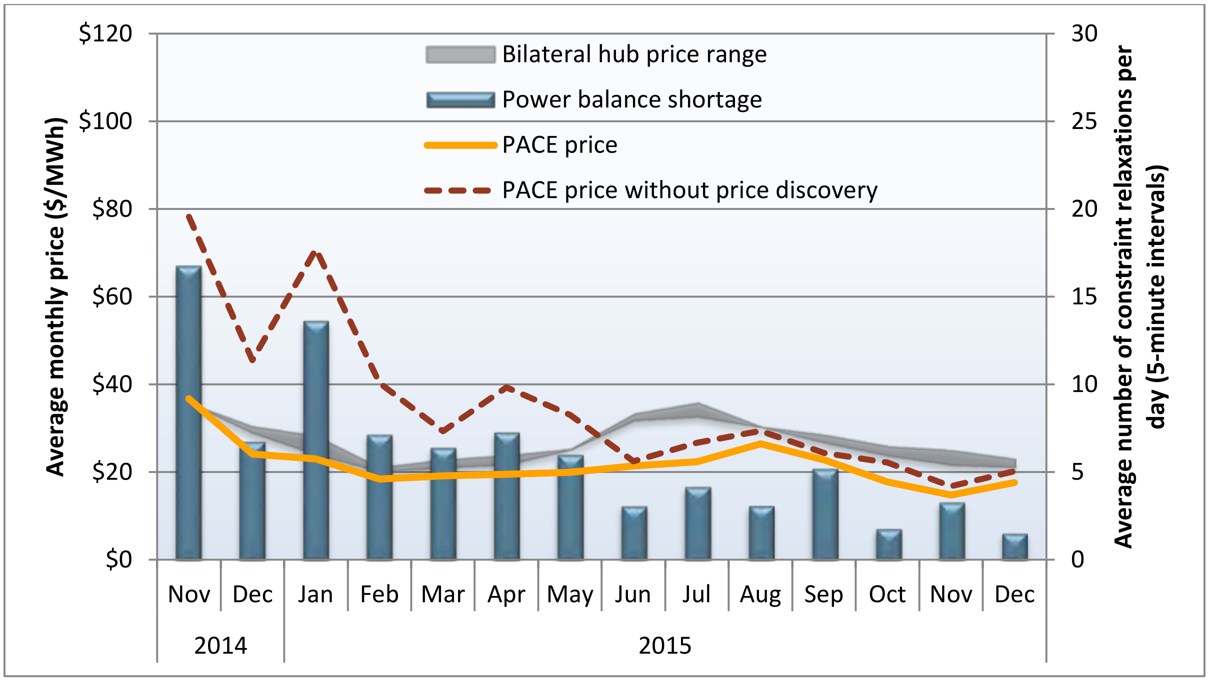


Figure 4.5 Frequency of constraint relaxation and average prices by month PacifiCorp West – 5-minute market

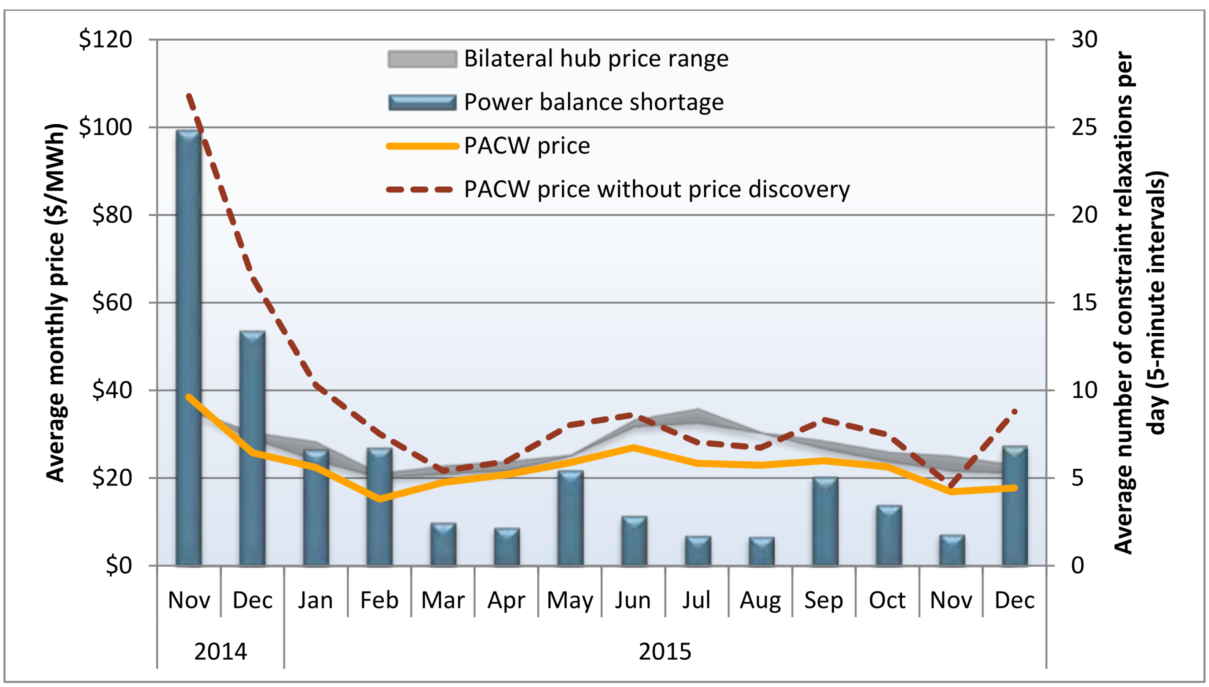


Figure 4.6 Frequency of constraint relaxation and average prices by week NV Energy – 15-minute market

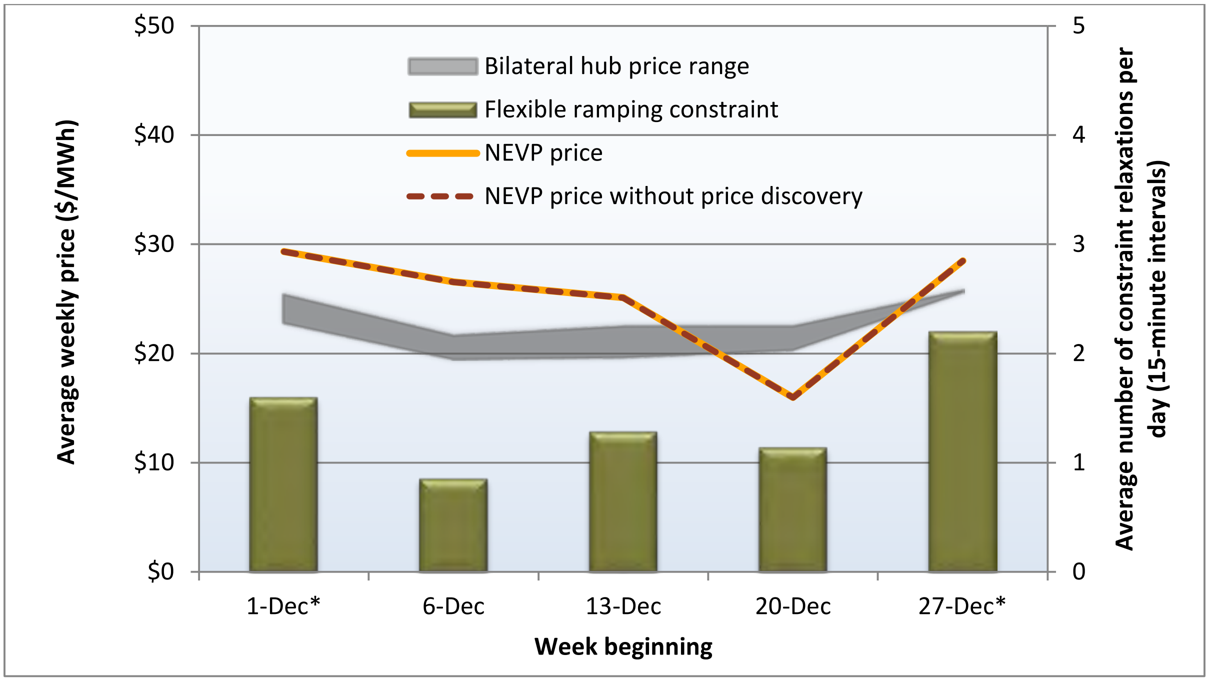
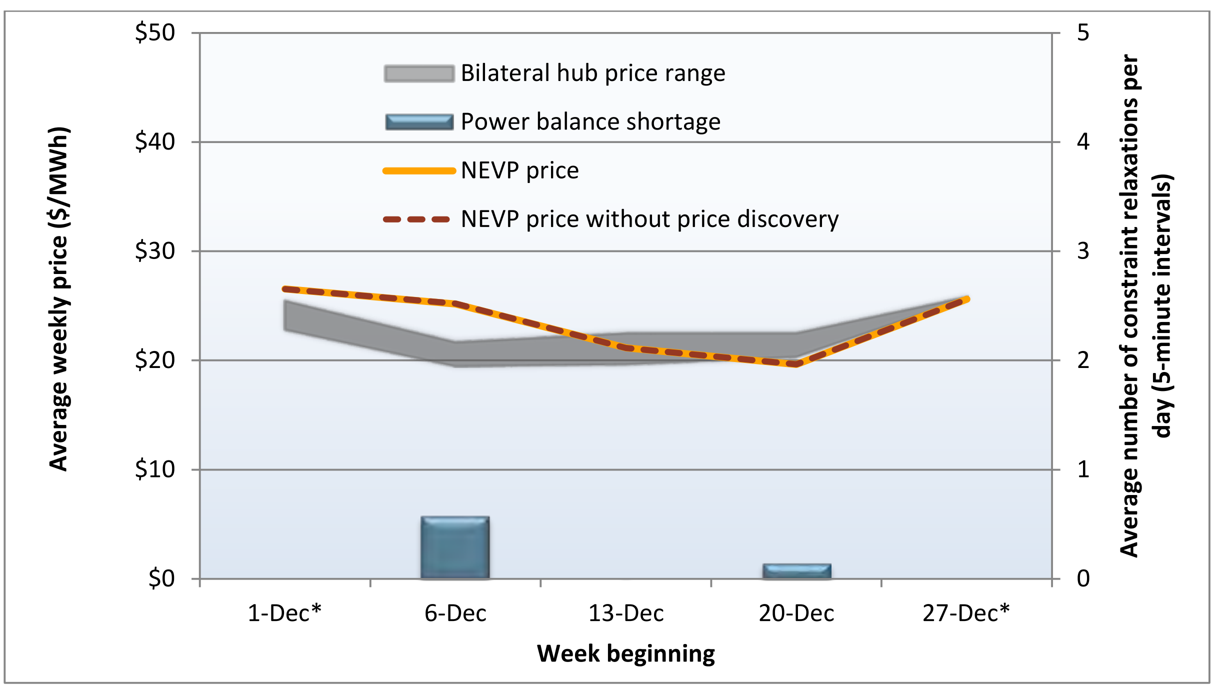


Figure 4.7 Frequency of constraint relaxation and average prices by week NV Energy – 5-minute market



4.2 Flexible ramping constraint and requirements

A detailed description of the flexible ramping constraint is provided in Section 3.3. This section provides additional information on the flexible ramping constraint impact on EIM prices as well as details on the flexible ramping constraint requirement.

The flexible ramping constraint was implemented along with the energy imbalance market in November 2014. The flexible ramping constraint holds back capacity within each balancing area to ensure that there is enough local generation available to meet unanticipated changes in demand and supply between the 15-minute and 5-minute markets. Originally, the requirement was a fairly static number, but, beginning in March, is now dynamically set by the same tool that calculates the ISO requirement. This tool is discussed in further detail below.

Figure 4.8 and Figure 4.9 show the incremental impact from shortages of flexible ramping capacity on average prices in the 15-minute market, the percentage of intervals that the flexible ramping constraint bound, and the percentage of intervals that the constraint was relaxed in the PacifiCorp East and PacifiCorp West balancing areas, respectively. Analysis in these two figures begins in March, when the ISO implemented the new tool to calculate flexible ramping requirements for each area.

These charts show that the number of intervals where the flexible ramping constraint was relaxed increased beginning in August and continued until November (green bar). This trend was most pronounced in PacifiCorp East and occurred because of increasing flexible ramping requirements (see Section 3.3 for further detail) and key generator outages. During October and November, flexible ramping constraint shortages increased 15-minute PacifiCorp East prices by around $8/MWh and $9/MWh, respectively. This resulted in 15-minute PacifiCorp East prices being higher than the range of bilateral prices by 34 to 54 percent during these months. Without the relaxations, these prices would have been within or below the range of bilateral prices during each month of the year.

In PacifiCorp West, flexible ramping constraint relaxations increased prices by about $2/MWh to $3/MWh from September through December. This resulted in 15-minute PacifiCorp West prices just above the bilateral trading hub prices.

Figure 4.8 Impact of flexible ramping constraint relaxation PacifiCorp East – 15-minute market

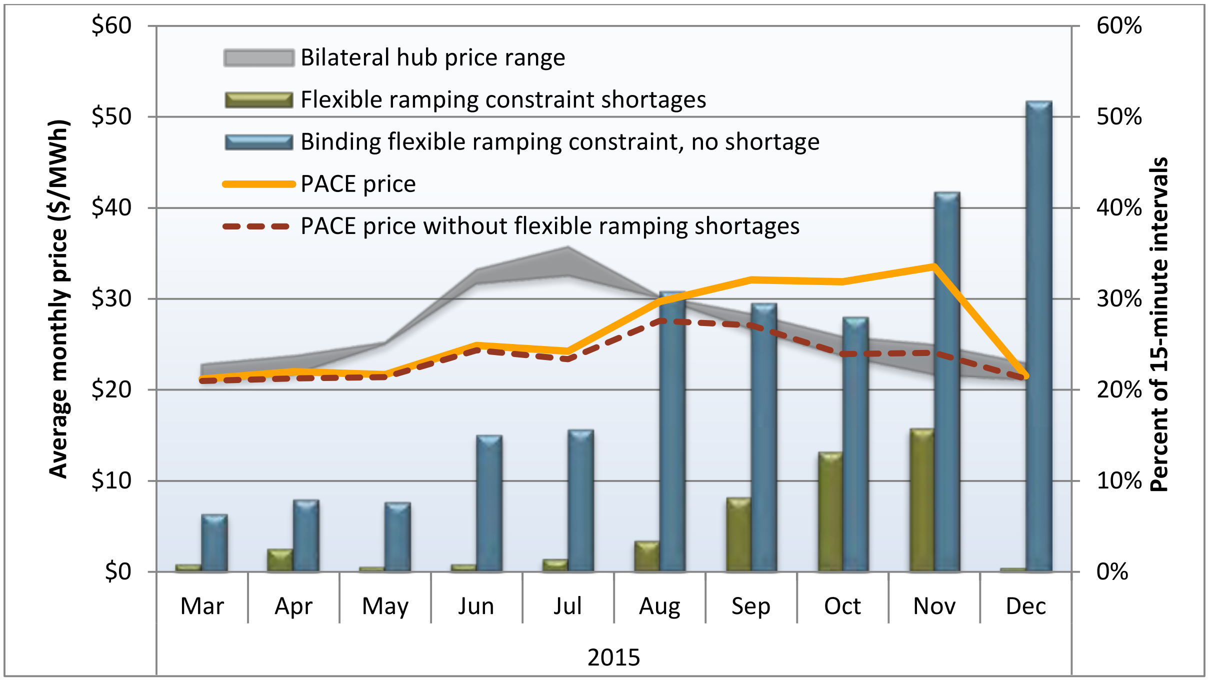
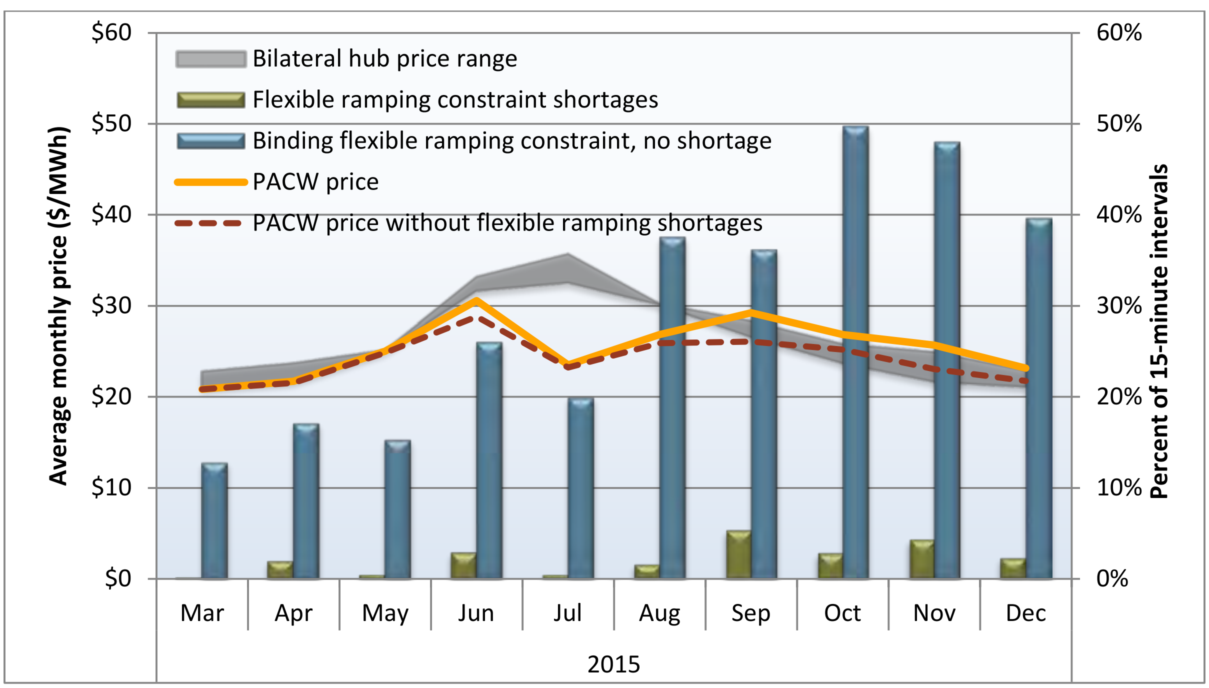


Figure 4.9 Impact of flexible ramping constraint relaxation PacifiCorp West – 15-minute market



DMM believes that a factor contributing to flexible ramping constraint relaxations may be a result of the ISO's current methodology to set the flexible ramping requirements. On March 30, the ISO implemented an automated procedure to set the flexible ramping requirement in both the ISO and PacifiCorp balancing areas. This procedure is called the balancing area ramp requirement (BARR) tool.

Because this tool calculates flexible ramping requirements based on a very limited set of historical observations, the tool can return results with high variabilities from one 15-minute interval to the next, in both the ISO and EIM areas. This results in the flexible ramping requirement being set frequently at either the lower or upper thresholds imposed on the requirement for each area. Both DMM and other ISO staff have been concerned about the limited number of observations used by this tool to calculate flexible ramping requirements, and the resulting high percentage of intervals when the requirement is set by the threshold. The limited number of observations used may set requirements unnecessarily high in some intervals and too low in others, when compared to the actual potential demand for ramping capacity in other intervals.

The ISO implemented tighter thresholds late in the second quarter of 2015 to decrease the variability of the flexible ramping requirements (see Table 3.1). While this change helped reduce the volatility of flexible ramping requirements, it did not address the underlying concern about the limited size of observations that were used by the tool. DMM has recommended increasing the set of observations used to calculate the requirement – preferably by grouping surrounding intervals together – to increase the accuracy of the calculation and reduce the high level of variability due to random variations in historical data. DMM has recommended that the ISO expedite the implementation of this enhancement, as described in Section 11.5, and the ISO has indicated it will seek to implement an enhancement to this tool in May 2016.

4.3 Load bias limiter

The load bias limiter is a tool that limits the effects of operator load bias on power balance relaxations. As mentioned in Section 3.2.1, when the magnitude of an operator load adjustment exceeds the magnitude of a power balance relaxation, the load bias limiter creates a feasible market solution. This solution is created in a similar manner to the special price discovery feature in that the price is set by the last economic bid rather than the penalty price.[106]

This tool was implemented in the ISO in December 2012 and was implemented into EIM in March 2015. With the price discovery feature in effect in EIM, which also sets prices to the price of the last dispatched resource when there is a power balance relaxation, application of the load bias limiter is duplicative. Even so, we can estimate what the load bias limiter effect would have been, had the special price discovery feature not been available.

The energy power balance constraint was relaxed to allow the market software to balance modeled supply and demand infrequently in 2015. Without special price discovery provisions in effect, the load

[106] The load bias limiter is not the same as the price discovery mechanism and only replaces the $1,000/MWh penalty with the highest price bid-in when the power balance is relaxed and the load bias is greater than the energy shortfall or excess. Additionally, the load bias entered needs to be positive to trigger the feature when there is an energy shortfall and negative for excesses. Conversely, the price discovery mechanism is activated whenever there is a power balance shortage, without exception. The primary function of the load bias limiter is to prevent operators from triggering power balance constraint relaxations, and the ISO has committed to reviewing this tool for future enhancements.

bias limiter feature would have been triggered during less than 40 percent of intervals with power balance constraint relaxations in each of the real-time markets.[107]

Figure 4.10 and Figure 4.11 illustrate the percent of 15-minute and 5-minute intervals where the power balance constraint was relaxed and the load bias limiter would have been triggered had the price discovery provision not been in effect for each area and quarter. The first quarter of 2015 is omitted since the load bias limiter was not implemented until March 20.

After implementation, the load bias limiter would have been active in about 31 and 42 percent of 15-minute intervals with power balance constraint relaxations for PacifiCorp East and PacifiCorp West, respectively. As there were no power balance constraint relaxations for NV Energy in the 15-minute market during December, the load bias limiter would have had no impact on NV Energy prices.

As shown in Figure 4.11, the load bias limiter would have been triggered during about half of the 5-minute intervals with power balance constraint relaxations in PacifiCorp East and about 27 percent of related intervals in PacifiCorp West. In particular, the load bias limiter was frequently active in the third quarter in PacifiCorp East in the 5-minute market. Had price discovery provisions not been in effect, PacifiCorp East 5-minute prices in this quarter would have been 26 percent lower than prices without the load bias limiter.

Table 4.1 shows estimated EIM prices if prices were set at the $1,000/MWh penalty price during intervals since March 20 when the load bias limiter would have been triggered and the price discovery provisions approved pursuant to FERC's December 2014 Order were not in effect. As shown in this table, without existing price discovery provisions, the load bias limiter would have reduced average 15-minute prices by about 6 percent in both PacifiCorp East and PacifiCorp West. In the 5-minute market, the load bias limiter would have reduced average prices by almost 19 percent in PacifiCorp East and about 9 percent in PacifiCorp West. The load bias limiter would have had little impact on NV Energy prices due to the low frequency that this feature would have been triggered.

Table 4.1 Impact of load bias limiter on EIM prices (March 20 – December 31)

	Bilateral trading hub range		Average EIM price	EIM price without price discovery	EIM price without price discovery or load bias limiter	Potential impact of load bias limiter	
	Low	High				Dollars	Percent
PacifiCorp East							
15-minute market (FMM)	$25.75	$26.85	$26.56	$30.72	$32.55	-$1.83	-6%
5-minute market (RTD)	$25.75	$26.85	$20.22	$26.07	$32.12	-$6.05	-19%
PacifiCorp West							
15-minute market (FMM)	$25.75	$26.85	$25.56	$28.30	$30.13	-$1.83	-6%
5-minute market (RTD)	$25.75	$26.85	$21.94	$28.76	$31.60	-$2.84	-9%
NV Energy*							
15-minute market (FMM)	$21.27	$23.35	$24.60	$24.60	$24.60	$0.00	0%
5-minute market (RTD)	$21.27	$23.35	$23.30	$23.31	$23.60	-$0.28	-1%

**December only.*

[107] This represents about 0.2 percent of all 15-minute intervals and about 0.5 percent of all 5-minute intervals.

Figure 4.10 Mitigation of power balance relaxation by load bias limiter – 15-minute market

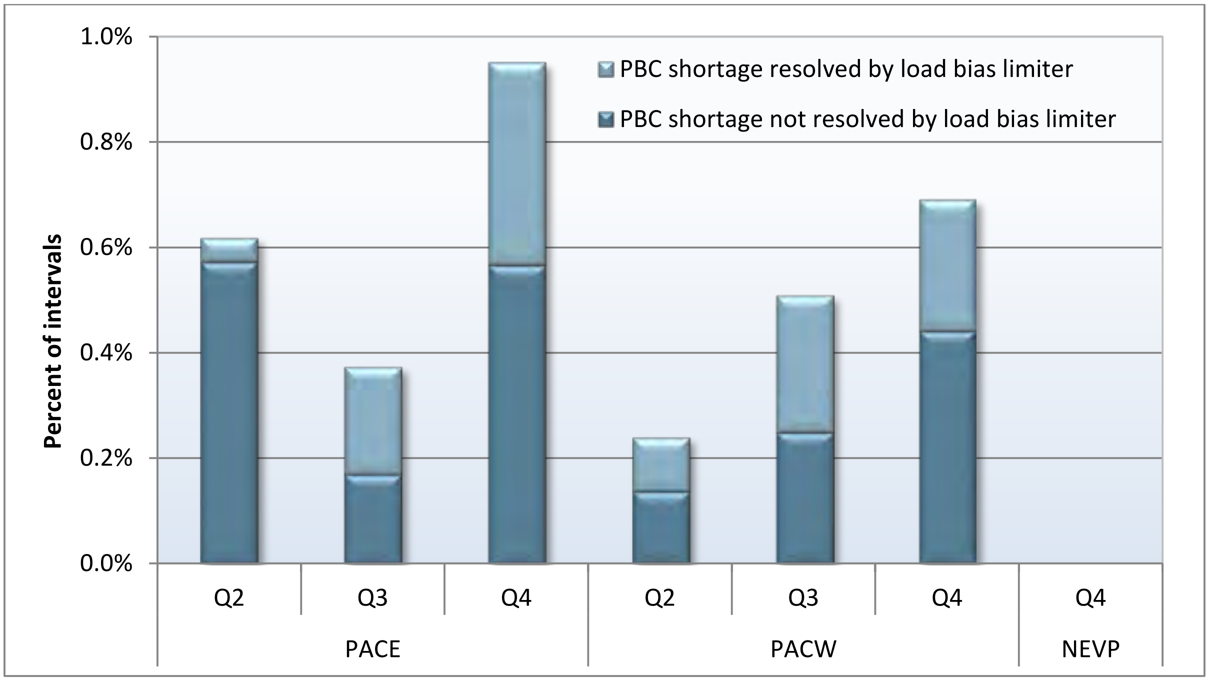
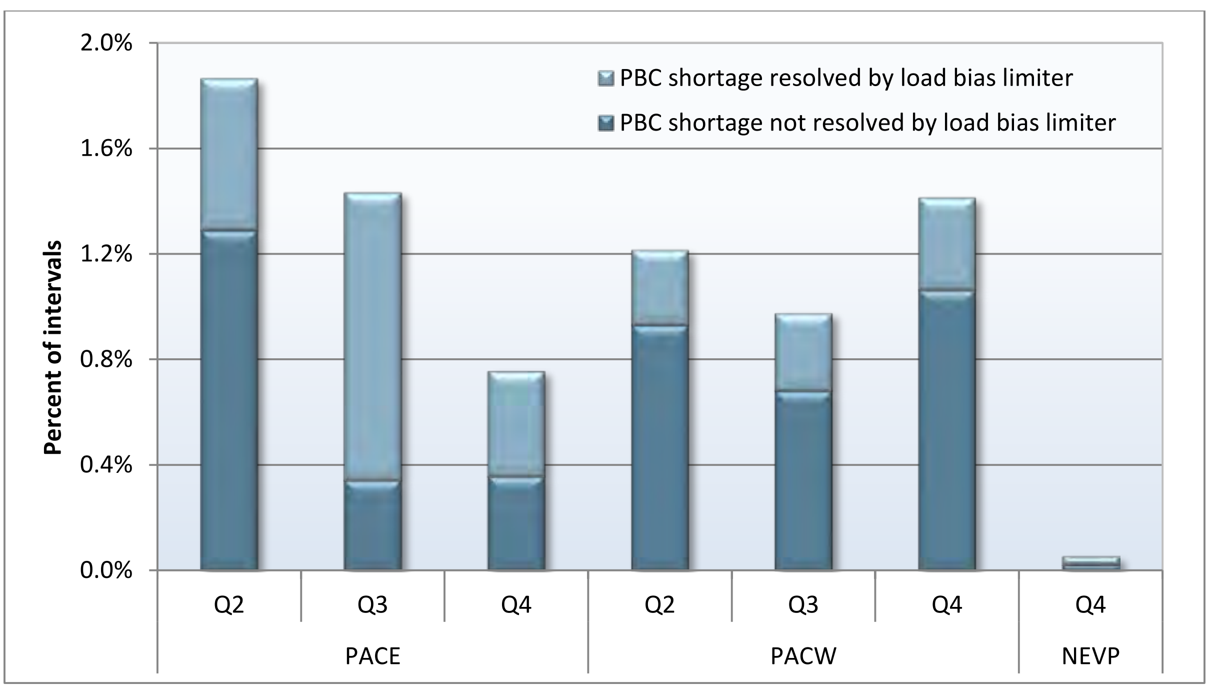


Figure 4.11 Mitigation of power balance relaxation by load bias limiter – 5-minute market

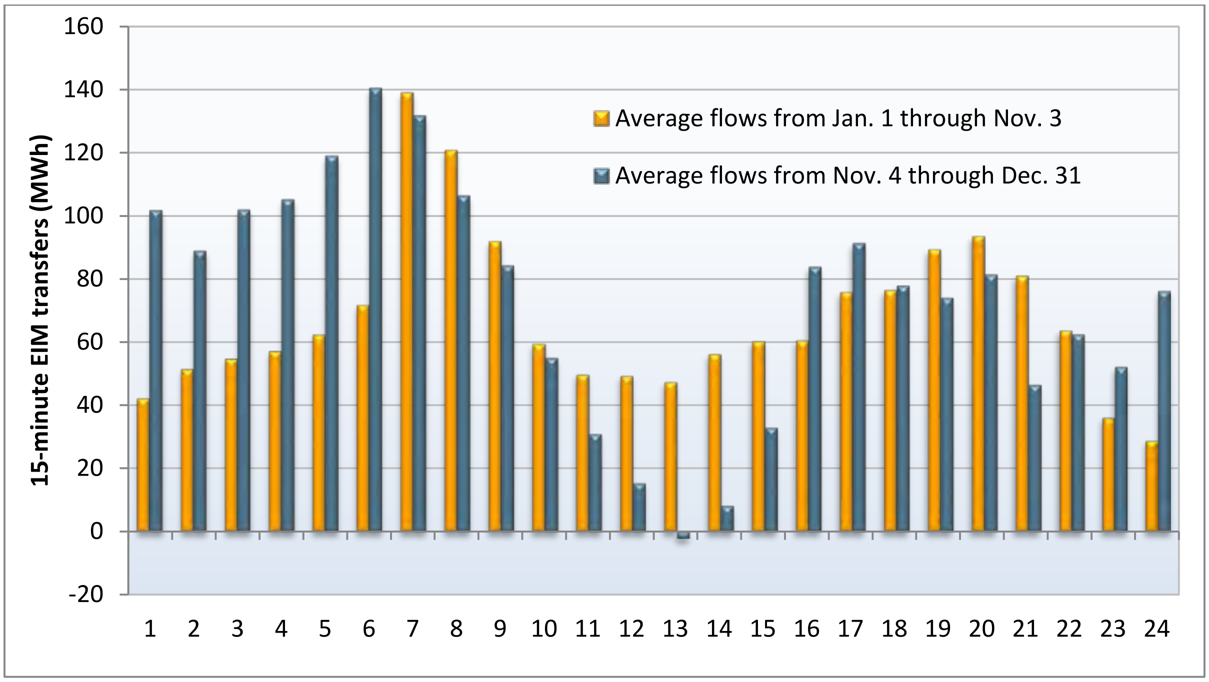


4.4 Energy imbalance market transfers

One source of value from the energy imbalance market is the ability to schedule transfers between areas through the 15-minute and 5-minute markets. The predominant flow, in 2015, was from EIM areas into the ISO. These transfers enable the EIM area as a whole to make best use of diverse resources, potentially avoiding or reducing downward dispatches for renewable resources and achieving efficient regional dispatch. The volume of these flows provides an indication of the magnitude of these potential EIM benefits. The ISO uses these transfers as a key component of its estimate of net EIM benefits.[108]

In the initial year of EIM operation, three different balancing authority areas could trade energy through EIM transfers: PacifiCorp East, PacifiCorp West and the ISO. The biggest impact of EIM on transfers is between the PacifiCorp areas and the ISO, as PacifiCorp East and PacifiCorp West could schedule some transfers between each other prior to EIM. Figure 4.12 shows the varying magnitude of EIM transfers between the ISO and PacifiCorp throughout the day.

Figure 4.12 Average net EIM transfers from PacifiCorp to the ISO in the 15-minute market



The average net transfers to the ISO from PacifiCorp peak during the heavy ramp times in the morning and evening. The lowest average transfers occur late in the night and during mid-day. Figure 4.12 shows the pattern of average transfers for each hour of the day. Each bar in the chart represents the average transfer from either of the PacifiCorp areas to the ISO during that hour of the day.

108 More information on EIM benefits can be found in the latest 2015 update at http://www.caiso.com/Documents/ISO_EIMBenefitsReportQ4_2015.pdf and in the methodology paper at: http://www.caiso.com/Documents/EIM_BenefitMethodology.pdf.

Beginning on November 4, following implementation of the EIM Year 1 Enhancements, the transfers were measured across each balancing authority area interface, shown as the blue bars on the graph. The equivalent to data from the earlier period is to examine the transfers between PacifiCorp West and the ISO on the Malin inter-tie, represented by the gold bars in the graph. Transfers from both periods show a similar pattern, with a net average transfer from the ISO in hour ending 13.

4.5 Greenhouse gas in the energy imbalance market

Under the current energy imbalance market design, all energy transferred into the ISO to serve California load through an EIM transfer is subject to California's cap-and-trade regulation.[109] With this design, resources submit separate bids representing the cost of compliance for any energy deemed delivered to California through the EIM. These bids, representing the cost of greenhouse gas compliance, are included in the optimization for EIM resource dispatch when serving the ISO load. Resource specific market results determined within the EIM optimization are reported to participating resource scheduling coordinators. This information serves as the basis for greenhouse gas compliance obligations under California's cap-and-trade program.

Under the original EIM design, greenhouse gas (GHG) bids were entered as an adder to energy bids in dollars per megawatt-hour. The optimization included these adders for power deemed delivered to the ISO, but not for other regions in the EIM. Scheduling coordinators could not choose to bid energy into EIM without being subject to potential dispatch into California. Under this design, suppliers could submit very high bids for greenhouse gas compliance so that energy from these resources would not be deemed delivered to California under almost all circumstances.

Under FERC's June 19, 2014, conditional acceptance of the tariff changes required to implement the EIM, the ISO was required to develop further tariff modifications that would both allow market participants to participate in EIM without participating in California's cap-and-trade program and require participating resources to submit cost-based bids.[110] Rule changes implemented on November 4, 2015, met this FERC requirement by allowing market participants to submit hourly bids for each resource outside of the ISO, which may include the quantity of output that may be deemed delivered to California and the associated compliance cost. Suppliers may choose not to offer supply for delivery to California by not submitting a greenhouse gas bid for all or part of any resource for each hour.[111] Market changes that took effect in November 2015 also capped greenhouse gas bids at 110 percent of a resource's

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[109] Further information on EIM entity obligations under the California Air Resources Board cap-and-trade regulation is available in a posted FAQ on ARB's website here: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/eim-faqs.pdf.

[110] FERC's acceptance, available at: http://www.caiso.com/Documents/Jun19_2014_OrderConditionallyAcceptingEIMTariffRevisions_ER14-1386.pdf, required "CAISO to make a compliance filing within one year after the date on which the EIM commences operation, with a proposal to implement the flag mechanism. Additionally, as the flag mechanism will obviate the need to use the GHG bid adder to signify that an EIM Participating Resource does not wish to be dispatched into California, such compliance filing should include revisions implementing a cost-based GHG bidder concurrent with implementation of the flag mechanism. A flag and cost-based GHG bid adder would support further expansion of the EIM." Paragraph 240.

[111] The Energy Imbalance Market Year 1 Enhancements – Phase 1 required tariff amendments which, in addition to changes in greenhouse gas bidding discussed above, allowed the use of available transmission capacity for EIM transfers, aligned the EIM administrative charge with the grid management charge, and introduced additional elements for the evaluation of resource sufficiency. Further information on the EIM enhancements stakeholder process, including tariff filings associated with this process, is available here: http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyImbalanceMarketYear1Enhancements.aspx.

estimated greenhouse gas costs, based on each unit's maximum heat rate multiplied by the ISO's daily greenhouse gas index.

The EIM optimization minimizes costs of serving load in both the ISO and EIM including the greenhouse gas compliance cost for all energy deemed delivered to California. The EIM greenhouse gas price in each 15-minute or 5-minute interval is set at the greenhouse gas bid of the marginal megawatt deemed delivered. The greenhouse gas price determined within the optimization is included in the price difference between serving the ISO and EIM load, which can contribute to lower EIM prices than those inside the ISO by at least the greenhouse gas price during any interval.[112]

This greenhouse gas revenue is returned to participating resource scheduling coordinators with energy that is deemed delivered as compensation for compliance obligations. The revenue is equal to the cleared 15-minute market quantity priced at the 15-minute price plus the incremental greenhouse gas dispatch in the 5-minute market valued at the 5-minute market price. Incremental dispatch in the 5-minute market may be either positive or negative.

Scheduling coordinators can guarantee that greenhouse gas compliance costs are covered by bidding in marginal compliance costs for greenhouse gas. The settlement price is set by the highest cleared greenhouse gas bid for the interval and will equal or exceed all cleared bids. The greenhouse gas price may thus be set above the greenhouse gas bid of a marginal resource, which provides EIM resources with low emissions incentive to export energy to the ISO.

The optimization minimizes costs in both the 15-minute and 5-minute markets subject to multiple constraints. The total amount of energy deemed delivered by the model is equal to the transfer into the ISO from the EIM. The total sum of greenhouse gas megawatts bid in any interval limits the energy transferred into the ISO from EIM, because no energy may be transferred in without being deemed delivered to the ISO. In addition, the EIM transfer limits set a cap on the total energy that may be deemed delivered to the ISO in any interval. On a resource level, the total quantity of energy deemed delivered is limited to the minimum of the dispatched quantity and the bid.

Figure 4.13 shows monthly average cleared EIM greenhouse gas prices and total deemed delivered quantities settled in EIM in 2015. Weighted average prices are calculated using 15-minute deemed delivered megawatts as weights in the 15-minute market and the absolute value of incremental 5-minute greenhouse gas dispatch in the 5-minute market. Daily average 15-minute deemed delivered quantities are represented by the blue bars in the chart. The daily average of the absolute value of incremental 5-minute deemed delivered dispatch is represented by the green portion of each bar.

On a weighted basis, 5-minute prices exceed 15-minute prices in some months, but are typically very close. Weighted average greenhouse gas prices appear to be at or below estimated cost for an efficient gas resource in most months and averaged less than $5/MWh for most of the year. Both 15-minute prices, represented by the light blue line, and 5-minute prices, represented by the green line, fell following the implementation of Phase 1 of the EIM Year 1 Enhancements which required greenhouse gas bids to be cost-based.

[112] Further detail on the determination of deemed delivered greenhouse gas megawatts within the EIM optimization is available in section 11.3.3, Locational Marginal Prices, of the EIM business practice manual located here: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Energy%20Imbalance%20Market.

Figure 4.13 EIM greenhouse gas price and cleared quantity

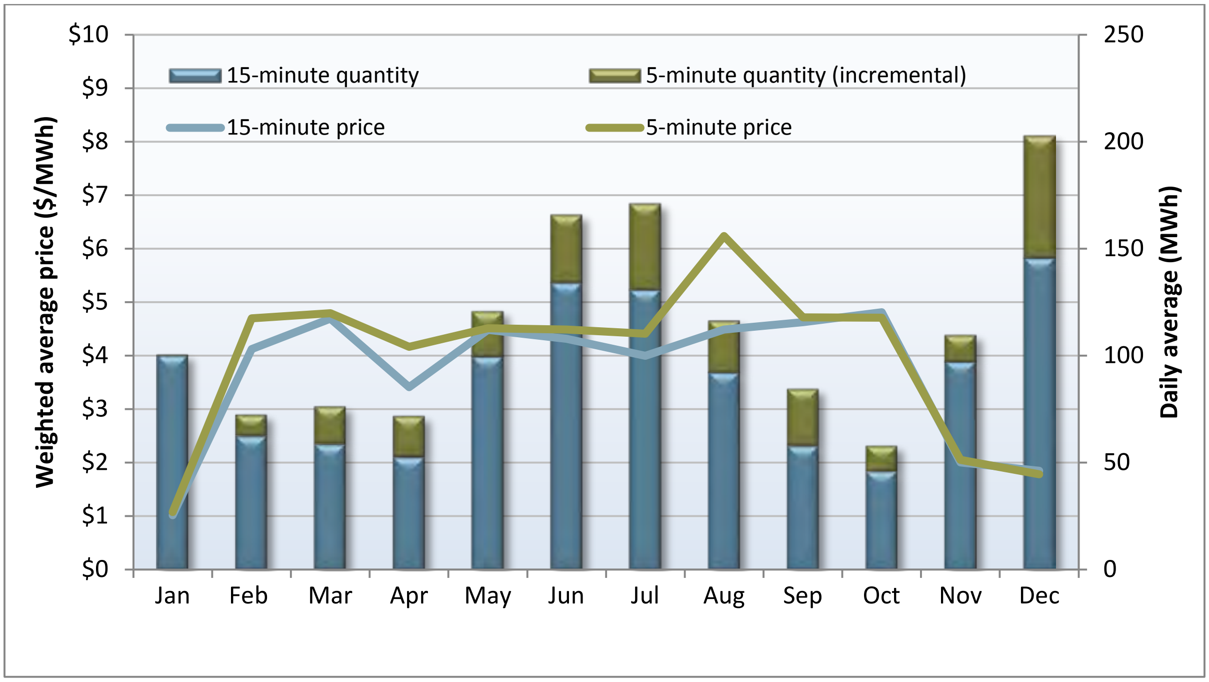
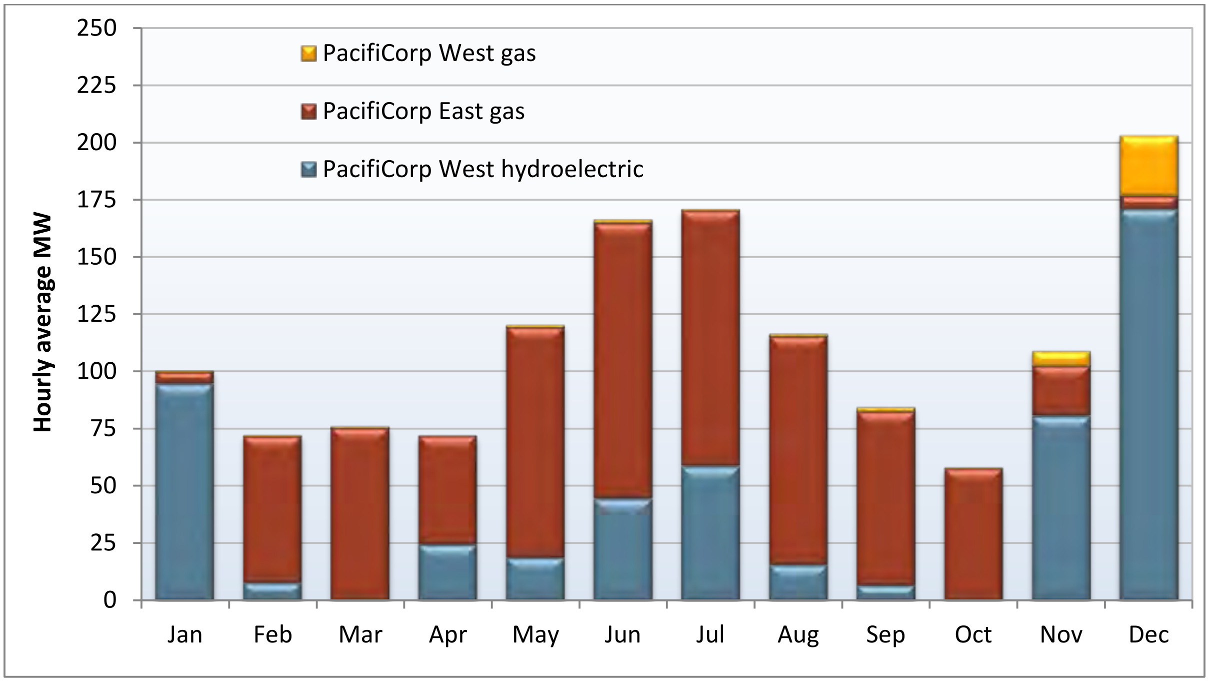


Figure 4.14 illustrates hourly average deemed delivered megawatts by fuel type and balancing area. Minimal quantities were deemed delivered from two additional fuel type balancing area combinations not shown on the graph. These included both wind and coal in PacifiCorp East with less than 0.5 MW on average in any month.

The total deemed delivered quantity increased in December as EIM transfer capacity increased with the addition of NV Energy in December. Over 61 percent of EIM greenhouse gas compliance obligations in 2015 were assigned to gas resources with almost all of the remaining assigned to hydro. Non-gas and non-hydro accounted for less than 0.1 percent for the year. Hydro resources accounted for most EIM energy deemed delivered to California following implementation of Phase 1 of the EIM Year 1 Enhancements. Following implementation of rule changes on November 4, 2015, non-emitting resources (such as hydro and wind) were required to bid greenhouse gas compliance costs at $0/MW or not bid in at all.

Figure 4.14 Hourly average EIM greenhouse gas megawatts by area and fuel



4.6 Conclusions

The performance of the EIM improved significantly over the course of 2015, while special price discovery provisions played a key role keeping EIM prices in-line with prices in an efficient competitive levels during the initial months of EIM implementation. Based on regular monitoring of the EIM market, DMM believes that the EIM market has provided significant benefits. While DMM has not quantified these benefits, the ISO has reported that the energy imbalance market has achieved benefits for customers through integration by enhancing the efficiency of dispatch instructions, reducing renewable curtailment and reducing the total requirements for flexible reserves.[113]

[113] For more information on EIM benefits refer to the ISO Benefits Reports, which can be found here: http://www.caiso.com/informed/Pages/EIMOverview/Default.aspx.

5 Convergence Bidding

Convergence bidders continued shifting away from virtual demand toward virtual supply in 2015, a trend that began in the latter half of 2013. Average hourly virtual supply that cleared in the day-ahead market exceeded virtual demand by about 580 MW per hour in 2015, compared to about 450 MW last year. This trend reflects that average real-time prices continued to be below average day-ahead prices during most periods (see Section 2.3).

The growth in net virtual supply was driven in part by an increase in cleared net virtual supply submitted by marketers. Virtual positions for financial participants, physical generation, and physical load decreased from 2014, but these decreases were balanced between virtual supply and virtual demand. Marketers, however, increased positions in cleared virtual supply by about 200 MW during 2015 compared to 2014, and increased virtual demand positions by about 100 MW during the same period.

Net revenues paid to entities engaging in convergence bidding, including bid cost recovery charges allocated to virtual bids, totaled around $21 million in 2015, compared to about $26 million in 2014. Most of these net revenues resulted from virtual supply bids. Despite generally higher net revenues on virtual supply, financial entities continued to place significant volumes of offsetting virtual demand and supply bids at different locations during the same hour, though at lower amounts than previous years. These offsetting bids, which are designed to hedge or profit from congestion, represented about 55 percent of all accepted virtual bids in 2015.

The $5 million decrease in convergence bidders' year-over-year net revenues resulted partly from increased bid cost recovery payments due to allocating residual unit commitment costs to virtual supply. The portion of these costs allocated to virtual supply increased from about $4 million in 2014 to over $7 million in 2015. This increase was driven in large part by high residual unit commitment levels in the third quarter related to high volumes of net virtual supply combined with periods of high loads.

About 51 percent of net revenues were paid to financial entities that only participate in virtual bidding and congestion revenue rights in the ISO markets. About 35 percent of net revenues were received by marketers who also engaged in scheduling of imports and exports, with physical generators and load-serving entities receiving slightly over 14 percent of net revenues.

Background

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 markets, virtual bidding is formally referred to as *convergence bidding*. The ISO implemented convergence bidding in February 2011.

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 similarly to physical supply and demand in the day-ahead market. However, all virtual bids clearing the day-ahead market are removed from the 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. These virtual demand bids are then liquidated in the real-time market and participants are paid the real-time price.

- Participants with accepted virtual supply bids are paid the day-ahead price for this virtual supply. These virtual supply bids are then liquidated in the real-time market and participants are charged the real-time price.

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.[114] 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.

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.

However, the degree to which convergence bidding has actually increased market efficiency by improving unit commitment and dispatches has not been assessed. In some cases, virtual bidding may be profitable for some market participants without increasing market efficiency significantly or may even decrease market efficiency.[115]

[114] 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 using the ISO forecasted load. If additional units are needed, the residual unit commitment process will commit more resources.

[115] A report reviewing the effectiveness of virtual bidding indicates that under certain conditions, virtual bidding may be parasitic to the market rather than adding value and improving efficiency. The report focused on issues that had been identified and noted in the California ISO markets. For more information see:

Parsons, John E., Cathleen Colbert, Jeremy Larrieu, Taylor Martin and Erin Mastrangelo. 2015. *Financial Arbitrage and Efficient Dispatch in Wholesale Electricity Markets*. MIT Center for Energy and Environmental Policy Research, Working Paper, February.

Retrieved from http://www.mit.edu/~jparsons/publications/20150300_Financial_Arbitrage_and_Efficient_Dispatch.pdf.

Virtual bids at internal points within the ISO system accepted in the day-ahead market began being settled in May 2014 based on prices in the 15-minute market rather than 5-minute market prices. All numbers reported in this section reflect the prevailing settlement rules at the time the market ran.

Virtual bidding on inter-ties was temporarily suspended in November 2011 due to issues with settlement of virtual bids at inter-ties that tended to lead to high revenue imbalance costs and reduced the potential benefits of virtual bids at nodes within the ISO system.[116] Virtual bidding on inter-ties was scheduled to be re-implemented in May 2015 – one year after implementation of the new 15-minute real-time market design. However, in April 2015, the ISO requested a waiver for the requirement to re-implement virtual bidding on inter-ties for up to an additional 12-month period. The basis of the ISO request was the concern that reintroducing inter-tie virtual bidding in light of the observed lack of liquidity in economic bidding in the 15-minute market would decrease economic efficiency, based on a supplemental report completed by DMM analyzing the connection between 15-minute market economic bids at the inter-ties and inter-tie virtual bidding.[117] FERC granted a temporary waiver delaying implementation of convergence bidding on the inter-ties pending further review.[118] FERC issued an order in late September 2015 requiring the ISO to remove tariff provisions that provided for reinstatement of convergence bids at inter-ties.[119]

5.1 Convergence bidding trends

Convergence bidding volumes were relatively stable throughout the year, and continued the trend of increasing net virtual supply that began in the latter half of 2013. Figure 5.1 shows the quantities of both virtual demand and supply offered and cleared in the market. Figure 5.2 shows the average net cleared virtual positions for each operating hour.

Key convergence bidding trends include the following:

- On average, 51 percent of virtual supply and demand bids offered into the market cleared in 2015, which remained consistent with about 50 percent in 2014.
- The average hourly cleared volume of virtual supply outweighed virtual demand during every quarter, by about 580 MW per hour. This is an increase from last year when the average hourly cleared net virtual supply was 450 MW in each hour. This pattern is consistent with systematically higher prices in the day-ahead market than the 15-minute market in 2015, which is discussed in detail in Section 2.3.
- Average hourly cleared virtual supply was about 1,800 MW in 2015, compared to about 1,900 MW in 2014. Average hourly cleared virtual demand decreased to 1,200 MW in 2015 from about 1,400 MW in 2014. Cleared virtual activity by marketers increased for both supply and demand. However,

[116] 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.

[117] *Potential market inefficiencies from convergence bidding at interties with insufficient liquidity of fifteen-minute bids*, Department of Market Monitoring, April 3, 2015: http://www.caiso.com/Documents/DMMReport-ConvergenceBiddingonInterties.pdf.

[118] See: http://www.caiso.com/Documents/Apr29_2015_OrderGrantingWaiverRequest_IntertieVirtualBidding_ER15-1451_ER14-480.pdf.

[119] For further details see: http://www.ferc.gov/CalendarFiles/20150925164451-ER15-1451-000.pdf.

this change was more than offset by a reduction in cleared virtual activity from financial and physical generation entities.

Figure 5.1 Quarterly average virtual bids offered and cleared

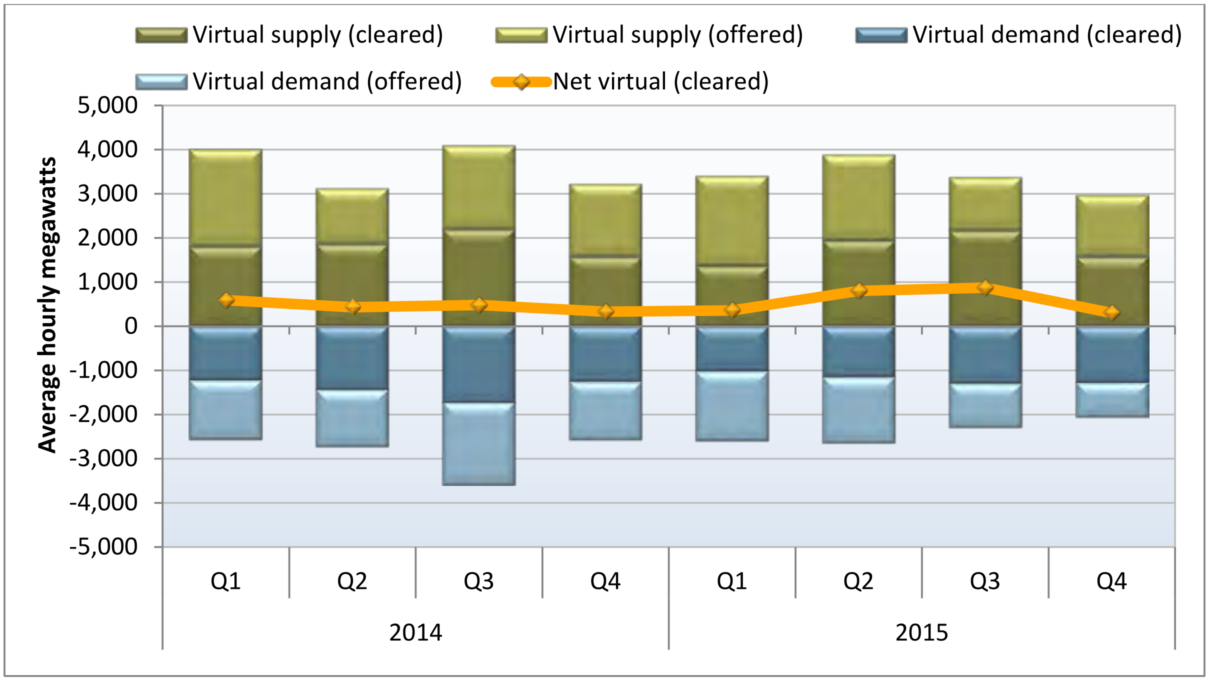
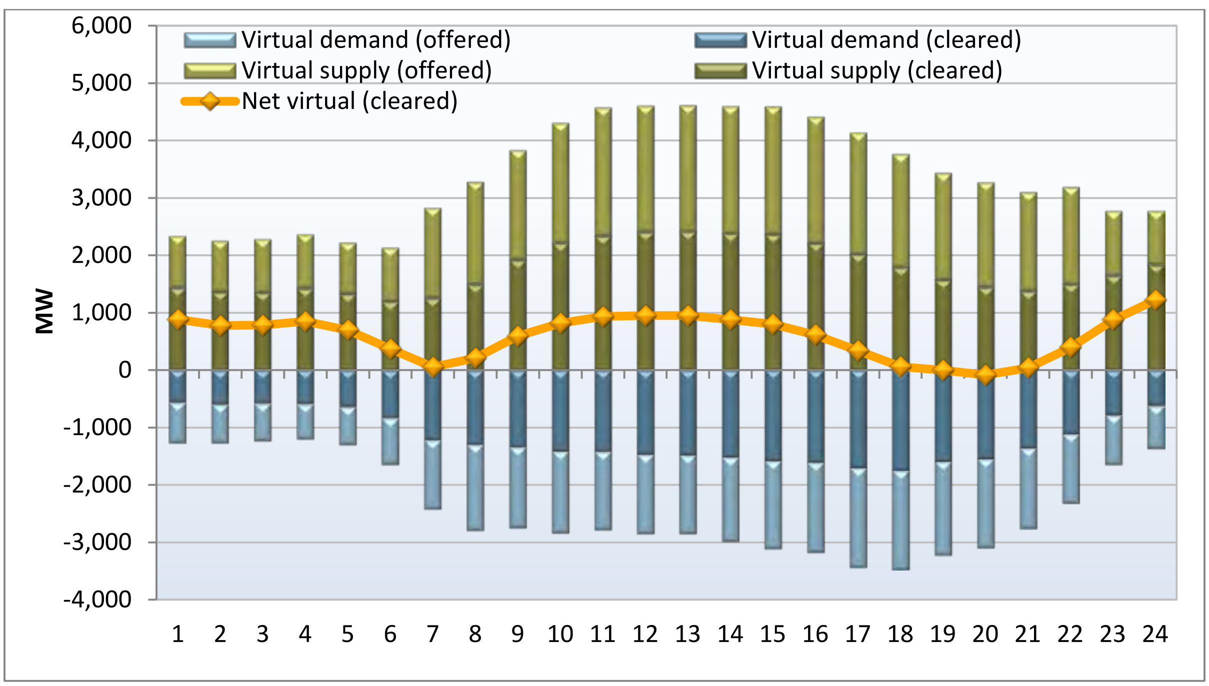


Figure 5.2 Average net cleared virtual bids in 2015



- Net virtual supply was most prevalent during May, July and August, where cleared virtual supply exceeded virtual demand by over 1,000 MW per hour on average. July and August also coincided with periods of high loads. These two factors combined to result in high day-ahead residual unit commitment costs from the need to commit long-start units to meet forecasted load.
- About 33 percent of cleared virtual positions in 2015 were held by marketers, a significant increase from about 20 percent in 2014. Marketers bid more virtual supply than demand in 2015, which contributed to the growth in net virtual supply.
- Net virtual supply was lowest during ramping and peak hours. During the morning ramping hours (hours 6 through 8) average hourly net virtual supply was only 210 MW, and during evening peak hours (hours 17 through 21) average hourly net virtual supply was only 70 MW. Virtual demand outweighed virtual supply during hours 19 and 20. The need to rapidly increase output from generation to offset declining solar generation and increasing load causes an increased frequency of power balance relaxations due to system conditions in the real-time market. This results in more frequent real-time price spikes and ultimately higher average real-time prices when compared to day-ahead prices. Thus, this makes virtual demand more attractive to virtual bidders during these periods than virtual supply.

Offsetting virtual supply and demand bids

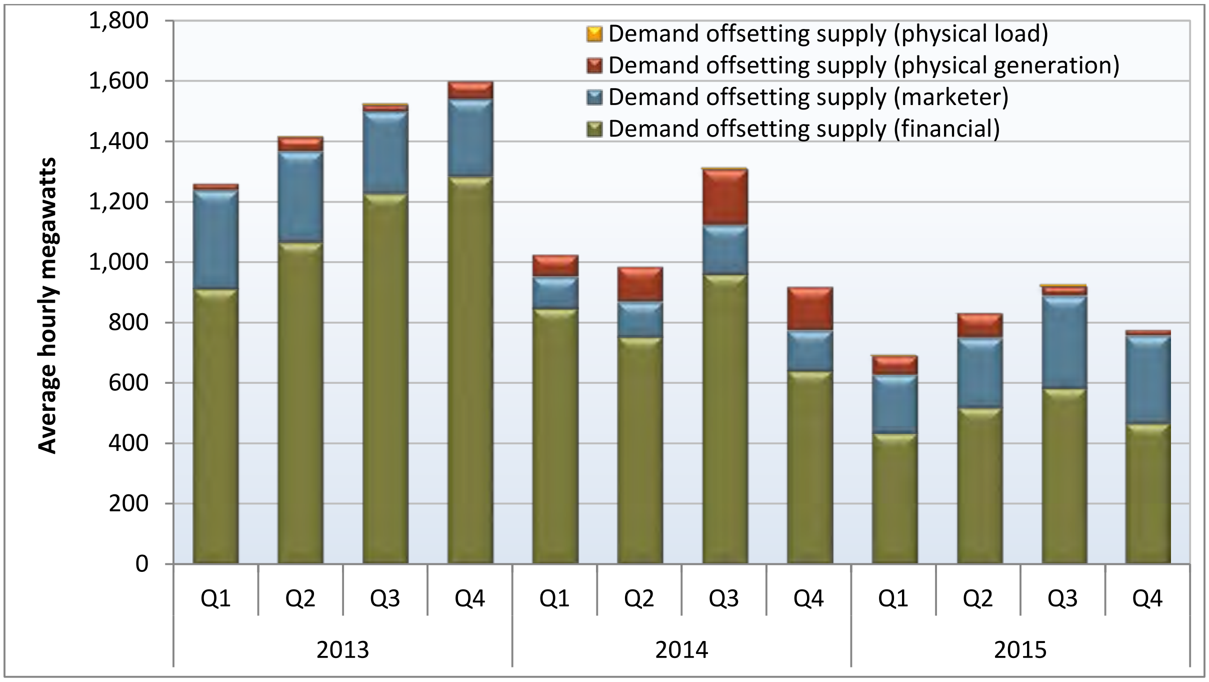
Market participants can also hedge congestion costs or seek to profit from differences in congestion between different points within the ISO system by placing equal quantities of virtual demand and supply bids at different locations during the same hour. These virtual demand and supply bids offset each 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.

Figure 5.3 shows the average hourly volume of offsetting virtual demand and supply positions by participant type. The bars represent the average hourly overlap between demand and supply by the same participants.

As shown in Figure 5.3, offsetting virtual positions accounted for an average of about 800 MW of virtual demand offset by 800 MW of virtual supply during each hour, a decrease from about 1,100 MW in 2014. The share of these offsetting bids decreased from about 65 percent of all cleared virtual bids in 2014 to about 55 percent of bids in 2015. Specifically, offsetting bids made up 46 percent of cleared virtual supply and 68 percent of cleared virtual demand during 2015.

The decrease in offsetting virtual positions suggests that while virtual bidding continues to be used to hedge or profit from congestion, it was used to a lesser extent than in prior years. In particular, financial entities have significantly decreased their hourly volume of offsetting virtual demand and supply bids in the last two years from around 1,100 MW in 2013 to 500 MW in 2015. This is likely due to the low levels of congestion over the last couple years.

Figure 5.3 Average hourly offsetting virtual demand and supply positions by participant type



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 generally consistent with price differences in most hours in all quarters of 2015, with the exception of the second quarter where convergence bids were only consistent in 13 hours of the day. Compared to the previous year, net convergence bidding volumes, on average, were more consistent with price differences between the day-ahead and real-time markets.

Figure 5.4 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 cleared at different locations.

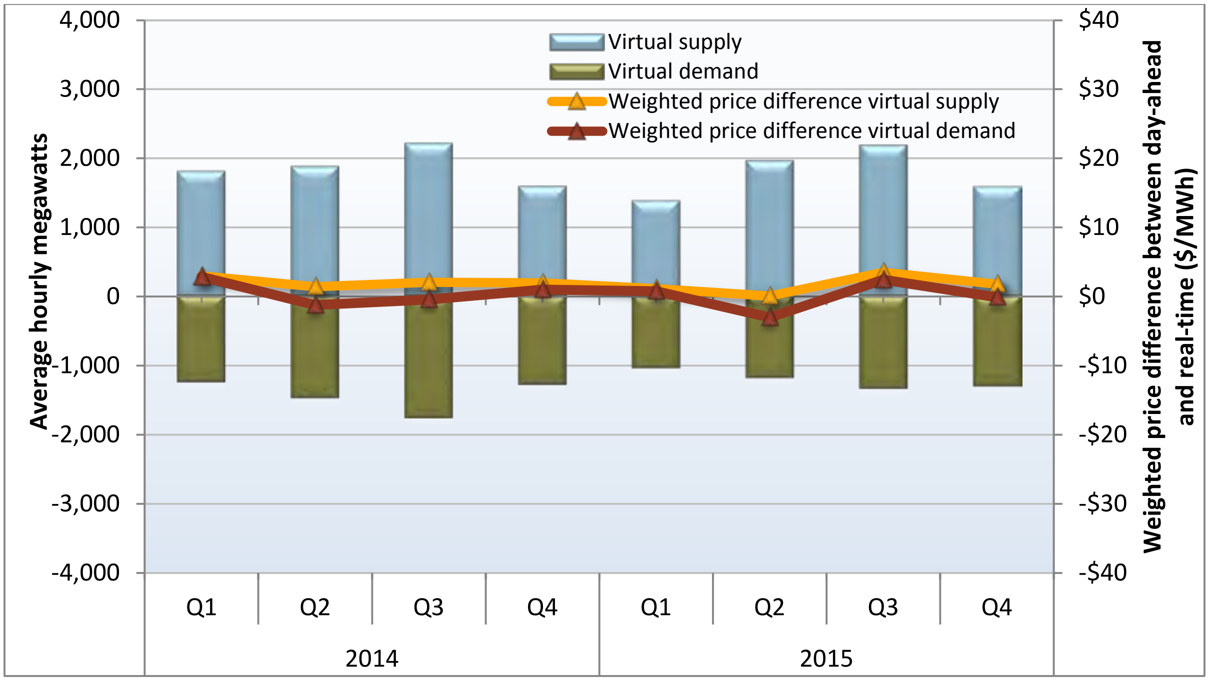
Periods when the red line is negative indicate that the weighted average price charged for virtual demand in the day-ahead market was lower than the weighted average real-time price paid for this virtual demand and, thus, was a profitable period. In 2015, virtual demand positions were not profitable in the first and third quarters and profits in the second and fourth quarters were a result of a few days with large price differences.[120]

Quarters when the yellow line is positive indicate 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

[120] June 8, October 10, and October 13 each had particularly high virtual demand revenue. These days had a similar pattern where higher than forecasted demand during peak load hours resulted in very high real-time prices.

supply was liquidated in the real-time market. As with 2014, virtual supply was consistently profitable in all quarters in 2015.

Figure 5.4 Convergence bidding volumes and weighted price differences



As noted earlier, a significant 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.

5.2 Convergence bidding payments

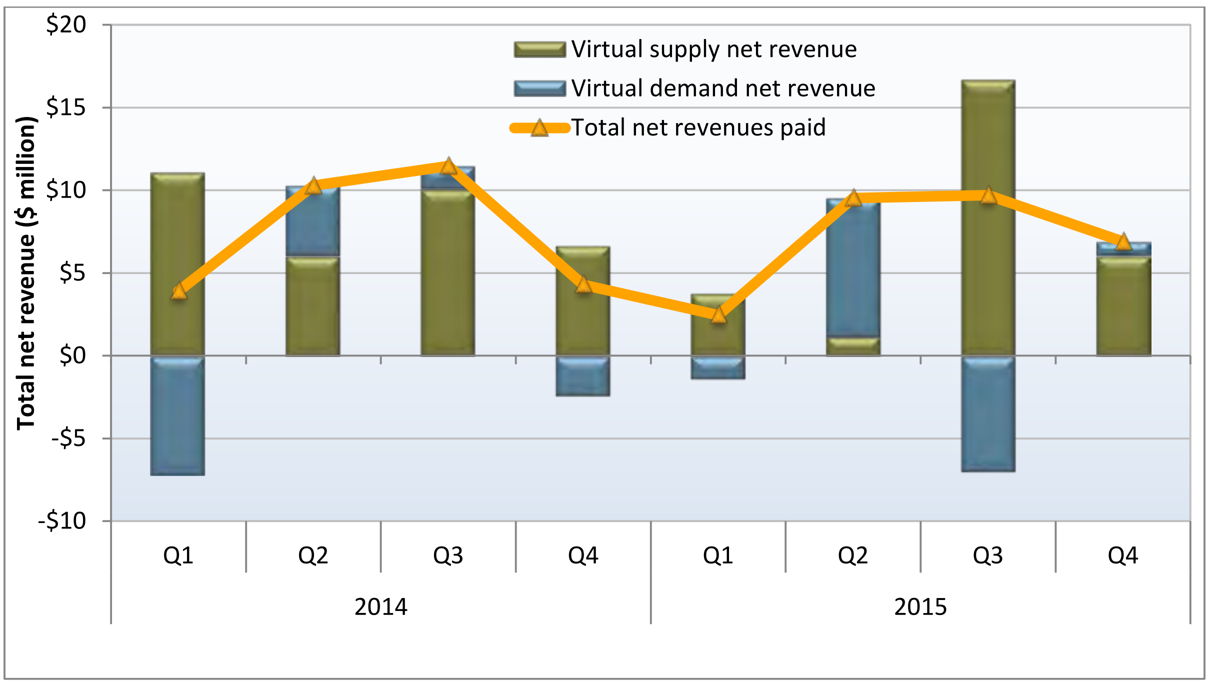
Net revenues paid to convergence bidders (prior to any allocation of bid cost recovery payments) totaled about $29 million in 2015, down about 4 percent from about $30 million in 2014. The large majority of these profits were associated with virtual supply. Figure 5.5 shows total quarterly net profits paid for accepted virtual supply and demand bids. As shown in this figure:

- Most net revenue ($28 million) was generated from cleared virtual supply. The remaining $1 million of net revenue was generated from cleared virtual demand.
- Virtual supply positions were profitable in all quarters during 2015. 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 infrequent. Virtual supply profitability is also a result of sustained higher prices in the day-ahead market compared with prices in the 15-minute market.
- In the first and third quarters, virtual demand positions were unprofitable with losses totaling over $8 million. Second and fourth quarter virtual demand revenues totaled about $9 million, with most

revenues during that period driven by market results from just one day, June 8, where several hours of extremely high real-time prices persisted significantly above day-ahead prices because of higher than forecasted demand. Overall, real-time prices were lower than day-ahead prices for most of the year, consistent with prior years.

- Total net revenues for virtual bidders peaked in the third quarter at $9.7 million, slightly higher than second quarter revenues of around $9.5 million. Three consecutive months of high virtual supply revenue in the third quarter resulted in $16.7 million in revenue for virtual supply, shown in Figure 5.5. During the second quarter, as discussed further in Section 5.3, high day-ahead residual unit commitment charges associated with net virtual supply (totaling about $4.6 million) significantly reduced the overall amount paid to cleared virtual supply. Total net revenues were lowest in the first quarter at $2.5 million.

Figure 5.5 Total quarterly net revenues from convergence bidding



Net revenues and volumes by participant type

DMM's analysis finds that most convergence bidding activity is typically conducted by entities engaging in purely financial trading that do not serve load or transact physical supply. These entities accounted for almost $15 million (about 51 percent) of the total convergence bidding revenues in 2015. This was a decrease from the previous year as total hourly virtual supply and demand from financial entities dropped to 1,490 MW in 2015 from about 1,980 MW in 2014. Conversely, there was a large growth in convergence bidding activity by marketers, which accounted for about 33 percent of trading volume and 35 percent of revenues in 2015, up from 20 percent and 19 percent, respectively, during the previous year.

Table 5.1 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.

Table 5.1 Convergence bidding volumes and revenues by participant type (2015)

Trading entities	Average hourly megawatts			Revenues\Losses ($ millions)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	715	769	1,484	$0.5	$14.1	$14.6
Marketer	401	563	964	$0.9	$9.0	$9.9
Physical generation	70	170	240	-$0.5	$2.1	$1.7
Physical load	3	269	272	-$0.1	$2.6	$2.4
Total	**1,189**	**1,771**	**2,960**	**$0.8**	**$27.7**	**$28.6**

DMM has defined financial entities as participants who own no physical energy 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 5.1, financial participants represent the largest segment of the virtual market, accounting for about 50 percent of cleared volume and about 51 percent of revenue. Marketers represent about 33 and 35 percent of volume and revenue, respectively. Generation owners and load-serving entities represent over 17 percent of the volume, but only about 14 percent of revenue.

Table 5.1 also shows that marketers, generation, and physical load all held significantly more virtual supply than virtual demand, while virtual supply and demand was more balanced for financial participants. The increase in hourly net virtual supply during 2015 from 2014 can in part be attributed to marketers, who increased net virtual positions by about 100 MW.

5.3 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.[121] When the ISO commits units, it may pay market participants through the bid

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

cost recovery mechanism to ensure that market participants are able to recover start-up costs, minimum load costs, transition costs, and energy bid costs.[122]

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.[123]

- Integrated forward market bid cost recovery tier 1 allocation addresses costs associated with situations when the market clears with positive net virtual demand.[124] 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.[125] 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.

The day-ahead residual unit commitment tier 1 allocation charge associated with virtual bids grew significantly from the previous year, particularly in July and August where high volumes of net virtual supply combined with periods of high loads caused additional resources to be committed in the residual unit commitment process. During July and August, total payments to virtual bidders decreased by almost 46 percent because of these charges.

Only 3 percent of total bid cost recovery charges in the first half of the year were attributed to the day-ahead residual unit commitment tier 1 allocation charge. However, during July and August this charge reached a peak of around 20 percent and 14 percent of total bid cost recovery payments, respectively. Following August, these charges remained high at around $0.5 million per month, accounting for about 7 percent of total bid cost recovery payments. The higher share of bid cost recovery payments and sum of charges to virtual supply in the second half of 2015 are similar to 2013 and higher than a relatively low 2014.

Figure 5.6 shows estimated total convergence bidding revenues, total revenues less bid cost recovery charges, and costs associated with the two charge codes. The total convergence bidding bid cost recovery costs for the year were over $7 million, an increase from nearly $4 million in 2014. As noted earlier, the total 2015 estimated net revenue for convergence bidding was around $29 million. Adjusting this total by the bid cost recovery costs allocated to virtual bids results in total convergence bidding revenue of about $21 million.

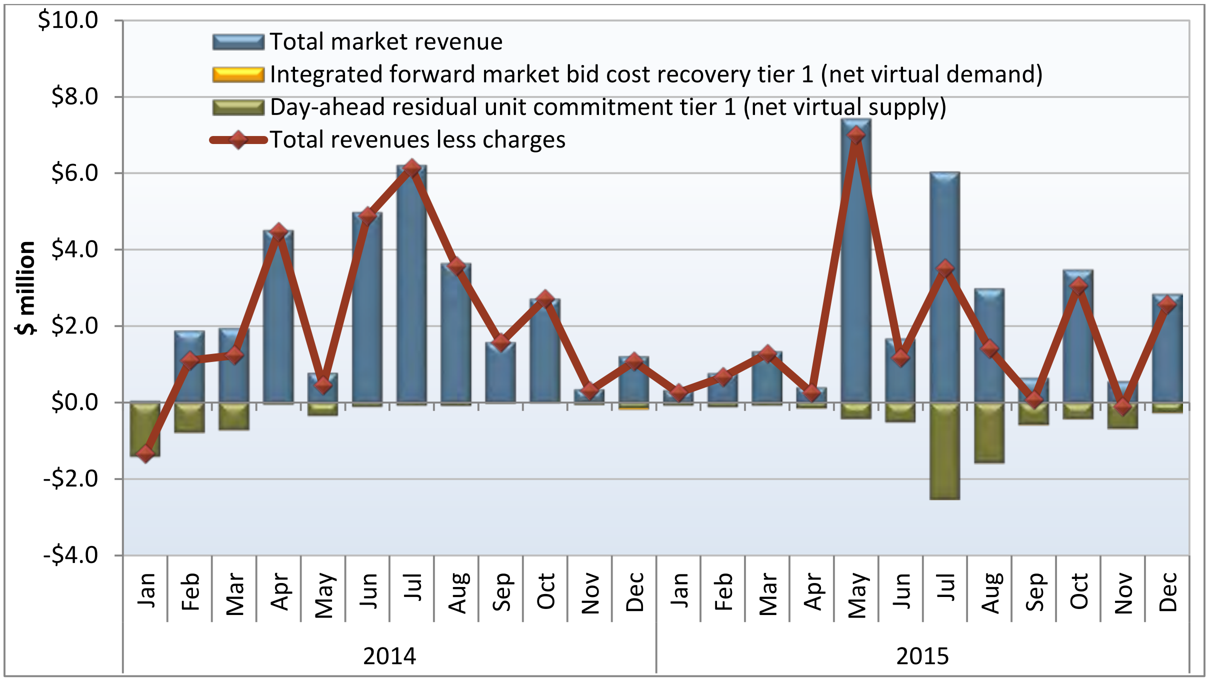
[122] Generating units, pumped-storage units, or resource-specific system resources are eligible to receive bid cost recovery payments.

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

[124] 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.

[125] 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 5.6 Convergence bidding revenues and costs associated with bid cost recovery tier 1 and RUC tier 1



6 Ancillary services

The ancillary service market continued to perform efficiently and competitively in 2015. The cost of ancillary services decreased, driven primarily by a decrease in natural gas prices. Key trends highlighted in this chapter include:

- Ancillary service costs decreased to $62 million in 2015, representing a 10 percent decrease from $69 million in 2014. This was likely driven by lower natural gas prices.
- Costs per megawatt-hour of load decreased to about $0.27/MWh in 2015 from about $0.30/MWh in 2014. However, ancillary service costs as a percent of total wholesale energy costs increased slightly to 0.7 percent in 2015 from 0.6 percent in 2014.
- The value of self-provided ancillary services accounted for about $3 million of total ancillary service costs in 2015, or about 5 percent.[126] 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 2014, self-provided ancillary services accounted for about 10 percent of total ancillary service costs, or about $7 million.
- The average hourly day-ahead requirement for operating reserves was 1,664 MW. This is down about 2 percent from 1,702 MW in 2014. The average hourly day-ahead requirements for regulation up and regulation down were 347 MW and 327 MW, respectively. Both of these requirements remained about the same from 2014. The real-time requirements for regulation were somewhat lower than the day-ahead requirements on average, as they were in previous years.
- On May 24, the ISO experienced its first ancillary service scarcity event in the day-ahead market since the scarcity pricing mechanism was implemented in 2010. The scarcity price was in place for 9 hours in the day-ahead market in the SP26 region on this day. There were a total of 15 intervals in the 15-minute market with scarcity events in 2015.
- During the final months of 2015, the ISO enhanced its testing procedures for operating reserves and increased the frequency of unannounced tests. In December 2015 the ISO performed seven unannounced tests of resources that had spinning or non-spinning reserve awards. All resources that were tested passed.

A detailed description of the ancillary service market design, implemented in 2009, is provided in DMM's 2010 annual report.[127] 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.

[126] 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.

[127] *2010 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2011, pp. 139-142: http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf.

6.1 Ancillary service costs

Ancillary service costs decreased to $0.27/MWh of load served in 2015 from $0.30/MWh in 2014. However, ancillary service costs as a percent of total wholesale energy costs increased slightly to 0.7 percent in 2015 from 0.6 percent in 2014. This resulted because wholesale energy costs decreased slightly more than ancillary service costs. This is likely related to the decrease in ancillary services provided by hydro-electric generation and imports, which were primarily replaced by higher cost natural gas capacity.

Figure 6.1 illustrates ancillary service costs both as a percentage of wholesale energy costs and per megawatt-hour of load from 2011 through 2015. Figure 6.2 shows the same costs broken out by quarter. Costs per megawatt-hour were highest in the third quarter ($0.29/MWh) when energy costs were also high. Costs as a percent of wholesale energy costs were highest in the fourth quarter (0.8 percent) when energy costs were lower.

Total ancillary service cost per megawatt-hour of load did not exhibit much seasonal variation in 2015, as shown in Figure 6.3. While this pattern is similar to 2013 and 2014, it 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 is likely a result of low hydro conditions in recent years.

Figure 6.1 Ancillary service cost as a percentage of wholesale energy costs (2011-2015)

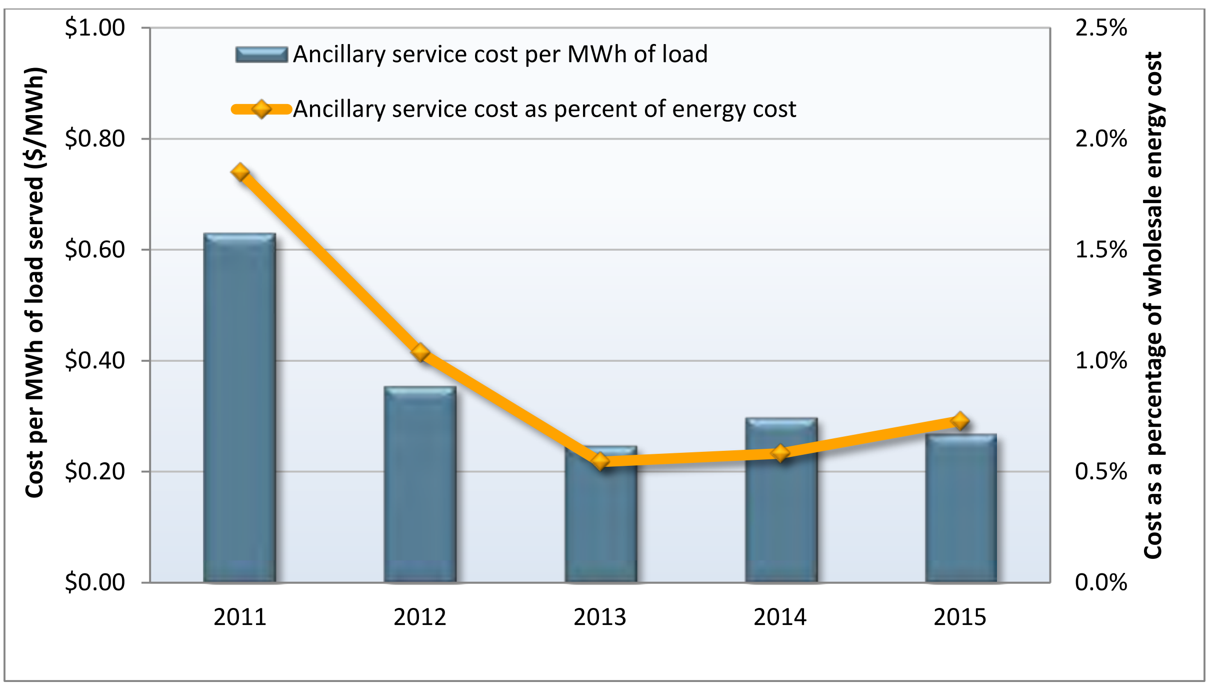


Figure 6.2 Ancillary service cost by quarter

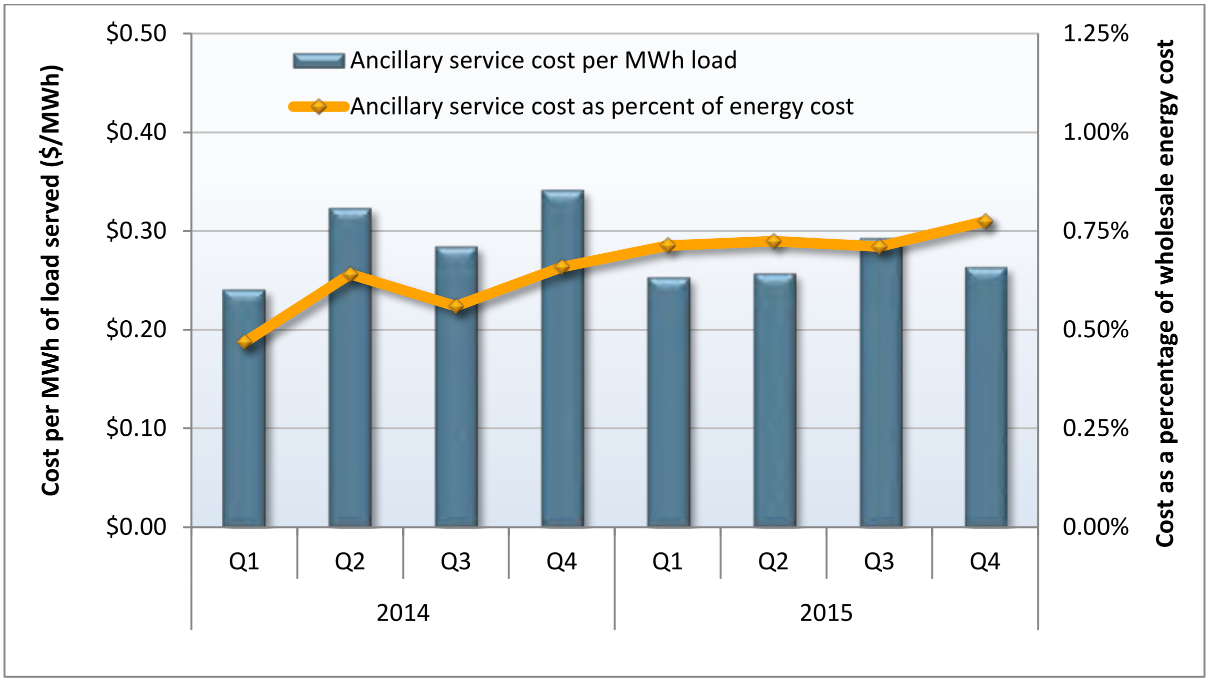
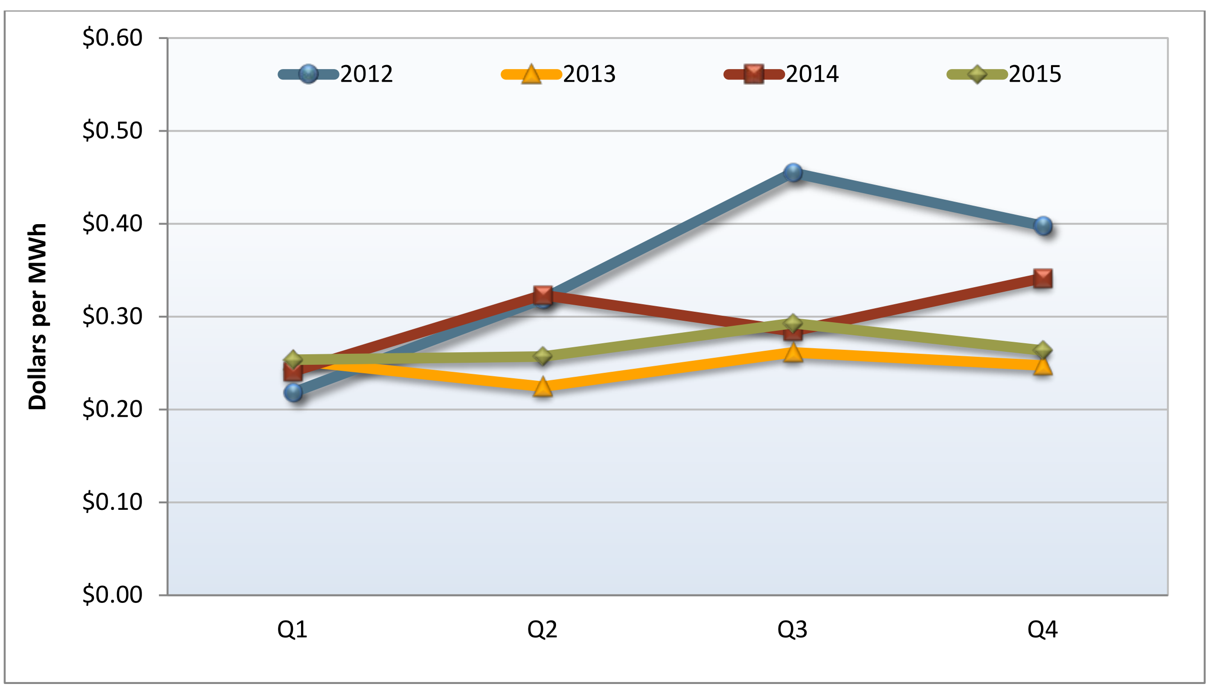


Figure 6.3 Ancillary service cost per MWh of load (2012-2015)



6.2 Ancillary service procurement

The ISO procures four ancillary services in the day-ahead and real-time markets: regulation up, regulation down, spinning reserves, and non-spinning reserves.[128] 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.

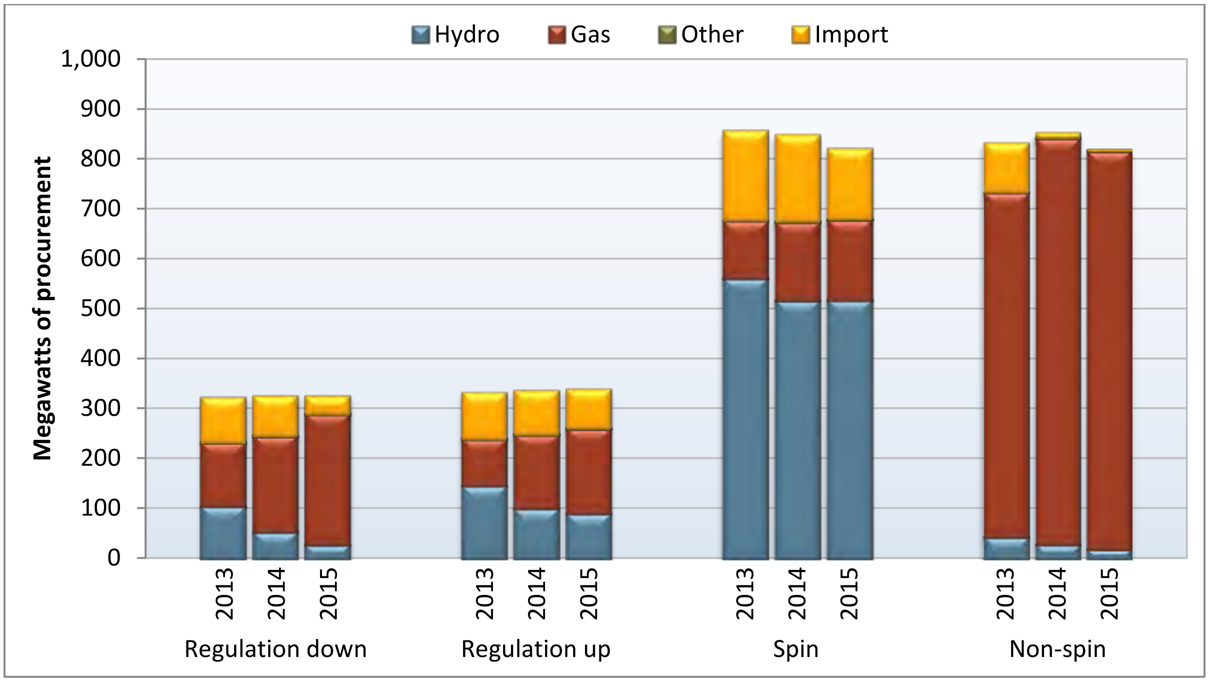
For spinning and non-spinning operating reserves, the procurement requirements are set to exceed the maximum of the single most severe contingency and 3 percent of the sum of load, internal generation and net pseudo and dynamic imports. The average hourly day-ahead requirement for operating reserves in 2015 was 1,664 MW, down 2 percent from 1,702 MW in 2014. The average hourly real-time operating reserve requirement was 1,589 MW in 2015, a 5 percent decrease from 1,664 MW in 2014. As in previous years, at least 50 percent of these totals were required to be spinning reserves.

Regulation requirements in the day-ahead market ranged between 300 MW and 400 MW, with an average of 347 MW for regulation up and 327 MW for regulation down in 2015. Compared to 2014, this represents a slight increase in average requirements by 6 MW for regulation up and by 1 MW for regulation down. In the real-time market, regulation requirements were consistently set to 300 MW in almost every 15-minute interval, which is similar to real-time requirements in 2014.

Figure 6.4 shows the portion of ancillary services procured by fuel type from 2013 through 2015. 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. Most ancillary service requirements continue to be met by ISO resources because scheduling coordinators awarded ancillary services are charged the applicable congestion rate when inter-ties are congested.

[128] In addition, in June 2013 the ISO added a performance payment to the regulation up and regulation down markets, separate from the existing capacity payment system. This product is often referred to as mileage.

Figure 6.4 Procurement by internal resources and imports



Total procurement of regulation in 2015 was similar to the amount procured in 2014 and 2013, whereas the total procurement of operating reserves decreased slightly. These patterns are consistent with the average changes in ancillary service requirements discussed above. Compared to 2014, gas-fired resources in 2015 provided a larger proportion of all ancillary services. The composition of ancillary service resources is characterized as follows:

- Average hourly provision of ancillary services from hydro-electric resources decreased in 2015 to 651 MW. This is a 7 percent decrease from 697 MW in 2014 and is likely due to lower hydro-electric generation conditions in 2015. Hydro-electric resources provided less of each ancillary service type except spinning reserves, where the amount provided was relatively unchanged.
- Total ancillary service imports decreased to 253 MW in 2015 from 348 MW in 2014 on an hourly average basis. Imports provided 11 percent of regulation down capacity, 23 percent of regulation up capacity, 17 percent of spinning reserves and less than 1 percent of non-spinning reserves.
- Gas-fired resources provided 1,390 MW on average in 2015, up 6 percent from 1,310 MW in 2014. These resources provide the vast majority of non-spinning reserves, as in previous years. Further, gas-fired resources increased their share of regulation down provided to 81 percent and regulation up to 50 percent.

The makeup of generation by fuel type providing regulation mileage differed from those providing regulation up and regulation down. While hydro-electric resources provided 26 percent of procured regulation up and 8 percent of procured regulation down, they provided 46 percent and 19 percent of total mileage up and mileage down, respectively. Correspondingly, gas resources and imports provided smaller proportions of mileage procured, compared to their proportions of regulation procurement.

6.3 Ancillary service pricing

Resources providing ancillary services receive a capacity payment at market clearing prices 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 weighted average market clearing prices for each ancillary service product by quarter in the day-ahead and real-time markets during 2014 and 2015.

Except for non-spinning reserves, weighted average day-ahead prices decreased from 2014 to 2015, as seen in Figure 6.5. Quarterly weighted average prices ranged from approximately $0.12/MWh for non-spinning reserve in the first quarter to $6.04/MWh for regulation up in the fourth quarter. Weighted average prices in the day-ahead market were generally lower than real-time prices. Prices were also generally highest for regulation up and lowest for non-spin resources, as they were in 2014.

Real-time weighted average ancillary service prices were higher in 2015 for all services, as illustrated in Figure 6.6. Most ancillary service procurement occurs in the day-ahead market, so real-time market prices have a relatively small impact on overall ancillary service costs.

Real-time weighted average ancillary service prices are to a large extent determined by the frequency and magnitude of price spikes. In the second quarter of 2015, the weighted average real-time prices for regulation up and spinning reserves were significantly impacted by events on June 8. On this day, real-time load significantly exceeded the day-ahead forecast, which resulted in high prices for both energy and upward ancillary services. The weighted average real-time prices for non-spinning reserves in the third quarter were significantly impacted by particularly high prices on August 28 and September 20. On both days, the shadow prices for non-spinning reserves were impacted by very high real-time energy prices.

The weighted average market clearing prices for mileage up and mileage down remained low throughout 2015 in both the day-ahead and real-time markets. The day-ahead weighted average price for mileage up decreased to $0.05 per unit in 2015 from $0.06 per unit of mileage in 2014. For mileage down, the day-ahead average price increased to $0.10 per unit in 2015 from $0.09 per unit in 2014. In the real-time market, weighted average mileage prices were even lower, averaging $0.02 for both mileage up and mileage down in 2015. One reason for the low average prices of mileage is that the least-cost regulation resources are often able to supply a sufficient amount of mileage resulting in a non-binding mileage requirement and a $0 market clearing price.

Figure 6.5 Day-ahead ancillary service market clearing prices

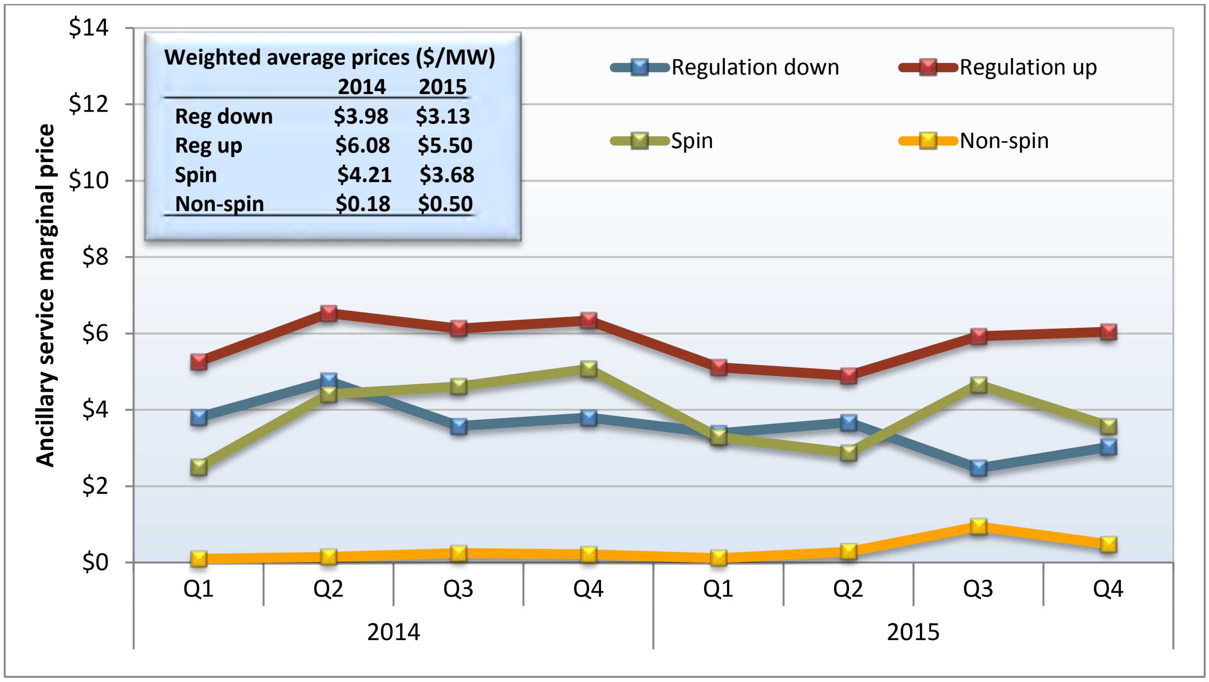
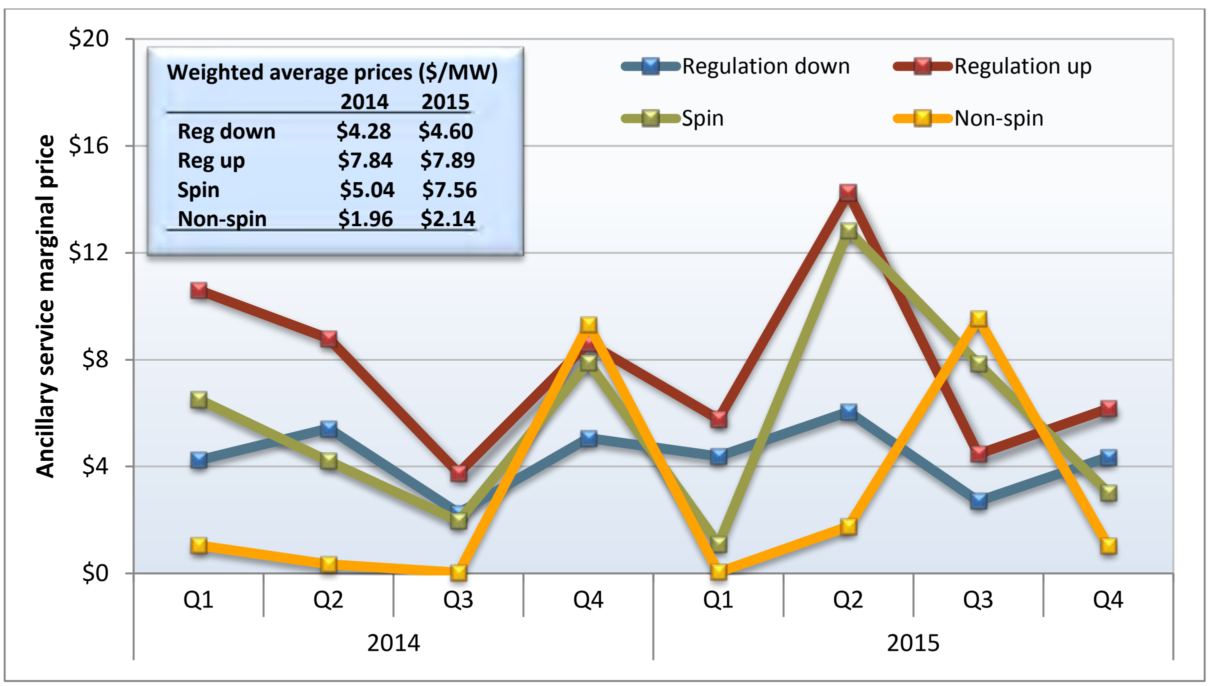


Figure 6.6 Real-time ancillary service market clearing prices

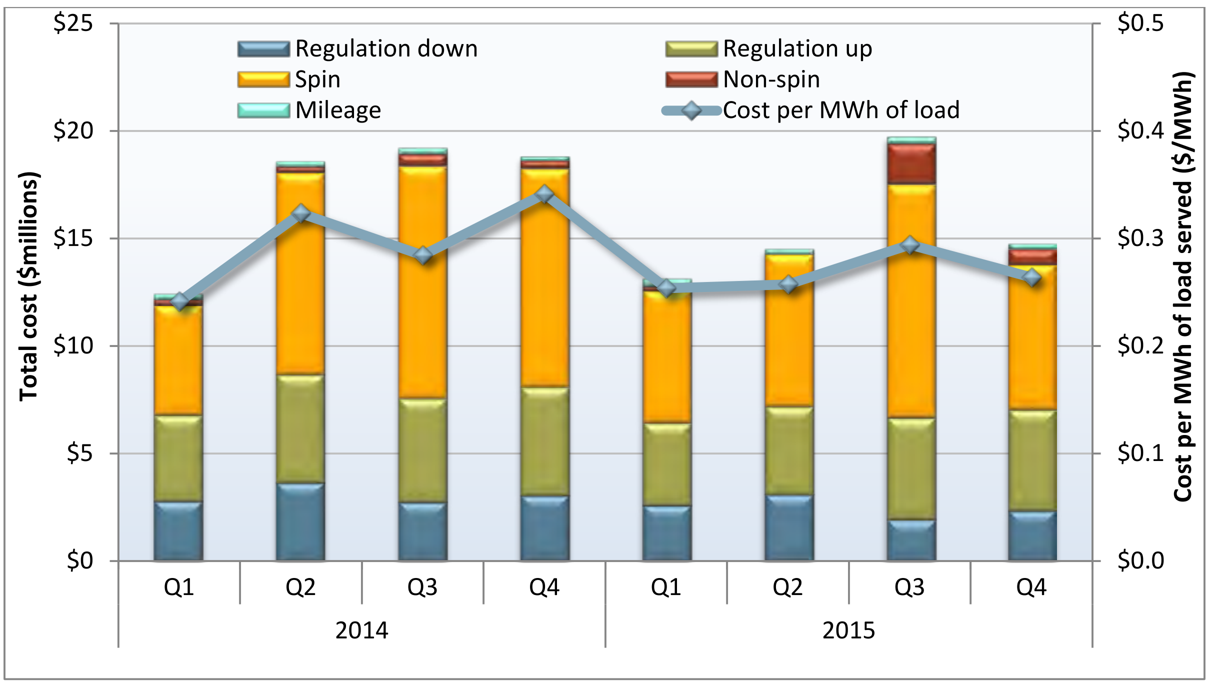


6.4 Ancillary service costs

Overall costs for ancillary services were low and remained below $0.30/MWh of load served during each quarter during 2015. Payments for ancillary services totaled about $62 million in 2015, a decrease of about 10 percent from 2014. The value of self-provided ancillary services by load-serving entities made up $2.9 million of this amount, or about 5 percent.

Figure 6.7 shows the total cost of procuring ancillary service products by quarter along with the total ancillary service cost for each megawatt-hour of load served. Total ancillary service costs peaked during the third quarter of the year. The decrease in total cost compared to 2014 was primarily driven by a decrease in the day-ahead prices for spinning reserves and regulation, and by a decrease in the total amount of spinning reserves procured.

Figure 6.7 Ancillary service cost by product



6.5 Special issues

This section highlights additional features of the ancillary service market including scarcity pricing and compliance testing.

Ancillary service scarcity pricing

Scarcity pricing of ancillary services occurs when there is insufficient supply to meet reserve requirements. Under the 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. The scarcity prices are determined by a scarcity demand curve, such that the scarcity price is higher when the procurement shortfall is larger.

Ancillary service scarcity pricing events occurred in February, April, May and October. Scarcity pricing occurred in a total of nine intervals in the day-ahead market and 15 intervals in the 15-minute real-time market. This was the first time since implementation of scarcity pricing in December 2010 that scarcity events occurred in the day-ahead market. For the real-time market, the number of intervals with scarcity pricing decreased slightly compared to 2014, when they occurred in two intervals in the hour-ahead market and 14 intervals in the 15-minute market.

The ISO experienced ancillary service scarcity events in the day-ahead market during nine hours on May 24. Regulation down procurement fell only 0.4 MW short of the requirement in hours ending 9 through 17 in the SP26 region. On this day, Southern California experienced energy prices that were very close to $0/MWh in the day-ahead market for multiple hours because of outage-related congestion on Path 15 in combination with low seasonal loads and significant amounts of renewable generation on-line. This likely contributed to the difficulty of committing more resources to provide regulation down.

Ancillary service scarcity events also occurred in the real-time market on May 24 for both spinning reserves and regulation down in SP26. For regulation down, the shortfall was 0.4 MW during two 15-minute intervals. There were five 15-minute intervals with insufficient procurement of spinning reserve, with the shortfall ranging from about 1 MW to almost 6 MW.

In addition to the events on May 24, ancillary service scarcity events occurred in the 15-minute market on the following dates in 2015:[129]

- February 15 - a shortage of regulation down during one interval;
- April 21 - a shortage of regulation down during two intervals and regulation up during two intervals;
- May 17 - a shortage of regulation down during two intervals; and
- October 13 - a shortage of non-spinning reserve during one interval.

Ancillary service compliance testing

In response to concerns that resources were not performing at ancillary service ratings during real-time ancillary service contingency events, the ISO announced that it would begin ancillary service compliance testing in November 2012.[130] During the final months of 2015, the ISO enhanced its testing procedures for operating reserves and increased the frequency of unannounced tests. In December 2015, the ISO performed seven unannounced tests of resources that had spinning or non-spinning reserve awards. All resources that were tested passed.

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 when 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

[129] The scarcity events on February 15, April 21, and May 17 did not coincide with high energy prices in the 15-minute market. During the scarcity event on October 13, energy prices in the 15-minute market reached $657/MWh. The energy price was, however, projected to be high during this interval irrespective of the ancillary service scarcity event.

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

made to the resource as payment for ancillary services provided. The ISO can initiate a compliance test without the resource first experiencing a contingency related performance audit.

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 — which accounts for most of the total wholesale market — remained structurally competitive on a system-wide level in almost all hours.
- The supply of capacity owned by non-load-serving entities meets or exceeds the additional capacity that load-serving entities need to procure to meet local resource adequacy requirements in the major local capacity areas. However, in some areas, one supplier is individually pivotal because some portion of this supplier's capacity is needed to meet local requirements.
- The dynamic path assessment, which is part of the enhanced local market power mitigation procedures implemented in 2013, is an automated test incorporated in the market software used to determine competitiveness of transmission constraints based on actual system and market conditions in each interval. This automated test effectively identified non-competitive constraints in the day-ahead and real-time markets in 2015.
- Most resources subject to mitigation submitted competitive offer prices, such that few bids were lowered as a result of the mitigation process. The number of units in the day-ahead market that had bids changed by mitigation remained very low and decreased to an average of about 2.2 units per hour in 2015 from an average of about 2.7 units per hour in 2014.
- The frequency of bid mitigation in the real-time market dropped to about 1 unit per hour in 2015 from about 1.3 units per hour in 2014.[131] The estimated impact of bid mitigation on the amount of additional real-time energy dispatched as a result of bid mitigation decreased in 2015 to about 6 MW per hour from about 9 MW per hour in 2014.
- Exceptional dispatches are instructions issued by grid operators when the automated market optimization is not able to address a particular reliability requirement or constraint. Most exceptional dispatches were for reasons that were not subject to mitigation. However, the volume and above-market cost of this exceptional dispatch energy was relatively low. The cost of exceptional dispatch incremental energy in excess of the market price totaled $1.2 million in 2015, up from $1 million in 2014.[132] Mitigation provisions that apply to exceptional dispatches for energy reduced costs by $14,000 in 2015, down from $144,000 in 2014.
- Gas-fired capacity opting for the registered cost option for start-up and minimum load costs declined considerably in 2015 compared to 2014, with the majority of gas-fired capacity now on the proxy cost option. This shift occurred because of a rule change in late 2014 that increased the cap on the proxy cost option from 100 percent to 125 percent and limited the eligibility for the registered cost option to only use-limited resources.

[131] For the real-time market comparison, data was only considered beginning in May 2014, following the implementation of FERC Order No. 764.

[132] Exceptional dispatch is discussed in more detail in Section 9.1 of this report.

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 the *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 are removed.

- **Residual supply index.** The residual supply index is the ratio of supply from non-pivotal suppliers to demand.[133] A residual supply index less than 1.0 indicates an uncompetitive level of supply.

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 RSI_1. With the two or three largest suppliers excluded, we refer to these results as RSI_2 and RSI_3, respectively.[134]

7.1.1 Day-ahead system energy

Figure 7.1 shows the hourly residual supply index for the day-ahead energy market in the ISO in 2015. This analysis is based on system energy only and ignores potential limitations due to transmission limitations.[135] 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 110 hours and only 1 in about 30 hours with the two largest suppliers removed (RSI_2). The hourly RSI_3 value was as low as 0.88 in 2015 compared to about 0.91 in 2014.

The residual supply index values reflect load conditions and generation availability, as well as resource ownership or control. 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, because 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.

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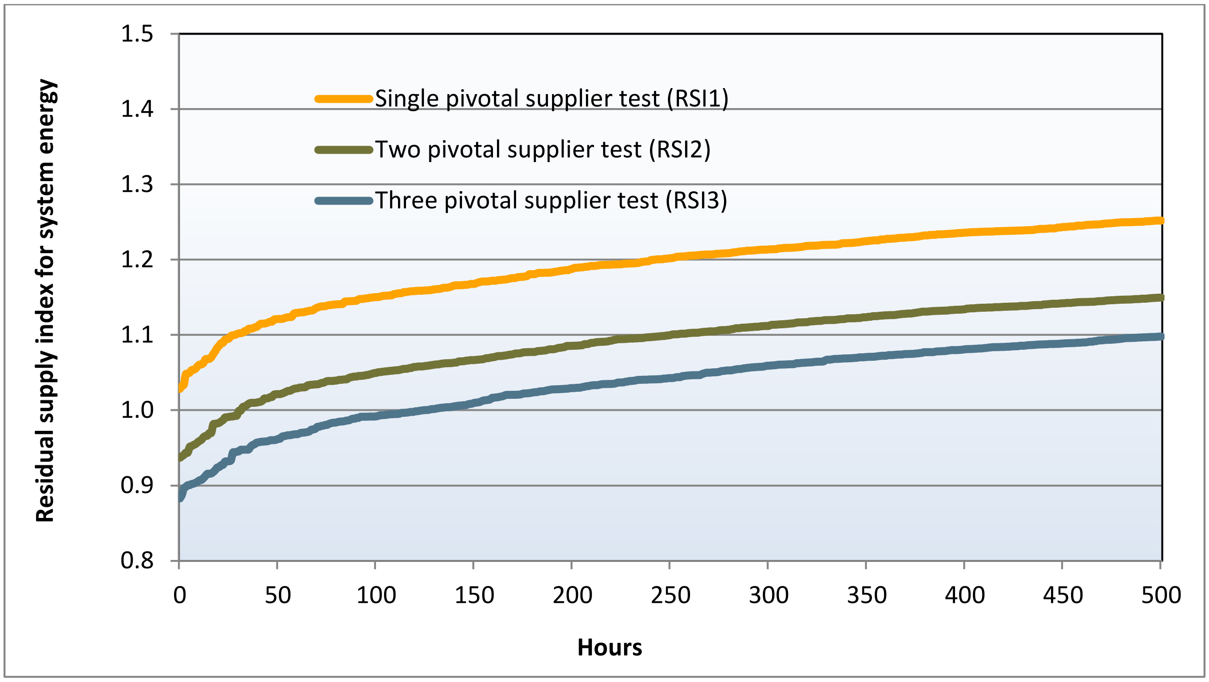
133 For instance, assume demand equals 100 MW and the total available supply equals 120 MW. If one supplier owns 30 MW of this supply, the residual supply index equals 0.90, or (120 – 30)/100.

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

135 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 load 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 the major local capacity areas. However, in some areas, one supplier is 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	2,083	5,137	2.47	1.19	0.19	0.11	0
North Coast/North Bay	415	735	1.77	0.08	0.01	0.00	1
SCE area							
LA Basin	4,990	6,731	1.35	0.58	0.28	0.15	1
Big Creek/Ventura	137	2,913	21.34	5.73	0.49	0.15	0
San Diego/Imperial Valley	1,669	2,445	1.47	0.78	0.43	0.08	1

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 that 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 under the capacity procurement mechanism of the ISO tariff. Section 7.2 describes these tariff provisions and the FERC approved changes to these provisions that will begin in 2016.

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. Section 7.3 examines the actual structural competitiveness of transmission constraints when congestion occurred in the day-ahead and real-time markets.

7.2 Capacity procurement mechanism

The capacity procurement mechanism within the ISO tariff provides backstop procurement authority to ensure that the ISO will have sufficient capacity available to maintain reliable grid operations. This backstop authority also helps to mitigate the potential for exercise of locational market power by units that are needed to meet local reliability requirements by establishing a reasonable price under which the ISO could procure this capacity if load-serving entities did not meet local resource adequacy capacity requirements through bilateral purchases. To date, this mechanism has rarely been used as essentially all local capacity requirements are being procured in the bilateral market by load-serving entities.

The current ISO capacity procurement mechanism tariff authority expired in 2016 and was replaced with a new approach. In a 2011 order, FERC instructed the ISO to develop enhanced backstop provisions that would 1) procure capacity at a price that accounts for market conditions that change over time; 2) provide a reasonable opportunity for suppliers to recover fixed costs; and 3) support incremental investment by existing resources to perform long-term maintenance or make improvements that are necessary to satisfy environmental requirements or address reliability needs associated with renewable resource integration.

In response, the ISO proposed to replace the current administrative rate with a competitive solicitation process to determine the backstop capacity procurement price under the capacity procurement mechanism. In October of 2015, FERC issued an order accepting the ISO's filing proposing tariff revisions to amend the existing capacity procurement mechanism.[136]

The tariff revisions include a soft offer cap initially set at the California Energy Commission with estimated levels for going-forward fixed costs for a mid-cost 550 MW combined cycle with duct firing resource in 2013 plus 20 percent. This equals $75.68/kW-year (or $6.31/kW-month). A supplier may go to FERC to cost-justify a price higher than the soft offer cap prior to offering the resource into the competitive solicitation process or after receiving a capacity procurement mechanism designation by the ISO.

The ISO will monitor the use of the capacity procurement mechanism to ensure that load-serving entities are not relying on this mechanism as an alternative to bilateral procurement as a means of capacity procurement to meet resource adequacy obligations. If the specific levels of procurement under this mechanism are made to meet resource adequacy requirements of a load-serving entity, the ISO will open a stakeholder initiative to explore the reasons for use of this mechanism for capacity procurement.

DMM supported the tariff revision as a means of continuing to balance the need for the ISO to have a means of procuring capacity to meet reliability requirements and mitigate potential local market power with the goal of continuing to provide an incentive for most or all capacity needs to be met by resource adequacy capacity procured in the bilateral market.

7.3 Competitiveness of transmission constraints

Local market power is created by insufficient or concentrated control of supply within a local area. In addition to load and generation, the availability of transmission to move supply into the local area from outside plays an important role in determining where local market power exists.

The ISO local market power mitigation provisions require that each transmission constraint be designated as either *competitive* or *non-competitive* prior to the binding market run using the *dynamic competitive path assessment*, or DCPA. The DCPA uses results of a pre-market mitigation run that clears supply and demand with 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.

Competitiveness of each constraint is measured using 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 residual supply index is greater than or equal to one, and the constraint is deemed competitive. Otherwise, it is deemed non-competitive. A non-competitive constraint is considered to be indicative of

[136] October 1, 2015 Order Accepting CAISO's Proposed Capacity Procurement Mechanism Tariff Revisions (ER15-1783): http://www.caiso.com/Documents/Oct1_2015_OrderAcceptingTariffRevisions_CapacityProcurementMechanism_ER15-1783.pdf.

local market power and resources that can supply counter-flow to a non-competitive constraint may subsequently be subject to bid mitigation.

Competitiveness results

The distribution of results of the 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 index for the most frequently congested transmission facilities for each market. 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.

Less than half of the most commonly congested constraints in the day-ahead market tend to be non-competitive. This fact is shown in Figure 7.2, where for 17 of the 30 most frequently binding constraints, the RSI measured above 1 in the majority of hours in which the constraint was congested. In the real-time market, the residual supply index tended to be greater than 1 for most of the hours when congestion occurred on most of the constraints. Only seven of the top 30 most frequently congested constraints in real time, shown in Figure 7.3, have large portions of hours where the residual supply index was below 1.

For the majority of time that constraints are congested in either the day-ahead or the real-time market, the constraints are found to be competitive. A significant number of constraints tend 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, which is the ability to test and designate the competitiveness of constraints based on actual system conditions as they change from day to day and hour to hour.

Figure 7.2 Transmission competitiveness in 2015 for the day-ahead market

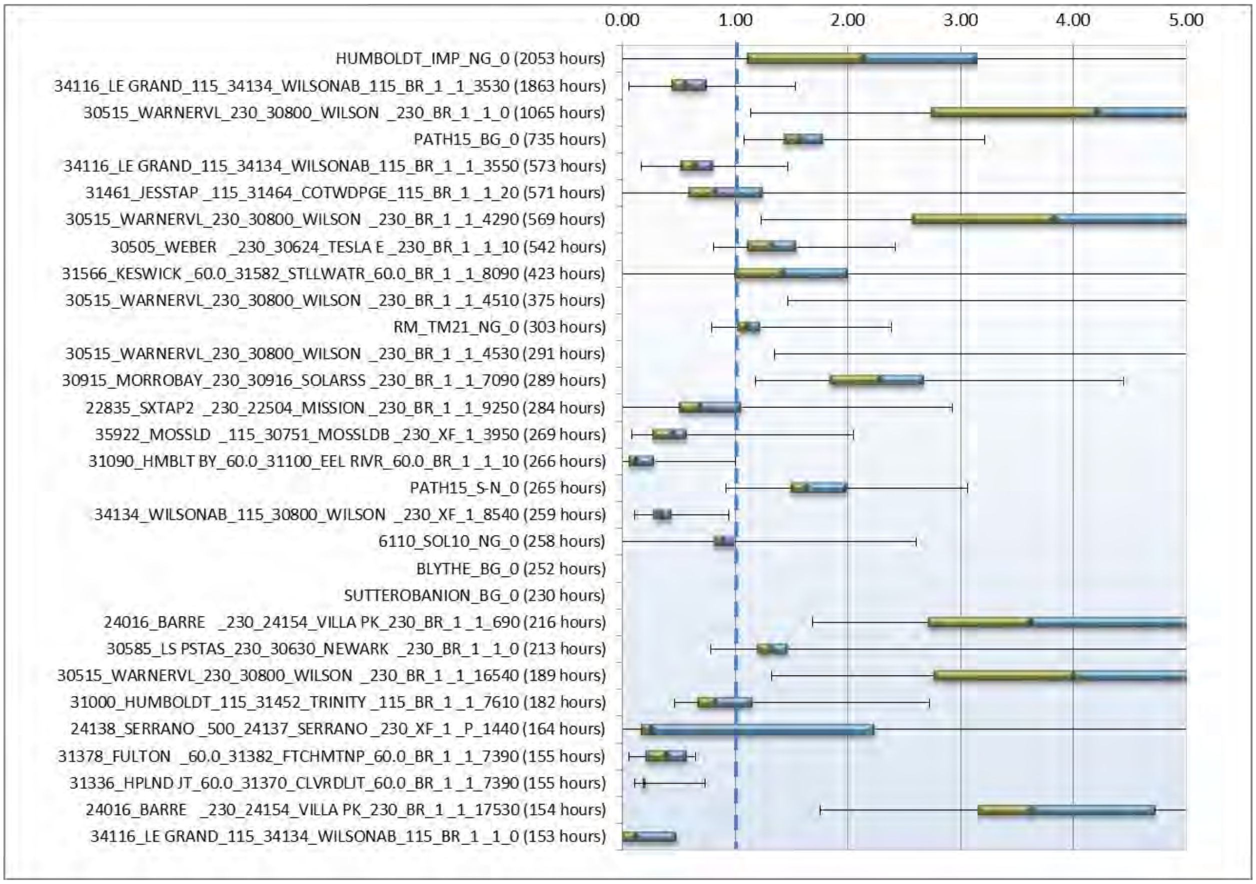
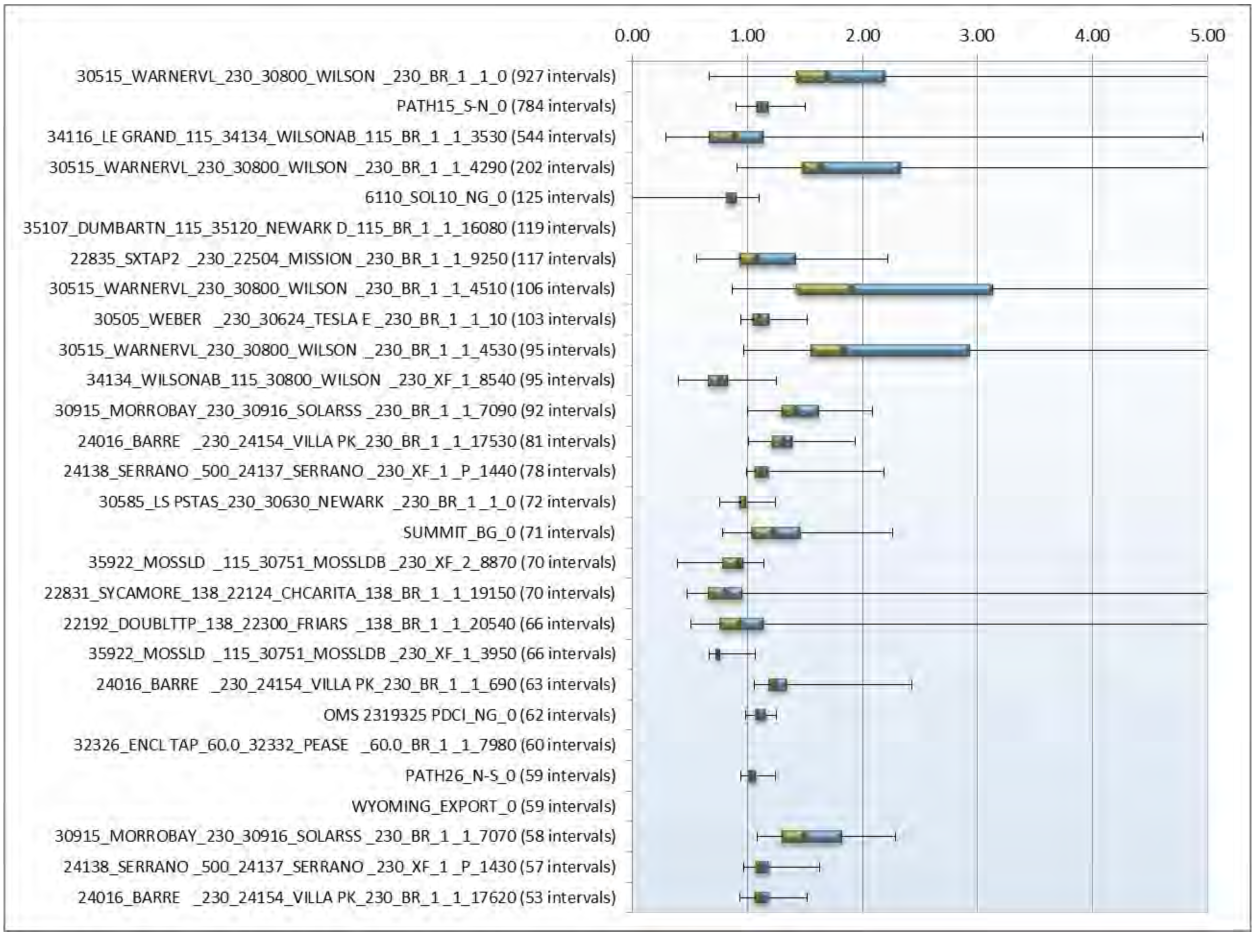


Figure 7.3 Transmission competitiveness in 2015 for the real-time market



Accuracy of transmission competitiveness assessment

Evaluating the performance of the current mitigation procedures involves examining the accuracy with which the mitigation run predicts congestion in the market run and the portion of constraints congested in the mitigation or market run which are non-competitive. The framework DMM has used to quantify overall accuracy of new mitigation procedures is shown graphically in Table 7.2.

All constraint intervals in the *consistent* group in Table 7.2 would have been treated appropriately. When congestion is *over-identified*, or is projected to occur in the mitigation run but is resolved in the market run, the congestion may have been resolved due to mitigation. In the real-time market, it is also possible that congestion was resolved due to different inputs in the market run. In this second case it is possible that mitigation did not play a role in resolving congestion. Mitigation is only applied when the congested constraint is deemed to be non-competitive, so this is a relatively rare circumstance. As described later in this section, the frequency of such mitigation has been extremely low in both the day-ahead and real-time markets under the current mitigation procedures. The frequency of this occurrence in 2015 was higher than in the previous year, but was of a similar magnitude to the frequency of the occurrence in that year.

When congestion is *under-identified*, or is not predicted in the mitigation run but then occurs in the market run, inaccurate mitigation can result if the congested constraint would have been deemed non-competitive. In these cases, mitigation should be applied but is not. This is referred to as *under-mitigation*. Because the dynamic competitive path assessment procedure does not evaluate uncongested constraints, we do not know exactly how many of these under-identified constraints would have been deemed competitive or non-competitive. However, as discussed in the following sections, other analysis by DMM indicates that constraints on which congestion occurs are competitive a high portion of the time.

Table 7.2 Framework for analysis of overall accuracy of transmission competitiveness

Congestion prediction	Competitive status	
(mitigation run vs. market run)	Competitive	Non-competitive
Consistent (congested in both runs)	No mitigation	Mitigation applied, congestion present in market run
Over-identified (congested in mitigation run, not in market run)	No mitigation	Mitigation applied, congestion resolved in market run
Under-identified (not congested in mitigation run, congested in market run)	No mitigation	Mitigation not applied, needed in market run

The unit of measurement for the analysis below is a constraint-interval. Each time a constraint is congested for a given interval it is counted as one constraint-interval. A total of 100 constraint-intervals, then, could include 100 constraints each congested for 1 interval, or 1 constraint congested for 100 intervals, or 50 constraints each congested for 2 intervals and so on. For day-ahead results, we refer to the constraint-intervals as constraint-hours, as the intervals in the day-ahead market each represent one hour.

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. DMM has found that the congestion predicted in the day-ahead mitigation run is highly consistent with actual congestion that occurs in the subsequent day-ahead market.

Table 7.3 shows that 82 percent of congested constraint-hours were consistent in the pre-market and market runs in 2015. This is slightly less than 88 percent in 2014. Another 8 percent were predicted to be congested, but that congestion was then resolved in the market run. About 10 percent of congested constraint-hours in the day-ahead market were under-identified, compared to 6 percent in 2014. If the proportion of competitive to non-competitive constraint-hours was the same for under-identified as it is for constraints with predicted congestion, this would mean that about 4 percent of congested constraint-hours may represent missed mitigation in 2015.

In the day-ahead market, the proportion of congested constraint-hours that were not consistent between the pre-market run and the market run was small. The changes that occurred between these two runs in the day-ahead market mostly consisted of bid mitigation. Because this was the primary change, the chances that conditions in the market run were less competitive than conditions in the pre-market run were small. Chances that something other than bid mitigation resolved the congestion that was present in the pre-run but not in the market run were also small.

Table 7.3 Consistency of congestion and competitiveness of constraints in the day-ahead local market power mitigation process[137]

Congestion prediction	Competitive # constraint hours	Competitive %	Non-competitive # constraint hours	Non-competitive %	Total # constraint hours	Total %
Consistent	13,018	48%	8,908	33%	21,926	82%
Over-identified	1,331	5%	940	3%	2,271	8%
Under-identified	---	---	---	---	2,689	10%
					26,886	**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.

Real-time market

The dynamic competitive path assessment is performed in an advisory interval of a 15-minute market run. For example, the market run that determines financially binding dispatch schedules for the first interval of the first hour of each day also encompasses the path assessment and mitigation protocol for the second interval of the first hour of the 15-minute market.

The accuracy of congestion prediction is notably lower in the real-time local market power mitigation process than in the day-ahead. Because of the delay between the dynamic competitive path assessment run and the market runs, there may be differences in the model inputs such as load, generation output, transmission limits, generation and transmission outages, and other factors. The differences in inputs can cause differences in congestion between the predictive assessment run and the final, binding market run. However, because most congested constraints are deemed competitive in real time, the overall impact of less accurate congestion prediction is low in the real-time market. In the near future, the ISO plans to make further improvements to systems to increase accuracy of real-time competitiveness measurement and mitigation.[138]

15-minute market

Consistency of the 15-minute assessment run with the binding 15-minute market run is not as close as that of the day-ahead runs, but is closer than the relationship of the 15-minute assessment run with the 5-minute market.

The results in Table 7.4 show the accuracy of the 15-minute dynamic competitive assessment process in predicting congestion in the binding run of the 15-minute market. Of all of the constraint-intervals that

137 The mitigation run consistently predicts no congestion in the market run in a very large number of instances.

138 More information on planned and proposed changes to the real-time LMPM procedures can be found on the LMPM Enhancements stakeholder initiative webpage, at: http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalMarketPowerMitigationEnhancements2015.aspx.

were congested in either the assessment run, the 15-minute market run, or both, the assessment run predicted congestion consistently with the 15-minute market run in about 71 percent of those constraint-intervals, compared to 69 percent in 2014. Under-identified congestion occurred in 11 percent of intervals, a slight decline from 12 percent in 2014. Overall, about 74 percent of constraint-intervals that were congested in the assessment run were competitive. If the same ratio of competitive to non-competitive intervals holds for the under-identified constraint-intervals, this suggests that under-mitigation occurred in just under 3 percent of the total number of congested constraint-intervals.

Table 7.4 Consistency of congestion and competitiveness in the 15-minute market local market power mitigation process

Congestion prediction		Competitive # constraint intervals	%	Non-competitive # constraint intervals	%	Total # constraint intervals	%
Consistent		13,592	54%	4,455	18%	18,047	71%
	Over-identified	3,243	13%	1,246	5%	4,489	18%
	Under-identified	---	---	---	---	2,809	11%
						25,345	**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.

5-minute market

The binding 5-minute market run happens further still from the dynamic competitive path assessment run in the 15-minute market that predicts congestion. The differences between the pre-market mitigation run and the financially binding market run are bigger in the 5-minute market than in either of the other markets discussed above.

For this analysis, the comparison is made between 15-minute intervals for the assessment run and the set of three 5-minute intervals for the 5-minute real-time market. If congestion occurs on a constraint in one, two, or all three of the 5-minute intervals that correspond to a 15-minute interval, we count that as a single constraint-interval of congestion.

Table 7.5 shows the results of congestion predictions for the 5-minute real-time market. Congestion occurred in both the 15-minute real-time mitigation and 5-minute market runs in about 55 percent of all relevant constraint-intervals, which was down slightly from 56 percent in 2014. In about 24 percent of the congested constraint-intervals, congestion that was present in the real-time mitigation run was resolved in the real-time market run.

The third row of Table 7.5 shows that in about 21 percent of the congested constraint-intervals, constraints were congested in the real-time market run but not in the real-time mitigation run. This is the same as in 2014. As noted previously, the market software does not provide results of the three-pivotal supplier test for these intervals, so data are not available to determine if the constraint was competitive or non-competitive. As with the other markets, we can apply the ratio of non-competitive constraints in the identified congestion to estimate under-mitigation in the 5-minute market. In this case, we estimate that just 5 percent of congested constraint-intervals in the 5-minute market may have had under-mitigation.

Table 7.5 Consistency of congestion and competitiveness in the 5-minute market local market power mitigation process

Congestion prediction	Competitive # constraint intervals	%	Non-competitive # constraint intervals	%	Total # constraint intervals	%
Consistent	11,334	41%	3,709	13%	15,043	55%
Over-identified	5,115	19%	1,599	6%	6,714	24%
Under-identified	---	---	---	---	5,806	21%
					27,563	**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.

7.4 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.

7.4.1 Frequency and impact of automated bid mitigation

The 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. The real-time mitigation procedures were enhanced in May 2013. As part of these changes, 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.

In the real-time market, the number of units subject to mitigation, the number of units mitigated, and the estimated increase in dispatch were lower in 2015 than in 2014. In the day-ahead market, the number of units subject to mitigation was higher in 2015 compared to 2014, but the number of units that were mitigated and the estimated increase in megawatts due to mitigation decreased.

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, overall prices in the ISO energy markets over the course of 2015 were highly competitive, averaging close to competitive baseline prices. 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.[139]

The frequency (as shown in Figure 7.4) increased while the average estimated change in schedules (as shown in Figure 7.5) lowered in the day-ahead market in 2015:

- An average of 20 units in each hour were subject to day-ahead mitigation in 2015, higher than an average of 16 units in 2014.
- An average of 2.2 units had day-ahead bids changed in 2015. This was down from an average of 2.7 units with day-ahead bids changed in 2014.
- The estimated increase in energy dispatched in the day-ahead market from these units averaged about 11 MW per hour in 2015, down from 17 MW in 2014.

Figure 7.6 highlights the frequency of real-time mitigation, whereas Figure 7.7 highlights the volume of real-time mitigation:

- Bids for an average of 1 unit per hour were lowered as a result of the real-time mitigation process in 2015. Beginning in May 2014, on average 1.3 units' bids were lowered due to mitigation.
- On average, 0.2 and 0.3 units per hour were dispatched at a higher level in the real-time market as a result of bid mitigation in 2014 and 2015, respectively.
- The estimated increase in real-time dispatches from these units because of bid mitigation averaged about 6 MW in 2015. The estimated increase was about 9 MW in 2014.

[139] 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. This methodology has been updated beginning in 2014 so the numbers will not be directly comparable to previous years' reports.

Figure 7.4 Average number of units mitigated in day-ahead market

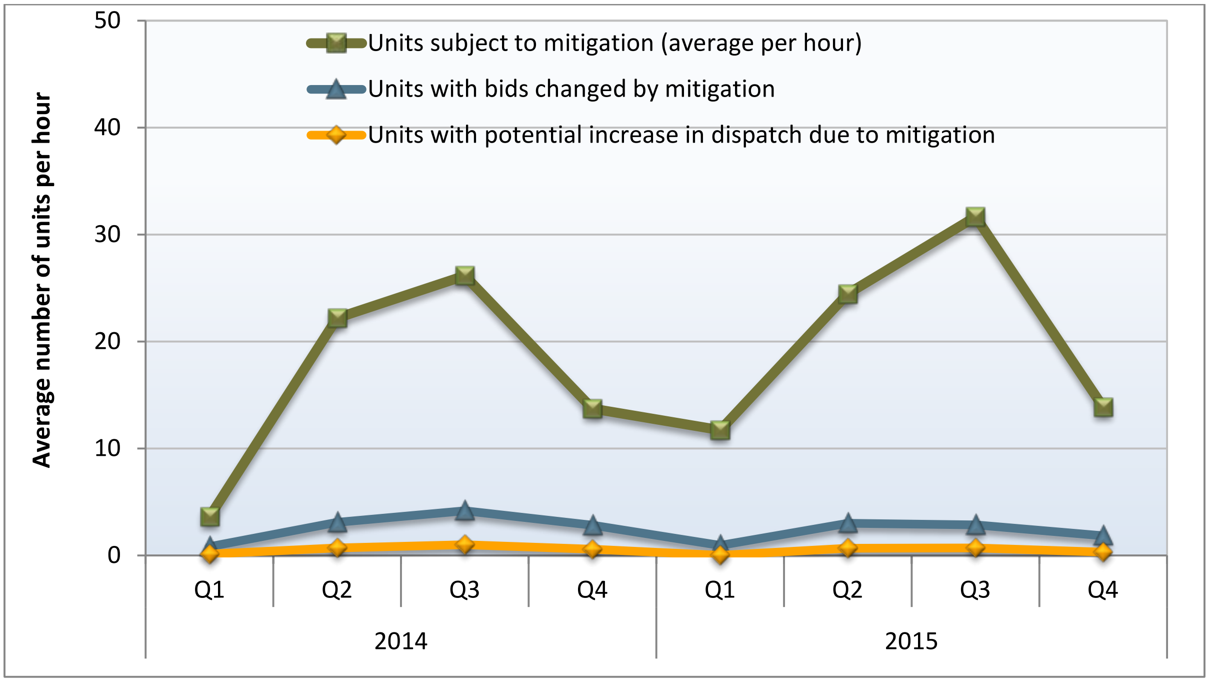


Figure 7.5 Potential increase in day-ahead dispatch due to mitigation (hourly averages)

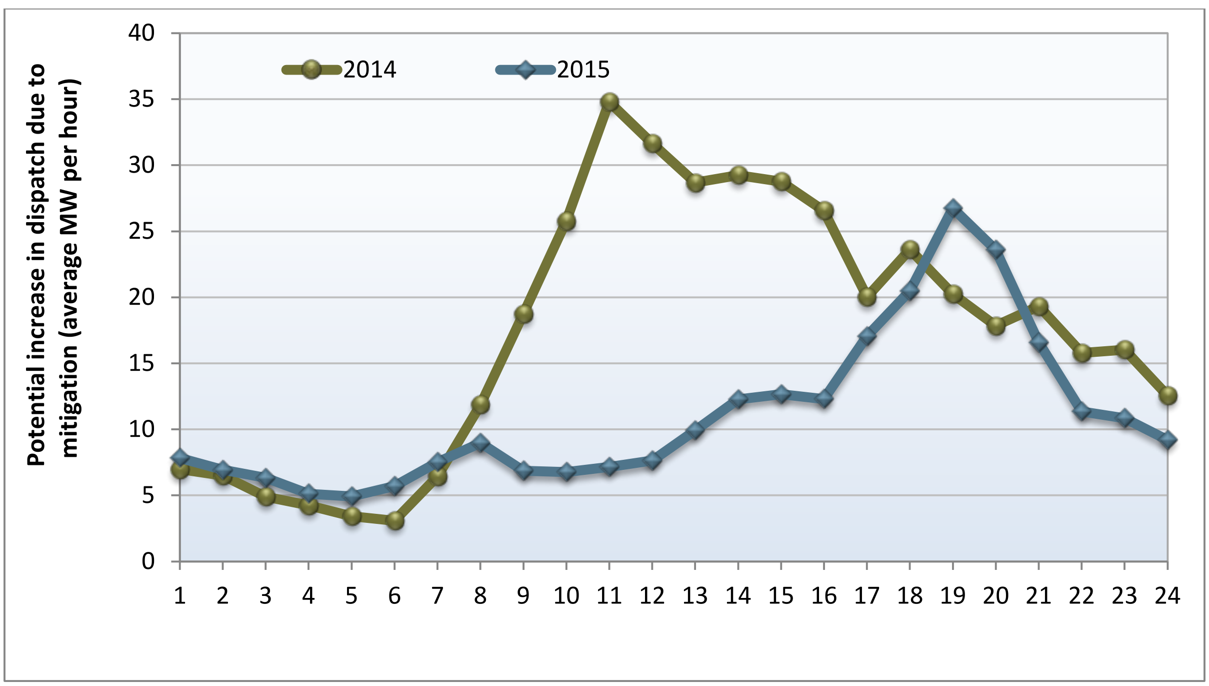


Figure 7.6 Average number of units mitigated in real-time market

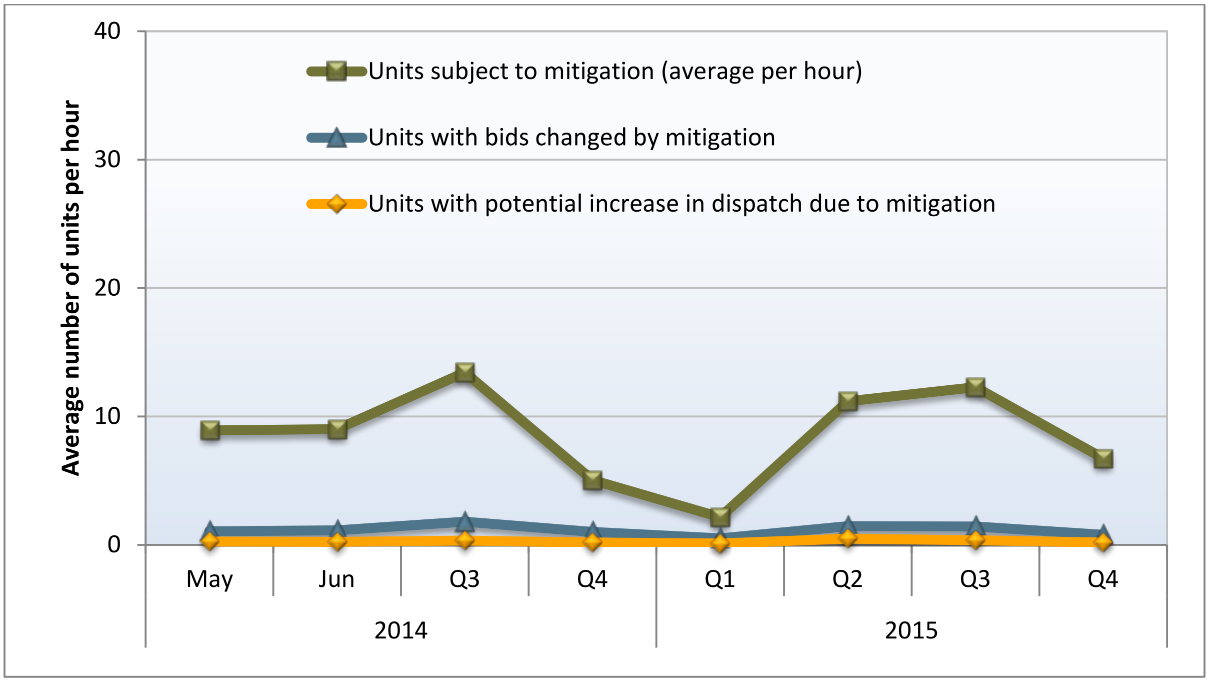
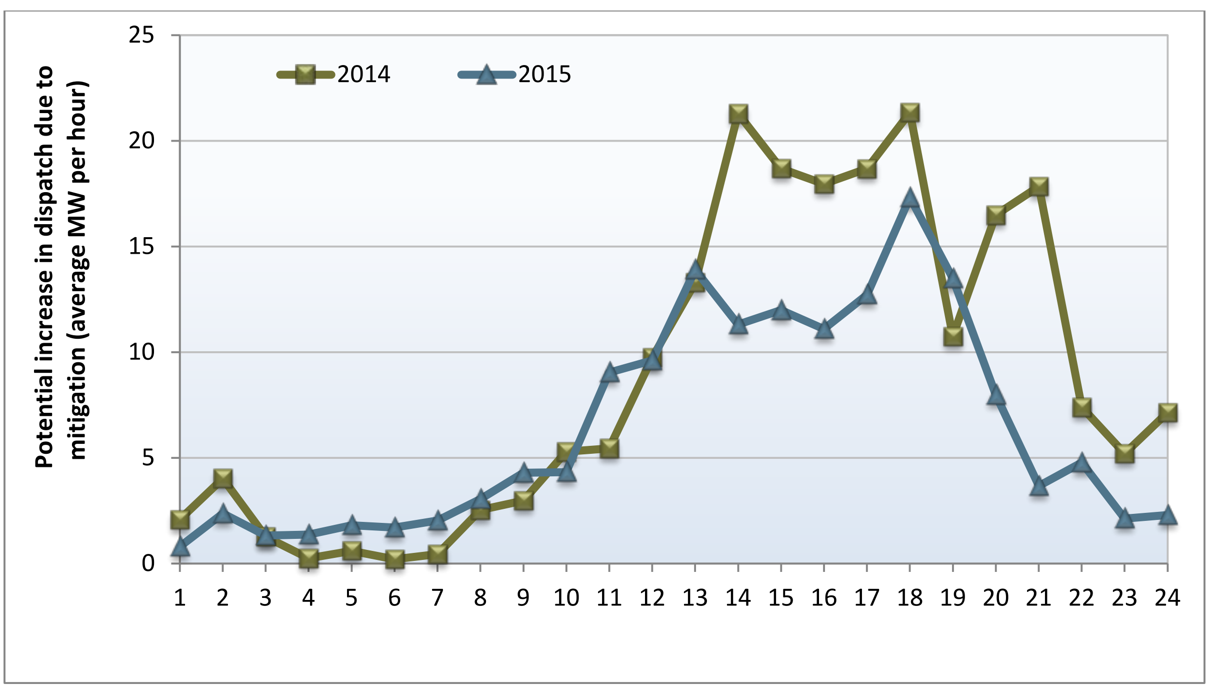


Figure 7.7 Potential increase in real-time dispatch due to mitigation (hourly averages)



7.4.2 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.[140] Total energy from exceptional dispatches increased in 2015. However, the above-market costs associated with these exceptional dispatches dropped to $9.3 million in 2015 from $11 million in 2014. As in 2014, local market power mitigation of exceptional dispatches played a small role in limiting above-market costs, and reduced costs by about $14,000 in 2015.

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 dispatch 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 ISO's market software that affect the dispatch of units in the Sacramento Delta, commonly known as *Delta Dispatch*.

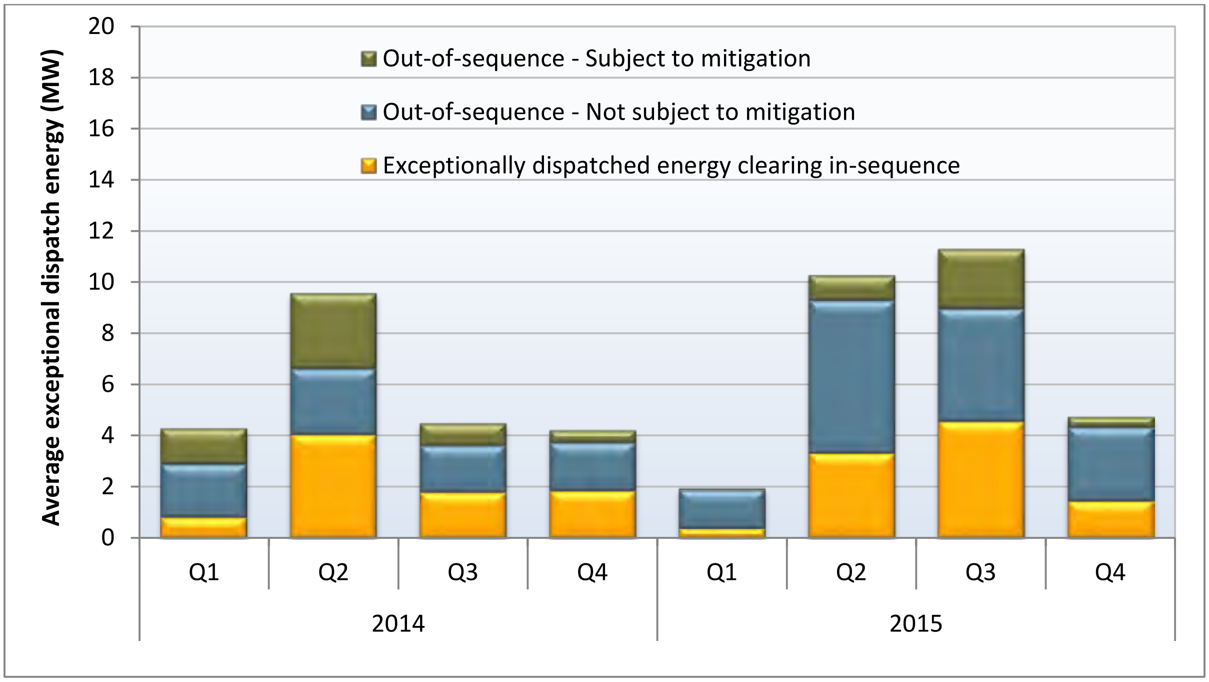
Although the ISO expanded exceptional dispatch market power mitigation provisions in 2012 and 2013, exceptional dispatch for reasons subject to mitigation accounted for a relatively low portion of incremental exceptional dispatch energy in 2014 and 2015. Further, a higher portion of exceptional dispatch energy was bid at or below locational marginal prices. Thus, the role of local market power mitigation in limiting exceptional dispatch above-market costs has been minimal in recent years.

Volume and percent of exceptional dispatches subject to mitigation

As shown in Figure 7.8, the overall volume of exceptional dispatch energy above minimum load rose in 2015 when compared to 2014. Figure 7.8 also shows that the greatest increase in exceptional dispatch energy occurred in out-of-sequence energy that was not subject to mitigation, which rose 76 percent in 2015; out-of-sequence energy that was subject to mitigation fell 34 percent. Out-of-sequence energy is energy with bid prices above the market clearing price. The majority of the increase in out-of-sequence energy occurred in the second and third quarters of 2015, and much of the exceptional dispatch activity in these quarters was for reasons not subject to exceptional dispatch mitigation. Out-of-sequence energy not subject to mitigation represented 80 percent of total out-of-sequence energy in 2015 compared to 60 percent in 2014.

[140] A more detailed discussion of exceptional dispatches is provided in Section 9.1.

Figure 7.8 Exceptional dispatches subject to bid mitigation



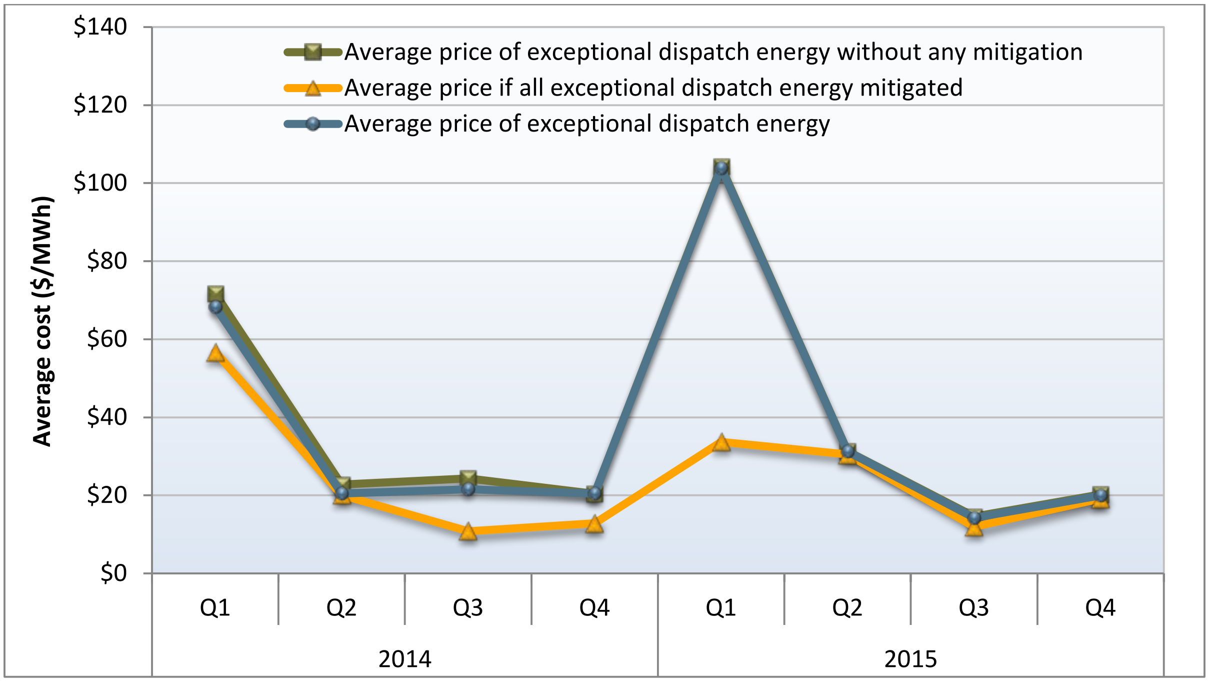
Impact of exceptional dispatch energy mitigation

Figure 7.9 shows the difference in the average price for exceptional dispatch energy under three scenarios. The distance between the green and blue lines in Figure 7.9 illustrates the impacts of exceptional dispatch mitigation. The distance between these lines is the difference between the settled average price of exceptional dispatch energy (blue line) and the average price of exceptional dispatch energy in the absence of mitigation (green line). Greater distance between these two lines implies a larger overall impact of mitigation. As Figure 7.9 shows, this impact was relatively low in 2014 and decreased further in 2015.

The yellow line in Figure 7.9 shows the average price of exceptional dispatch energy if all exceptional dispatch energy had been subject to mitigation. A greater distance between the green line and the yellow line is indicative of lower quantities of exceptional dispatch energy subject to mitigation. The distance between these lines is greatest in the first quarter of 2015, which is consistent with the lower levels of out-of-sequence energy subject to mitigation shown in Figure 7.8.

The average price of exceptional dispatch energy increased in 2015 to $42/MWh from $33/MWh in 2014. The first quarter of 2015 saw the highest average price for exceptional dispatch energy at $104/MWh; however, this quarter also saw the lowest level of exceptional dispatch energy of any quarter in 2014 or 2015. Further, the average price of exceptional dispatch energy in the first quarter was heavily influenced by a single exceptional dispatch of one generator on one day for a reliability reason not subject to mitigation. This one exceptional dispatch accounted for 31 percent of first quarter out-of-sequence exceptional dispatch energy, and about 90 percent of first quarter out-of-sequence exceptional dispatch energy costs. Mitigation continued to play a small role in subsequent quarters of 2015. Bid prices for exceptional dispatch energy in the second through fourth quarters were competitive, and many exceptional dispatches in this time were not subject to mitigation.

Figure 7.9 Average prices for out-of-sequence exceptional dispatch energy



Mitigation of exceptional dispatches decreased costs by about $14,000 in 2015, down from $144,000 in avoided out-of-sequence costs in 2014. The amount that was ultimately paid for exceptional dispatch incremental energy in excess of the market price totaled $1.2 million in 2015, up from $1 million in 2014.[141] The primary driver of this increase was higher levels of out-of-sequence energy in the second, third, and fourth quarters. Although the first quarter of 2015 had the highest average price of exceptional dispatch energy, out-of-sequence energy costs fell 32 percent compared to the first quarter of 2014. Reduced quantities of out-of-sequence exceptional dispatch energy in the first quarter contributed to this decline.

7.5 Start-up and minimum load bids

Additional start-up and minimum load bidding flexibility was implemented at the very end of 2014. Depending on the limitations of a resource, owners could choose from two options for their start-up and minimum load bid costs: proxy costs (variable cost) and registered costs (fixed cost). The proxy cost bid cap was increased from 100 percent to 125 percent and remained available to all resources.[142] The ISO modified this option to capture the fluctuations of daily fuel prices for natural gas-fired resources and combined it with the flexibility to bid above 100 percent of proxy costs to incorporate additional costs that may not be captured under the proxy cost option. The ISO retained the registered cost option, but restricted it to use-limited resources. Participants with resources on the registered cost option

141 Exceptional dispatch is discussed in more detail in Section 9.1 of this report.

142 For more information, see the following FERC order accepting the tariff revisions: https://www.caiso.com/Documents/Dec302014_OrderAcceptingCommitmentCostEnhancementsTariffRevision_ER15-15-001.pdf.

continued to have the ability to bid up to 150 percent of the cap.[143] However, the registered costs continued to remain fixed for a period of 30 days.[144] The ISO implemented these changes, in part, in response to the high and volatile natural gas prices on certain days in December 2013 and February 2014.

While participants began to shift their resources from the registered to the proxy cost option after these gas events, there was a significant shift to the proxy cost option at the beginning of 2015 as most gas units are not use-limited. The analysis below highlights this shift.

Capacity under the registered cost option

Gas-fired capacity opting for the registered cost option declined considerably in 2015 compared to 2014 as few resources are use-limited. As shown in Figure 7.10 through Figure 7.13, major changes occurred in the amount of capacity under the registered cost option for both start-up and minimum load costs in 2015. As shown in these figures:

- The portion of all gas-fired capacity selecting registered costs for both start-up and minimum load declined significantly in the first quarter of 2015 and stayed at about the same level through 2015.
- About 30 percent of combustion turbines remained on the registered cost start-up option, compared to about 5 percent of steam turbines and combined cycles. For minimum load costs, about 40 percent of combustion turbines and 5 percent of combined cycles were on the registered cost option.
- In December 2015, about 11 percent of all natural gas-fueled capacity, or approximately 3,800 MW, elected the registered cost start-up option.[145] In December 2014, about 54 percent or 18,500 MW elected the registered cost start-up option.
- Natural gas-fueled minimum load capacity also decreased in December 2015 to about 4,300 MW (11 percent) compared to 12,300 MW (32 percent) in 2014.
- By the end of 2015, around 2 percent of all gas-fired capacity chose the registered cost option for start-up costs only, a decrease from 33 percent in 2014. Approximately 26 percent of gas-fired capacity solely elected the registered cost minimum load option, down from 41 percent in 2014.

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[143] Registered cost bids were 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/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/CommitmentCostsRefinement2012.aspx.

[144] As outlined in Section 40.6.4 of the ISO tariff, a Use-Limited Resource is defined as a resource that, due to design considerations, environmental restrictions on operations, cyclical requirements such as the need to recharge or refill, or other non-economic reasons, is unable to operate continuously on a daily basis, but is able to operate for a minimum set of consecutive Trading Hours each Trading Day. Examples are hydro-electric resources and gas turbine resources with emissions limitations. Any resource which cannot generate for all hours of the day due to emission limitations from a local air quality board is a Use-Limited Resource. These costs are 'fixed' for a 30 day period.

[145] Some resources are registered as multi-stage generating (MSG) resources, which means they can be operated in various discrete configurations. In some cases, these resources can start up in only a subset of the configurations. This analysis includes the "non-startable" configurations and calculates the capacity at the resource level. As such, 2014 numbers have been updated to remain consistent with 2015 analysis.

- The portion of capacity at or near or below the floor (calculated proxy cost) for start-up costs and minimum load costs decreased substantially compared to 2014, as shown in Figure 7.12 and Figure 7.13. Most start-up costs were near the cap, whereas minimum load costs were more variable.

Figure 7.10 Gas-fired capacity under registered cost option for start-up cost bids

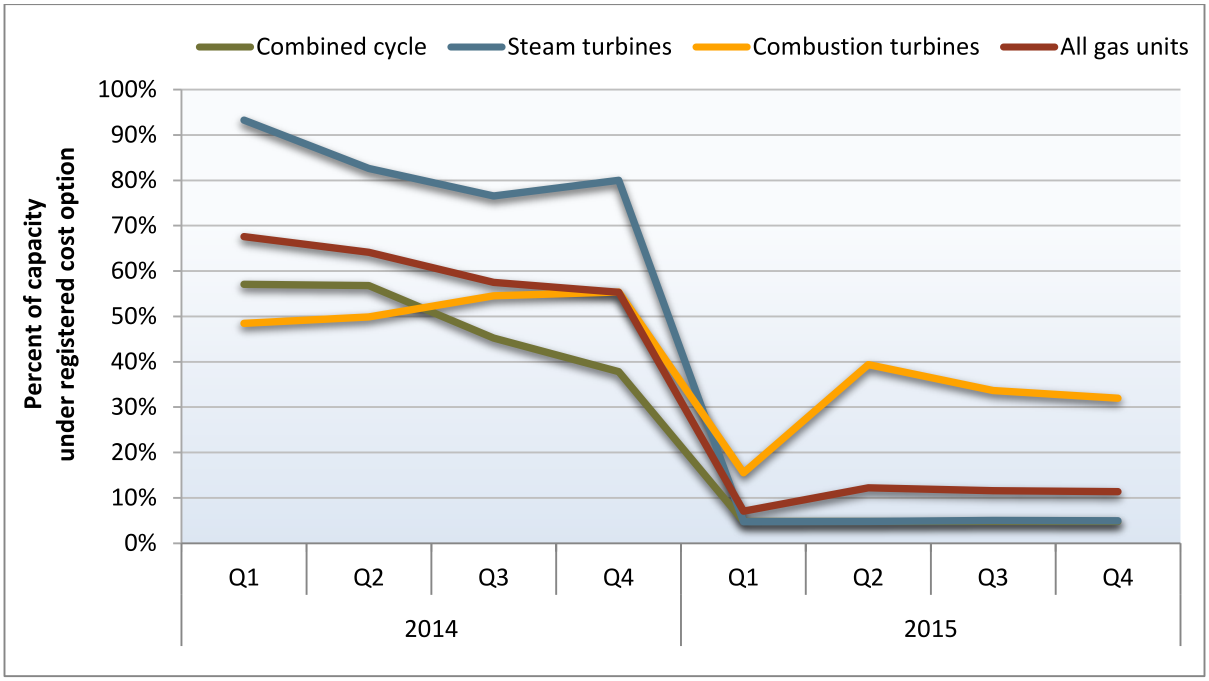


Figure 7.11 Gas-fired capacity under registered cost option for minimum load bids

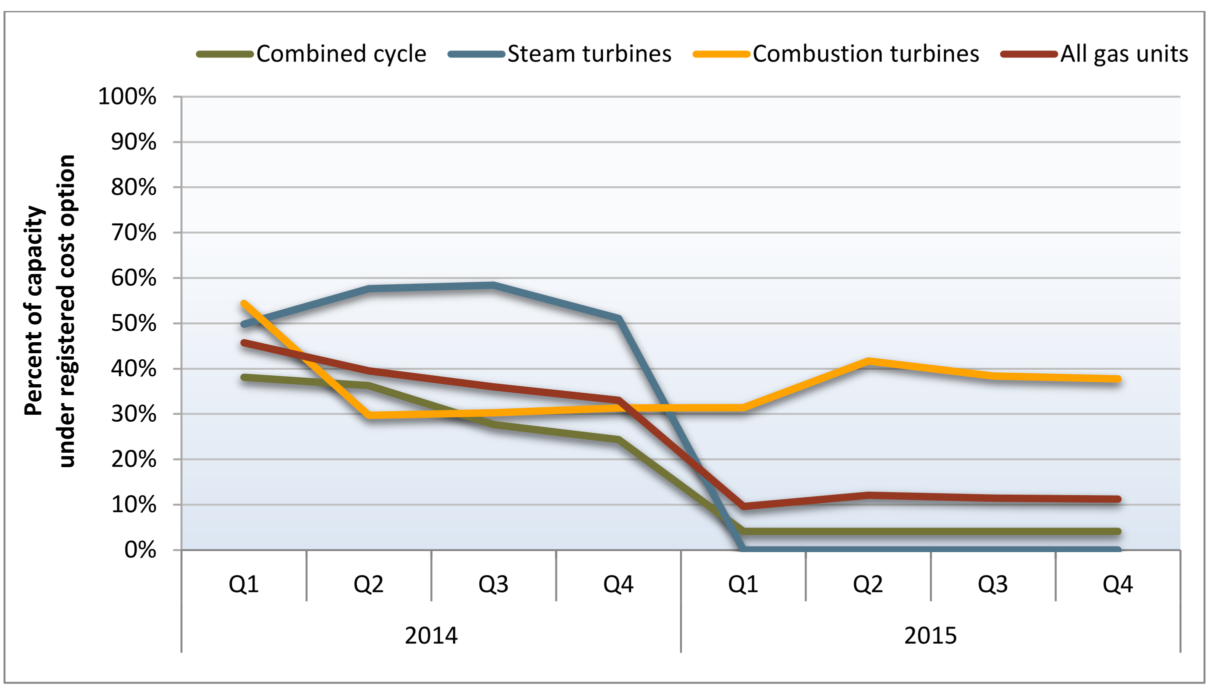


Figure 7.12 Registered cost start-up bids

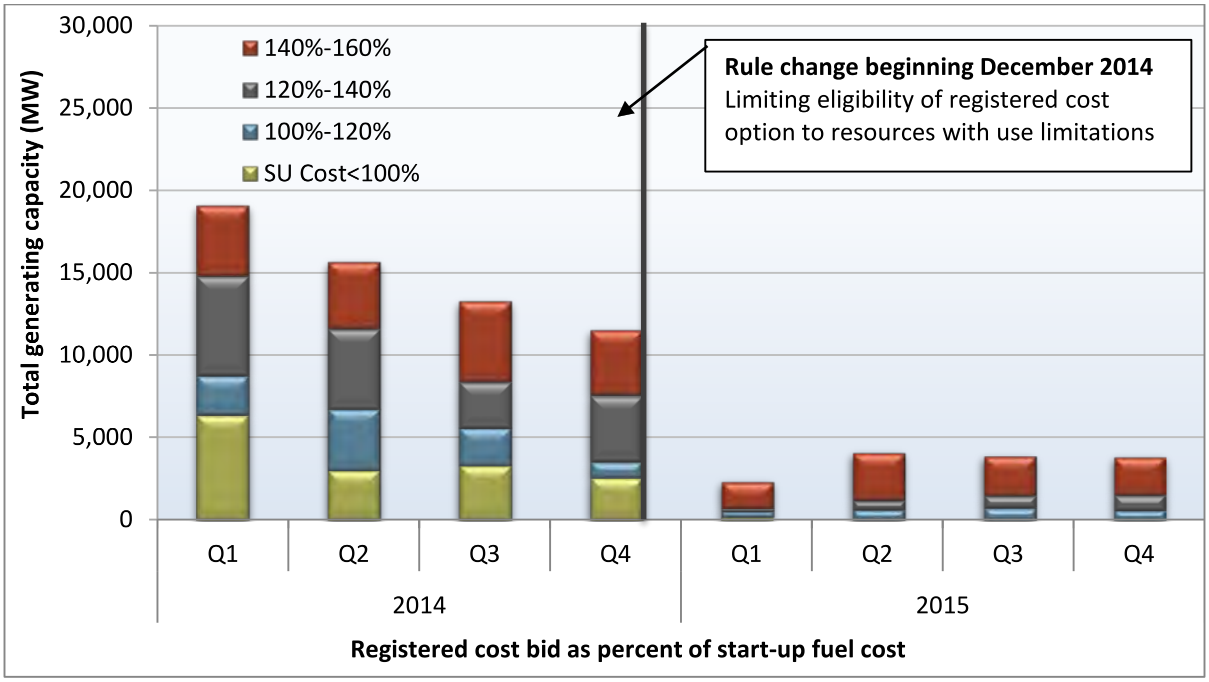
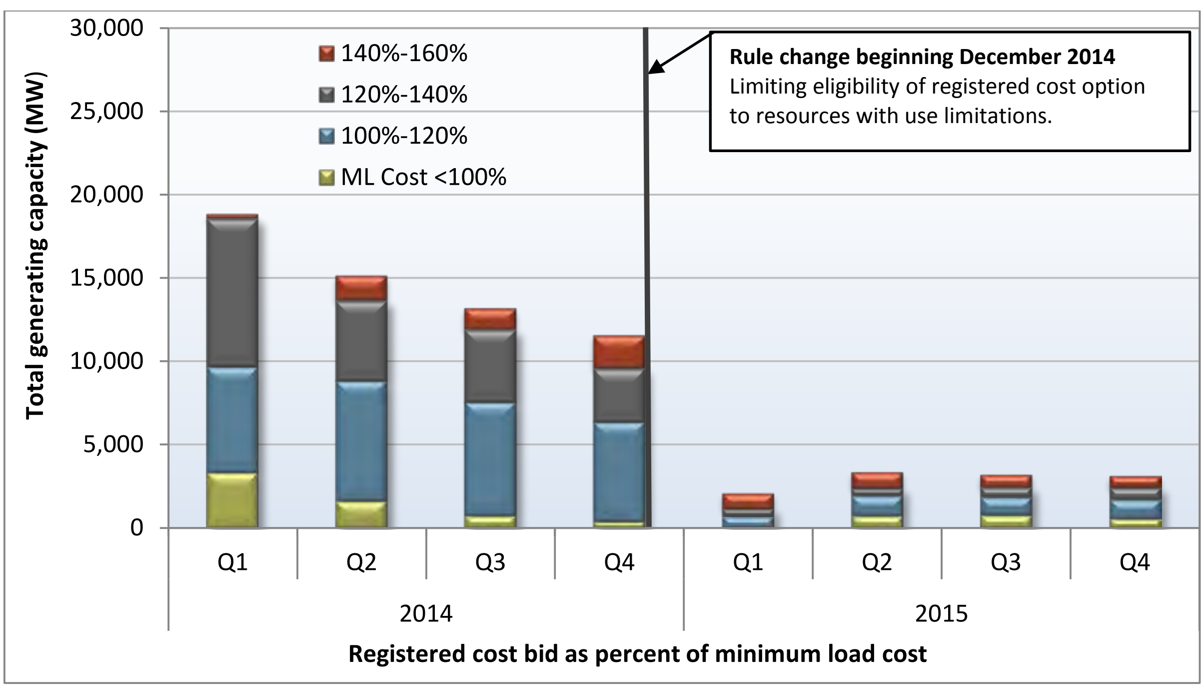


Figure 7.13 Registered cost minimum load bids

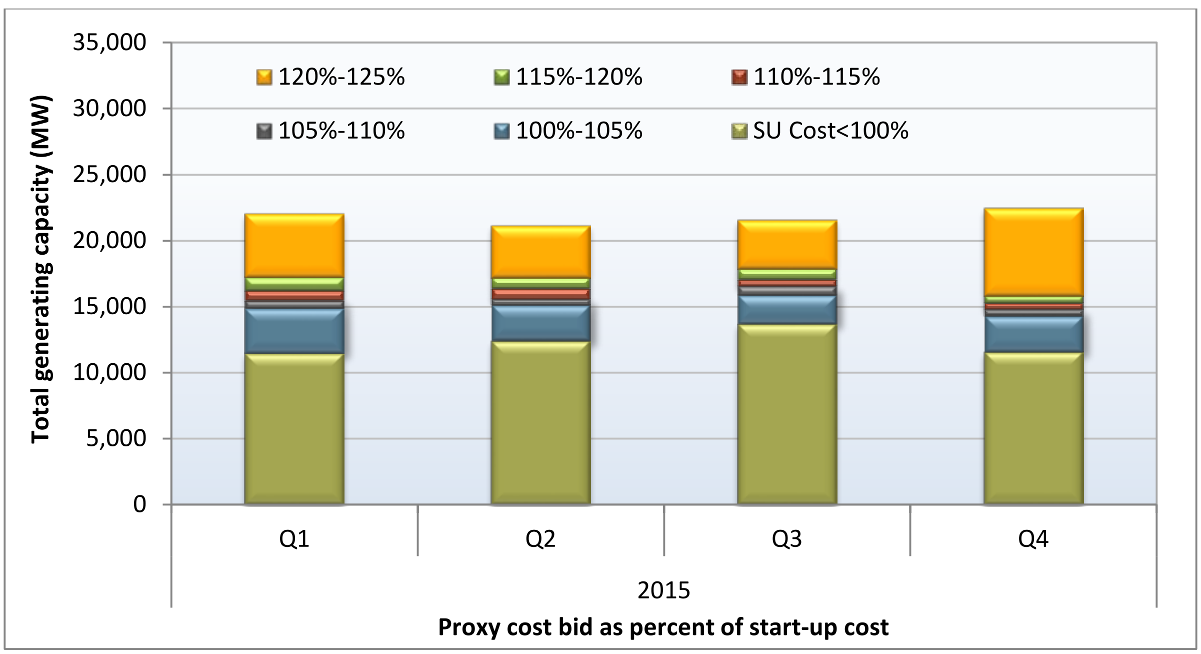


Capacity under the proxy cost option

In prior years, most natural gas-fired resources elected the registered cost option as the proxy cost option was capped at 100 percent of calculated costs. Resources electing the proxy cost option increased in 2014 after significant natural gas market events resulted in issues as volatile natural gas prices were not reflected in commitment costs. As a result of these events, the ISO and its stakeholders modified the commitment cost rules, which FERC accepted in late 2014.[146] Specifically, the proxy cost bid cap was increased from 100 percent to 125 percent. Furthermore, the registered cost option was retained only for use-limited resources. Coincident with these changes, the majority of capacity shifted from the registered cost to the proxy cost option. The following figures highlight how proxy costs were bid into the market in 2015.

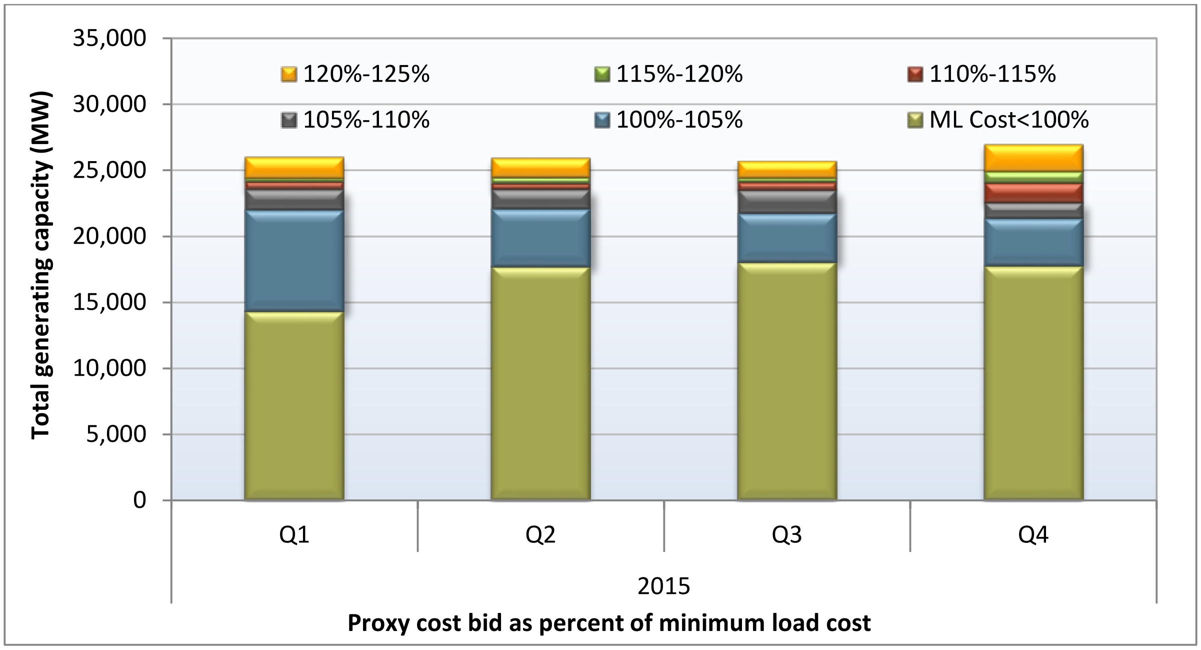
A significant portion of both start-up and minimum load proxy bids in 2015 were near or below the calculated (100 percent) costs. Figure 7.14 shows that 70 percent of start-up costs and Figure 7.15 shows that 84 percent of minimum load costs were bid at or below the proxy cost cap. Conversely, about 20 percent of the capacity associated with start-up bids was at or near the cap, whereas about 6 percent of minimum load bids were at or near the cap. Only a handful of market participants bid a small number of resources consistently at or near the cap for both start-up and minimum load costs. Overall, this pattern is fairly consistent with how registered costs were bid in at or near the cap in 2014.

Figure 7.14 Gas-fired capacity under the proxy cost option for start-up cost bids



[146] See footnote 142.

Figure 7.15 Gas-fired capacity under the proxy cost option for minimum load cost bids



8 Congestion

This chapter provides a review of congestion and the market for congestion revenue rights in 2015. The findings include the following:

- Congestion on transmission constraints within the ISO system was low and had a limited impact on average overall prices across the system.
- The overall impact of congestion increased prices in the PG&E area above the system average by about $0.43/MWh (1.3 percent) in the day-ahead market and $0.86/MWh (2.6 percent) in the 15-minute market. Much of the impact in the PG&E area was related to Path 15 planned maintenance during most of the second quarter.
- Congestion decreased average day-ahead prices in the SCE area below the system average by about $0.28/MWh (0.9 percent), and decreased real-time prices by $0.55/MWh (1.8 percent).
- Prices in the SDG&E area were impacted the least overall by internal congestion. Average day-ahead prices in this area increased above the system average by about $0.20/MWh (0.6 percent) while real-time congestion decreased prices by about $0.19/MWh (0.6 percent).
- The frequency and impact of congestion was lower in 2015 than 2014 on most major inter-ties connecting the ISO with other balancing authority areas, particularly for inter-ties connecting the ISO to the Pacific Northwest and Palo Verde.
- Total day-ahead congestion rents fell 50 percent to $230 million in 2015 from $460 million in 2014. This dramatic decrease in day-ahead congestion contributed significantly to improvements in a variety of metrics related to congestion revenue rights.

This chapter includes an analysis of the performance of the congestion revenue rights auction from the perspective of the ratepayers of load-serving entities. Key findings of this analysis include the following:

- Congestion revenue rights not allocated to load-serving entities that are sold in the auction consistently generate significantly less revenue than is paid to the entities purchasing these rights at auction. From 2012 through 2015, ratepayers received about 45 percent of the value of their congestion revenue rights that the ISO auctioned.[147] This represents an average of about $130 million per year less in revenues received by ratepayers than the congestion payments to entities purchasing these rights over the last four years. In 2015 this difference was $45 million.
- As indicated in DMM's prior annual reports, entities purchasing congestion revenue rights are primarily financial entities not purchasing these rights as a hedge for any physical load or generation. Thus, DMM recommends that the ISO and stakeholders reconsider the standard electricity market design assumption that ISOs should auction off transmission capacity in excess of the capacity allocated to load-serving entities.

[147] The large discrepancy between what congestion revenue rights sell for at auction and what they end up being worth is not unique to the California ISO. For a description of this phenomenon in PJM, see the PJM Independent Market Monitor's "2015 State of the Market Report for PJM" available at: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015.shtml.

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.

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 bind:

- Flowgates represent a single transmission line or path 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 imports. This congestion also affects payments for congestion revenue rights. However, inter-tie congestion has generally had a minimal impact on prices for loads and generation within the ISO system. This is because when congestion limits additional imports on one or more inter-ties, there has typically been additional supply available from other inter-ties or from within the ISO 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 2015 than in the previous year, particularly for inter-ties connecting the ISO to the Pacific Northwest and to Palo Verde.

Table 8.1 provides a detailed summary of congestion frequency 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, this congestion price represents the decrease in the price 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 during 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:

- Overall congestion on inter-ties declined to just over $66 million, compared with $192 million in 2014 and about $100 million in 2013. This was largely driven by substantial decreases in congestion 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/Malin 500).[148]
- Total congestion on the Nevada/Oregon Border and the Pacific A/C Intertie decreased to about $50 million from about $147 million in 2014. This is likely driven by less hydro-electric generation availability in the Northwest and relative price differences between the Northwest and Northern California.
- Congestion also decreased on Palo Verde, which is the largest inter-tie linking the ISO system with the Southwest. Congestion charges on Palo Verde decreased to $9 million from about $36 million in 2014.

[148] The California ISO Technical Bulletin 'Pricing Logic for Scheduling Point – Tie Combination,' revised on February 24, 2016, (http://www.caiso.com/Documents/RevisedTechnicalBulletin_PricingLogicforSchedulingPoint-TieCombination.pdf) describes that the PACI ITC constraint was replaced by the MALIN 500 inter-tie scheduling limit with the implementation of the full network model on October 15, 2014.

Table 8.1 Summary of import congestion (2013-2015)

Import region	Inter-tie	Frequency of import congestion			Average congestion charge ($/MW)			Import congestion charges (thousands)		
		2013	2014	2015	2013	2014	2015	2013	2014	2015
Northwest	PACI/Malin 500	21%	25%	26%	$8.6	$17.0	$6.2	$34,026	$88,731	$37,687
	NOB	24%	37%	22%	$9.8	$12.7	$6.4	$27,823	$58,902	$12,375
	Cascade	14%	6%	2%	$13.5	$10.6	$7.5	$1,280	$490	$101
	COTPISO		1%	1%		$17.8	$36.2		$37	$97
	Tracy 500	2%	3%	0.1%	$21.3	$27.3	$6.2	$1,292	$2,262	$20
	Summit	1%	1%	0.2%	$10.6	$16.4	$2.8	$38	$57	$3
	Tracy 230		0.1%			$72.5			$17	
Southwest	Palo Verde	14%	17%	3%	$13.2	$15.1	$13.2	$26,438	$36,551	$9,261
	North Gila			6%			$47.0			$3,728
	Mead	3%	1%	1%	$7.7	$8.5	$14.4	$2,181	$1,206	$1,278
	IPP Utah		7%	22%		$7.2	$2.9		$879	$1,079
	West Wing Mead		1%	1%		$30.1	$34.3		$280	$330
	Market Place Adelanto		0.3%	0.3%		$16.6	$18.9		$261	$330
	IPP DC Adelanto (BG)	2%	5%	1%		$8.5	$3.7		$1,727	$77
	El Dorado	3%		0.1%	$6.3		$3.0	$1,639		$14
	Sylmar AC		0.4%			$9.7			$251	
	IID - SCE	3%	0.5%		$49.8	$53.0		$5,735	$1,005	
	Other							$169	$142	$3
Total								***$100,621***	***$192,797***	***$66,381***

* The IPP DC Adelanto branch group is not an inter-tie, but is included here because of the function it serves in limiting imports from the Adelanto region and the frequency with which it was binding.

Figure 8.1 Percent of hours with congestion on major inter-ties (2013-2015)

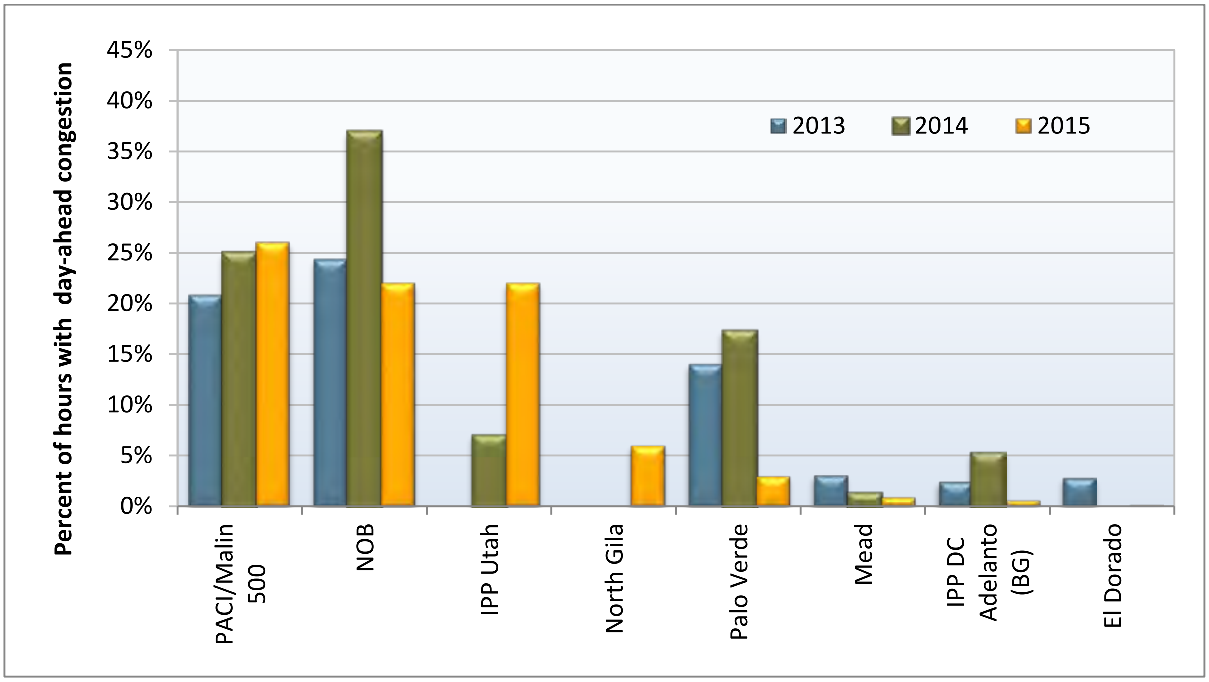
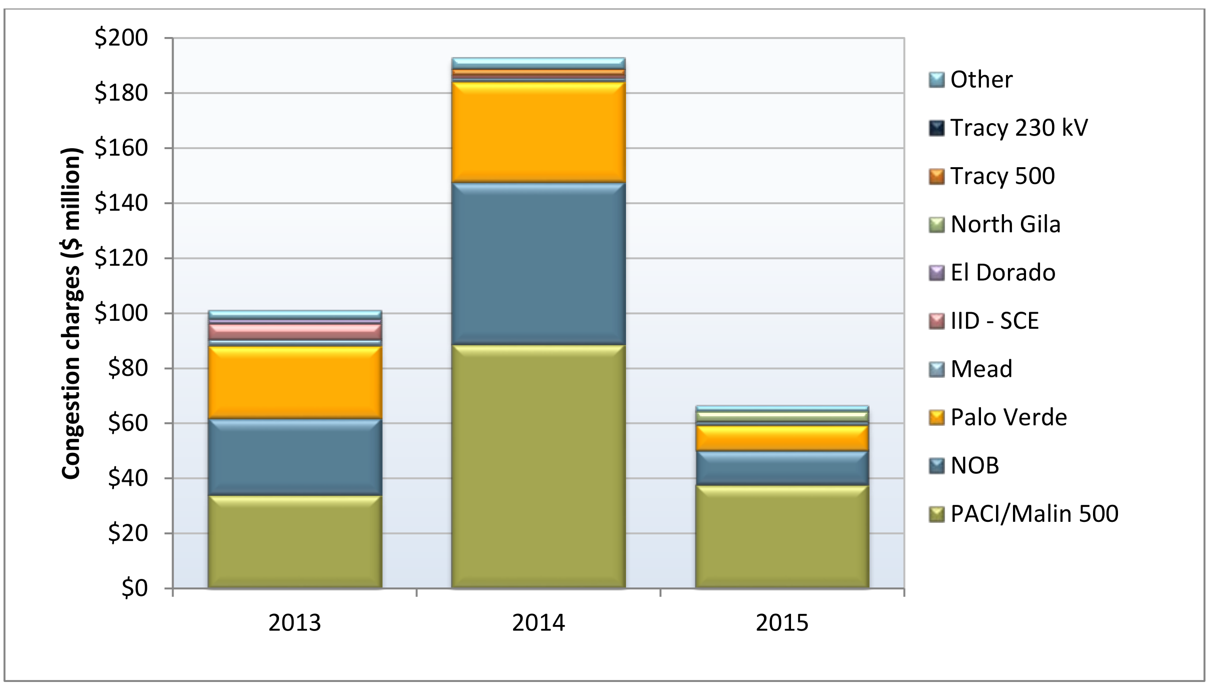


Figure 8.2 Import congestion charges on major inter-ties (2013-2015)



8.3 Congestion impacts of internal constraints

When a constraint within the ISO system is congested, resources on both sides of the constraint are re-dispatched to maintain flows below the constraint limit. In this case, congestion has a clear and direct impact on prices within the ISO system.

The impact of congestion from 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.[149]

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. Constraints are grouped by price impact within each utility area, which, depending on system topography, may not always correspond to the physical location of the constraint.

Quarterly highlights of congestion in 2015 include the following.

- In the first quarter, congestion increased SDG&E area prices, but had a relatively small net impact on PG&E and SCE load area prices. Much of the congestion was due to unscheduled flows and planned outages related to the Path 15 constraint. Some of the negative price impact from Path 15 was reduced by other binding constraints.
- Congestion had the highest impact on prices in the second quarter and increased PG&E prices while decreasing SDG&E and SCE prices. The high levels of congestion in the second quarter were attributable to congestion on Path 15 in the south-to-north direction from multiple prolonged planned transmission outages beginning in mid-March.
- In the third quarter, congestion declined significantly after the early June completion of transmission outages impacting Path 15 in the south-to-north direction.
- Congestion had a low impact on all the load area prices in the fourth quarter. Much of the congestion occurred because of the Barre-Villa Park 230 kV constraint in Southern California and an outage on the Pacific DC inter-tie which represents imports into 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. This table depicts the magnitude of congestion on load areas when constraints were binding.

In the PG&E area, Path 15 constraints (Path15_S-N and Path15_BG) were the most congested constraints in the day-ahead market. Combined, these constraints were binding during about 37 percent of hours in the second quarter of 2015, many of which were peak hours. During hours when the constraint bound, prices in the PG&E area increased by about $4.50/MWh while prices in the SCE and SDG&E areas decreased by about $3.70/MWh. This congestion occurred largely as a result of

[149] 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.

planned maintenance on nearby transmission that lasted from mid-March to early June, anticipated variable resource deviation, and unscheduled flows on the California-Oregon Intertie (COI).

In the SCE area, the Barre-Villa Park 230 kV and the Barre-Lewis 230 kV constraints bound most frequently during 2015, and were congested on average in about 7 percent and 2 percent of the hours, respectively. These constraints were used by the ISO to manage contingencies at a more granular level than in prior years, where the ISO previously applied the Barre-Lewis 230 kV nomogram instead. The Barre-Villa Park 230 kV constraint was congested in all quarters, but bound most frequently during the fourth quarter at about 12 percent of hours. This was due in large part to an outage on the Miraloma-Olinda 220 kV line for most of December. The overall impact of both constraints was low, as they only increased average day-ahead prices in SCE by about $0.72/MWh and $1.14/MWh, respectively, during hours when they were binding. Together, these constraints affected SCE area prices by less than $0.10/MWh for the entire year.

Table 8.2 Impact of congestion on day-ahead prices during congested hours

		Frequency				Q1			Q2			Q3			Q4		
Area	Constraint	Q1	Q2	Q3	Q4	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
PG&E	40687_MALIN _500_30005_ROUND MT_500_BR_1 _3				3.6%										$0.60	-$0.47	-$0.61
	PATH15_S-N		9.1%	0.5%	2.5%				$4.05	-$3.65	-$3.42	$0.63	-$0.52	-$0.49	$1.17	-$0.97	-$0.90
	33020_MORAGA _115_30550_MORAGA _230_XF_3 _P				2.4%										$0.32	-$0.35	-$0.35
	30050_LOSBANOS_500_30069_L.BANS M_ 1.0_XF_1				0.3%										$1.26	-$1.05	-$0.99
	RM_TM21_NG			7.0%								$0.54		-$0.47			
	30915_MORROBAY_230_30916_SOLARSS _230_BR_1 _1			1.4%								$3.24					
	30055_GATES1 _500_30900_GATES _230_XF_11_P		2.7%	0.7%					$0.70	-$0.60	-$0.59	$0.73	-$0.60	-$0.59			
	LOSBANOSNORTH_BG			0.2%								$6.49	-$5.71	-$5.27			
	PATH15_BG	6.2%	27.6%			$4.02	-$3.29	-$3.06	$4.54	-$3.86	-$3.64						
	30751_MOSSLDB _230_30750_MOSSLD _230_BR_1 _1		2.3%						$1.97	-$1.72	-$1.63						
	35922_MOSSLD _115_30751_MOSSLDB _230_XF_1		1.5%						$2.02								
	35922_MOSSLD _115_30751_MOSSLDB _230_XF_2		1.3%						$4.13	-$6.42	-$6.20						
	30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1		0.6%						$2.96	-$1.36							
	30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3		0.3%						$4.13	-$3.82	-$3.62						
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	9.0%	0.8%	3.9%	12.4%	-$0.95	$0.92	$1.51	-$1.78	$2.51	-$0.41	-$0.43	$0.86	-$2.68	-$0.65	$1.14	-$0.49
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	1.9%	0.9%	1.5%	1.5%	-$0.74	$1.00	-$0.59				-$0.44	$0.57		-$0.51	$0.72	-$0.41
	24087_MAGUNDEN_230_24153_VESTAL _230_BR_2 _1		2.2%						-$0.41	$0.49	$0.40						
SDG&E	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1		2.4%	2.4%	11.1%						-$2.11			-$2.24			-$1.20
	22768_SOUTHBAY_69.0_22352_IMPRLBCH_69.0_BR_1 _1				3.7%												$0.25
	22768_SOUTHBAY_69.0_22772_SOUTHBAY_138_XF_1	0.5%		1.3%	2.5%			$6.85						$2.26			$3.36
	22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_80				1.7%												$0.74
	22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1			2.3%	1.3%									-$1.83			-$1.18
	OMS 2319325 PDCI_NG				1.2%										-$2.60	$2.24	$2.78
	22828_SYCAMORE_69.0_22756_SCRIPPS _69.0_BR_1 _1			1.3%	1.1%									$1.14			$1.40
	22500_MISSION _138_22120_CARLTNHS_138_BR_1 _1				0.8%												$1.51
	22462_ML60 TAP_138_22772_SOUTHBAY_138_BR_1 _1		1.3%	0.3%	0.7%						$9.18			$5.55			$10.61
	22408_LOSCOCHS_69.0_22412_LOSCOCHS_138_XF_2				0.2%												$5.20
	22831_SYCAMORE_138_22124_CHCARITA_138_BR_1 _1		0.6%	6.1%							$5.26			$1.30			
	22609_OTAYMESA_230_22467_MLSXTAP _230_BR_1 _1			2.1%										$0.50			
	22668_POWAY _69.0_22664_POMERADO_69.0_BR_1 _1			1.0%										$1.06			
	22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1		2.8%	0.6%							-$2.14			-$2.36			
	24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1		0.3%	0.05%					-$5.06	$3.49	$7.21	-$13.67	$8.54	$12.63			
	22716_SANLUSRY_230_22504_MISSION _230_BR_2 _1		0.2%							$0.70	-$5.89						
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	4.2%	1.3%					-$0.47	-$0.72		$1.17						
	SLIC 2584248 50002_OOS_TDM		0.6%								$4.70						
	22835_SXTAP2 _230_22504_MISSION _230_BR_1 _1	24.7%						$5.04									
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	13.1%				-$2.80	$1.70	$5.15									
	IVALLY-ELCNTO_230_BR_1_1	1.7%				-$0.05		$1.47									
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	1.5%				-$3.81	$2.35	$6.50									

In the SDG&E area, the Sxtap2-Mission 230 kV line and the Serrano 500-230 kV transformer were the top binding constraints in the first quarter of 2015, congested in approximately 25 percent and 13 percent of the hours, respectively. When these constraints were binding, they increased the SDG&E prices by $5/MWh. The Doubletap-Friars 138 kV constraint was binding in all quarters except the first quarter in 2015 and typically decreased prices in the SDG&E area with negligible price impact on the SCE and PG&E areas.

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.[150]

Table 8.3 shows the overall impact of congestion on different constraints on average prices in each load aggregation area in 2015. These results show that:

- The overall impact of congestion increased prices in the PG&E area above the system average by about $0.43/MWh, an increase of about 1.3 percent. The constraint with the largest impact was the Path 15 branch group at $0.37/MWh (1.1 percent). This constraint was binding mainly because of forced outages, planned maintenance and California-Oregon Intertie (COI) de-rate.
- Congestion increased average prices in the San Diego area above the system average by about $0.20/MWh or about 0.6 percent. The Sxtap2-Mission 230 kV constraint, which was binding in the day-ahead because of an outage on Miguel-Mission 230 kV line and conforming down to its contingency limit, had the largest price impact in the San Diego area at $0.31/MWh (0.92 percent).
- Congestion drove prices down in the SCE area by about $0.28/MWh or almost 1 percent. This is in contrast to 2014, where the SCE prices were above the system average by about $0.23/MWh. The Path 15 branch group had the largest overall impact, decreasing SCE prices by about $0.32/MWh (0.97 percent).

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

Table 8.3 Impact of constraint congestion on overall day-ahead prices during all hours

Constraint	PG&E $/MWh	PG&E Percent	SCE $/MWh	SCE Percent	SDG&E $/MWh	SDG&E Percent
PATH15_BG	$0.37	1.10%	-$0.32	-0.97%	-$0.30	-0.89%
24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	-$0.09	-0.27%	$0.06	0.17%	$0.17	0.50%
22835_SXTAP2 _230_22504_MISSION _230_BR_1 _1					$0.31	0.92%
PATH15_S-N	$0.10	0.29%	-$0.09	-0.27%	-$0.08	-0.25%
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.05	-0.14%	$0.07	0.21%	$0.00	0.00%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					-$0.06	-0.18%
22462_ML60 TAP_138_22772_SOUTHBAY_138_BR_1 _1					$0.05	0.16%
24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.02	-0.04%	$0.01	0.03%	$0.03	0.07%
22768_SOUTHBAY_69.0_22772_SOUTHBAY_138_XF_1					$0.04	0.11%
35922_MOSSLD _115_30751_MOSSLDB _230_XF_2	$0.01	0.04%	-$0.01	-0.03%	-$0.01	-0.03%
30751_MOSSLDB _230_30750_MOSSLD _230_BR_1 _1	$0.01	0.03%	-$0.01	-0.03%	-$0.01	-0.03%
22831_SYCAMORE_138_22124_CHCARITA_138_BR_1 _1					$0.03	0.09%
OMS 2319325 PDCI_NG	-$0.01	-0.02%	$0.01	0.02%	$0.01	0.03%
22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1					-$0.02	-0.06%
24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.01	-0.02%	$0.01	0.03%	$0.00	0.00%
RM_TM21_NG	$0.01	0.03%			-$0.01	-0.02%
30055_GATES1 _500_30900_GATES _230_XF_11_P	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.02%
24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1	-$0.01	-0.02%	$0.00	0.01%	$0.01	0.02%
22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1					-$0.01	-0.04%
40687_MALIN _500_30005_ROUND MT_500_BR_1 _3	$0.01	0.02%	$0.00	-0.01%	-$0.01	-0.02%
30915_MORROBAY_230_30916_SOLARSS _230_BR_1 _1	$0.01	0.04%				
LOSBANOSNORTH_BG	$0.01	0.01%	$0.00	-0.01%	$0.00	-0.01%
Other	$0.07	0.19%	$0.00	0.01%	$0.09	0.25%
Total	$0.43	1.3%	-$0.28	-0.9%	$0.20	0.61%

8.3.2 Real-time congestion

Congestion in the 15-minute real-time market differs from congestion in the day-ahead market. Real-time congestion typically occurs less frequently overall, but often on a larger number of constraints and with a bigger impact on prices.[151] This section provides highlights of congestion in the 15-minute market.

15-minute market congestion

The congestion effect on prices was larger in the 15-minute market, but overall congestion occurred less frequently than in the day-ahead market. Table 8.4 shows the frequency and magnitude of congestion by quarter in 2015.

Sxtap2-Mission 230 kV line and the Serrano 500-230 kV transformer constraints bound most frequently in the SDG&E area during the first quarter in about 3 percent and 2 percent of the intervals, respectively. The Path 15 south-to-north constraint bound during about 1 percent of intervals and increased prices in the PG&E area by about $16.30/MWh and decreased prices in the SCE and SDG&E areas by about the same amount.

[151] For example, in the fourth quarter, Barre-Villa Park 230 kV constraint was binding during roughly 12 percent of hours in the day-ahead market compared to around 1 percent of intervals in the 15-minute market. Prices were increased by $4.20/MWh in the 15-minute market in SCE area when the constraint bound, but only by $1.14/MWh in the day-ahead market.

During the second quarter, the Path 15 south-to-north constraint was the top binding constraint and had the greatest price impact on the SCE area. This constraint bound during about 6.7 percent of the intervals in the second quarter and, when binding, increased prices in the PG&E area and decreased prices in the SCE and SDG&E areas by about $14/MWh. Much of the congestion was related to planned transmission outages associated with Path 15, which began in mid-March and continued to early June. Further contributing to the congestion were lower loads and a high level of renewable generation south of Path 15, particularly from solar resources. Renewable resources were dispatched down at times and frequently set low prices in Southern California.

The Barre-Villa Park 230 kV constraint, which is located in the SCE area and protects for the loss of the Barre-Lewis 230 kV line, was the top binding constraint in the third quarter. This constraint was binding in 0.8 percent of intervals and drove up SCE area prices by $3.21/MWh while decreasing PG&E and SDG&E area prices by about $1.45/MWh and $6.56/MWh, respectively. The Path 15 south-to-north and Path 26 north-to-south constraints were the next most frequently binding constraints in the third quarter, affecting about 0.5 percent of all intervals. The Path 15 south-to-north constraint increased the PG&E area prices by $13.80/MWh and decreased SCE and SDG&E area prices by about the same amount. Conversely, the Path 26 north-to-south constraint had a positive impact on both the SCE and SDG&E areas, driving prices up by about $7/MWh while decreasing PG&E area prices by over $9/MWh.

Much of the fourth quarter congestion was related to Path 15, Barre-Villa Park 230 kV and the Southern California Import Transmission (OMS 2319325 PDCI_NG) constraints. Path 15 bound in the south-to-north direction because limits on the constraint were lowered because of nearby outages. Congestion on the Barre-Villa Park 230 kV constraint was because of an outage during most of December on the nearby Miraloma-Olinda 220 kV line. The Southern California Import Transmission (SCIT) constraint bound because of an outage on the Pacific DC inter-tie, a component of the SCIT limit. The loss of this transmission capacity increased prices in the SCE and SDG&E areas by about $8/MWh, and decreased prices in the PG&E area by about $3/MWh.

Table 8.4 Impact of congestion on 15-minute prices by load aggregation point in congested intervals

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	PATH15_S-N	1.0%	6.7%	0.5%	0.8%	$16.27	-$16.36	-$15.30	$14.16	-$14.62	-$13.81	$13.80	-$13.31	-$12.53	$21.54	-$21.50	-$20.10
	LBN_S-N				0.2%										$5.53	-$6.64	-$6.20
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2				0.1%										-$11.11	$9.24	$8.52
	30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2				0.1%										$17.57	$7.32	$5.72
	PATH15_N-S				0.1%										-$42.92	$29.59	$28.07
	30055_GATES1 _500_30900_GATES _230_XF_11_P			0.4%								$6.72	-$5.41	-$5.26			
	30751_MOSSLDB _230_30750_MOSSLD _230_BR_1 _1		0.3%						$6.59	-$6.62	-$6.29						
	6110_SOL10_NG		0.2%						$4.96	$2.13	$1.50						
	PATH15_BG	0.2%				$5.87	-$6.08	-$5.72									
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	0.5%	0.1%	0.8%	1.1%	-$3.09	$7.15	$3.45	-$5.92	$16.52	$2.76	-$1.45	$3.21	-$6.56	-$2.73	$4.20	$0.25
	24156_VINCENT _500_24155_VINCENT _230_XF_1 _P				0.1%										-$9.44	$10.38	$6.59
	PATH26_N-S	0.1%		0.5%		-$46.75	$44.20	$41.92				-$9.46	$7.08	$6.68			
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1			0.1%								-$5.14	$12.24	-$32.72			
	24087_MAGUNDEN_230_24153_VESTAL _230_BR_1 _1		0.5%								$14.09						
	SLIC 2584248 50002_SCIT		0.1%						-$4.18	$9.51	$9.92						
SDG&E	OMS 2319325 PDCI_NG				0.7%										-$2.95	$7.73	$8.75
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1			0.4%	0.7%									-$6.42			-$5.22
	OMS 3560161 TL50004_NG				0.1%												$46.71
	7820_TL 230S_OVERLOAD_NG			0.4%								-$1.97		$27.45			
	22256_ESCNDIDO_69.0_22724_SANMRCOS_69.0_BR_1 _1			0.2%										-$10.81			
	22227_ENCINATP_230_22716_SANLUSRY_230_BR_2 _1		0.1%							$9.67	-$100.16						
	24086_LUGO _500_24092_MIRALOMA_500_BR_3 _1		0.1%						-$5.35	$5.99	$10.80						
	SDGEIMP_BG		0.1%						-$1.74	-$1.74	$24.03						
	22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1		0.1%							$3.57	-$30.20						
	22835_SXTAP2 _230_22504_MISSION _230_BR_1 _1	2.7%						$14.80									
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	1.7%				-$7.01	$8.42	$19.96									
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	0.5%				-$9.33	$10.25	$25.01									

Overall 15-minute price impacts

Table 8.5 shows the overall impact of 15-minute congestion in 2015 on average prices in each load area by constraint.[152] The overall impact of congestion increased the PG&E area price by about $0.86/MWh (2.58 percent) and decreased the SCE and SDG&E area prices by about $0.55/MWh (1.78 percent) and $0.19/MWh (0.59 percent), respectively.

The Path 15 constraint had the largest overall impact on real-time load area prices in 2015. It increased PG&E prices by $0.34/MWh (1.01 percent) and decreased SCE and SDG&E prices by $0.34/MWh (1.10 percent) and $0.32/MWh (1.02 percent), respectively. The "Other" category had the largest impact in the PG&E area and is a collection of constraints below a very low price threshold where data collection and presentation is limited.

Table 8.5 Impact of constraint congestion on overall 15-minute prices during all hours

	PG&E		SCE		SDG&E	
Constraint	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
PATH15_S-N	$0.34	1.01%	-$0.34	-1.10%	-$0.32	-1.02%
24138_SERRANO _500_24137_SERRANO _230_XF_1 _P	-$0.03	-0.09%	$0.04	0.12%	$0.09	0.27%
22835_SXTAP2 _230_22504_MISSION _230_BR_1 _1					$0.10	0.31%
PATH26_N-S	-$0.02	-0.07%	$0.02	0.06%	$0.02	0.06%
24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.01	-0.04%	$0.01	0.04%	$0.03	0.10%
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.01	-0.02%	$0.03	0.10%	-$0.01	-0.02%
22227_ENCINATP_230_22716_SANLUSRY_230_BR_2 _1	$0.00	0.00%	$0.00	0.01%	-$0.04	-0.11%
OMS 2319325 PDCI_NG	-$0.01	-0.02%	$0.01	0.04%	$0.02	0.05%
7820_TL 230S_OVERLOAD_NG	$0.00	-0.01%			$0.03	0.09%
PATH15_N-S	-$0.01	-0.03%	$0.01	0.02%	$0.01	0.02%
30055_GATES1 _500_30900_GATES _230_XF_11_P	$0.01	0.03%	-$0.01	-0.02%	-$0.01	-0.02%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					-$0.02	-0.06%
24087_MAGUNDEN_230_24153_VESTAL _230_BR_1 _1			$0.02	0.05%		
24016_BARRE _230_25201_LEWIS _230_BR_1 _1	$0.00	-0.01%	$0.01	0.02%	$0.00	-0.01%
30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	-$0.01	-0.02%	$0.00	0.01%	$0.00	0.01%
30751_MOSSLDB _230_30750_MOSSLD _230_BR_1 _1	$0.00	0.01%	$0.00	-0.01%	$0.00	-0.01%
LBN_S-N	$0.00	0.01%	$0.00	-0.01%	$0.00	-0.01%
22356_IMPRLVLY_230_21025_ELCENTRO_230_BR_1 _1	$0.00	0.00%	$0.00	0.00%	-$0.01	-0.03%
PATH15_BG	$0.00	0.01%	$0.00	-0.01%	$0.00	-0.01%
25201_LEWIS _230_24154_VILLA PK_230_BR_1 _1	$0.00	-0.01%	$0.00	0.01%	$0.00	0.01%
Other	$0.60	1.80%	-$0.34	-1.11%	-$0.06	-0.20%
Total	$0.86	2.58%	-$0.55	-1.78%	-$0.19	-0.59%

Figure 8.3 and Figure 8.4 show hourly average prices for the day-ahead and 15-minute markets at PG&E, SCE and SDG&E areas in the second quarter of 2015. These figures further illustrate the price impact of Path 15 congestion, which was mainly prevalent during the second quarter. The price separation between PG&E area and Southern California prices during most peak hours is very noticeable in both markets, with average differences of about $5/MWh in day-ahead peak hours and $9/MWh in

[152] Due to data issues, details on specific constraints below a very low price impact could not be calculated and were included in the *other* category.

15-minute peak hours. As mentioned earlier, the congestion was driven primarily by transmission outages and de-rates that reduced Path 15 capacity by an average of about 40 percent. Moreover, low seasonal loads combined with a higher portion of solar generation on the system in Southern California also contributed to the congestion.

Figure 8.3 Hourly comparison of day-ahead market load area prices (April – June)

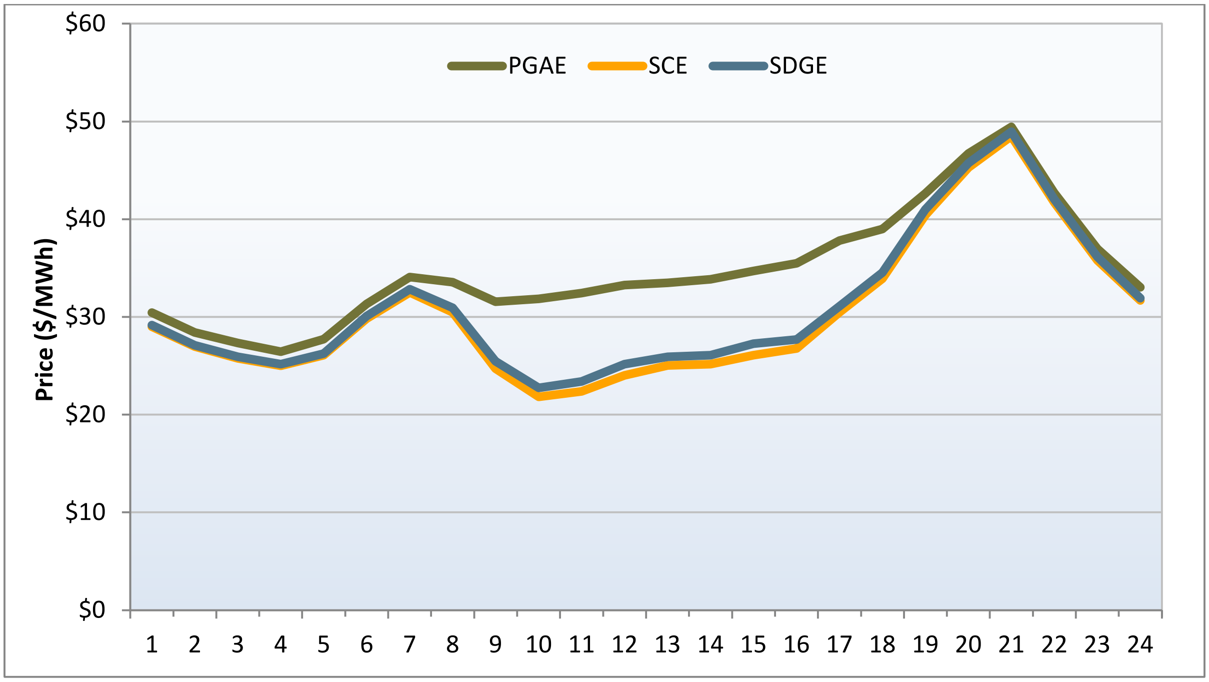
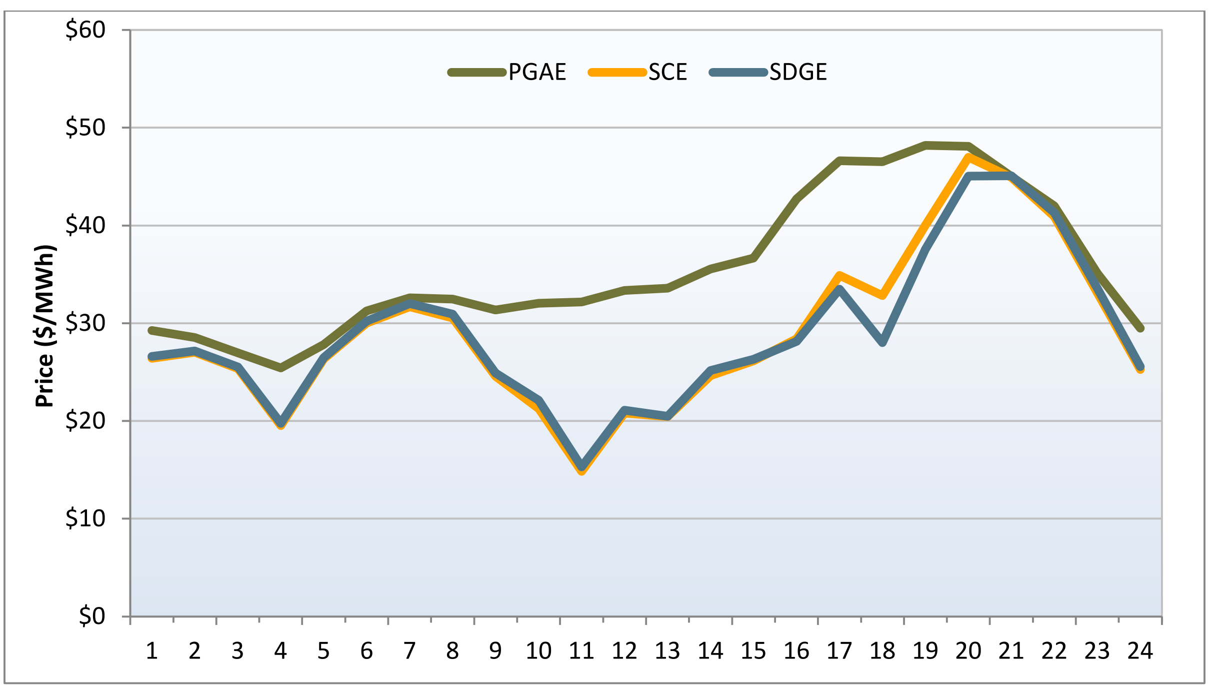


Figure 8.4 Hourly comparison of 15-minute market load area prices (April – June)



Energy imbalance market congestion

Congestion in the energy imbalance market can occur in two ways. First, internal constraints within a balancing area can bind and, second, transfer constraints between balancing areas can also bind. The previous sections of this report have focused on internal congestion within the ISO balancing area. Congestion internal to both PacifiCorp balancing areas occurred very infrequently in 2015.[153]

Unlike internal balancing area congestion, transfer congestion occurred fairly frequently between balancing areas. This was primarily because of the limited transfer capabilities between the areas. PacifiCorp East and PacifiCorp West had only 200 MW in the east-to-west direction, while PacifiCorp West and the ISO had about 300 MW flowing north and 200 MW flowing south in the 15-minute market and only 11 MW for much of the year in the 5-minute market.

Prior to the EIM Year 1 Enhancements implemented in November 2015, EIM transfer constraints included: PacifiCorp East and PacifiCorp East and PacifiCorp West combined. After the EIM Year 1 Enhancements took effect on November 4, the combined constraint was dropped and the transfer constraint for only PacifiCorp West began to be enforced. Additionally, the ISO began enforcing the NV Energy transfer constraint when NV Energy joined the EIM on December 1, 2015. With the addition of NV Energy in December, the transfer capacity between NV Energy and the ISO is over 1,000 MW and the transfer capacity between PacifiCorp East and NV Energy is about 700 MW.

Figure 8.5 and Figure 8.6 show the frequency at which the EIM schedule-based transfer constraints bound in the 15-minute and 5-minute markets. In the 5-minute market, the PacifiCorp East constraint was binding during 59 percent of intervals and the combined PacifiCorp East and West constraint was binding during 63 percent of the intervals. The combined East and West constraint bound less frequently in the 15-minute market because of the higher transfer limits in the 15-minute market compared to the 5-minute market. The PacifiCorp West constraint was binding in about 75 percent of 5-minute intervals in November and December and the NV Energy constraint was binding in about 35 percent of 5-minute intervals in December.

[153] There were about five internal constraints within the PacifiCorp balancing area that were binding in less than 0.5 percent of all the 15-minute market and 5-minute market intervals in 2015.

Figure 8.5 Energy imbalance market transfer constraints binding frequency (15-minute market)

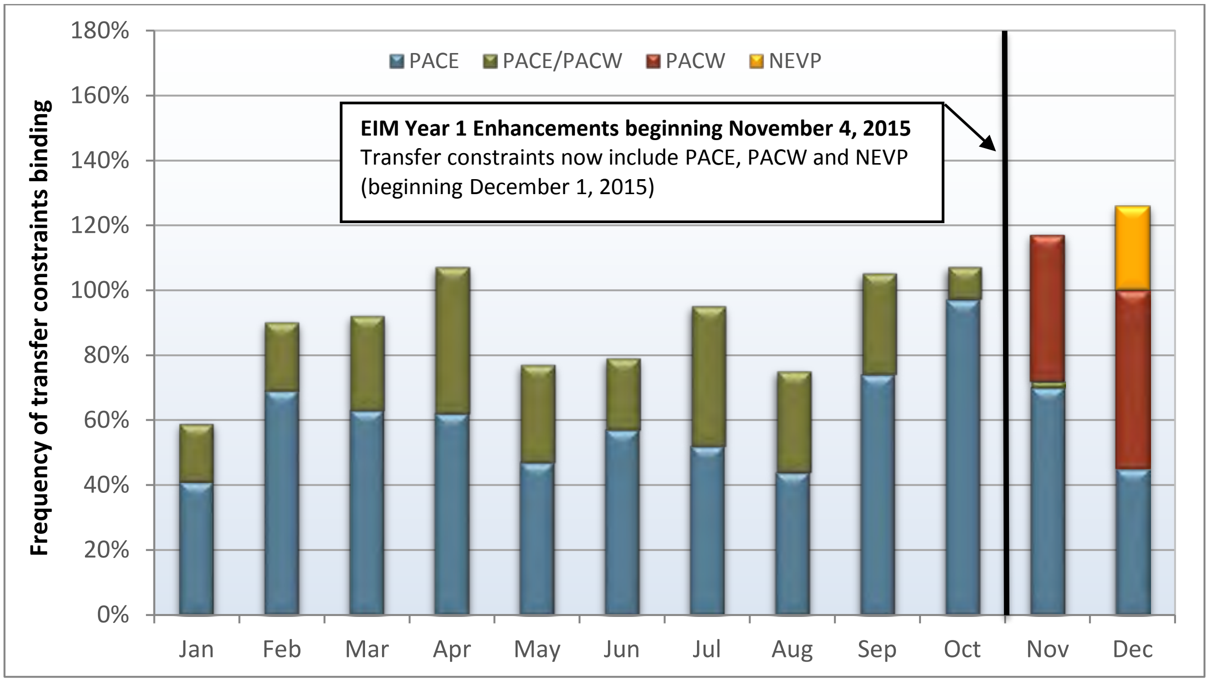
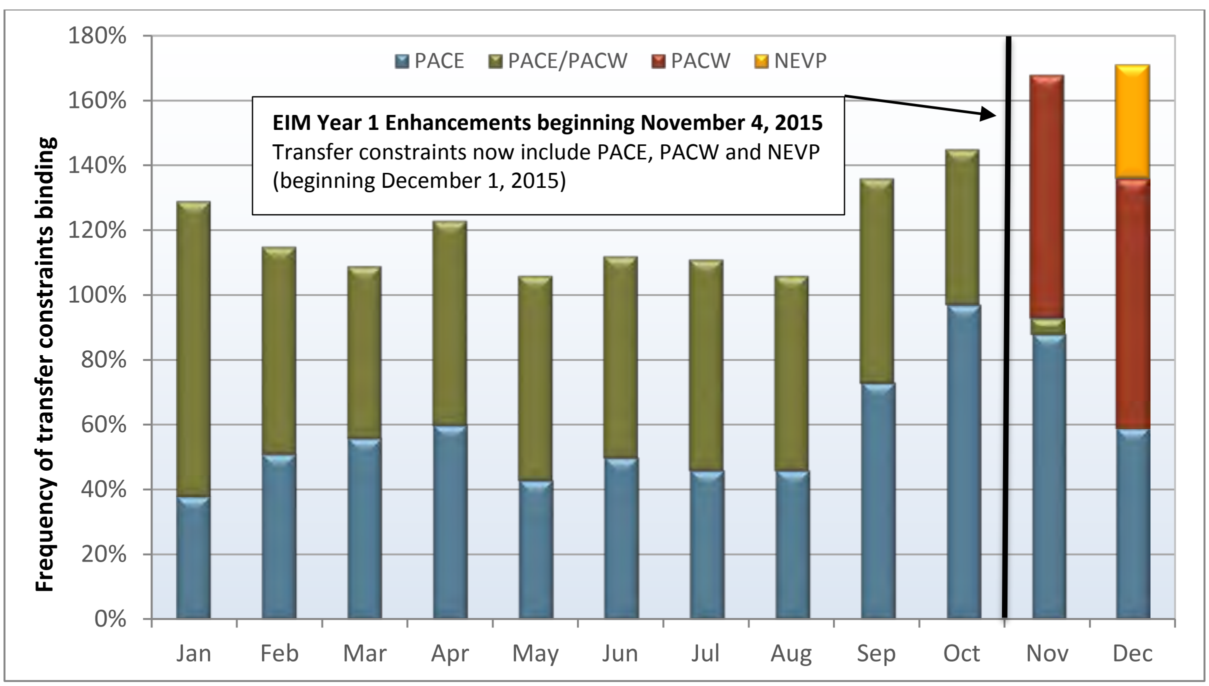


Figure 8.6 Energy imbalance market transfer constraints binding frequency (5-minute market)



8.4 Congestion revenue rights

In 2015, the congestion revenue rights balancing account was in surplus rather than deficit and revenue inadequacy fell significantly. These changes were due to the 50 percent decline in day-ahead congestion rents to $230 million in 2015 from $460 million in 2014.

The congestion revenue right balancing account held a nearly $12 million surplus in 2015 compared to a $95 million deficit in 2014. Congestion revenue right payments exceeded day-ahead market congestion rent collections by $98 million dollars in 2015. This revenue inadequacy, which excludes auction revenues, was lower than the $200 million shortfall in 2014. However, congestion revenue right payments remained over 140 percent of day-ahead congestion rents in both 2015 and 2014.[154]

Section 8.4.1 provides an overview of both allocated and auctioned congestion revenue right holdings. Section 8.4.2 provides more details on the performance of the congestion revenue right auction.

8.4.1 Allocated and auctioned congestion revenue rights

Background

Congestion revenue rights are paid (or charged), for each megawatt held, the difference between the hourly day-ahead congestion prices at the sink and source node defining the right. These rights can have monthly or seasonal (quarterly) terms, and can include on-peak or off-peak hourly prices.

Congestion revenue rights are either allocated or auctioned to market participants. Participants serving load are allocated rights monthly, annually (with seasonal terms), or for 10 years (for the same seasonal term each year). All participants can procure congestion revenue rights in the auctions. Annual auctions are held prior to the year in which the rights will settle. Rights sold in the annual auctions have seasonal terms. Monthly auctions are held the month prior to the settlement month. Rights sold in the monthly auction have monthly terms.[155]

Ratepayers own the day-ahead transmission rights not held by merchant transmission or long-term rights holders. In this report rights owned by ratepayers are referred to as non-merchant day-ahead transmission rights.

Allocated congestion revenue rights are a means of distributing the revenue from the sale of these non-merchant day-ahead rights, also known as congestion rent, to entities serving load to then be passed to ratepayers. Any revenues remaining after the distribution to allocated congestion revenue rights are allocated based on load share, or are used to pay congestion revenue rights procured at auction.

In exchange for backing the auctioned rights, ratepayers receive the net auction revenue which is allocated by load share. If there is insufficient transmission sales revenue to pay all the congestion revenue rights, a condition known as revenue inadequacy, ratepayers are charged based on load share to cover the difference.

[154] These congestion rents are after accounting for payments to merchant transmission and long-term rights holders.

[155] A more detailed explanation of the congestion revenue right processes is provided in the ISO's *2015 Annual CRR Market Results Report*. See: http://www.caiso.com/Documents/2015AnnualCRRMarketResultsReport.pdf.

Congestion revenue right holdings

Figure 8.7 and Figure 8.8 show the quarterly peak and off-peak hour average megawatt holdings of congestion revenue rights awarded by type since 2012.

- The total megawatt volume of congestion revenue rights increased by 6 percent in 2015 compared to 2014.
- During 2015, megawatts of rights held decreased notably in the second half of the year both year-over-year and compared to the first half of the year. Lower megawatts purchased at monthly auctions drove the overall decrease. Allocated and seasonal auctioned megawatt holdings, procured in late 2014, increased but were more than offset by the lower monthly megawatts cleared.

Interpreting congestion revenue right megawatt holding changes can be difficult as it is not clear what the megawatt volume represents. Consider a participant holding 10 megawatts from node A to node B, and 10 megawatts from node B to node A. The participant's net holding of transmission rights is zero megawatts but the total megawatts of congestion revenue rights held is 20 megawatts. Total congestion revenue right megawatts does not give a complete view of the transmission rights held.

One alternative is measuring the implied value of transmission rights held by congestion revenue rights. Congestion revenue rights are allocated and auctioned across different time frames. Valuing the rights held can be done using seasonal auction, monthly auction, or day-ahead transmission prices. Figure 8.9 shows the percentage congestion revenue right megawatts held by allocated, seasonally auctioned, and monthly auctioned rights. Figure 8.10 shows the percentage of rights held when valued at the monthly auction prices. Both figures include all peak and off-peak rights. Allocated congestion revenue rights make up less than a third of total megawatts but about two-thirds of the implied value of rights at monthly auction prices.

Figure 8.11 shows payments to congestion revenue rights with auction prices at or below zero dollars per megawatt-hour.[156] Figure 8.12 shows payments to rights with auction prices greater than zero dollars, which indicate positions in the prevailing flow of congestion, which are typically from a generation area to a load area. Both figures include peak and off-peak rights. The majority of payments were to rights with positive auction prices which were in the prevailing flow of congestion.

Although there continued to be significant megawatt holdings of zero priced congestion revenue rights,[157] payments to these rights were about 5 percent of total payments to auctioned rights. Payments to zero priced rights were $7 million in 2015, down from $18 million in 2014. Total payments to auctioned rights were about $170 million in 2015 and $290 million in 2014. Congestion revenue rights priced below zero dollars but greater than negative 25 cents were charged over $1 million in 2015

[156] This includes congestion revenue right positions that are counter to the prevailing flow of generation and are known as counter-flow positions. For example, a counter-flow congestion revenue right may go from a load area to a generation area. These positions are paid to take the congestion revenue right in the auction and then make payments based on day-ahead congestion. This grouping also includes positions that are have a $0/MW price in the auction and cannot be classified as counter-flow or prevailing flow because it is possible that they may be prevailing flow or counter-flow in the day-ahead market, which differs from the results in the auction.

[157] In 2013 and 2014 megawatts with $0 prices trended up sharply. See Section 7.4 of the *2014 Annual Report on Market Issues and Performance*, Department of Market Monitoring: http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf.

versus being paid about $18 million in 2014. This reversed the trend starting in 2013 of rights priced in this category on net being paid in both the auctions and day-ahead markets.

Figure 8.7 Congestion revenue right megawatts held by procurement type (peak)

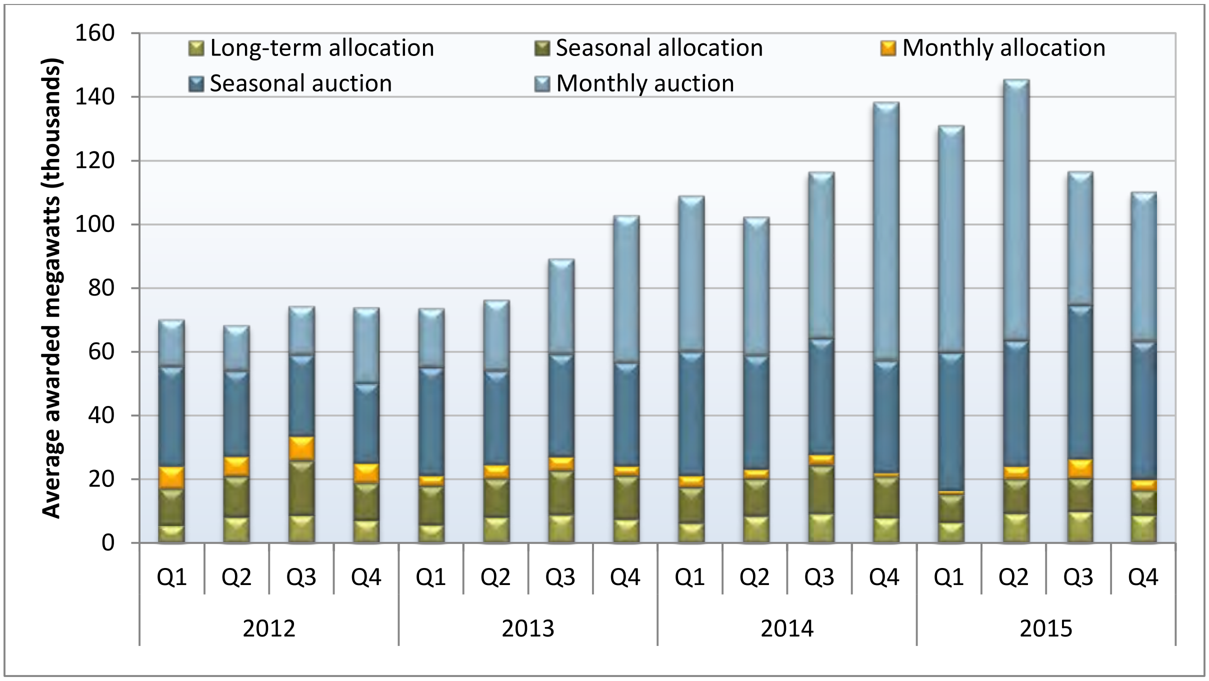


Figure 8.8 Congestion revenue right megawatts held by procurement type (off-peak)

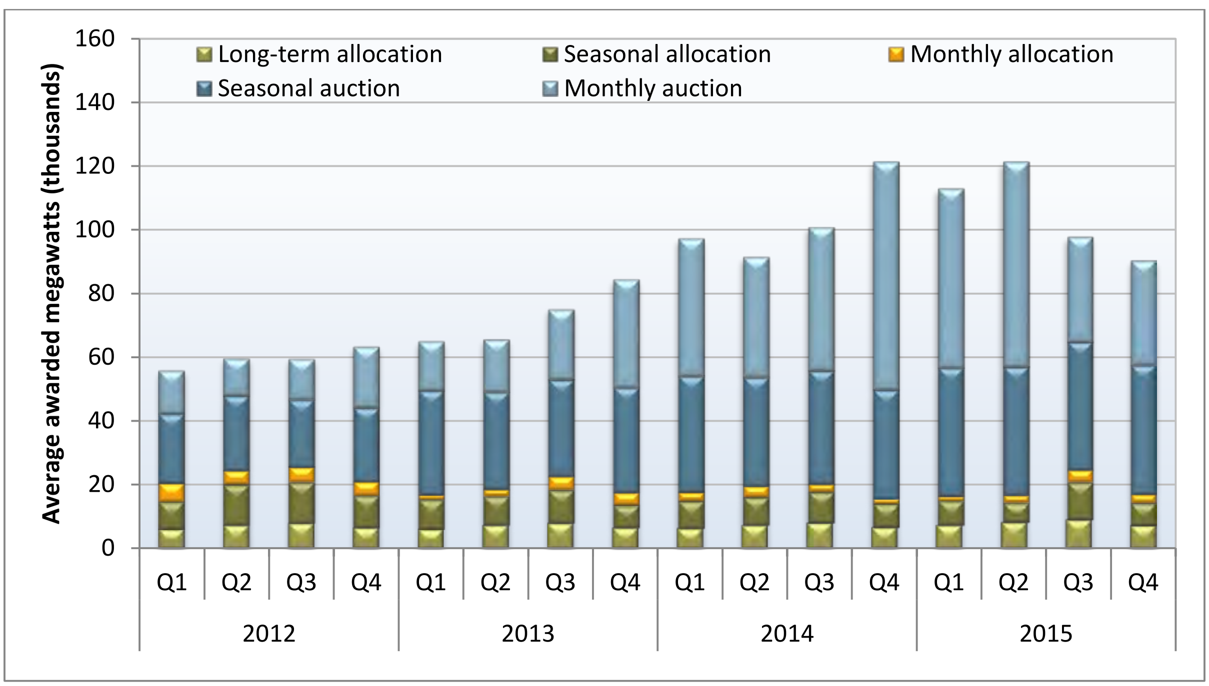


Figure 8.9 Percent of congestion revenue right megawatts held by procurement type

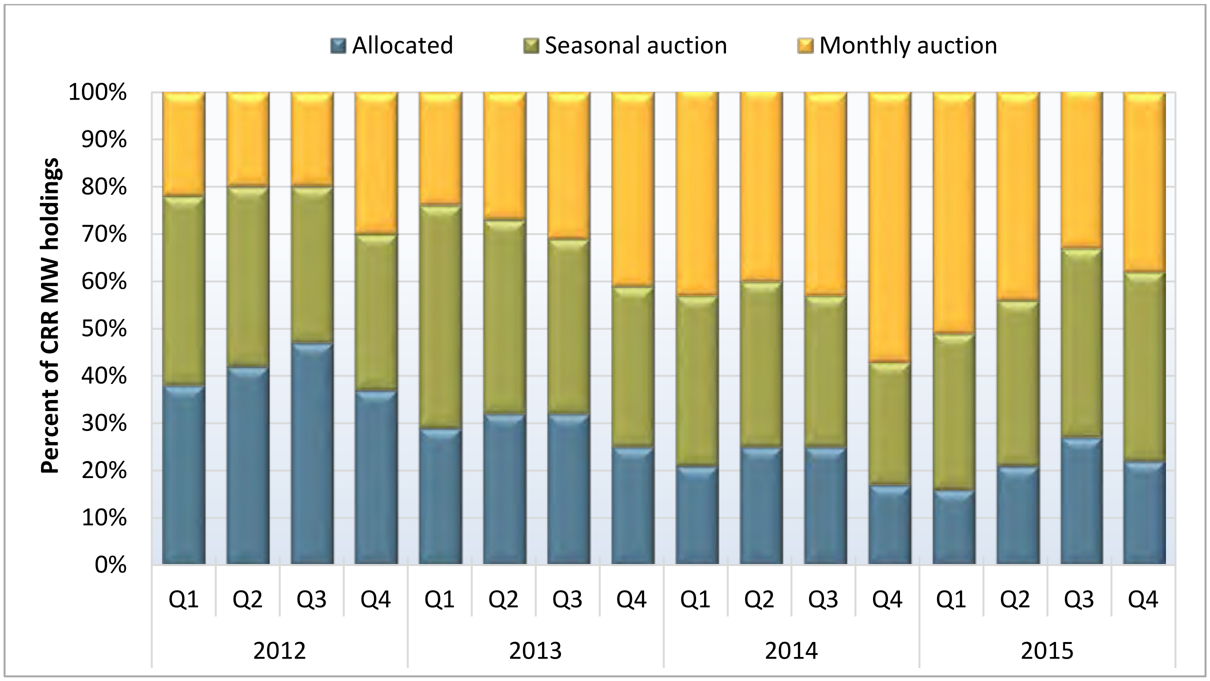


Figure 8.10 Percent of congestion revenue right monthly auction value by procurement type

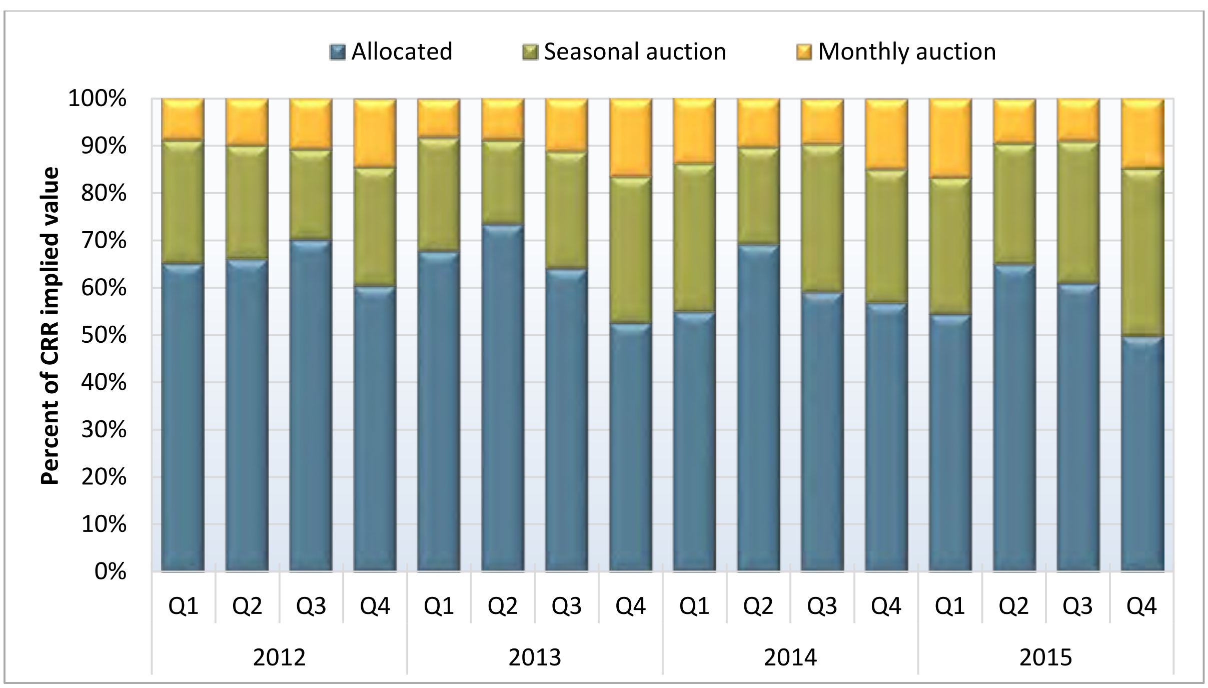


Figure 8.11 Payments to non-positively priced auctioned congestion revenue rights

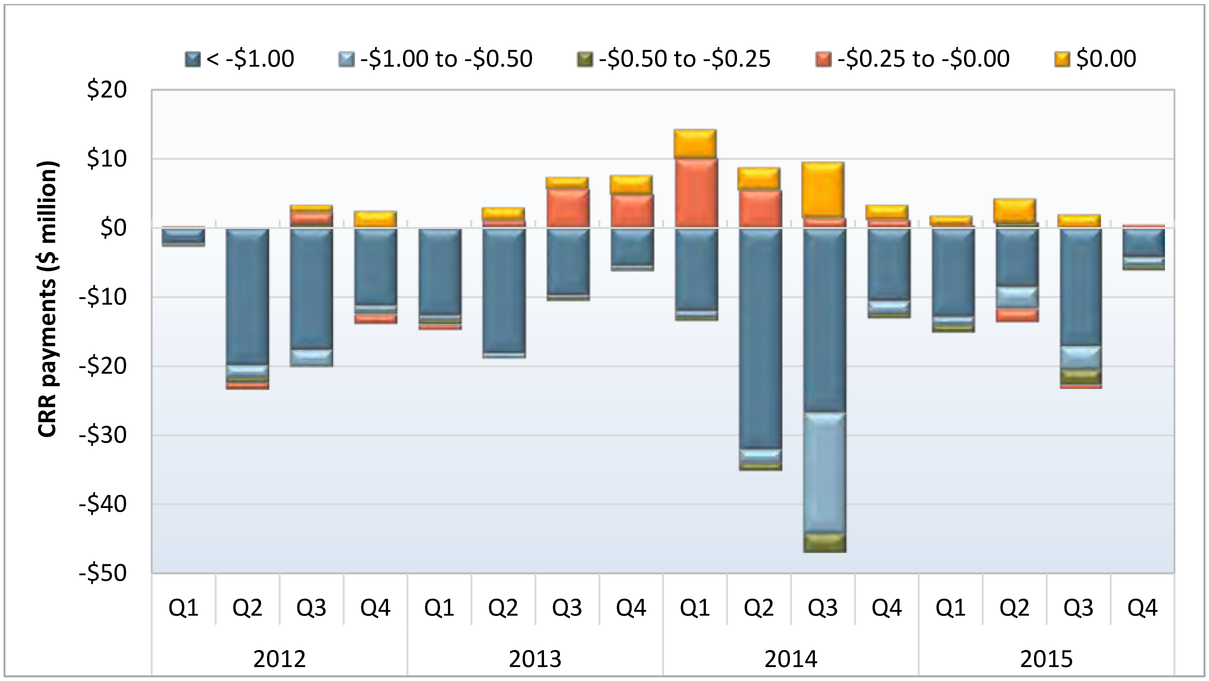
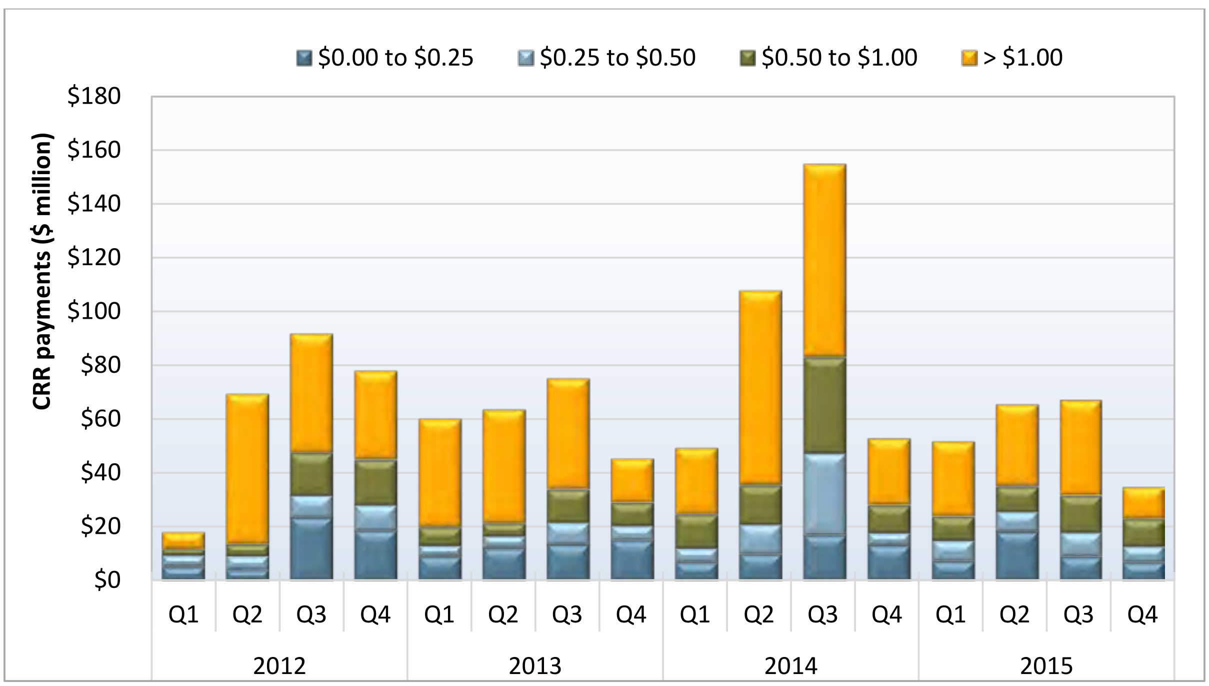


Figure 8.12 Payments to positively priced auctioned congestion revenue rights



8.4.2 Congestion revenue right auction returns

The ISO and DMM have traditionally tracked and reported on congestion revenue right revenue inadequacy as a primary metric on how well the congestion revenue right market is functioning. This section presents an alternative metric that DMM believes is more appropriate for assessing the congestion revenue right market.[158] This metric compares the auction revenues that ratepayers receive for rights sold in the ISO's auction to the payments made to these auctioned rights at day-ahead market prices.

Results presented in this report show that auction revenues received by ratepayers have persistently been far below day-ahead market congestion revenues that ratepayers would have received if the ISO had not auctioned any congestion revenue rights. DMM believes this discrepancy warrants reassessing the standard electricity market design assumption that ISOs should auction off transmission capacity in excess of the capacity allocated to load-serving entities.[159]

Background

When a transmission constraint is binding in the day-ahead market, this creates congestion revenue. This is because load that is within the congested area of a constraint is charged a higher price than the price paid to generation on the uncongested side of the constraint. When congestion occurs, each megawatt of the constraint's transmission capacity produces market revenue equal to the constraint's day-ahead market congestion price (or shadow price). For instance, when a 1,000 MW constraint is binding at a $10/MWh congestion price, this generates $10,000 in congestion revenues.

The owners of transmission – or entities paying for the cost of building and maintaining transmission – are entitled to the congestion revenues associated with transmission capacity in the day-ahead market. In the ISO, most transmission is paid for by ratepayers of the state's investor-owned utilities and other load-serving entities through the transmission access charge (TAC).[160] The ISO charges load-serving entities the transmission access charge in order to reimburse the entity that builds each transmission line for the costs incurred. Load-serving entities then pass that transmission access charge through to ratepayers in their customers' electricity bill. Therefore, these ratepayers are entitled to the revenues from this transmission.

These ratepayers currently receive the day-ahead market revenues from a large part of their transmission directly through the congestion revenue right allocation process. This process allocates a portion of congestion rights to load-serving entities which pay the transmission access charge based on these entities' historical load. These entities receive the day-ahead market congestion revenues associated with these congestion revenue rights. These entities then pass on these congestion revenues — along with transmission access charges — to their ratepayers. The analysis in this section does not

[158] The ISO reports on a similar metric in its market performance metric catalogue in its congestion revenue right section: http://www.caiso.com/market/Pages/ReportsBulletins/Default.aspx.

[159] It is a convenient analogy to describe the auction as selling excess transmission rights. However, an alternative analogy is that the auction makes ratepayers the counterparty to financial cash settled forward contracts. The difference between the auction revenues and payments to the rights are the gains or losses to ratepayers on these forward contracts.

[160] Some ISO transmission is built or owned by other entities such as merchant transmission operators. The revenues from transmission not owned or paid for by load-serving entities gets paid directly to the owners through transmission ownership rights or existing transmission contracts. The analysis in this section is not applicable to this transmission. Instead, this analysis focuses on transmission that is owned or paid for by load-serving entities only.

apply to this portion of ratepayers' transmission. Instead, this analysis only includes the portion of transmission that is paid for by ratepayers, but is not directly allocated to their load-serving entities, so that the congestion revenues from this transmission are not given directly to ratepayers through this congestion revenue right allocation process.

Not all transmission is allocated through the congestion revenue right allocation process. Ratepayers are still entitled to the day-ahead market congestion revenues generated by the transmission capacity that is not allocated to ratepayers through the congestion revenue right allocation process. However, a current principle incorporated in standard electricity market design is that the day-ahead market congestion revenues from this additional transmission capacity is not provided directly to ratepayers. Instead, the ISO auctions off congestion revenue rights, which are intended to represent the rights to the day-ahead market congestion revenues of this excess transmission capacity.

For each megawatt of ratepayer transmission capacity auctioned off by the ISO, ratepayers are effectively giving up their right to the day-ahead market congestion revenue of that capacity. In exchange for the right to this congestion revenue, ratepayers receive the auction revenues generated from auctioning off this excess capacity. Ratepayers directly receive the day-ahead market congestion revenues for any of the excess transmission that is available in the day-ahead market that has not been auctioned off through the congestion revenue right balancing account.

As long as the auction revenue that ratepayers receive for a megawatt auctioned off is greater than or equal to the day-ahead market congestion revenues for that megawatt, ratepayers benefit from having the ISO auction off that megawatt. However, if the auction revenue from that megawatt is expected to be less than the day-ahead market congestion revenue of that megawatt, then ratepayers should not want the ISO to auction off this extra transmission. Ratepayers would be better off directly receiving revenues from this transmission when congestion occurs in the day-ahead market, rather than receiving a lower price through the congestion revenue right auction process. For this reason, DMM believes it is appropriate to assess the performance of the congestion revenue right auction from the perspective of ratepayers by comparing the auction revenues that ratepayers receive for rights sold in the ISO's auction to the day-ahead market congestion revenues that ratepayers would have received if these congestion revenue rights were not sold in the auction.[161]

Revenue inadequacy

The ISO and DMM have traditionally tracked and reported on congestion revenue right revenue inadequacy as a primary metric on how well the congestion revenue right market is functioning. This section explains why the revenue inadequacy commonly reported is not an accurate or appropriate measure of how well the congestion revenue right market is functioning from the perspective of ratepayers.

Consider the following example:

[161] For example, consider a case where there is expected to be 1,000 MW of transmission capacity available in the day-ahead market which has not already been allocated to load-serving entities through the congestion revenue right allocation process. If the ISO auctions off the rights to the day-ahead market congestion revenues for 50 percent of this 1,000 MW capacity, ratepayers receive the auction revenues for this 500 MW of capacity. Ratepayers also receive day-ahead congestion revenues from the other 500 MW of capacity that was not auctioned off through the congestion revenue right balancing account. From the perspective of ratepayers, it is appropriate to compare the auction revenues received for 500 MW of congestion revenue rights sold in the ISO's auction to the day-ahead market congestion revenues that ratepayers would have received for the 500 MW of transmission if these rights were not sold in the auction.

- There is 100 MW of transmission, which is paid for by ratepayers of a load-serving entity through the transmission access charge.
- The load-serving entity is allocated 75 MW of this transmission in the allocation process. These congestion revenue rights exactly match the transmission needed to meet the load-serving entity's actual load.
- The remaining 25 MW is sold to a financial entity in the auction for a price of $5/MWh, resulting in a $125 credit in the balancing account.
- The day-ahead transmission price is $10/MWh.
- The load-serving entity's ratepayers pay $750 into the balancing account as part of the day-ahead congestion charges to meet their load and receive $750 from the balancing account for their 75 MW of congestion revenue rights.
- Other entities utilizing the remaining 25 MW of transmission in the day-ahead market pay $250 into the balancing account.
- The financial entity receives $250 from the balancing account for their 25 MW of congestion revenue rights.

In this example, the balancing account has a net balance of $0 without auction revenues, and a +$125 balance with auction revenues. However, the $125 in the balancing account that is paid to the load-serving entity represents only 50 percent of the $250 value of the 25 MW of transmission paid for by ratepayers that is sold in the congestion revenue rights auction. The remaining $125 of this value is paid to the financial entity purchasing these 25 MW of congestion revenue rights.

As illustrated by this example, revenue inadequacy represents only a portion of the overall performance of the congestion revenue rights auction from the perspective of ratepayers. A positive congestion revenue right account balance with auction revenues does not reflect the actual market value of additional congestion revenue rights sold in the auction. As described in this section, the performance of the congestion revenue rights auction from the perspective of ratepayers should instead be assessed by directly comparing the revenues from auctioning off additional transmission rights to the payments made to these rights at day-ahead prices.

Sources of revenue inadequacy

Revenue inadequacy is, under some conditions, reflective of the additional financial consequences to ratepayers that occurs if more transmission capacity is auctioned off than is actually available in the day-ahead market. This situation can occur for a variety of reasons, including outages, modeling discrepancies, and errors, as described in DMM's 2014 annual report.[162] In practice, these factors tend to create a systematic tendency for transmission capacity sold in the congestion revenue right auction to exceed the amount of transmission actually available in the day-ahead market. In this situation, the congestion revenues paid for rights in excess of transmission actually available in the day-ahead market is ultimately allocated to the ratepayers of load-serving entities through the congestion revenue right balancing account.

[162] *2014 Annual Report on Market Issues and Performance*, Department of Market Monitoring, June 2015, pp. 159-162.

Given the same example in the prior section, with a $5/MWh auction price and $10/MWh day-ahead price, assume now that only 90 MW of transmission service is available in the day-ahead market. In this example:

- There is 100 MW of transmission, which is paid for by ratepayers of a load-serving entity through the transmission access charge.
- The load-serving entity is allocated 75 MW of this transmission in the allocation process. These congestion revenue rights exactly match the transmission needed to meet the load-serving entity's actual load.
- The remaining 25 MW is sold to a financial entity in the auction for a price of $5/MWh, resulting in a $125 credit in the revenue adequacy account.
- The day-ahead transmission price is $10/MWh.
- The load-serving entity's ratepayers pay $750 into the balancing account as part of the day-ahead congestion charges to meet their load and receive $750 from the balancing account for their 75 MW of congestion revenue rights.
- Other entities utilizing the remaining 15 MW of transmission in the day-ahead market pay $150 into the balancing account.
- The financial entity receives $250 from the balancing account for their 25 MW of congestion revenue rights.
- In total financial entities are making positive revenue of $125 ($250 - $125), and this amount is paid for by load.

In this example the congestion revenue right balancing account has a net balance of -$100 without auction revenues and +$25 with auction revenues.[163] However, if the 25 MW of congestion revenue rights had not been auctioned off, the balancing account value would have been $150 (with or without including the $0 auction revenues).[164] The $125 difference equals the auction revenues less the payments to the auctioned congestion revenue rights.[165]

As illustrated by this example, revenue inadequacy reflects the shortfall between the total payments to congestion revenue rights and day-ahead congestion rents collected from the available transmission capacity. However, this revenue inadequacy represents only a portion of the overall performance of the congestion revenue rights auction from the perspective of ratepayers. If auction revenues are less than the congestion payments to the non-load-serving entities purchasing congestion revenue rights in the

[163] The amount collected in day-ahead congestion is equal to 90 MW * $10/MWh for a total of $900. From this number we subtract what is owed to the congestion revenue rights holders which is $750 (75 MW * $10/MWh) for the load-serving entities plus $250 (25 MW * $10/MWh) for the financial entities, or a total of $1,000. Thus $900 - $1,000 results in -$100 without auction revenues. The balance with auction revenues can be calculated as $25 ($125 -$100), or the total auction revenues ($125) less the total without auction revenues.

[164] In this case congestion revenue right holdings are 75 MW, whereas the day-ahead flows exceed this by 15 MW. Thus, the congestion revenue rights holders are owed $750 (75 MW * $10/MWh) for the load-serving entities and day-ahead congestion collections were $900. This results in a surplus collection of congestion of $150 ($900 - $750).

[165] This is the difference between the account balance in the allocation only scenario ($150) and the account balance ($25) in the auction scenario.

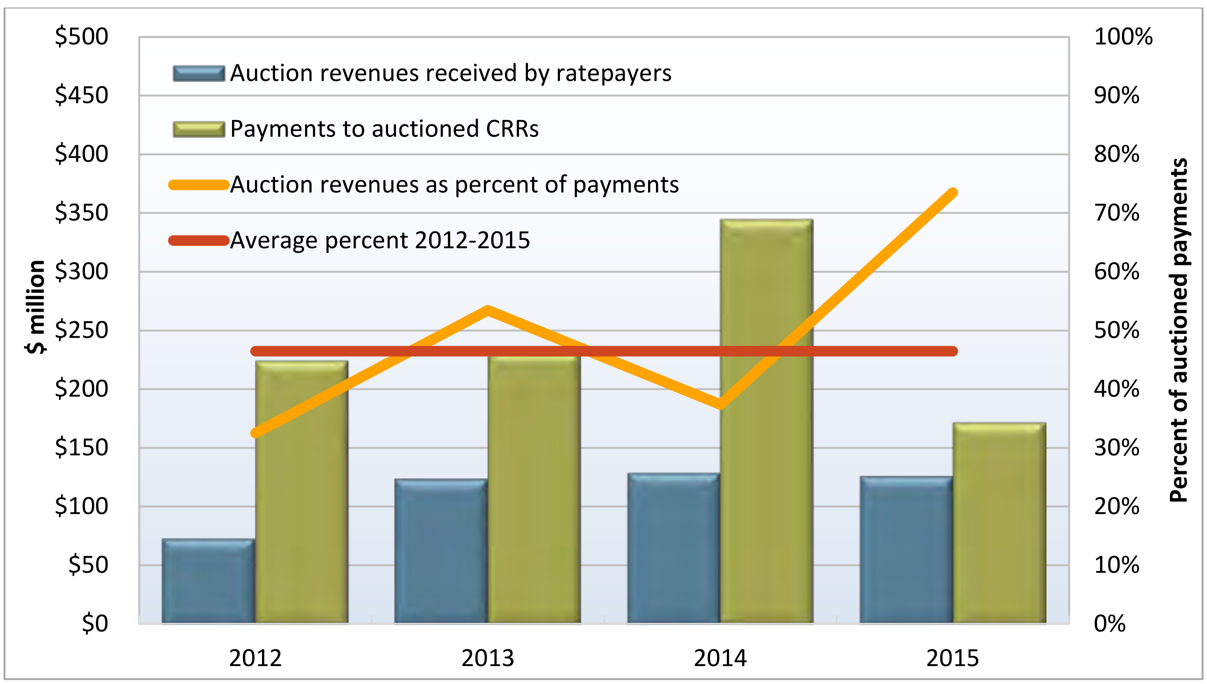
auction, then each additional megawatt of transmission capacity auctioned was not financially beneficial for ratepayers.

Analysis of congestion revenue right auction returns

As described above, the performance of the congestion revenue rights auction from the perspective of ratepayers can be assessed by comparing the auction revenues received for auctioning transmission rights to the day-ahead congestion payments to these rights. Figure 8.13 compares the following for each of the last four years:

- Auction revenues received by ratepayers from congestion revenue rights sold in auction (blue bars on left axis).[166]
- Net payments made to the non-load-serving entities purchasing congestion revenue rights in auction (green bars on left axis).
- Auction revenues received by ratepayers as a percentage of the net payments made to the entities purchasing congestion revenue rights in auction (yellow line on right axis)

Figure 8.13 Ratepayer auction revenues compared with congestion payments for auctioned CRRs



Between 2012 and 2015, ratepayers received, on average, about $130 million less per year from congestion revenue right auction revenues than entities purchasing these congestion revenue rights in the auction received from day-ahead congestion revenues. Over this four year period, ratepayers

[166] The auction revenues received by ratepayers are the auction revenues from CRRs paying into the auction less the revenues paid to “counter-flow” CRRs. Similarly day-ahead payments made by ratepayers are net of payments by “counter-flow” CRRs.

received an average of only about 45 percent of these congestion payments through these auction revenues.

These findings are not unique to the California ISO market design. The PJM Independent Market Monitor reports similar underpricing of congestion revenue rights in auctions.[167] Potential factors contributing to this trend include the following:

- Auctioning a product for which the seller cannot set a reservation price;
- Technical, economic, and regulatory barriers that restrict the participation of ratepayers or their representatives in the auctions; and
- Inconsistencies between the products as auctioned and as settled at day-ahead prices.

This analysis illustrates that auction revenues that ratepayers receive have been consistently below the day-ahead market congestion revenues that ratepayers would have received if these congestion revenue rights were not auctioned off. DMM believes these results warrant reassessing the standard electricity market design assumption that ISOs should auction off transmission capacity that remains in excess of the capacity allocated to load-serving entities. Instead, it would be much more beneficial to allow ratepayers to collect these congestion revenues directly.

Figure 8.14 through Figure 8.17 compare the auction revenue payments received by ratepayers and ratepayer payments to auctioned congestion revenue rights by market participant type.[168] The difference between auction revenues and the congestion revenue right payments are the profits for the entities holding the auctioned congestion revenue rights. These profits are losses to ratepayers.

- Financial entities continued to have the highest net revenue among auctioned rights holders in 2015 with $47 million. This was down from $95 million in 2014, largely related to the 50 percent decline in day-ahead congestion rent.
- Marketers had net revenues from auctioned rights of negative $7 million in 2015, down from positive $87 million in 2014. This was due to the low inter-tie congestion in 2015 and the large portion of congestion revenue rights purchased in the seasonal auction. Marketers spent $42 million in the seasonal auction and $18 million in the monthly auction in 2015, down from $52 million and $37 million in 2014.
- Physical generation entities had net revenue from auctioned rights of nearly $7 million in 2015, down from nearly $34 million in 2014. Physical generators continued to receive the lowest overall payments from auctioned congestion revenue rights among non-load-serving entities.
- Load-serving entities had net revenue from auction rights of $14 million in 2015, up from negative $29 million in 2014. 2015 was the only year since 2012 that load-serving entities received auction revenues greater than their auctioned congestion revenue rights day-ahead costs. Because the auction revenues and congestion revenue right payments are made simultaneously to and from

[167] For a description of this issue in PJM, see the PJM Independent Market Monitor's "2015 State of the Market Report for PJM" available at: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015.shtml.

[168] DMM has defined financial entities as participants who own no physical energy 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. Balancing authority areas are participants that are balancing authority areas outside the ISO.

load-serving entities as a group, they are not the direct effect on ratepayers. However, these losses are opportunity costs for ratepayers from making the congestion revenue rights available in the auction that show up in the net payments made to other entities.

One of the benefits of auctioning congestion revenue rights is to allow day-ahead market participants to hedge their congestion costs. However, in 2015 physical generators as a group accounted for a relatively small portion of congestion revenue rights. As a group, generators received the lowest overall payments from congestion revenue rights, even after including allocated rights. Generators received congestion revenue rights payments of $40 million, while incurring day-ahead congestion costs of $43 million. Except for balancing authority areas,[169] the other categories of entities had congestion revenue right payments well in excess of their day-ahead congestion costs.

The losses to ratepayers from the congestion revenue rights auction could in theory be avoided if load-serving entities purchased the congestion revenue rights at the auction from themselves. However, there are significant technical and regulatory hurdles making it difficult for load-serving entities to purchase these rights. Moreover, DMM does not believe it is appropriate to design an auction so that load-serving entities would have to purchase rights in order to avoid obligations to pay other congestion revenue rights holders. DMM believes it would be more appropriate to design the auction so that load-serving entities will only enter obligations to pay other participants if they are actively willing to enter these obligations at the prices offered by the other participants. With this approach, any entity placing a value on purchasing a hedge against congestion costs could seek to purchase this directly from the load serving, financial, or other entities.

[169] Balancing authority areas held only allocated rights and did not participate in the auctions. Because balancing authority areas did not participate in the auction they do not affect the auction performance metric.

Figure 8.14 Ratepayer auction revenues compared with congestion payments for auctioned CRRs (Financial entities)

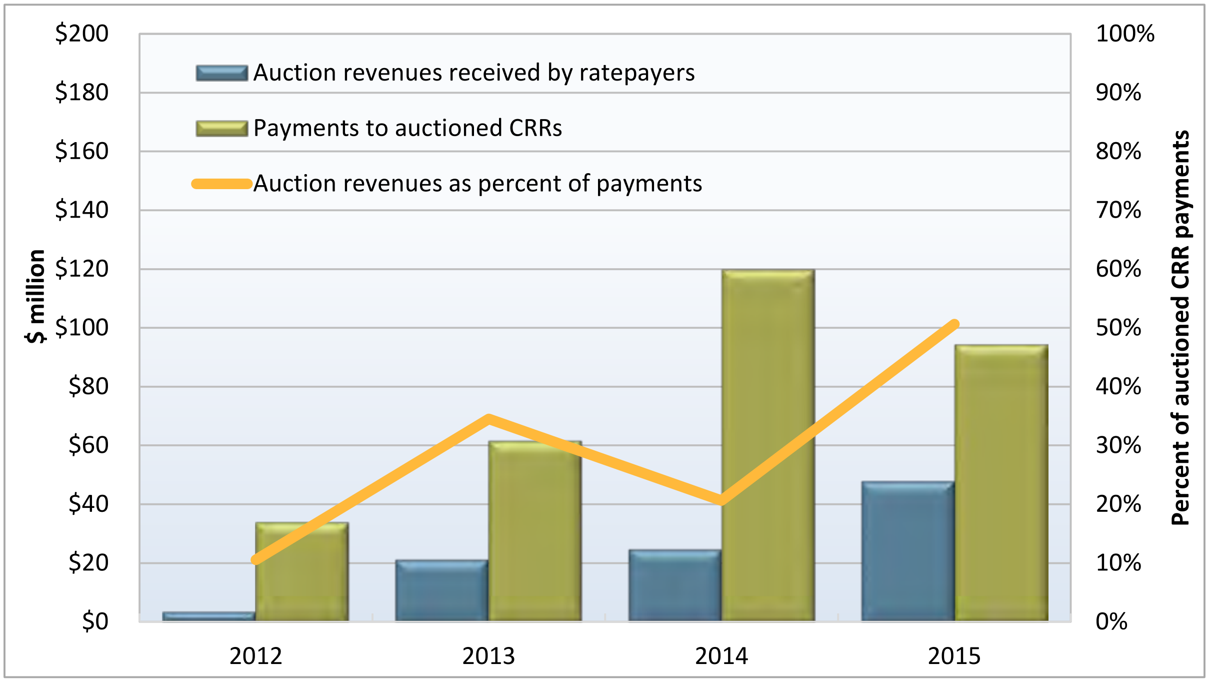


Figure 8.15 Ratepayer auction revenues compared with congestion payments for auctioned CRRs (Marketers)

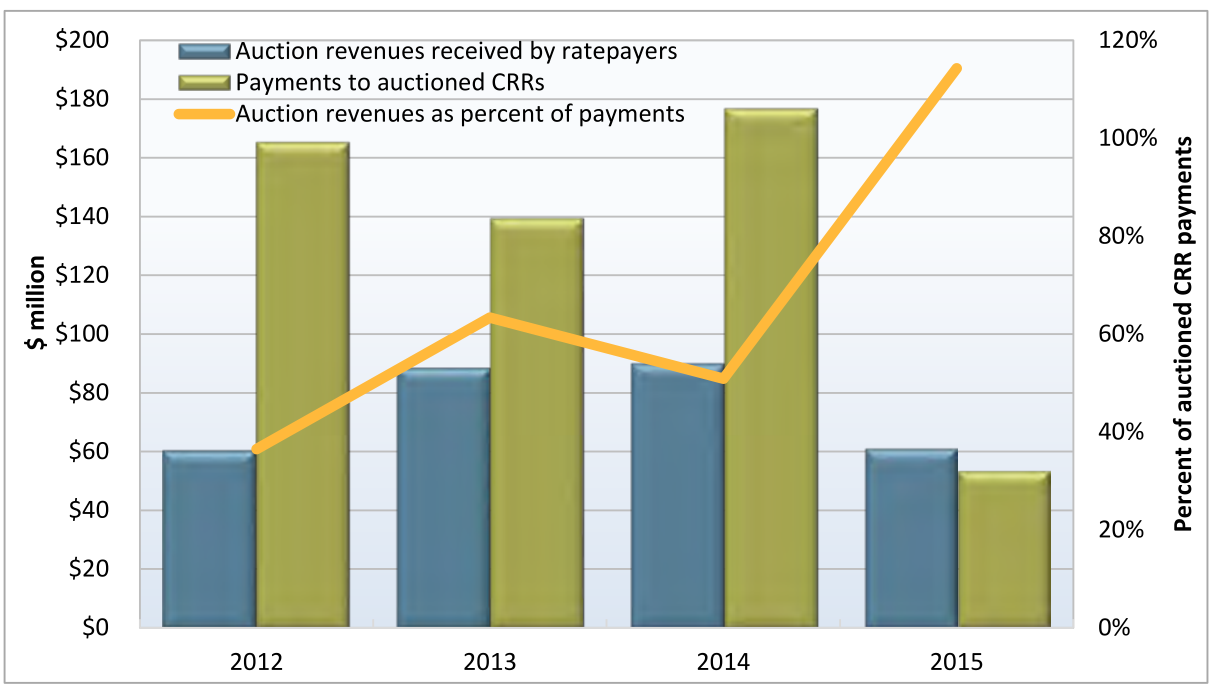


Figure 8.16 Ratepayer auction revenues compared with congestion payments for auctioned CRRs (Generators)

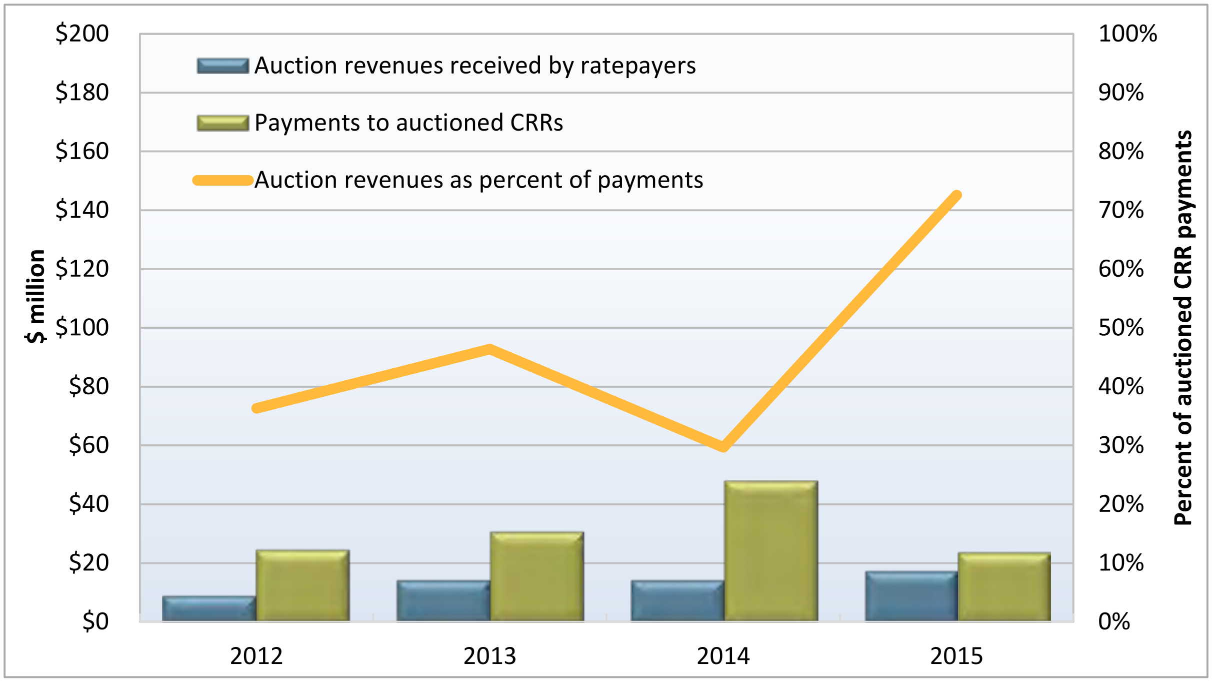
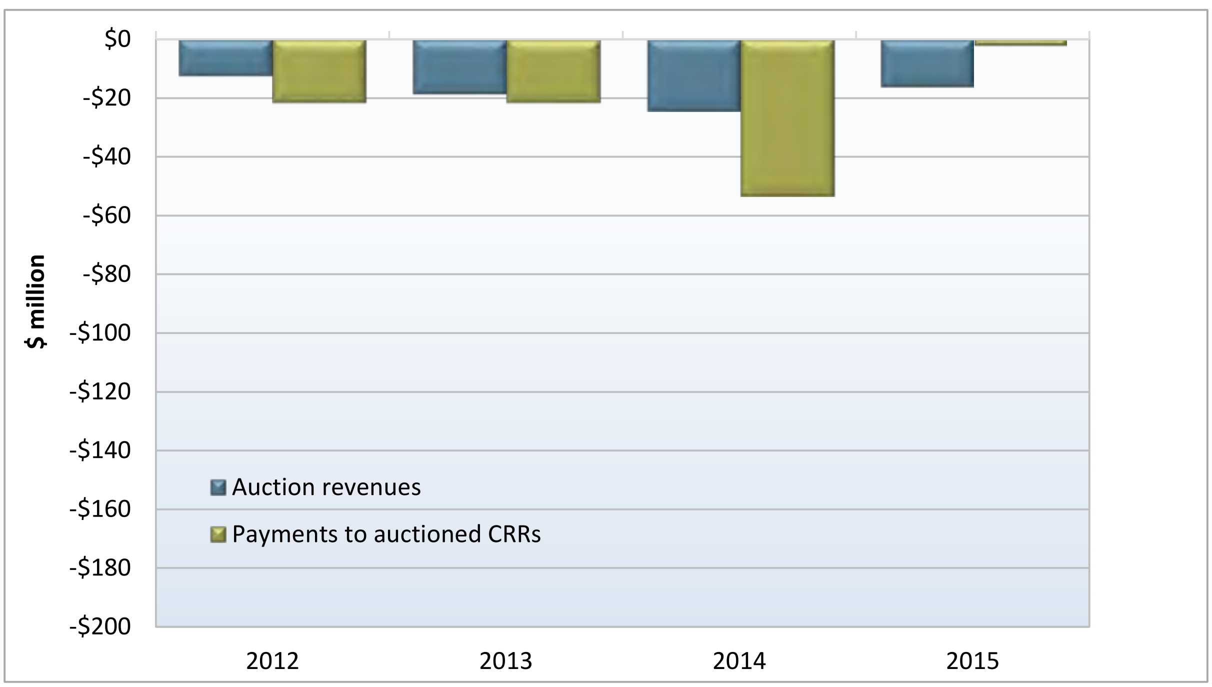


Figure 8.17 Ratepayer auction revenues compared with congestion payments for auctioned CRRs (Load-serving entities)



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.[170] 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.

In this chapter, DMM reviews the frequency of and reasons for a variety of key market adjustments, including the following:

- exceptional dispatches;
- modeled load adjustments;
- blocked dispatch instructions;
- aborted and blocked pricing runs in the real-time market; 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 2016.

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.

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 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.

[170] 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.

- **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.

Increased total energy from exceptional dispatch

Total energy resulting from all types of exceptional dispatches increased by approximately 30 percent in 2015 from 2014, as shown in Figure 9.1.[171] The percentage of total exceptional dispatch energy from minimum load energy accounted for about 86 percent of all energy from exceptional dispatches in 2015. About 9 percent of energy from exceptional dispatches in 2015 was from out-of-sequence energy, with the remaining 5 percent from in-sequence energy. These proportions are comparable to the distribution of exceptional dispatch energy in 2014 and 2013. While total energy from exceptional dispatches increased in 2015, total out-of-market costs from exceptional dispatches fell compared to 2014. This drop in out-of-market exceptional dispatch costs was driven by a decline in bid cost recovery payments associated with exceptional dispatch unit commitments.

Total energy from exceptional dispatches, including minimum load energy from unit commitments, equaled 0.2 percent of system loads in 2015, compared to 0.16 percent in 2014. Thus, while 2015 saw a slight increase in exceptional dispatch, this energy continues to account for a relatively low portion of total system loads.

Nearly all of the increase in total energy from exceptional dispatches was driven by an increase in minimum load energy, particularly in the first and third quarters of 2015. The second and third quarters also saw an increase in out-of-sequence energy above minimum load. These increases in exceptional dispatch energy were primarily driven by the following:

- Increased exceptional dispatch to manage transmission constraints;
- Exceptional dispatch for voltage support in Southern California in February and March 2015; and
- Exceptional dispatch made in response to load forecasting challenges in the third quarter of 2015.

Exceptional dispatch energy related to the management of the Southern California Import Transmission limit was negligible in 2015. While exceptional dispatch ticked up from 2014, overall exceptional dispatch levels remain relatively low and below 2013 values. This continues to reflect the 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.

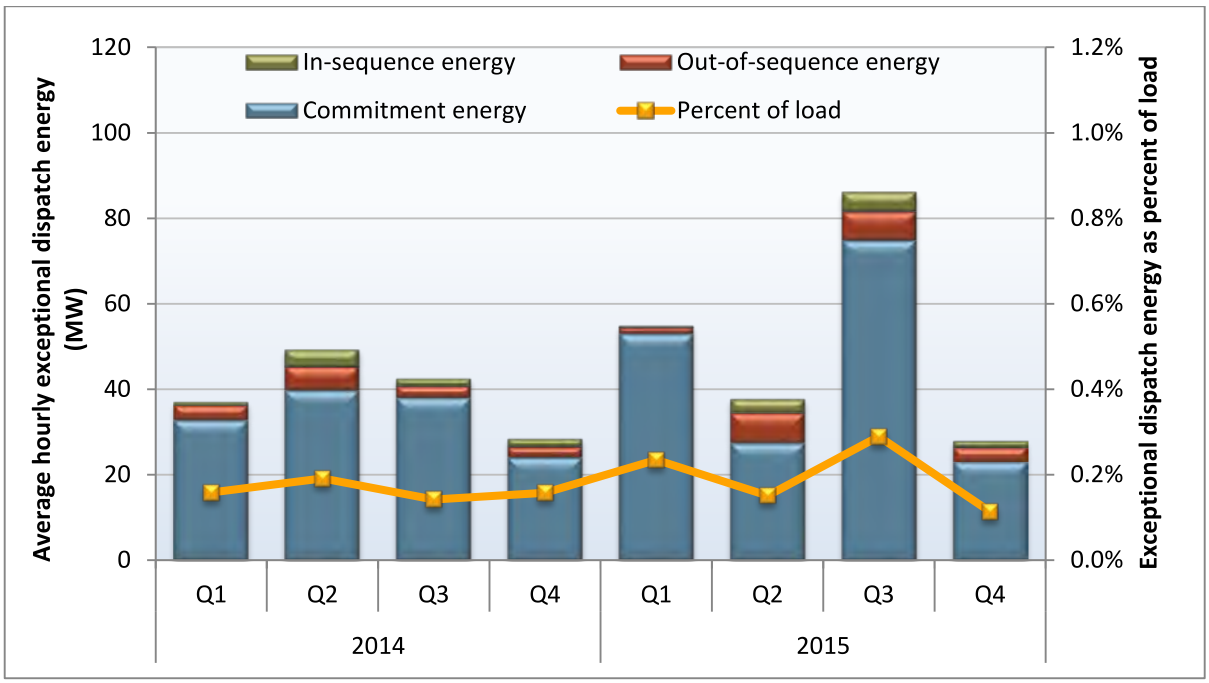
Although exceptional dispatches are priced and paid outside of the market, they can have an effect on the market clearing price for energy. Energy resulting from exceptional dispatch effectively reduces the remaining load to be met by the rest of the supply. This can reduce market prices relative to a case where no exceptional dispatch was made. However, most exceptional dispatches appear to be made to

[171] All exceptional dispatch data are estimates derived from 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.

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 dispatch 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

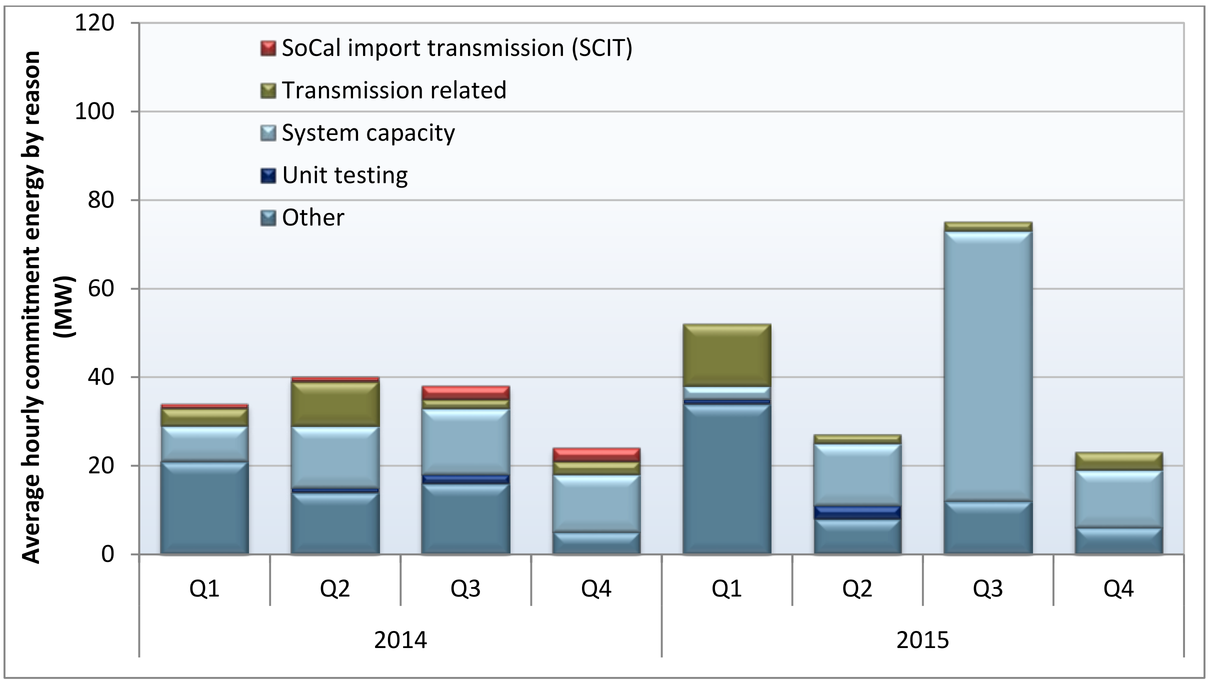
The ISO sometimes finds instances where the day-ahead market process did not commit sufficient capacity to meet certain reliability requirements not directly incorporated in the day-ahead market model. Alternatively, a scheduling coordinator may wish to operate a resource out-of-market for purposes of unit testing. In these instances, the ISO may commit additional capacity by issuing an exceptional dispatch for resources to come on-line and operate at minimum load.

Minimum load energy from exceptional dispatch unit commitments increased by over 30 percent in 2015 compared to 2014. As shown in Figure 9.2, the annual increase in minimum load energy from exceptional dispatch unit commitments was driven by the first and third quarters. Levels fell in the second quarter and remained near 2014 levels in the fourth quarter. The need to manage potential contingencies associated with the Southern California Import Transmission limit fell to negligible levels throughout the year.

Increases in minimum load energy related to transmission constraints as well as a need for voltage support in Southern California were the primary drivers of increased exceptional dispatch commitment in the first quarter of 2015. Exceptional dispatch unit commitment increased the most in the third quarter, with a 97 percent increase over 2014 values. This increase was driven almost entirely by load forecasting challenges over the quarter and is represented in Figure 9.2 as system capacity.

The relationship of load forecasting challenges and exceptional dispatch unit commitment was exacerbated by the timing and magnitude of load forecast errors. Under-forecasting in the day-ahead market occurred on several days with particularly high load. Further, when load was under-forecasted in the day-ahead market for peak load hours, the size of the forecast error tended to be significant. These factors resulted in the increased need for out-of-market unit commitment to meet real-time load.

Figure 9.2 Average minimum load energy from exceptional dispatch unit commitments

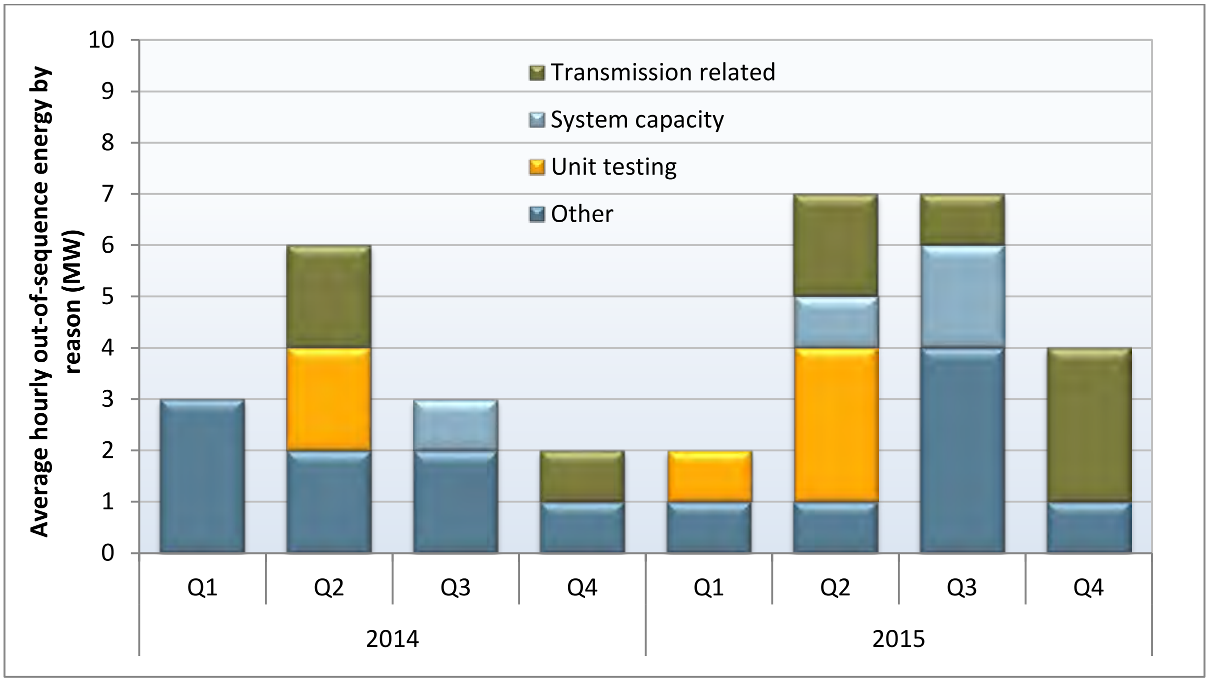


Exceptional dispatches for energy

Energy from real-time exceptional dispatches to ramp units up above minimum load or their regular market dispatch level increased by about 43 percent in 2015. As previously illustrated in Figure 9.1, much of this exceptional dispatch energy (about 65 percent) was out-of-sequence, meaning the bid price was greater than the locational market clearing price. While this represents a 5 percent increase from 2014 levels, it remains 5 percent below 2013 levels.

Figure 9.3 shows the change in out-of-sequence exceptional dispatch energy over the year in 2014. Out-of-sequence exceptional dispatch energy fell in the first quarter of 2015, but rose in all other quarters. The most significant increase occurred in the third quarter. Load forecasting challenges on high load days and during peak hours were a key driver of out-of-sequence exceptional dispatch energy in the third quarter, as were exceptional dispatches related to ISO operating procedures in the Humboldt, Fresno, and San Diego areas. Increased out-of-sequence exceptional dispatch energy in the second quarter was primarily related to unit testing, while fourth quarter increases were primarily related to management of transmission constraints. The volume of out-of-sequence exceptional dispatch energy related to Southern California Import Transmission remained at a negligible level, unchanged from 2014.

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.

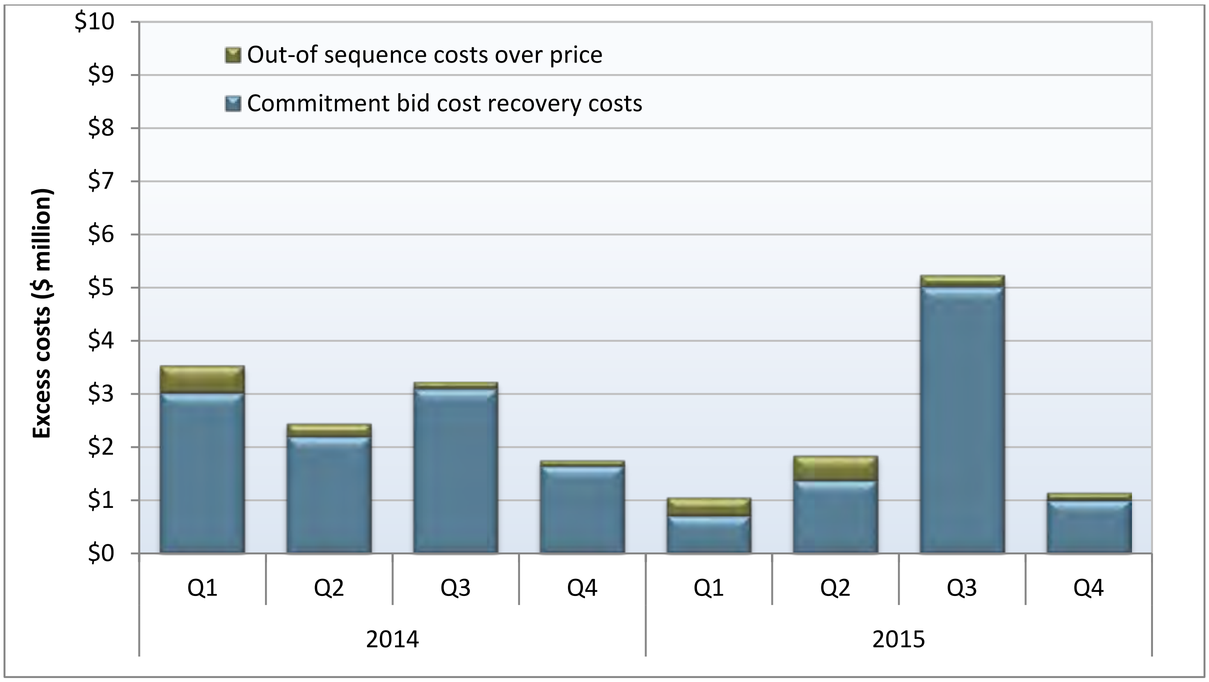
- Units being exceptionally dispatched for real-time energy out-of-sequence may be eligible to receive an additional payment to cover the difference in their market bid price and their locational marginal energy price.

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 for exceptional dispatch paid through bid cost recovery decreased from $10 million to $8.1 million, while out-of-sequence energy costs increased from $1 million to $1.2 million.[172] Overall, these above-market costs decreased 15 percent from $11 million in 2014 to $9.3 million in 2015. Decreases were seen in the first,

[172] 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.

second, and fourth quarters in 2015 compared to 2014, while exceptional dispatch costs increased in the third quarter of 2015, compared to the third quarter of 2014. Elevated third quarter levels of bid cost recovery related to exceptional dispatch commitment correlate with the highest levels of exceptional dispatch commitment seen in 2015. As discussed above, load forecasting challenges during peak load days and hours were a primary driver of exceptional dispatch commitment in the third quarter.

Figure 9.4 Excess exceptional dispatch cost by type



9.2 Load adjustments

The ISO frequently adjusts loads in the 15-minute and 5-minute real-time markets to account for potential modeling inconsistencies or inaccuracies. Some of these inconsistencies are because of changing system and market conditions, such as changes in load and supply, between the executions of the different real-time markets. Specifically, an operator may use this load adjustment feature to manage load deviation, generation deviation, scheduled interchange variation, reliability events, and software issues.[173]

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

[173] See 153 FERC ¶ 61,305, order on compliance filing, issued December 17, 2015: http://www.caiso.com/Documents/Dec17_2015_OrderAcceptingComplianceFiling_AvailableBalancingCapacity_ER15-861-006.pdf.

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, known as the *load bias limiter* (see Section 4.3 for further detail), load adjustments made by operators are less likely to have an extreme effect on market prices. DMM will continue to monitor and analyze load adjustments in the ISO and EIM regions.

Figure 9.5 shows the average hourly load adjustment profile for the 15-minute and 5-minute markets during 2015.[174] During 2015, 15-minute market adjustments exceeded 5-minute market adjustments for most hours of the day. Particularly, the largest deviation was observed in hours ending 9 and 10 when the 15-minute adjustments exceeded the 5-minute adjustments by around 200 MW. Negative biasing in these morning hours often occurred following higher than expected renewable generation or over-forecasted load.

Figure 9.6 identifies how load adjustment amounts changed over the course of 2015 for the 15-minute and 5-minute markets in the ISO. The solid and dotted lines show the average magnitude of the load adjustment when it is positive and negative, respectively. Additionally, Figure 9.7 shows the percent of intervals in the 15-minute and 5-minute markets in which operators and automated tools adjusted the load forecast along with the direction of the adjustment.[175]

- The use of negative load adjustments in the 5-minute market increased significantly in both magnitude and frequency throughout 2015. Negative load adjustments were largest and most frequent in November at around -430 MW in almost 70 percent of intervals. However, negative load adjustments in the 15-minute market were more constant throughout 2015 at around -250 MW in about 24 percent of intervals.

- The average size of positive load adjustments trended upward in both markets between January and September to over 400 MW, but decreased throughout the fourth quarter. Large positive load adjustments in the 15-minute and 5-minute markets were most common in hours ending 18 and 19 when load levels peak.

- The frequency of intervals with load adjustments in the 5-minute market increased over the course of 2015 from about 69 percent of intervals in the first quarter to almost 80 percent of intervals in the fourth quarter. In the 15-minute market, load adjustments were more constant over the year at around 53 percent of intervals in 2015.

[174] Hour-ahead adjustments were similar to 15-minute adjustments and have been omitted from the chart.

[175] Hour-ahead adjustment amounts and frequencies tracked very closely to 15-minute market levels and were also omitted in these charts.

Figure 9.5 Average hourly load adjustments (2015)

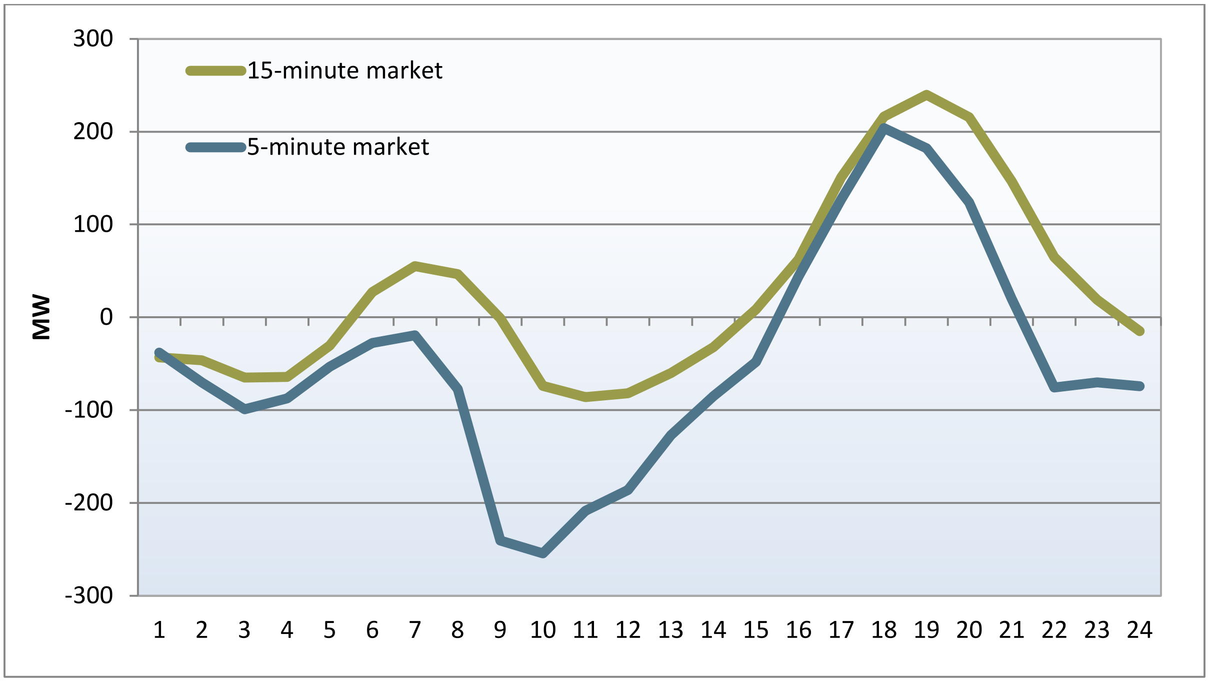


Figure 9.6 Average size of positive and negative load adjustments (2015)

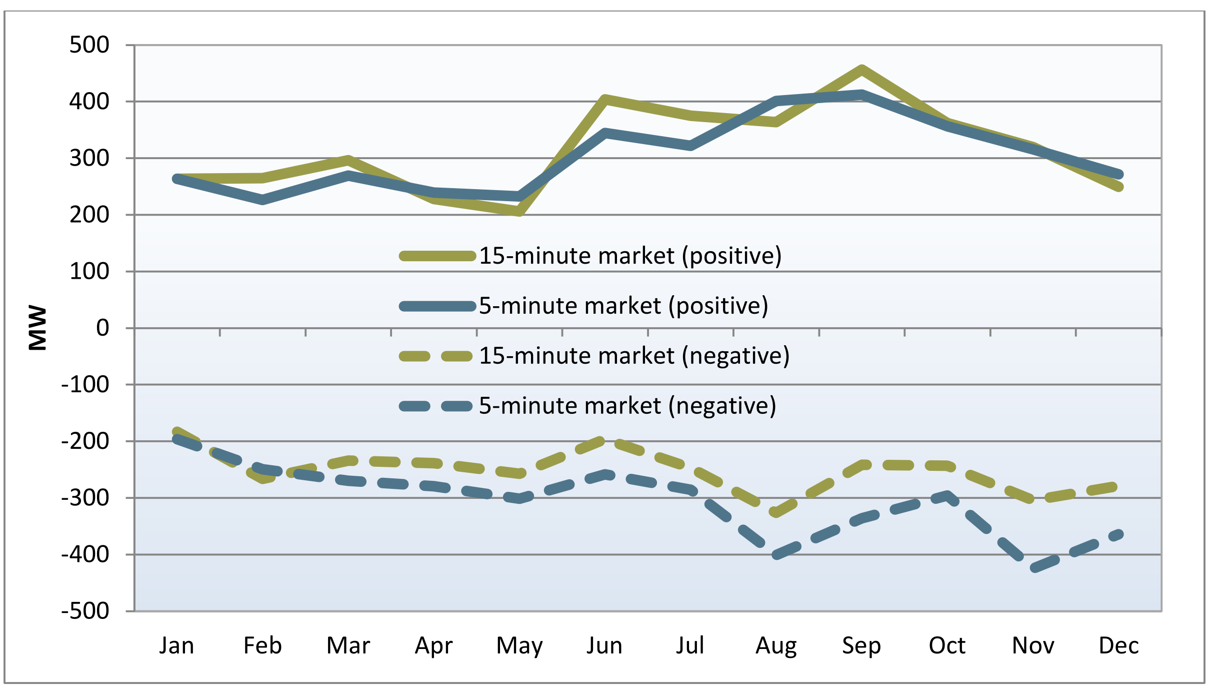


Figure 9.7 Average frequency of positive and negative load adjustments in 2015 (ISO)

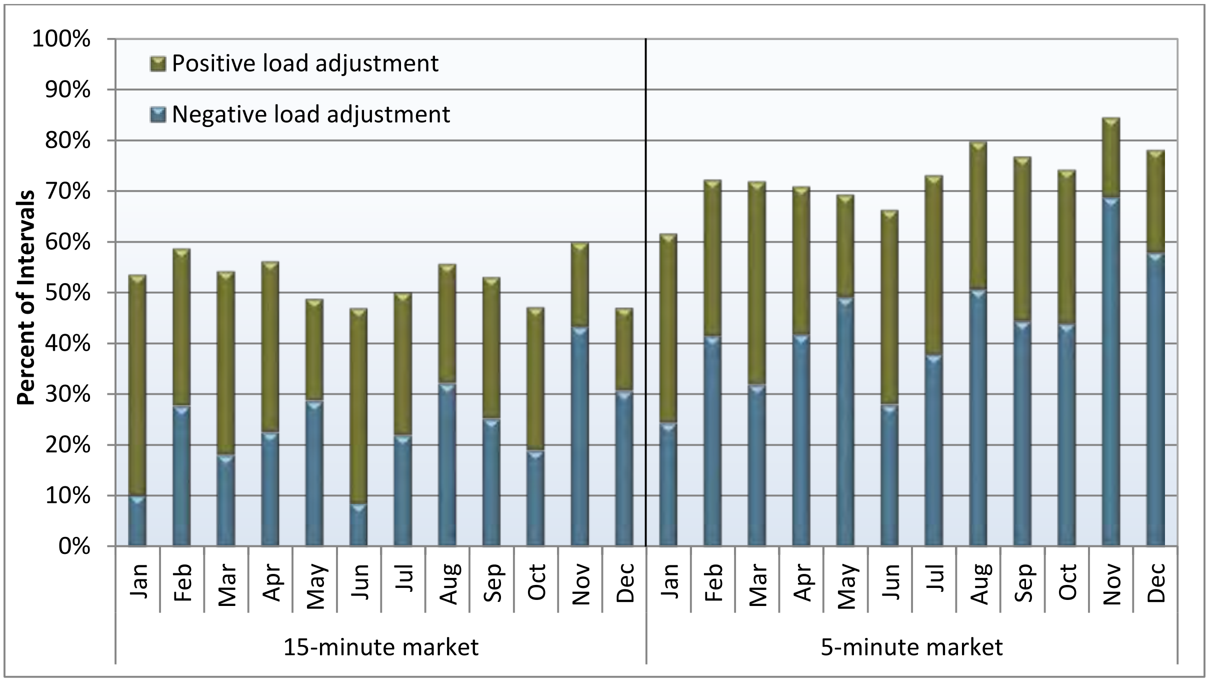


Figure 9.8 and Figure 9.9 show load adjustment frequency for PacifiCorp East and PacifiCorp West. The frequency of negative load adjustments decreased significantly in both areas and real-time markets from January where these adjustments occurred in about 80 percent of intervals. During the last five months of the year, negative load adjustments were much more infrequent, occurring in less than 10 percent of both 15-minute and 5-minute intervals in each area. Negative biasing averaged around -100 MW for PacifiCorp East and -80 MW for PacifiCorp West during 2015. For PacifiCorp East positive load adjustments were most frequent during the third quarter at around 53 percent of intervals and averaged 100 MW in both real-time markets. DMM will continue to monitor EIM entities' load forecast adjustment and its impact on the EIM in forthcoming quarterly reports.

Figure 9.8 Average frequency of positive and negative load forecast adjustments in 2015 (PacifiCorp East)

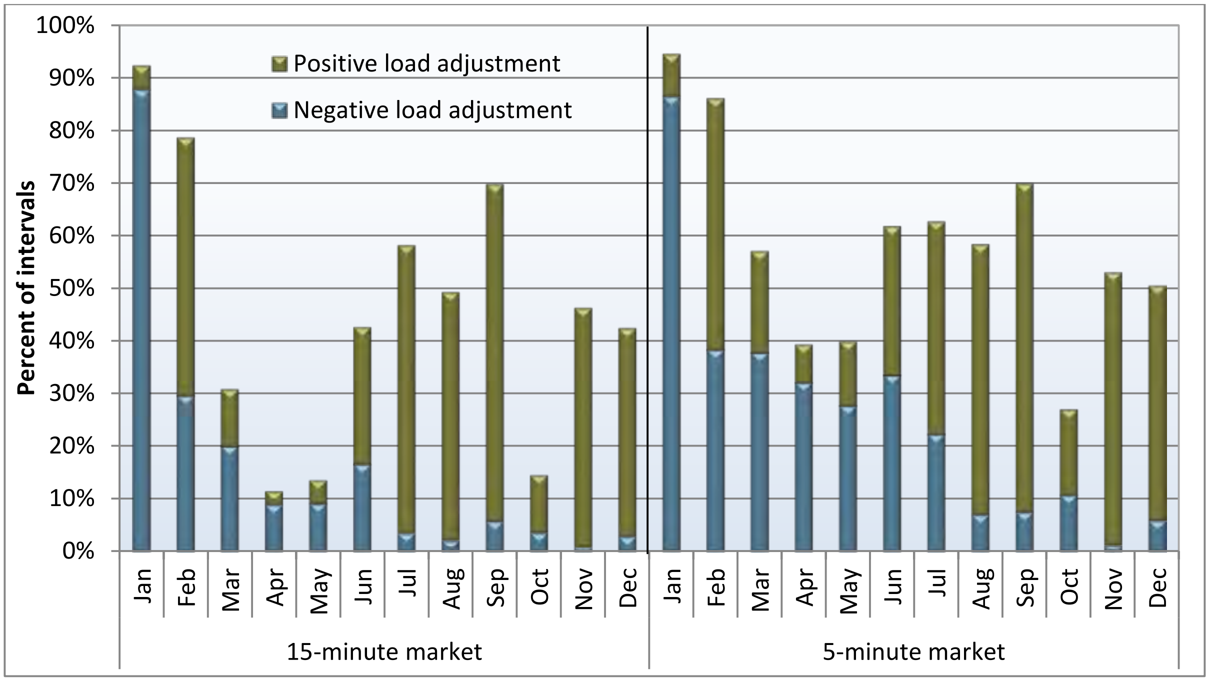
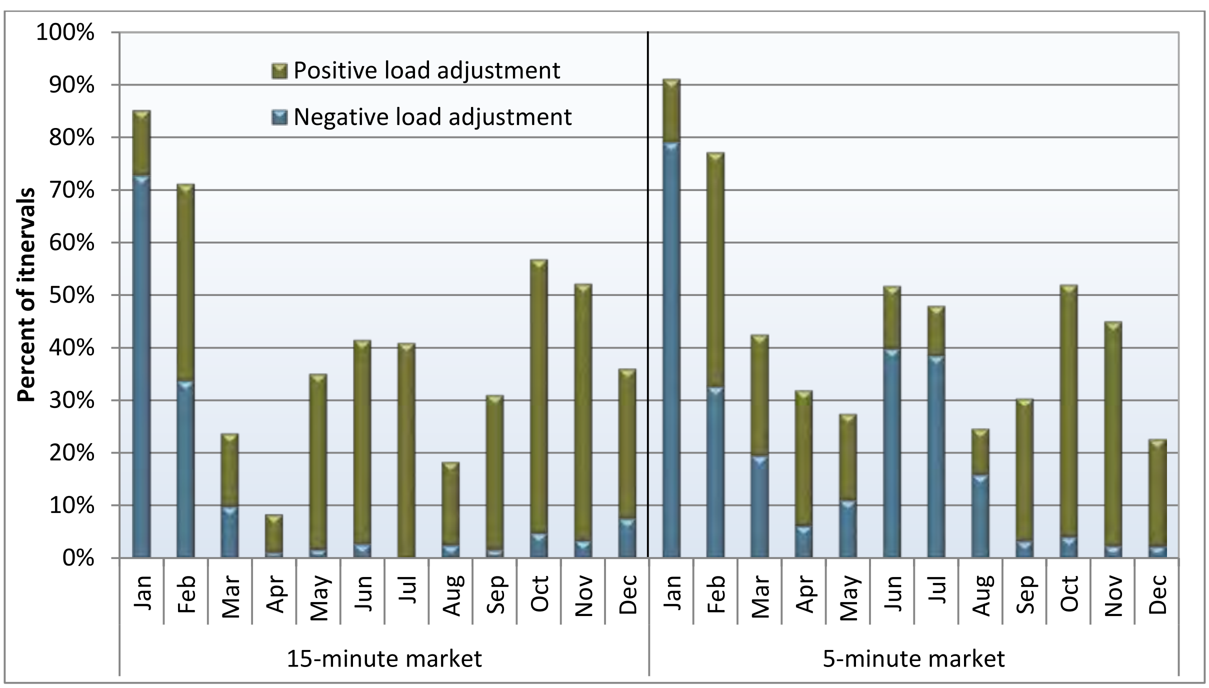


Figure 9.9 Average frequency of positive and negative load forecast adjustments in 2015 (PacifiCorp West)



9.3 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 on-line resources within the ISO.

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.[176] 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 may 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.

While the overall number and megawatt volume of blocked instructions for internal units increased slightly in 2015 compared to 2014, blocked instructions on the inter-ties increased significantly. Figure 9.10 shows the frequency and volume of blocked dispatches on inter-ties. Figure 9.11 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 2015 increased fivefold from 2014. This was driven entirely by two hours in April where the hour-ahead scheduling process was either aborted or infeasible.

Blocked instructions for internal resources increased in 2015 compared to 2014. In particular, blocked shut-down instructions were the most common reason for blocked instructions at almost 69 percent in 2015. Blocked shut-down instructions increased 31 percent in 2015, compared to 2014. Blocked start-up instructions accounted for almost 26 percent of blocked instructions within the ISO in 2015, while blocked transition instructions to multi-stage generating units accounted for only 6 percent. Blocked start-up instructions increased 28 percent in 2015 compared to 2014, while blocked transition

[176] 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/Pages/documentsbygroup.aspx?GroupID=01F12F53-57DF-4861-B8CF-02D87FD1DA5D.

instructions increased 71 percent over the same period. The ISO listed possible reasons including multi-stage generating unit transition issues, configuration issues, a limited number of start-ups for peaking units, and non-uniform pump and generation instructions for some units.

Figure 9.10 Frequency and volume of blocked real-time inter-tie instructions

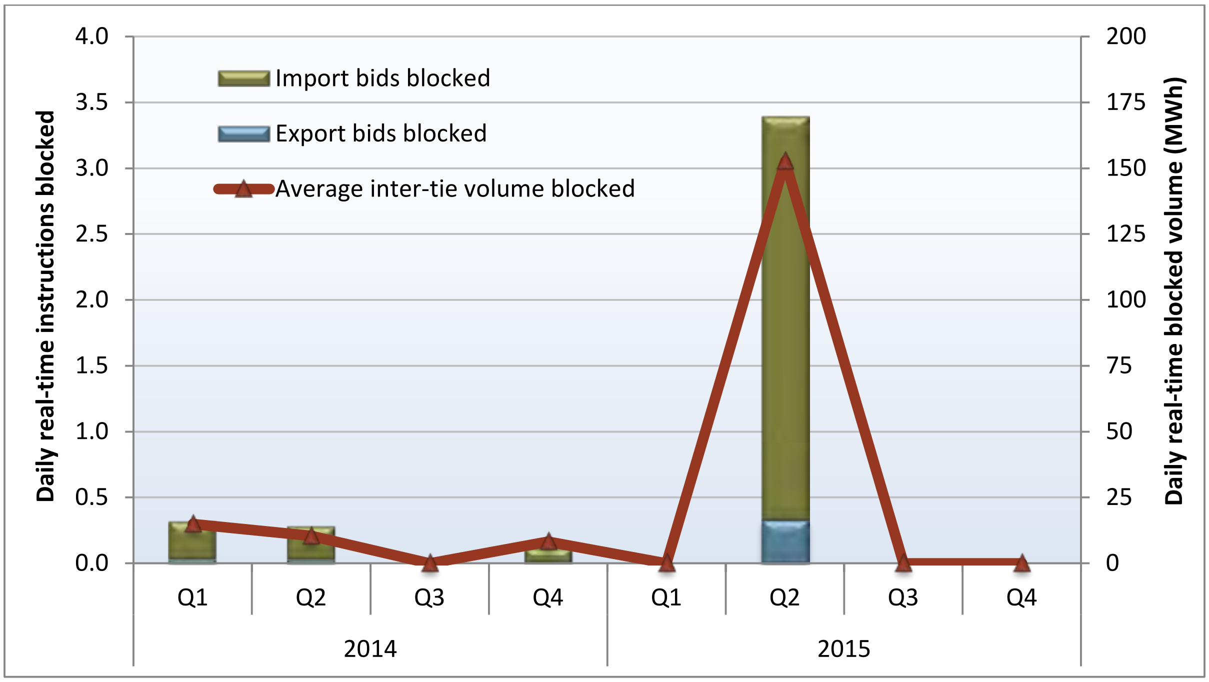
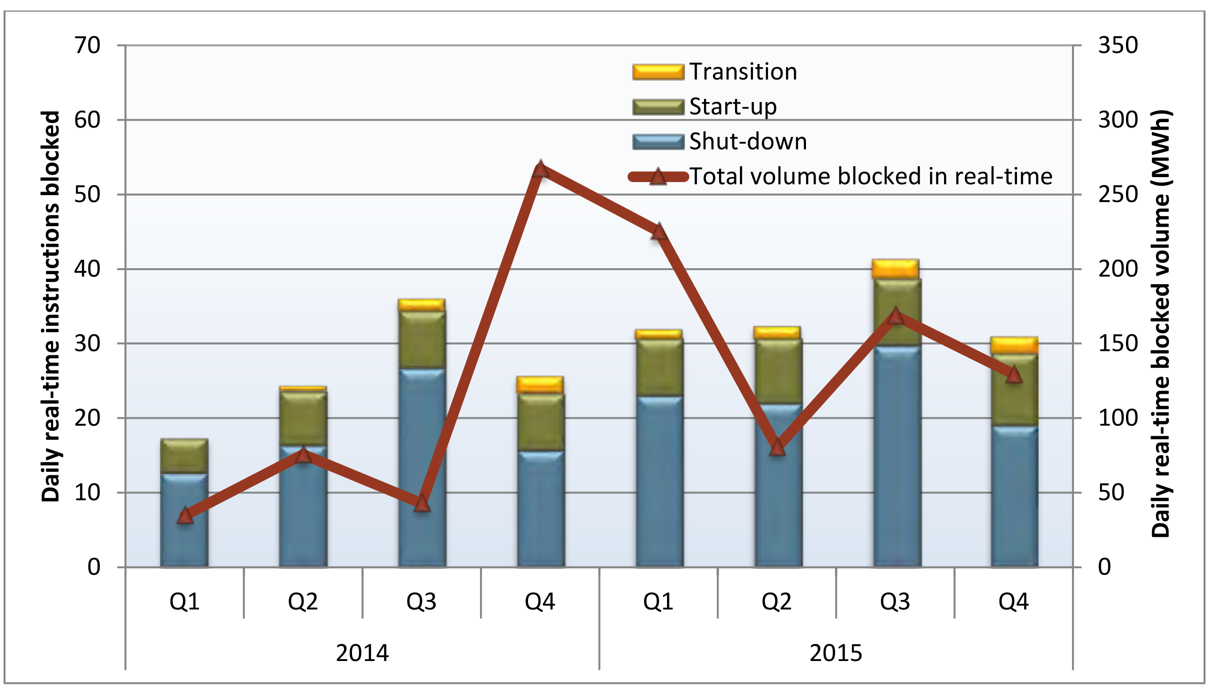


Figure 9.11 Frequency and volume of blocked real-time internal instructions



9.4 Blocked dispatches

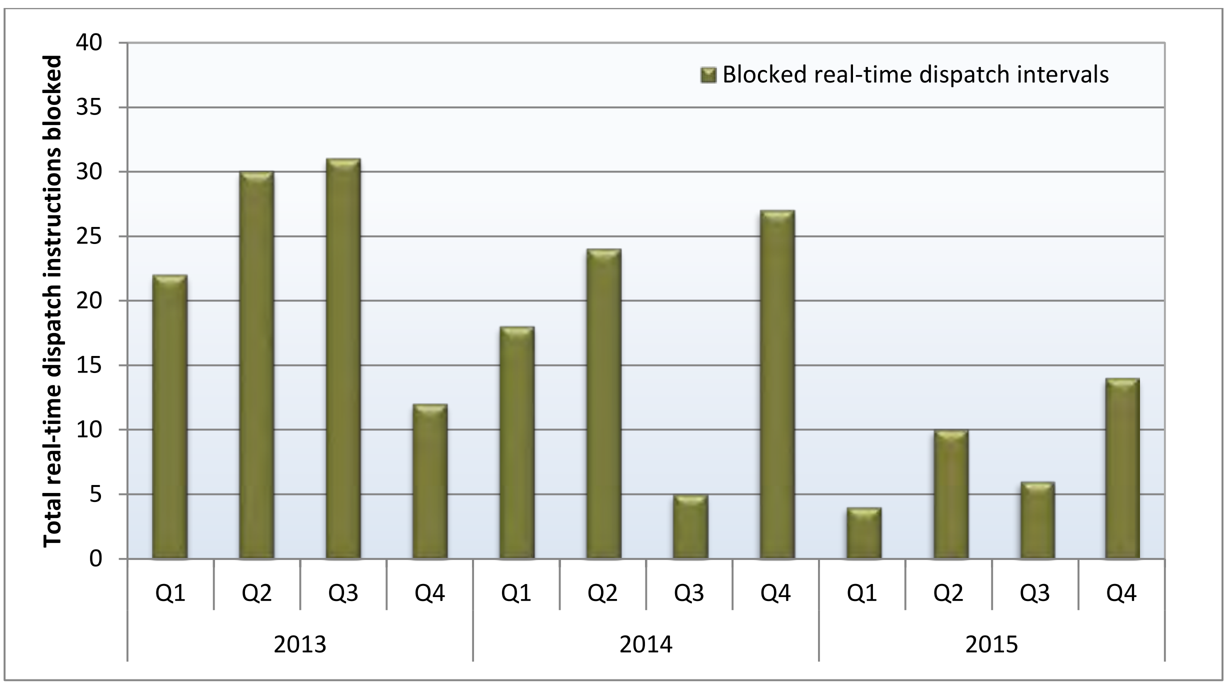
Operators review dispatches issued in the real-time market before these dispatch and price signals are sent to the market. If the operators determine that the 5-minute dispatch results are inappropriate, they are able to block the entire real-time dispatch instructions and prices from reaching the market.

The ISO began blocking dispatches 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.[177]

Figure 9.12 shows the frequency that operators blocked price results in the real-time dispatch from 2013 through 2015. The total number of blocked intervals in 2015 dropped by about 54 percent from 2014 levels. This change is driven by the decrease in blocked dispatches triggered by ISO operators due to continued improvement in market software functionality.

Figure 9.12 Frequency of blocked real-time dispatch intervals



[177] For example, if the load were to drop by 50 percent in one interval, the software can automatically block the results.

9.5 Residual unit commitment adjustments

As noted in Section 2.4, the purpose of the residual unit commitment market is to ensure that there is sufficient capacity on-line 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 residual unit commitment requirements for reliability purposes. Use of this procedure was minimal in 2014 and declined overall in 2015.

As illustrated in Figure 9.13, 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 2015 than in 2014 (see Chapter 5 for further detail).

The ISO introduced an automatic adjustment to residual unit commitment schedules to account for differences between the day-ahead schedules of participating intermittent resource program (PIRP) resources and the forecast output of these renewable resources.[178] This adjustment, called the eligible intermittent resource adjustment, went into effect in February 2014 and is represented by the yellow bar in Figure 9.13. In the future, this adjustment may be expanded to include adjustments for forecasts of participating intermittent resource program renewables without day-ahead schedules. DMM supports this change.

The day-ahead forecasted load versus cleared day-ahead capacity (blue bar) represents the difference in cleared supply (both physical and virtual) compared to the ISO's load forecast.[179] On average, this factor was not a significant factor in increasing residual unit commitment requirements in 2015. Operator adjustments to the residual unit commitment process (red bar) played a minimal role in the residual unit commitment procurement in 2015 similar to 2014, averaging just about 31 MW per hour.

Figure 9.14 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 14 to 20. While ISO operator adjustments were low in the off-peak hours, net virtual supply was a major driver of residual unit commitment procurement in these periods. On average, day-ahead cleared capacity was greater than day-ahead load forecast during most hours in 2015, except for a few late evening hours. Intermittent resource adjustments were greatest in hours ending 9 to 18 and hour ending 24.

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

[179] Due to the loss of source data, DMM estimated the values reported in the blue bar by subtracting price sensitive load including losses from the sum of forecast load, day-ahead exports and pumped storage load.

Figure 9.13 Determinants of residual unit commitment procurement

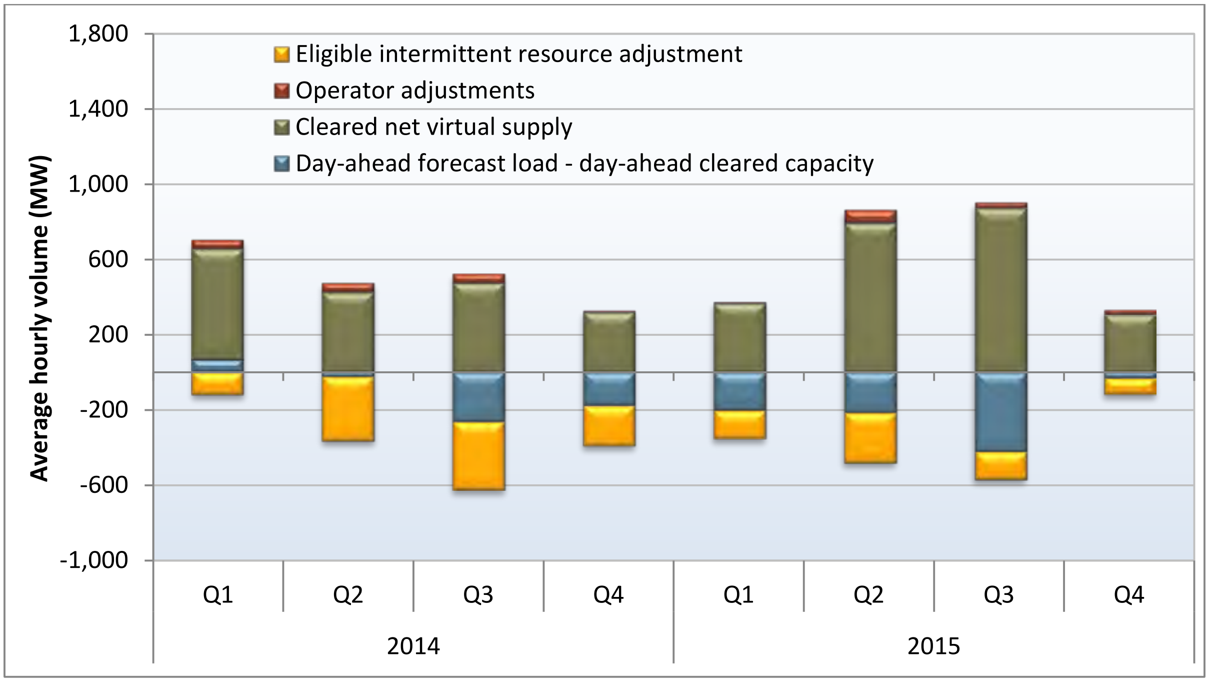
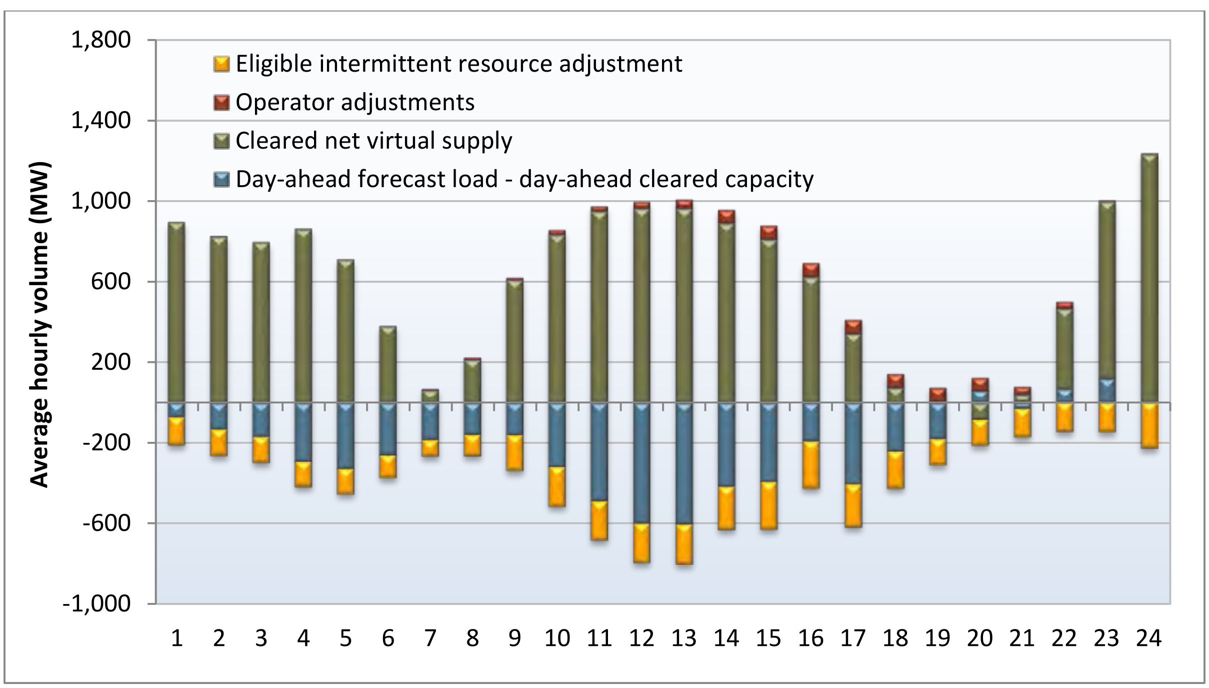


Figure 9.14 Average hourly determinants of residual unit commitment procurement (2015)



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. This year's report highlights analysis of flexible resource adequacy requirements and procurement since 2015 was the first year these requirements were in place. Key findings of this analysis include the following:

- The total flexible resource adequacy requirement exceeded the actual maximum three-hour net load ramp in every month but January. However, because there are varying must-offer hours for the different flexible categories, the effective flexible resource adequacy requirement *during* the hours of the actual maximum net load ramp was often less than the ramping need.

- Collectively, load-serving entities procured more flexible capacity than required. This capacity exceeded the actual maximum three-hour net load ramp in every month. Procurement consisted mostly of gas-fired generation that qualified as Category 1 (base flexibility) capacity.

- Flexible resource adequacy capacity had fairly high levels of availability in 2015 even though there was not an incentive mechanism in place and resources could not provide substitute capacity when on outage or when a use-limitation was reached. Average availability ranged from 80 percent to 94 percent in the day-ahead market and from 84 percent to 92 percent in the real-time market.

This report also analyzes the availability of resources used to meet the system level resource adequacy requirement during the 210 hours with the highest system loads. In 2015, these 210 hours included all hours with peak load over 38,590 MW. This analysis provides an indication of how well the program requirements are meeting actual peak loads. Key findings of this analysis include the following:

- During the 210 hours with the highest loads, about 93 percent of the resource adequacy capacity procured 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 decrease from 95 percent availability in 2014.

- Capacity made available under the resource adequacy program in 2015 was mostly sufficient to meet system-wide and local area reliability requirements. However, due to the retirement of the two San Onofre nuclear units with a capacity of over 2.2 GW, the ISO continued to rely on reliability must-run contracts with synchronous condensers at Huntington Beach units 3 and 4 to improve local reliability in Southern California.

The CPUC and the ISO continue to refine and enhance the resource adequacy framework. Currently, the CPUC and ISO are developing protocols for determining requirements for flexible capacity, counting flexible resource adequacy showings, expanding replacement and substitution provisions, and resolving any shortfalls through backstop procurement.

10.1 Background

The traditional system resource adequacy provisions require load-serving entities to procure generation capacity to meet 115 percent of their forecast peak demand in each month.[180] In addition to a system-wide requirement, load-serving entities are also required to procure generation capacity to meet requirements for local capacity areas. The resource adequacy provisions further evolved in 2015 to require procurement of specific resource attributes to address extended periods of upward ramping need through the recently established flexible resource adequacy program.

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. Resource adequacy capacity must then be bid into the ISO markets through a must-offer requirement. The must-offer requirements differ for system and flexible resource adequacy. The system resource adequacy requirements are explained below and the flexible program requirements are described in more detail in Sections 10.2 and 10.3.

Around half of the generating capacity counted toward system 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 and imports, with a total capacity of around 29,300 MW. If the market participant does not submit bids, the ISO automatically creates bids for these resources.

The remaining generation resources that are counted toward the system 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 available to the market consistent with their operating limitations. These include the following:

- Hydro resources, which represent 13 percent of system resource adequacy capacity;
- Use-limited thermal resources, such as combustion turbines subject to use limitations under air emission permits, which represent 12 percent of system resource adequacy capacity;[181]
- Non-dispatchable generators, which include nuclear, qualifying facilities, wind, solar and other miscellaneous resources. These resources account for about 17 percent of system capacity.

Imports represent around 5 percent of system 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 committed in the day-ahead market, the importer is not required to submit a bid for this capacity in the real-time market. If an import clears in 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.

[180] 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).

[181] 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 year. Market participants submit use plans to the ISO for these resources. These plans describe their restrictions and outline their planned operation.

All available system 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.
- **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 Flexible resource adequacy requirements

The resource adequacy program is currently evolving from a program focused solely on peak demand needs to one focused on the grid's operational needs more broadly. The integration of large amounts of renewable generation has changed the grid's operating conditions by increasing ramping needs, particularly as solar generation increases and decreases. The CPUC and ISO now require not just a certain amount of capacity to meet peak load, but also specific resource attributes to address these changing conditions. As such, grid reliability is now also maintained through the recently established flexible resource adequacy program. This program was approved by FERC in 2014 and became effective January 1, 2015.[182]

The flexible resource adequacy framework is specifically designed to provide capacity with the attributes required to manage the grid during extended periods of upward ramping needs. Under this framework, the monthly flexible requirement is set at the forecasted maximum contiguous three-hour net load ramp plus a contingency factor.[183] Resources may qualify as flexible capacity based on their ability to provide upward ramp (or reduce ramping needs) during the periods of predicted net load ramp.[184] Because the grid commonly faces two pronounced net load ramps a day,[185] the flexible resource adequacy categories are designed to address both the maximum primary and secondary net load ramp while allowing for a variety of resources to provide flexible capacity.

The must-offer obligations differ amongst the flexible capacity categories but require all resources to submit economic energy and ancillary service bids in both the day-ahead and real-time markets and

[182] For more information, see the following FERC order: http://www.caiso.com/Documents/Oct16_2014_OrderConditionallyAcceptingTariffRevisions-FRAC-MOO_ER14-2574.pdf.

[183] The capacity factor is the greater of the loss of the most severe single contingency or 3.5 percent of expected peak load for the month.

[184] Net load is defined as total load less wind and solar production.

[185] The ISO system typically experiences two extended periods of net load ramps, one in the morning and one in the evening. The magnitude and timing of these ramps change throughout the year. The larger of the two three-hour net load ramps (the primary ramp) generally occurs in the evening for non-summer months and in the morning during the summer. The must-offer obligation hours vary seasonally based on this pattern for Category 2 and 3 flexible resource adequacy.

participate in the residual unit commitment process. A brief description of the purpose, requirements, and must-offer obligation for each category is presented below.

- **Category 1 (Base flexibility):** Category 1 resources must have the ability to address both the primary and secondary net load ramps each day. These resources must submit economic bids for 17 hours a day and be available 7 days a week. The Category 1 requirement is designed to cover 100 percent of the secondary net load ramp and a portion of the primary net load ramp. The requirement is therefore based on the forecasted maximum three-hour secondary ramp. There is no limit to the amount of resources that meet the Category 1 criteria that can be used to meet the total system flexible capacity requirement.
- **Category 2 (Peak flexibility):** Category 2 resources must be able to address the primary net load ramp each day. These resources must submit economic bids for 5 hours a day (which vary seasonally) and be available 7 days a week. The Category 2 operational need is based on the difference between the forecasted maximum three-hour secondary net load ramp (the Category 1 requirement) and 95 percent of the forecasted maximum three-hour net load ramp. The calculated Category 2 operational need serves as the *maximum* amount of flexible capacity in this category that can be used to meet the total system flexible capacity requirement.
- **Category 3 (Super-peak flexibility):** Category 3 resources must be able to address the primary net load ramp. These resources must submit economic bids for 5 hours (which vary seasonally) on non-holiday weekdays. The Category 3 operational need is set at 5 percent of the forecasted three-hour net load ramp. The calculated Category 3 operational need serves as the *maximum* amount of flexible capacity in this category that can be used to meet the total system flexible capacity requirement.

Figure 10.1 Flexible resource adequacy requirements during the actual maximum net load ramp

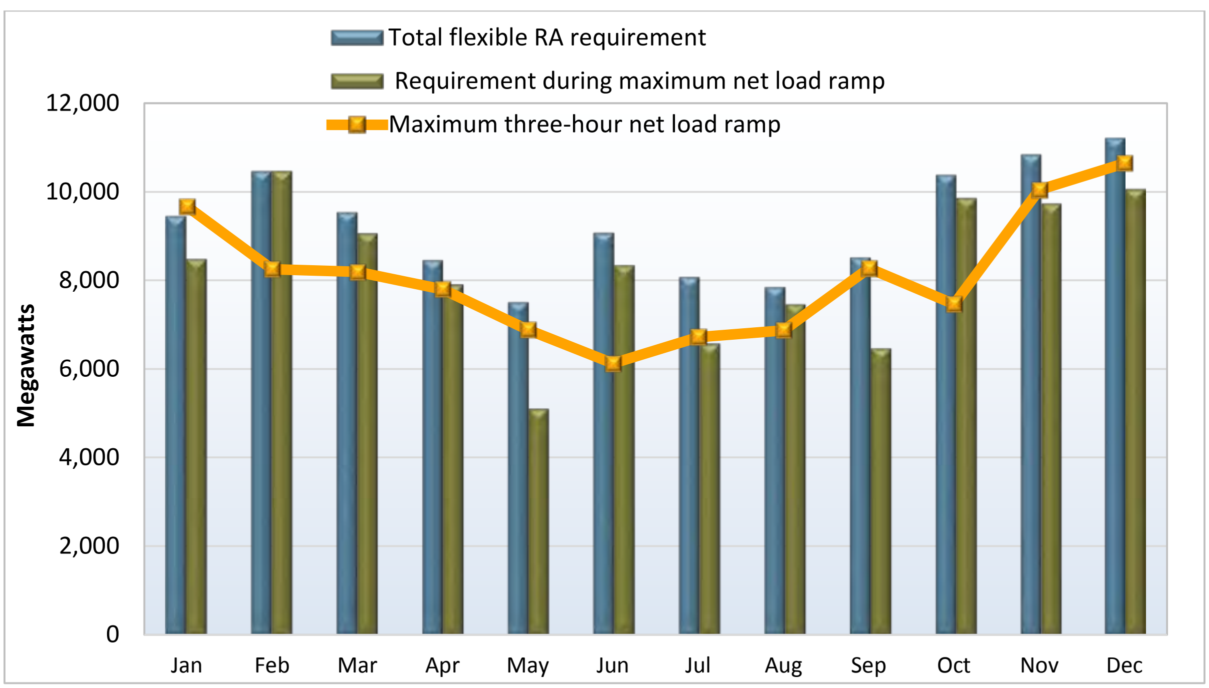


Figure 10.1 compares the monthly flexible resource adequacy requirements and the actual maximum three-hour net load ramp.[186] The blue bars represent the total system flexible capacity requirement for the month and the gold line represents the maximum three-hour net load ramp. January was the only month in 2015 during which the maximum three-hour net load ramp exceeded the flexible resource adequacy requirement.

The green bars in Figure 10.1 represent the requirement *during* the period of the maximum three-hour net load ramp. Because each category of flexible resource capacity has different must-offer hours, the requirement will effectively differ from day-to-day and hour-to-hour.[187] This figure was calculated by first identifying the day and hours the maximum net load ramp occurred, then averaging the flexible capacity requirements for the categories with must-offer obligations during those hours.

The flexible resource adequacy requirement was less than the ramping needs during the maximum net load ramp for six months in 2015. This is shown in Figure 10.1 for months when the green bars fall below the yellow line. Table 10.1 below provides a description of when the monthly maximum three-hour net load occurred and if the flexible resource adequacy requirement was less than the total requirement during that period.

[186] Our estimates of the net load ramp may vary slightly from the ISO's calculations because we used 5-minute interval data and the ISO uses one-minute interval data.

[187] For example, because Category 3 resources do not have must-offer obligations on weekends and holidays, the effective requirement during the net load ramps on those days will be less than the total flexible requirement set for the month.

Table 10.1 Maximum three-hour net load ramp and flexible resource adequacy requirements

Month	Maximum 3-hour net load ramp (MW)	Total flexible RA requirement (MW)	Average requirement during maximum net load ramp (MW)	Date of maximum net load ramp	Ramp start time	Average requirement met ramp? (Y/N)	Why average requirement during max net load ramp does not equal total requirement
Jan	9,666	9,459	8,489	1/1/2015	14:35	N	Ramp occurred on a holiday and one hour did not overlap with must offer hours
Feb	8,255	10,465	10,465	2/11/2015	15:00	Y	
Mar	8,192	9,543	9,066	3/22/2015	16:30	Y	Ramp occurred on a weekend
Apr	7,799	8,468	7,917	4/8/2015	17:00	Y	One hour of ramp did not overlap with must offer hours
May	6,884	7,520	5,114	5/23/2015	17:20	N	Ramp occurred on a weekend and entirely outside of must offer hours
Jun	6,124	9,078	8,352	6/30/2015	10:25	Y	One hour of ramp did not overlap with must offer hours
Jul	6,720	8,083	6,587	7/19/2015	11:15	N	Ramp occurred on a weekend and two hours did not overlap with must offer hours
Aug	6,874	7,861	7,467	8/16/2015	9:55	Y	Ramp occurred on a weekend
Sep	8,272	8,523	6,478	9/8/2015	12:20	N	Three hours of ramp did not overlap with must offer hours
Oct	7,461	10,381	9,862	10/4/2015	16:05	Y	Ramp occurred on a weekend
Nov	10,042	10,848	9,737	11/29/2015	14:30	N	Ramp occurred on a weekend and one hour did not overlap with must offer hours
Dec	10,675	11,212	10,063	12/26/2015	14:30	N	Ramp occurred on a weekend and one hour did not overlap with must offer hours

Table 10.1 highlights several notable issues, which include the definition of summer and non-summer months as well as the treatment of holidays and weekends. For example, in May the maximum net load ramp not only occurred on a Sunday but also in the evening, completely outside the hours of the Category 2 must-offer obligation. In the *Final 2014 Flexible Capacity Needs Assessment*, the ISO established morning must-offer hours in the summer months (hours ending 8 through 13) for Category 2 and 3 capacity and evening must-offer hours in the non-summer months (hours ending 16 through 20).[188] The ISO identified May as a transition month where the ISO's ramping needs shift from the evening hours to the morning hours. Even though the average projected maximum net load ramp occurred in the evening in May, the ISO imposed morning must-offer hours in order to align the obligations with the summer and non-summer demarcation used for the resource adequacy program.

In addition, the daily maximum net load ramps also occurred in evening hours for 28 days in May. There were 33 days in 2015 when the flexible resource adequacy requirements during the daily maximum net load ramp were less than ramping needs, with 17 of those days in the month of May. Another seven of these 33 days occurred in September, another transition month.

188 http://www.caiso.com/Documents/Final_2014_FlexCapacityNeedsAssessment.pdf.

The flexible resource adequacy requirements and must-offer rules are very dependent on the ability to predict the size of the maximum net load ramp as well as the time of day the ramp occurs. This analysis suggests that the 2015 requirements and must-offer hours were insufficient in reflecting actual ramping needs. Most of the maximum net load ramps occurred at least partially outside of Category 2 and 3 must-offer hours.[189] In eight months of the year, the maximum net load ramp occurred on a holiday or weekend when Category 3 capacity does not have a must-offer obligation.

If load-serving entities had procured just the minimum Category 1 and maximum Category 2 and 3 requirements, the ISO may have been short the necessary flexibility to meet ramping needs. However, as discussed below, the load-serving entities procured significantly more flexible capacity than required. DMM recommends that the ISO and local regulatory authorities further evaluate the must-offer rules for Category 2 and 3 flexible capacity to better address weekend and holiday availability and, especially, to address transition months such as May and September.

10.3 Flexible resource adequacy procurement

Flexible resource adequacy procurement exceeded requirements in 2015. As seen in Figure 10.2, total procurement (gold bars) exceeded the total requirement (blue bars) in every month by up to 2,200 MW. The green bars represent the must-offer obligation of procured flexible capacity *during* the hours of the maximum three-hour net load ramp.[190] The obligation is lower than the total procurement in most months because must-offer hours vary by flexible category and the maximum net load ramps often occurred outside of Category 2 and 3 must-offer hours (see Table 10.1). However, the flexible capacity obligation during the maximum net load ramp exceeded the actual maximum net load ramp in every month. This suggests that the total procurement of flexible capacity was sufficient to meet the maximum net load ramps. The availability of this procured capacity is summarized in Section 10.7.

Table 10.2 presents the average monthly flexible capacity procurement in 2015 by resource type. The flexible resource adequacy categories and must-offer rules were designed to be technology neutral allowing for a variety of resources to provide flexibility to the ISO. While the CPUC and ISO created counting criteria for a variety of resource types, almost all flexible ramping procurement in 2015 was composed of gas-fired generation.

Hydro-electric generators made up the next largest volume at about 3 percent on average of Category 1 flexible capacity, although for the first months of the year (January through April) hydro resources made up about 10 percent of Category 1 capacity. Load-serving entities procured an average of only 50 MW of Category 3 capacity, significantly less than the maximum allowed (roughly 465 MW). Instead, the load-serving entities procured greater amounts of Category 1 capacity.

[189] The maximum net load ramps in months June-September began in the late morning and continued into the early afternoon at least partially (with the exception of August) outside of the morning must-offer hours (hours ending 8 to 13). However, the ISO changed the must-offer hours for 2016 summer months to hours ending 13 to 17 to reflect the later timing of the net load ramp.

[190] The must-offer obligation estimate used in this chart is hypothetical. We sum the must-offer obligation of all resources including long-start and extra-long-start resources regardless of whether or not they were committed in the necessary time frame to actually have an obligation in real time.

Figure 10.2 Flexible resource adequacy procurement during the maximum net load ramp

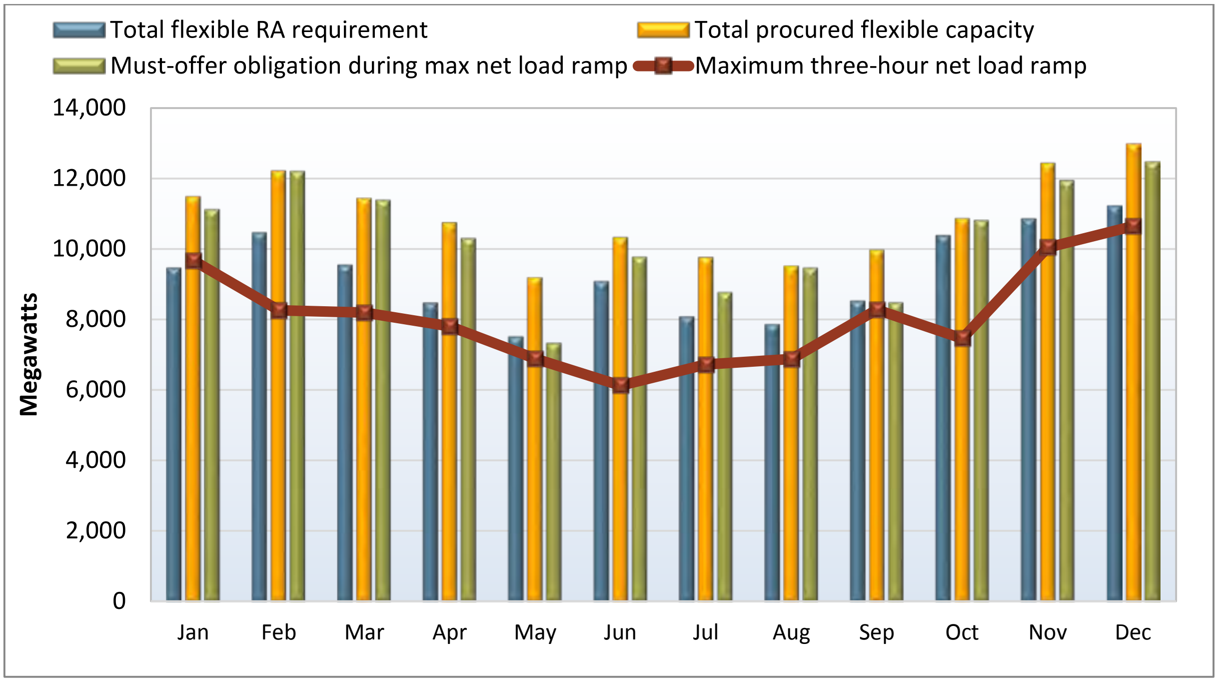


Table 10.2 Average monthly flexible resource adequacy procurement by resource type

Resource Type	Category 1		Category 2		Category 3	
	Average MW	Total %	Average MW	Total %	Average MW	Total %
Gas-fired Generators	8,016	88%	92	5%	2	4%
Use-Limited Gas Units	750	8%	1,696	95%	48	95%
Hydro Generators	303	3%	0	0%	0.2	0.3%
Geothermal	8	0.1%	0	0%	0	0%
Total	**9,077**	**100%**	**1,789**	**100%**	**50**	**100%**

10.4 Overall system resource adequacy availability

System resource adequacy capacity is especially important to meet peak loads during 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 the remaining available resources offering resource adequacy capacity instrumental in meeting even moderate loads during these months.

A high portion of resource adequacy capacity was available to the market throughout 2015. Figure 10.3 summarizes the average amount of resource adequacy capacity made available to the day-ahead, residual unit commitment and real-time markets in each quarter. The red line shows the total amount of this capacity used to meet resource adequacy requirements.[191] The bars show the amount of resource adequacy capacity that was made available during critical hours in the day-ahead, residual unit commitment, and real-time markets.[192]

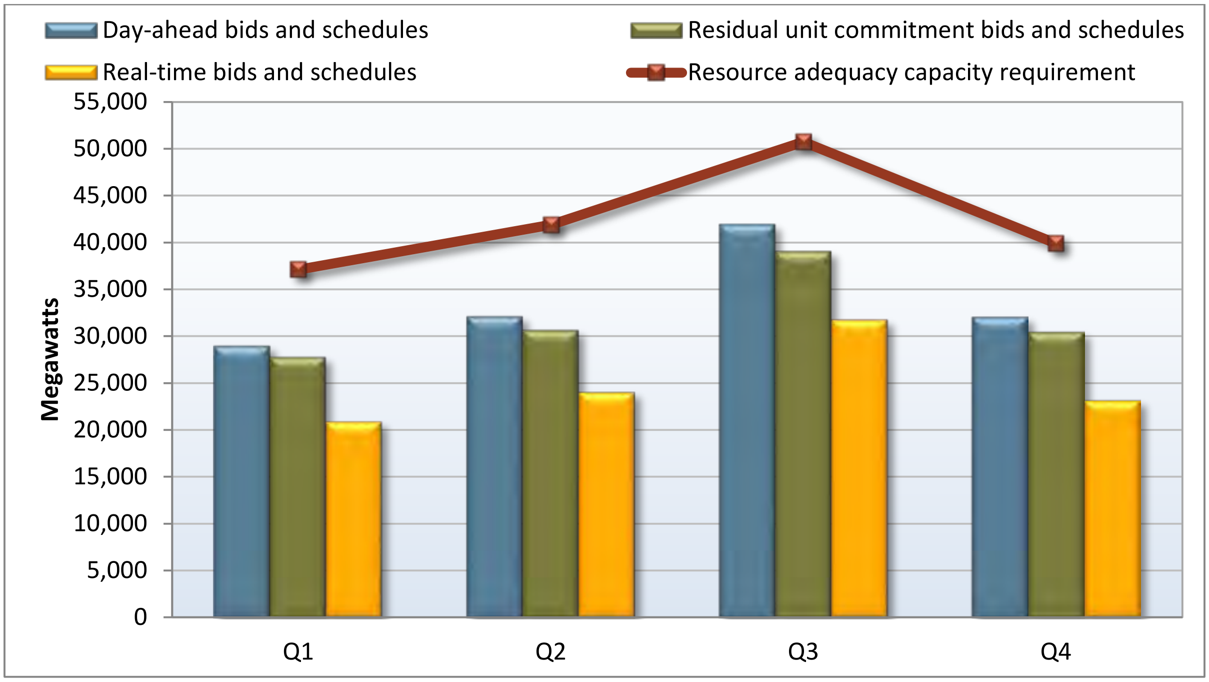
Key findings of this analysis include the following:

- The highest percentage of procurements were available during the third quarter, from July through September. During these months, out of about 50,700 MW of resource adequacy capacity procured, an average of around 42,000 MW (or about 83 percent) was available in the day-ahead market.
- The lowest level of availability was during the second quarter, during which about 76 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 10.3 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.

[191] 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 resources representing some imports and firm import liquidated damages contracts, capacity from reliability must-run resources, resource adequacy requirements met by demand response programs, and load-following metered subsystem resources.

[192] 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 10.3 Quarterly resource adequacy capacity scheduled and bid into ISO markets (2015)



10.5 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.[193] The rules do not specify that these hours must include the hours of the highest load or most critical system conditions. Because 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. In 2015, this included all hours with peak load equal to or over 38,590 MW.

Figure 10.4 provides an overview of monthly resource adequacy capacity, monthly peak load, and the number of hours with loads equal to or over 38,590 MW during that period. Many of the highest load hours (blue bar) occurred during heat waves in August and September. The red and 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.

[193] The CPUC requires the resources be available 30, 40, 40, 60, and 40 hours during each of these months, respectively.

Figure 10.4 Summer monthly resource adequacy capacity, peak load, and peak load hours (May through September 2015)

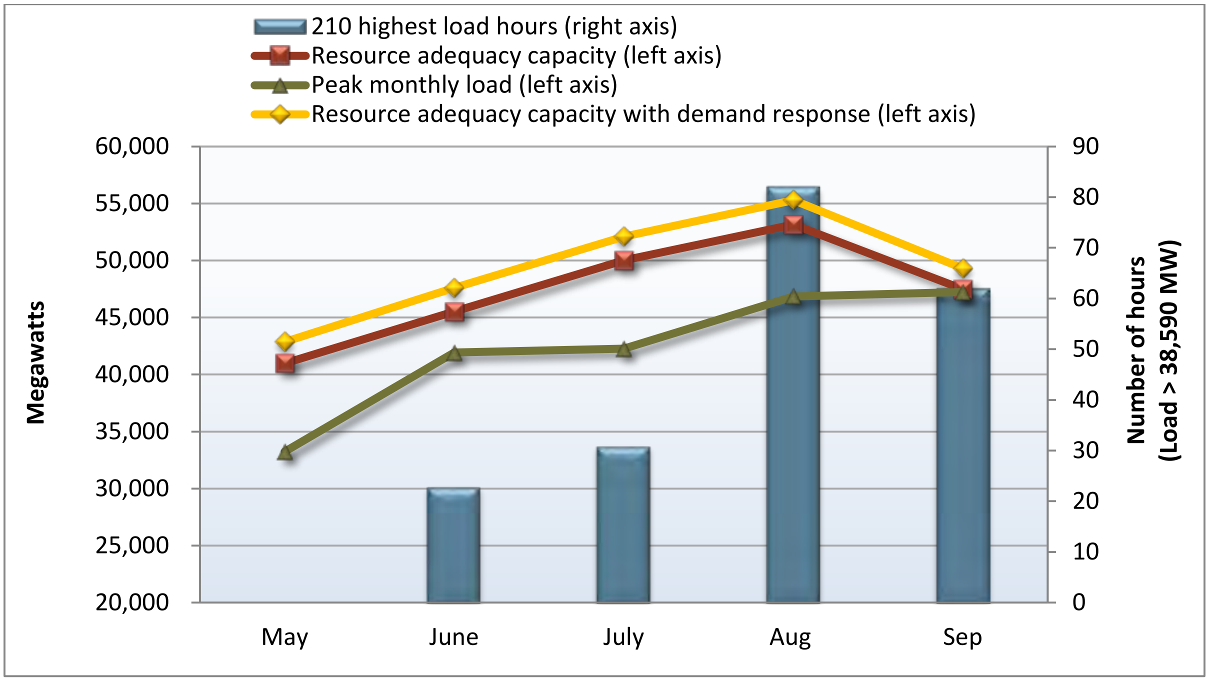


Table 10.3 provides a detailed summary of the availability of resource adequacy capacity over the 210 summer peak load hours for each type of generation. Separate sub-totals are provided for resources for which the ISO creates bids if market participants do not submit a bid or self-schedule, and resources for which the ISO does not create bids. As shown in Table 10.3:

- ***Resource adequacy capacity after reported outages and derates*** — Average resource adequacy capacity was around 50,200 MW during the 210 highest load hours in 2015. Similar to the previous year, after adjusting for outages and derates, the remaining capacity equals about 93 percent of the overall resource adequacy capacity. This represents an outage rate of about 7 percent during these hours.

- ***Day-ahead market availability*** — For the 16,200 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 77 percent of the available capacity of these resources. This compares to the 94 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 about 5 percent more than that available to the day-ahead market.

- ***Real-time market availability*** — The last three columns of Table 10.3 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. The resource adequacy capacity available in the real-time market timeframe is calculated as the remaining resource adequacy capacity from resources with a day-ahead or residual unit commitment schedule plus the resource adequacy capacity from uncommitted short-start units (not adjusted for outages or derates). 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. This bid-in capacity has been adjusted for outages and derates.

- ***Use-limited gas units*** — Around 5,900 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 typically allowed to operate in only 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 4,700 MW of this 5,900 MW of capacity was scheduled or bid into the real-time market.

- ***Nuclear units*** — In 2015 around 2,800 MW of nuclear resources were used to meet resource adequacy requirements. This is similar to the previous year and reflects the retirement of the San Onofre Nuclear Generating Station units in June of 2013.

- ***Imports*** — Around 2,700 MW of imports were used to meet resource adequacy requirements. This was down almost 30 percent, from about 3,800 MW of imports used to meet resource adequacy requirements in 2014. This decline was offset by an increase in wind and solar resource adequacy capacity and use-limited gas resources in 2015. About 97 percent of import 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. About 93 percent of real-time capacity was scheduled or bid into the real-time market. The availability of imports is discussed in more detail in Section 10.6.

Table 10.3 Average system resource adequacy capacity and availability (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	24,645	23,323	95%	23,229	94%	22,549	91%	20,164	19,315	96%
Other Generators	1,787	1,557	87%	1,505	84%	1,501	84%	1,746	1,498	86%
Imports	2,626	2,626	100%	2,553	97%	2,448	93%	2,160	2,014	93%
Subtotal	**29,058**	**27,506**	**95%**	**27,287**	**94%**	**26,499**	**91%**	**24,070**	**22,827**	**95%**
ISO Does Not Create Bids:										
Use-Limited Gas Units	5,916	5,260	89%	5,114	86%	5,009	85%	4,726	4,062	86%
Hydro Generators	6,415	5,331	83%	4,398	69%	4,181	65%	6,415	4,304	67%
Nuclear Generators	2,840	2,728	96%	2,710	95%	2,710	95%	2,840	2,710	95%
Wind/Solar Generators	4,297	4,277	100%	2,525	59%	2,517	59%	4,231	2,654	63%
Qualifying Facilities	1,497	1,477	99%	1,293	86%	1,293	86%	1,497	1,281	86%
Other Non-Dispatchable	196	192	98%	157	80%	157	80%	196	173	88%
Subtotal	**21,161**	**19,265**	**91%**	**16,197**	**77%**	**19,073**	**90%**	**19,905**	**15,184**	**76%**
Total	**50,219**	**46,771**	**93%**	**43,484**	**87%**	**45,572**	**91%**	**43,975**	**38,011**	**86%**

10.6 Imports

Load-serving entities are allowed to use imports to meet their system resource adequacy requirement. While total import capability into the ISO system is about 11,000 MW, net imports averaged about 8,400 MW during the peak summer months. Utilities used imports to meet around 2,600 MW, or about 5 percent, of the system resource adequacy requirements during the 210 highest load hours. This reflects about a 30 percent decrease in the resource adequacy capacity from imports compared to 2014 and nearly a 42 percent decrease compared to 2013. This reduction in resource adequacy capacity from imports appears to have been replaced by higher levels of resource adequacy capacity from use-limited gas units as well as wind and solar generation.

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 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 real-time market.

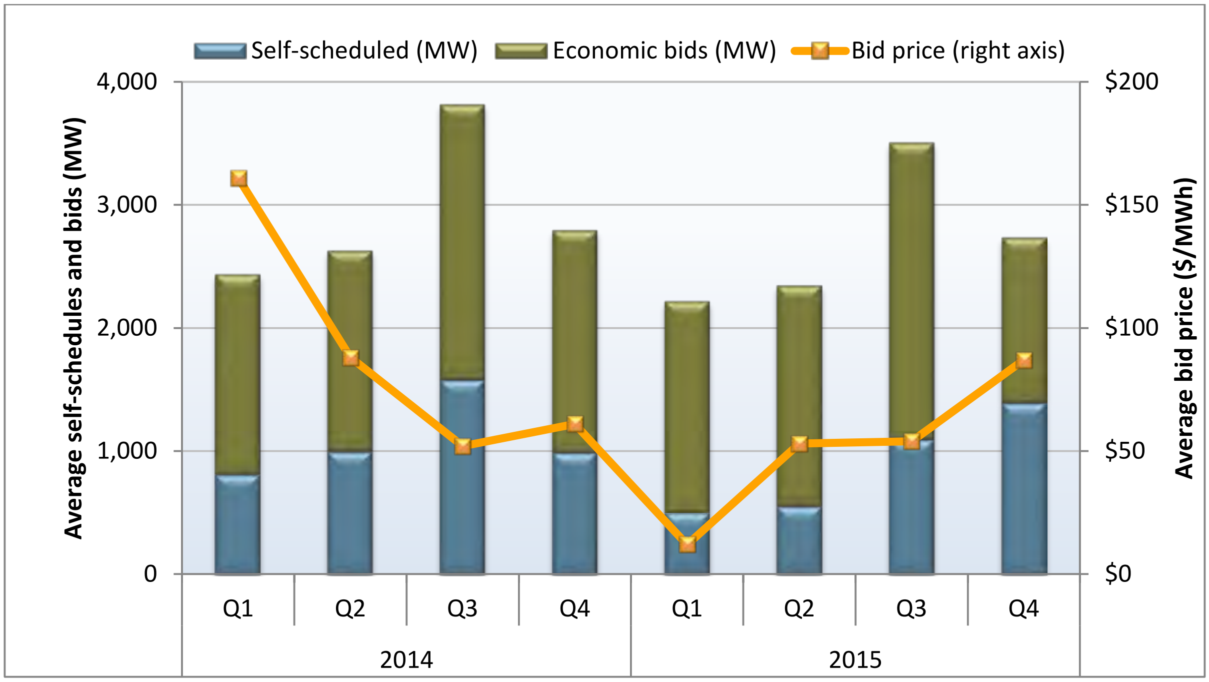
The trend of increased quantity and prices of economic bids for resource adequacy imports, which began in 2012, continued in 2015. Economic bids increased from 62 percent in 2014 to 67 percent in 2015. Self-scheduled import bids only constituted around 33 percent of total bids in the day-ahead market in 2015 compared to 38 percent the previous year.

Figure 10.5 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.

The quantity of imports with economic bids in 2015 was similar to the level in 2014. The quantity of economic bids was greater than the quantity of self-scheduled bids in every quarter.

Figure 10.5 also shows that market participants submitted higher-priced economic bids as the year progressed with the highest prices in the fourth quarter. The weighted average of bid prices increased throughout 2015, starting in the first quarter at $12/MWh and ending at $87/MWh in the fourth quarter. Overall, weighted average bid prices were lower in 2015 compared to 2014, averaging $50/MWh in 2015 compared to $87/MWh in 2014.

Figure 10.5 Resource adequacy import self-schedules and bids (peak hours)



10.7 Flexible resource adequacy availability

Flexible resource adequacy capacity has different must-offer obligations than that of system resource adequacy. As explained in Section 10.2, the flexible resource adequacy program is designed to provide capacity that can meet the grid's needs during extended periods of upward ramping. The must-offer hours for flexible capacity are set with respect to when the ISO predicts the greatest ramping needs are. Flexible resource adequacy capacity is also specifically required to submit economic bids in both the day-ahead and real-time markets in order to provide flexibility.

Table 10.4 presents flexible resource adequacy capacity and availability for 2015. The table includes an assessment of the average must-offer obligation and availability of flexible resource adequacy capacity in both the day-ahead and real-time markets each month. For purposes of this analysis, flexible resource adequacy availability was measured by assessing economic bids and outages in the day-ahead and real-time markets. Availability was assessed according to the must-offer obligation of the flexible resource adequacy category. For the resources where their minimum output qualified as flexible capacity, the minimum output was only assessed as available if no part of the resource was self-scheduled.

Extra-long-start resources are required to participate in the extra-long-start commitment process and economically bid into the day-ahead and real-time markets when committed by this process. For purposes of this analysis, extra-long-start resources were assessed as available in the day-ahead market to the extent that the resource did not have outages limiting its ability to provide its full obligation. Long-start and extra-long-start resources were only assessed in the real-time market analysis if they received schedules in the day-ahead market or residual unit commitment process.

This analysis is not intended to replicate how availability will be measured under the resource adequacy availability incentive mechanism (RAAIM) that begins in May 2016. Rather, this is a high level assessment of the extent that flexible resource adequacy capacity was available to the day-ahead and real-time markets in 2015.

Table 10.4 Average flexible resource adequacy capacity and availability

Month	Average DA flexible capacity (MW)	Average DA Availability		Average RT flexible capacity (MW)	Average RT Availability	
		MW	% of RA Capacity		MW	% of RA Capacity
January	10,565	9,402	89%	6,154	5,524	90%
February	10,750	8,549	80%	5,755	4,905	85%
March	10,360	8,982	87%	5,929	5,013	85%
April	9,489	7,717	81%	4,846	4,315	89%
May	7,961	6,672	84%	3,598	3,218	89%
June	8,876	8,091	91%	5,398	4,979	92%
July	8,486	8,006	94%	5,593	5,146	92%
August	8,315	7,726	93%	5,423	4,858	90%
September	8,655	8,009	93%	5,681	5,163	91%
October	9,751	8,616	88%	6,505	5,438	84%
November	11,139	9,834	88%	6,114	5,373	88%
December	11,645	10,588	91%	7,114	6,251	88%

Results presented in Table 10.4 suggest that flexible resource adequacy had fairly high levels of availability in 2015 considering there was not an incentive mechanism in place and resources could not provide substitute capacity when an outage occurred or when a use-limitation was reached.[194] Average availability ranged from 80 percent to 94 percent in the day-ahead market and from 84 percent to 92 percent in the real-time market. Availability may increase in 2016 with implementation of the resource adequacy availability incentive mechanism, which is described in Section 10.9. For example, resources will have the opportunity to provide substitute capacity during forced outages. Results presented in Table 10.4 also show that the real-time average must-offer obligation is much lower than the day-ahead obligation. This reflects several factors. First, resources may receive ancillary service awards in the day-ahead market covering all or part of their resource adequacy obligation. Second, long-start and extra-long-start resources do not have an obligation in the real-time market if they are not committed in the day-ahead market, residual unit commitment process or the extra-long-start commitment process. On average, roughly 3,250 MW of flexible capacity from long-start and extra-long-start resources did not have an obligation in real time.

Total procured flexible capacity from extra-long-start resources ranged from about 1,500 MW to 1,770 MW each month. Total procured flexible capacity from long-start resources ranged from about 3,500 MW to 5,500 MW each month. DMM is concerned that this procurement trend could lead to issues in real time if this capacity is not committed before the real-time market. This is because non-resource adequacy resources, which may be scheduled in the day-ahead market instead of the long-

[194] Flexible resource adequacy resources were not subject to the standard capacity product in 2015. Substitution rules and provisions for managing use-limitations were also not yet developed for flexible resources in 2015. In 2016, flexible resource adequacy resources will be subject to the resource adequacy availability incentive mechanism and will have tools for managing outages and use-limitations under the mechanism.

start resource adequacy resources, do not have a must-offer obligation in real-time. These resources may self-schedule in real-time or be of lower quality (for example, hourly-block resources), which will ultimately provide less flexibility to the market.

10.8 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.

Because 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 $26 million in 2015 from $25 million in 2014. Over two thirds of these costs resulted from the reliability must-run agreement that placed synchronous condensers at Huntington Beach units 3 and 4 into service, which began in late June 2013. This agreement was put into place due to the outage and subsequent retirement of the SONGS units in June 2013. The other costs are associated with the Oakland Station Units 1, 2 and 3.

Capacity payments related to the capacity procurement mechanism decreased in 2015. Capacity procurement mechanism costs decreased from $7.7 million in 2014 to under $1 million on two contracts in 2015. The Oildale resource received capacity procurement payments in the summer to address thermal overload for a 115 kV line in the Kern local reliability area. Also in the summer, capacity procurement payments were made to the Moss Landing Unit 6 resource due to load and weather conditions.

Table 10.5 Capacity procurement mechanism costs (2015)

Resource	Local capacity area	CPM designation (MW)	Estimated cost	CPM designation dates
Moss Landing 6	CAISO System	52	$11,661	6/30 - 7/29
Oildale 1	CAISO System	40	$538,215	7/15 - 9/12
		92	**$549,876**	

10.9 Resource adequacy developments

Flexible resource adequacy

The current flexible resource adequacy framework was approved by FERC in 2014 and became effective on January 1, 2015.[195] An analysis of the program for 2015 is in Section 10.7. The flexible resource adequacy framework was designed to help the ISO manage the integration of high levels of renewable energy, and largely mirrored similar requirements approved by the CPUC. It is important to note that

[195] For more information see the following FERC order: http://www.caiso.com/Documents/Oct16_2014_OrderConditionallyAcceptingTariffRevisions-FRAC-MOO_ER14-2574.pdf.

the 2015 to 2017 flexible resource adequacy framework that was adopted by the CPUC was considered an *interim* framework. The CPUC is currently developing a permanent program for post-2017 resource adequacy compliance years. In phase two of the flexible resource adequacy criteria and must-offer obligation initiative, the ISO is also exploring modifications to the current framework.[196] Considerations include the need for requirements to address downward ramping needs, oversupply concerns, and the ability of inter-tie resources and pump-storage technologies to provide flexible capacity.

DMM is supportive of resource adequacy requirements that focus more broadly on the grid's evolving operational needs. DMM encourages the ISO to continue to study flexibility needs and challenges and to explore improvements in the structure, rules and procedures of the resource adequacy framework to ensure that the necessary resource characteristics are available to the ISO.

Reliability services initiative

The reliability services initiative is a two-phase initiative focusing on the ISO's rules and processes relating to the resource adequacy program. Issues addressed in this initiative include resource adequacy rules for replacement and substitute capacity, definitions and qualifying criteria for new technology resources, and a compliance mechanism for resource adequacy resources. The first stage of the initiative was approved by FERC in October 2015 and implementation will begin in May 2016.

One of the biggest developments in the filing approved by FERC was the creation of the resource adequacy availability incentive mechanism, which is a new compliance measurement mechanism. This mechanism differs from the previous standard capacity product (SCP) mechanism in numerous ways, most notably by measuring availability by compliance with a resource's must-offer obligation as opposed to whether or not the resource was on outage. The basic concept of the must-offer obligation is that a resource must be available to the market, through self-scheduling or by submitting bids. This change allows for evaluation of the more detailed must-offer obligation of flexible resource adequacy resources. Though DMM believes that this mechanism is a significant improvement over the previous standard capacity product, it could be further improved by incorporating a measure of performance. It is problematic to rely solely on market bids as a measure for compliance because a resource could offer into the market without necessarily having the ability to perform. The ISO, in consultation with local regulatory agencies, specifies the criteria for resource characteristics and locations that will ensure system reliability. However, if resource adequacy resources do not perform according to the characteristics the ISO assumes for the resources, the resource adequacy process may not ensure system reliability. Therefore, DMM encourages the ISO to consider performance based enhancements to this mechanism to penalize resources that cannot consistently perform at the standards the ISO assumes for the resources in the ISO's reliability studies.

DMM is also concerned about the mechanism's penalty price. The ISO set the penalty price for not meeting availability standards at 60 percent of the soft offer cap for the capacity procurement mechanism. As DMM has noted in past annual reports, if the cost of replacement capacity approaches the soft offer cap, it will be less costly for generating unit owners to pay the penalty rather than provide substitute capacity. This could decrease reliability and increase the probability of costly backstop procurement. DMM recommends that the ISO monitor this issue once the new incentive mechanism has been implemented.

[196] For more information on this initiative see the ISO's website at: http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleResourceAdequacyCriteria-MustOfferObligations.aspx.

Capacity procurement mechanism replacement

FERC issued an order in October 2015 accepting the ISO's filing proposing tariff revisions to amend the existing capacity procurement mechanism, which is set to expire in May 2016.[197] The capacity procurement mechanism is a tool that the ISO can use to ensure that it has the capacity necessary to operate the grid. It is primarily used to overcome unexpected situations, although it could also be utilized to address shortcomings in resource adequacy procurement. The amended mechanism is expected to function very similar to the existing approach, but is designed to allow competition between different resources that may meet any capacity needs when possible. The new program allows resources to submit bids for capacity. The ISO will look to those bids first when possible to fulfill procurement needs.

[197] For more information on the initiative and implementation see the ISO's website at: http://www.caiso.com/informed/Pages/StakeholderProcesses/CapacityProcurementMechanismReplacement.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 recommendations on key market design initiatives and issues.

11.1 Congestion revenue rights

Auctioning congestion revenue rights

In the ISO most transmission is paid for by ratepayers of the state's investor owned utilities and other load-serving entities through the transmission access charge (TAC).[198] The ISO charges load-serving entities the transmission access charge in order to reimburse the entity that builds each transmission line for the costs incurred. Load-serving entities then pass that transmission access charge through to ratepayers in their customers' electricity bill. Therefore, these ratepayers are entitled to the revenues from this transmission.

These ratepayers currently receive the day-ahead market revenues from a large part of their transmission directly through the congestion revenue right allocation process. This process allocates a portion of congestion rights to load-serving entities, which pay the transmission access charge, based on historical load. These entities receive the day-ahead market congestion revenues associated with these congestion revenue rights. They then pass on these congestion revenues — along with transmission access charges — to their ratepayers.

Not all transmission is allocated through the congestion revenue right allocation process. Ratepayers are still entitled to the day-ahead market congestion revenues generated by the transmission capacity that is not allocated to ratepayers through the congestion revenue right allocation process. However, a current principle incorporated in standard electricity market design is that the day-ahead market congestion revenues from this additional transmission capacity is not provided directly to ratepayers. Instead, the ISO auctions off congestion revenue rights, which are intended to represent the rights to the day-ahead market congestion revenues of this excess transmission capacity.

The ISO and DMM have traditionally tracked and reported on congestion revenue right revenue inadequacy as a primary metric on how well the congestion revenue right market is functioning. This section explains why the revenue inadequacy commonly reported is not an accurate or appropriate measure of how well the congestion revenue right market is functioning from the perspective of ratepayers.

In this report, the performance of the congestion revenue rights auction is assessed from the perspective of the ratepayers of load-serving entities by comparing the auction revenues that ratepayers receive for rights sold in the ISO's auction to the payments made to these auctioned rights at day-ahead market prices. This represents the difference in revenues received by ratepayers as a result of

[198] Some ISO transmission is built or owned by other entities such as merchant transmission operators. The revenues from transmission not owned or paid for by load-serving entities gets paid directly to the owners through transmission ownership rights or existing transmission contracts. The analysis in this section is not applicable to this transmission. Instead, this analysis focuses on transmission that is owned or paid for by load-serving entities.

auctioning off these congestion revenue rights instead of having ratepayers collect these congestion revenues directly.

This analysis shows that congestion revenue rights not allocated to load-serving entities that are sold in the auction consistently generate significantly less revenue than is paid to the entities purchasing these rights at auction. From 2012 through 2015, ratepayers received about 45 percent of the value of their congestion revenue rights that the ISO auctioned.[199] This represents an average of about $130 million per year less in revenues received by ratepayers than the congestion payments received by entities purchasing these congestion revenue rights over the last four years. This difference was $45 million in 2015.

One of the benefits of auctioning congestion revenue rights is to allow day-ahead market participants to hedge their congestion costs. However, physical generators have consistently accounted for a relatively small portion of congestion revenue rights. Financial entities have consistently accounted for the bulk of congestion revenue rights and profits from the congestion revenue rights auction.

DMM believes these results warrant reassessing the standard electricity market design assumption that ISOs should auction off transmission capacity that remains in excess of the capacity allocated to load-serving entities. Instead, it would be much more beneficial to allow ratepayers to collect these congestion revenues directly.

The losses to ratepayers from the congestion revenue rights auction could in theory be avoided if load-serving entities purchased the congestion revenue rights at the auction from themselves. However, there are significant technical and regulatory hurdles making it difficult for load-serving entities to purchase these rights. Moreover, DMM does not believe it is appropriate to design an auction so that load-serving entities would have to purchase rights in order to avoid obligations to pay other congestion revenue rights holders.

DMM believes it would be more appropriate to design the auction so that load-serving entities will only enter obligations to pay other participants if they are actively willing to enter these obligations at the prices offered by the other participants. With this approach, any entity placing a value on purchasing a hedge against congestion costs could seek to purchase this directly from the financial entities.

Revenue inadequacy

When the amount of transmission available in the day-ahead market on a constraint exceeds the amount of transmission on the constraint for which congestion revenue rights are sold in this auction, this tends to result in *revenue inadequacy*. This results from the fact that revenues from each megawatt sold in the congestion revenue rights auction are consistently less than the congestion payments made to entities purchasing these congestion revenue rights. The ISO currently allocates any congestion revenue rights revenue inadequacy to load-serving entities based on measured demand.

[199] The large discrepancy between what congestion revenue rights sell for at auction and what they end up being worth is not unique to the California ISO. For a description of this phenomenon in PJM, see the PJM Independent Market Monitor's "2015 State of the Market Report for PJM" available at: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015.shtml.

This revenue inadequacy is generally due to differences between the network transmission model used in the congestion revenue rights process and the final day-ahead market model.[200] The ISO has taken steps to address the revenue inadequacy by accounting for more constraints in the congestion revenue rights model in future auctions. This essentially limits the amount of congestion revenue rights that are auctioned off going forward. However, DMM has noted that there are a variety of modeling issues that can tend to create discrepancies in the network transmission model used in the congestion revenue rights process and the final day-ahead market model.[201]

In 2015, congestion revenue right payments exceeded day-ahead market congestion rent collections by $98 million, compared to a $200 million shortfall in 2014. This drop in revenue inadequacy was driven largely by a 50 percent drop in overall congestion in the ISO system in 2015. Thus, DMM continues to recommend that the ISO continue to closely monitor and seek to address causes of revenue inadequacy.

In 2014, DMM provided a general methodology that could be used to allocate congestion revenue rights revenue inadequacy costs back to holders of congestion revenue rights on an interval and constraint specific basis. This alternative allocation approach would limit the total amount of revenues that can be transferred from load-serving entities to congestion revenue rights holders through revenue inadequacy. Moreover, this allocation method would reduce the incentive for entities purchasing congestion revenue rights to target the modeling differences that create revenue inadequacy costs.[202]

Numerous market participants ranked consideration of options for modifying the method for allocating congestion revenue rights revenue imbalances as a high priority in the 2014 market initiative issue ranking process. However, the ISO did not include this in its list of initiatives that would be pursued in 2015 due to resource limitations and the ISO assessment that this would involve a complicated stakeholder process.

DMM continues to recommend that the ISO consider modifying the method for allocating congestion revenue rights revenue imbalances using the general methodology proposed by DMM in 2014. However, based on analysis of the congestion revenue rights auction in this report, DMM believes a more comprehensive approach is to reassess the standard electricity market design assumption that ISOs should auction off transmission capacity that remains in excess of the capacity allocated to load-serving entities. Instead, it would be much more beneficial to allow ratepayers to collect these congestion revenues directly. With this approach, any entity placing a value on purchasing a hedge against congestion costs could seek to purchase this directly from financial entities.

[200] *2014 Annual Report on Market Issues and Performance*, Department of Market Monitoring, June 2015, Section 7.4: http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf.

[201] Ibid.

[202] *Allocating CRR Revenue Inadequacy by Constraint to CRR Holders*, Department of Market Monitoring, October 6, 2014: https://www.caiso.com/Documents/AllocatingCRRRevenueInadequacy-Constraint-CRRHolders_DMMWhitePaper.pdf.

11.2 Virtual bidding

Impact of virtual bidding on real-time imbalance offset costs

As discussed in DMM's 2014 annual report, the ISO frequently needs to adjust constraint limits downward in the 15-minute market below levels incorporated in the day-ahead market model. For instance, this occurs due to transmission de-rates or modeling inaccuracies that cause actual flows to exceed the available transmission. This can cause significant real-time imbalance offset costs allocated primarily to load-serving entities. Virtual bidding tends to exacerbate this revenue inadequacy by allowing virtual bidders to essentially purchase transmission on constraints in the day-ahead market and sell it at a higher price when increased congestion occurs in the real-time market.

DMM has suggested the ISO implement a settlement rule that would allocate a portion of congestion offset costs back to convergence bidders based on the level by which these virtual bids directly contributed to these offset costs.[203] DMM continues to recommend that the ISO consider this rule change.

Virtual bidding on inter-ties

The ISO implemented virtual bidding in 2011 at both internal nodes and the inter-ties. Soon afterwards, issues arose with virtual bidding on the inter-ties that eventually resulted in the ISO filing a tariff amendment to discontinue inter-tie virtual bidding. The FERC accepted the ISO's proposal to discontinue virtual bidding on the inter-ties until the ISO could develop a "comprehensive, long-term structural solution that will permit the reinstatement of inter-tie convergence bidding with just and reasonable outcomes, improving market efficiency by committing supply resources to meet real-time needs."[204]

The ISO implemented comprehensive real-time market design enhancements in May 2014, which included the establishment of a 15-minute market to schedule and settle both inter-tie and internal resources on financially binding 15-minute intervals. Numerous stakeholders and DMM raised concerns about the potential risks of reinstating virtual bidding on inter-ties concurrent with these major market design changes. To address these concerns, the ISO proposed reinstatement of virtual bidding at the inter-ties 12 months after the ISO implemented the new 15-minute market, on May 1, 2015.

In April 2015, the ISO filed a report by DMM regarding reinstatement of virtual bidding on inter-ties.[205] As noted in the ISO's filing, this report demonstrated "that due to the lack of liquidity with respect to economic bids in the ISO's fifteen-minute markets at the majority of the ISO's inter-ties, reinstating virtual bidding at this time would, on balance, lead to market inefficiencies."[206] DMM's report recommended that "careful consideration should be given to understanding the structural barriers

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[203] See *Real-time Revenue Imbalance in CAISO Markets*, Department of Market Monitoring, April 24, 2013: http://www.caiso.com/Documents/DiscussionPaper-Real-timeRevenueImbalance_CaliforniaISO_Markets.pdf.

[204] See: https://www.caiso.com/Documents/May2_2013OrderCndnlyAcceptTariffRevs-ConvergenceBiddingIntertiesER11-4580-000.pdf, pp. 26-27.

[205] *Potential market inefficiencies from convergence bidding at interties with insufficient liquidity of fifteen-minute bids,* Department of Market Monitoring, April 3, 2015: http://www.caiso.com/Documents/Apr3_2015_DMMSupplementalReport_ConvergenceBiddingIntertiesER14-480.pdf.

[206] Ibid, p. 1.

outside of ISO markets preventing such fifteen-minute market bidding before fully implementing convergence bidding on the inter-ties."[207] The ISO subsequently filed for a waiver to defer reinstatement of virtual bidding on inter-ties on May 1, 2015.

In September 2015, FERC issued an order that found virtual bidding at inter-ties to be "unjust and unreasonable" under current market conditions and required the ISO to amend its tariff to eliminate virtual bidding on inter-ties.[208] To reinstate virtual bidding on inter-ties, the ISO would now need to file at FERC and demonstrate that this market feature would "function properly." DMM does not believe that the potential benefits of reinstating virtual bidding at inter-ties outweighs the potential market inefficiencies and other potential unforeseen issues that could result from virtual bidding at inter-ties.

11.3 Start-up and minimum load bids for natural gas units

Background

The ISO completed a multiphase stakeholder process in early 2016 that resulted in Board approval of several changes to the way that start-up and minimum load costs for natural gas units are calculated.[209] DMM has provided detailed comments on this initiative internally as well though written comments submitted as part of the stakeholder process.[210]

DMM supports the ISO's overall proposal for commitment cost bidding improvements as a step forward in addressing a variety of important, but difficult and controversial issues. However, DMM notes that this initiative incorporates several market design changes which are being made to accommodate various stakeholders, but which could have the effect of reducing overall market efficiency and the flexibility of the ISO's gas-fired fleet at a time when the ISO will likely need to rely on a smaller but more flexible gas fleet to integrate the growing volume of renewable resources on the ISO system.

The impact and effectiveness of this initiative will also depend on a number of important implementation details, including how some of the proposed rules are ultimately interpreted and implemented in practice. DMM will continue to provide input in the process to help ensure this initiative is implemented in a manner that helps ensure more efficient unit commitment and recovery of reasonably incurred commitment costs. The following sections address several of the key components of the ISO's final proposal.

Opportunity cost bid adders

Use-limited resources have start and run limitations due to environmental or other operational restrictions. Under a market rule change proposed by the ISO, use-limited resources will be eligible to include a calculated opportunity cost adder in their daily commitment cost bids. This opportunity cost adder will represent the potential revenues that a unit would forgo by running and not being available in

[207] Ibid, p. 1.

[208] For more information see the following FERC order: http://www.caiso.com/Documents/Sep25_2015_Order_Request_Waiver_InstitutingSection206Proceeding_IntertieConvergenceBidding_EL15-98_ER15-1451_ER14-480.pdf.

[209] *Commitment Cost Enhancements Phase 3 Draft Final Proposal*, February 17, 2016: http://www.caiso.com/Documents/DraftFinalProposal-CommitmentCostEnhancementsPhase3.pdf.

[210] *Comments on Commitment Cost Enhancements Phase 3 Draft Final Proposal*, Department of Market Monitoring, March 4, 2016: http://www.caiso.com/Documents/DMMComments-CommitmentCostEnhancementsPhase3-DraftFinalProposal.pdf.

future potentially higher priced hours. This will allow unit commitments made by the day-ahead and real-time market optimization software to reflect use limitations that extend over a longer period of time, such as monthly or annual limitations.

DMM is very supportive of this market enhancement, but notes that the effectiveness of the opportunity cost bid adders will depend on the details of the opportunity cost model process – including input assumptions, methods for determining unit start and run hour limitations, and the frequency with which the opportunity cost calculation may be updated as actual market conditions unfold. DMM also recommends that the ISO complete development of a fully functional opportunity cost model and then utilize this model to work with stakeholders using actual unit and market data to identify any needed refinements prior to implementation.

Exemption for contractual limitations

The ISO has a "longstanding position that economic limits like limitations originating from contracts such as power purchasing or tolling agreements are not acceptable limitations for establishing an opportunity cost adder to a resource's commitment cost bid cap… These limitations exist not as a result of restrictions imposed by external statutes or regulations, but rather reflect economic trade-offs made by the contracting parties."[211] However, the ISO has proposed to allow units to seek a three-year exemption for contractual limitations incorporated in long-term contracts that have undergone "extensive regulatory scrutiny" and were entered prior to January 1, 2015.

DMM continues to believe it is inefficient to treat contractual limitations as physical limitations in the ISO market optimization, whether these contractual provisions are treated directly as physical unit operating constraints or indirectly through an opportunity cost adder. To the extent that these contractual limitations may reflect actual physical or environmental limits, it is more efficient and appropriate to incorporate these directly into unit operating constraints or opportunity cost bid adders. The ISO's prior proposals involving use-limited status and opportunity costs have always been designed based on this principle.

If these contract limitations reflect maintenance costs, DMM notes that the ISO market is explicitly designed so that any incremental maintenance costs associated with starting up and operating units can be incorporated directly in commitment cost bids through *major maintenance adders*. These major maintenance adders represent the most economically efficient way of incorporating any incremental maintenance costs associated with starting up and operating resources into unit commitments. By incorporating these costs into commitment cost bids, the market software optimizes unit dispatch decisions. These major maintenance bid adders also ensure that generators can recover the full incremental costs of starting up and operating a unit – through a combination of market revenues plus any supplemental bid cost recovery payments.

The actual amount and location of capacity eligible for the proposed exemption, and the actual contractual limitations of these resources, will only be known with certainty after approval and implementation of the ISO's proposal. However, DMM understands that an additional 5,000 MW to 10,000 MW of recently built gas-fired capacity may be eligible under this three-year exemption and that much of this capacity is located in transmission constrained areas. While providing exemptions for a limited number of contracts may not have significant detrimental impacts, DMM is concerned about

[211] Memorandum to ISO Board of Governors, Re: Decision on commitment cost bidding improvements proposal, March 17, 2016: http://www.caiso.com/Documents/DecisionCommitmentCostBiddingImprovementsProposal-Memo-Mar2016.pdf.

these cumulative impacts if exemptions are provided to a significant amount of capacity, particularly if this includes a relatively large amount of capacity used to meet resource adequacy requirements in transmission constrained areas. DMM also questions the equity of this approach for entities that do not have eligible contractual limitations.

The opinion of the ISO's Market Surveillance Committee and comments by the CPUC and some other stakeholders suggest that this exemption should be extended beyond three years to the life of these contracts. DMM believes this would be imprudent given the lack of information on these contract limitations, especially at a time when the ISO will likely need to rely on a smaller but more flexible gas fleet to integrate the growing volume of renewable resources on the ISO system.

Negotiated opportunity cost bid adders

The ISO's proposal offers a negotiated opportunity cost option to a potentially large set of resources. However, the proposed opportunity cost model will not include modeling of the most common type of multi-stage generating resource – a combined cycle unit – which may have a limit on the number of transitions between configurations. Under the ISO's proposal, these types of resource constraints would need to be addressed through a special negotiated opportunity cost bid adder. If modeling this type of resource is too complex to be incorporated in the opportunity cost models being developed by the ISO, it may be challenging for ISO staff and generators to assess the opportunity costs of this type of resource through a process of negotiation.

It is difficult to assess how widespread or problematic this situation might be given the lack of data on units and constraints that would be eligible under the proposed criteria and exemptions. However, DMM notes that this could conceivably represent a significant category of units requiring the ISO to establish special negotiated opportunity cost bid adders – without having the type of optimization tool that will be developed for some units. Consequently, DMM has recommended the optimization tool be expanded, if possible, to allow modeling of additional resource types if a significant number of units apply for negotiated opportunity cost adders.

Resource operating characteristics

The ISO tariff currently requires resource operating characteristics submitted to the ISO's master file used by the market to reflect only actual physical characteristics. The ISO is proposing to provide generators flexibility to submit lower values for three key unit characteristics used in the market software: maximum daily starts, maximum multi-stage generator daily transitions, and ramp rates. Resources will be restricted from submitting less than two starts per day as a preferred resource characteristic unless the resource is only physically capable of one start per day.

DMM notes that this change may reduce the overall flexibility of the ISO's fleet at a time when the ISO will likely need to rely on a smaller but more flexible gas fleet to integrate the growing volume of renewable resources on the ISO system. Although some generators appear to view this change as a "tightening" of market rules, this actually represents a reduction of current tariff requirements concerning unit start-ups and ramp rates.

Under the ISO's proposal, generator owners may seek an exemption to the two start per day requirement. The ISO's final proposal appears to limit exemptions to this requirement based on the "design capability" of a unit or if "resources nearing the end of its life cycle may warrant the resource only starting once per day despite its design capabilities allowing it to start more than once per day."[212] When implementing this provision, DMM notes that exemptions should not be granted on the grounds that starting a unit up to twice a day may increase maintenance. Again, ISO market rules are designed so that any incremental maintenance costs associated with starting up and operating a unit can be incorporated directly in commitment cost bids through major maintenance adders. To help manage this issue, the ISO will need to develop a process, guidelines and expertise to carefully evaluate any exemptions to the two start per day requirement.

Recovery of commitment costs that exceed the commitment cost bid cap

The ISO is also proposing to add tariff provisions that will allow market participants to seek after-the-fact FERC approval of incurred actual commitment costs that exceed the commitment cost bid caps. The ISO would then reimburse the FERC approved costs through its bid cost recovery mechanism. As a result the market participant would only be reimbursed for these costs to the extent the resource had a net revenue shortfall over the day considering all market revenue.

DMM is supportive of providing a mechanism for participants to seek after-the-fact reimbursement for any prudently incurred gas costs due to unit commitments in excess of commitment cost bid caps that are not recovered through market revenues. As part of this initiative, DMM performed extensive analysis of historical gas price data which indicates that the actual need to rely on this mechanism should be very infrequent – but could be important in the case of extreme events.

Even though the proposal calls for FERC to assess any gas reimbursement filings by generators, DMM has encouraged the ISO to continue to work with stakeholders – and personnel with additional expertise in gas markets and procurement – to develop more specific guidelines, requirements and methodological details. DMM believes this additional detail would help reduce potential uncertainty about how this provision will be implemented for participants and avoid potential disputes.

11.4 Market power mitigation enhancements

The ISO's market power mitigation procedures are triggered when congestion is projected to occur on a constraint. With this approach, when congestion is not projected to occur in the 15-minute advisory run, but congestion does occur in the 15-minute or 5-minute binding runs, bid mitigation is not triggered. In DMM's prior reports, this is referred to as potential *under-mitigation*.

As discussed in DMM's prior annual and quarterly reports, DMM has continually monitored this potential under-mitigation and determined that it has not had a significant impact on outcomes because of the overall market competitiveness.[213] Within the ISO system, in most cases when real-time congestion occurs but mitigation was not triggered based on an advisory run the supply of generation that relieves this congestion is structurally competitive.

Over the course of 2015, DMM continued to work with the ISO to develop software enhancements to effectively address the issue of potential under-mitigation in the real-time market. As a result of this

[212] *Commitment Cost Enhancements Phase 3 Draft Final Proposal*, February 17, 2016, p. 46: http://www.caiso.com/Documents/DraftFinalProposal-CommitmentCostEnhancementsPhase3.pdf.

[213] *2014 Annual Report on Market Issues and Performance*, Department of Market Monitoring, pp. 126-131. http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf.

effort, enhancements are being implemented in the 2016 spring and fall software releases to address the issue of potential under-mitigation. These modifications will make the current process more effective by integrating market power mitigation procedures more closely with the final software run used to determine final schedules and prices. These enhancements will increase the accuracy of mitigation in terms of applying mitigation during intervals when potential market power exists in the real-time market.[214]

11.5 Flexible ramping product

Background

The ISO completed development of a flexible ramping product in early 2016 that would replace the flexible ramping constraint currently incorporated in the real-time market software. DMM is highly supportive of the ISO's final proposal for establishing a flexible ramping product. This proposal was developed through an extensive market design and stakeholder process beginning in late 2011. Over this period, DMM worked closely with the ISO, stakeholders and the Market Surveillance Committee on developing and refining this proposal.

Management's final proposal incorporates a variety of key enhancements through this process that make the flexible ramping product a significant improvement over the current flexible ramping constraint. Key elements of this proposal include the following:

- **Bidding.** The initial proposal suggested that bids would be submitted by each generator for flexible ramping capacity. DMM recommended that this feature be eliminated unless it was demonstrated that generators incurred any significant marginal costs associated with providing flexible ramping capacity beyond the opportunity cost upon which the price for the flexible ramping product is based.[215] The proposal was subsequently modified to eliminate bidding for the flexible ramping product.

- **Day-ahead procurement**. The initial flexible ramping proposal also called for procurement of flexible ramping capacity in the day-ahead market. This feature was dropped from the market design after concerns were raised regarding systematic procurement of incorrect amounts of capacity and that this capacity procured in the day-ahead would likely not increase real-time flexibility.[216]

- **Settlement of costs based directly on market prices versus out-of-market uplift charges**. More recently, the proposal was modified so that most costs for the flexible ramping product would be charged based on the flexible ramping product price and the expected ramping capability of each resource, rather than by allocating costs through an out-of-market uplift payment. DMM strongly

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[214] Further detail can be found under the Local Market Power Mitigation stakeholder initiative: https://www.caiso.com/informed/Pages/StakeholderProcesses/LocalMarketPowerMitigationEnhancements2015.aspx.

[215] *DMM Comments on Flexible Ramping Products Straw Proposal Incorporating FMM and EIM,* July 7, 2014: http://www.caiso.com/Documents/DMM-CommentsFlexibleRampingProductsStrawProposal.pdf.

The Role of Separate Capacity Offers in Capacity Reserve Markets, July 31, 2014: http://www.caiso.com/Documents/RoleSeparateCapacityOffers-SpotCapacityReserveMarkets.pdf.

[216] *Comments on Flexible Ramping Products Incorporating FMM and EIM Draft Final Proposal*, December 31, 2014: http://www.caiso.com/Documents/DMMComments_FlexibleRampingProduct-DraftFinalProposal.pdf.

advocated for this change as a major improvement that provides better price signals to market participants reflecting the value of upward and downward flexibility. This design provides a strong framework for other enhancements as the ISO continues to adapt its markets to the changing energy grid by facilitating the integration of additional renewable generation, energy storage and demand response resources.

- **Procurement based on demand curve**. Under the ISO's final proposal, the flexible ramping product will be procured based on a price-sensitive demand curve. This represents another improvement over the current flexible ramping constraint, which incorporates a fixed requirement. Use of a demand curve allows flexible capacity costs to be balanced with the value of flexibility. More flexible capacity will be procured when expected benefits outweigh the incremental cost of capacity, and less capacity will be procured as the costs rise above the benefits.

DMM has provided extensive input into how this demand curve should be derived based on operational data and looks forward to working with the ISO to implement this approach.[217] As noted by the Market Surveillance Committee, the determination of the amount of ramp capability needed is a critical element of the overall flexible ramping constraint:

> "The DMM has pointed out that the methodology initially used to calculate the amount of ramp capability needed resulted in rather extreme hour to hour variability in the estimated ramp needs, with the target often set at the floor or ceiling. We concur with the DMM critique of the performance of the initial ramp need forecasting tool. Cost-effective choices regarding the amount of ramp procured at different times of day and year are critical to the cost effective performance of the flexiramp design."[218]

DMM and the Market Surveillance Committee have recommended that the ISO needs to thoroughly analyze the performance of the forecasting tool before it is implemented. The ISO also needs to track the performance of the methodology used to calculate ramp requirements after implementation and correct elements of the methodology that lead to poor projections of flexible ramping needs without long lags.

DMM believes that further refinements can be made to the initial cost allocation approach incorporated in the ISO's proposal to better align the allocation of flexible ramping costs with resources and performance that create demand for this product.[219] DMM is also supportive of further market design efforts that might allow the flexible ramping products to be effectively incorporated into the day-ahead market.

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[217] The demand curve in the ISO's straw proposal was based on the historical incidence of power balance violations which would not have correctly valued flexibility. DMM proposed the alternative demand curve formulation based on the distribution of net load forecast errors which the ISO adopted for the final proposal.

DMM Comments on Flexible Ramping Products Straw Proposal Incorporating FMM and EIM, July 7, 2014: http://www.caiso.com/Documents/DMM-CommentsFlexibleRampingProductsStrawProposal.pdf.

DMM Comments on Demand Curves in the Flexible Ramping Product Draft Technical Appendix, July 15, 2015: http://www.caiso.com/Documents/DMMComments_FlexibleRampingProductTechnicalAppendix_DemandCurves.pdf.

[218] *Opinion on Flexible Ramping Product*, Market Surveillance Committee, January 26, 2016, p. 8: http://www.caiso.com/Documents/Decision_FlexibleRampingProductProposal-MSC_Opinion-Feb2016.pdf.

[219] *DMM Comments on Flexible Ramping Product Revised Draft Final Proposal*, January 15, 2016: http://www.caiso.com/Documents/DMMComments-FlexibleRampingProductRevisedDraftFinalProposal.pdf.

11.6 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 their system operating limits (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 on-line capacity constraints to position resources so that the ability is available to return critical paths to their operating limits within 30 minutes in the event of such a contingency.

The ISO has proposed an alternative modeling approach aimed at reducing the use of exceptional dispatches and minimum on-line capacity constraints. The modeling enhancements proposed by the ISO include modeling 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 in the market model.[220] The ISO has noted that incorporating constraints in the market model should reduce exceptional dispatches, replace some minimum on-line constraints, provide greater compensation through locational marginal clearing prices, and may result in separate capacity payments for resources (both generation and demand response) that help meet the reliability standards.

Recommendations

DMM is supportive of this initiative. DMM believes one of the main additional benefits of this approach is that it will allow these reliability requirements to be met more efficiently 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. Completion of this has been deferred pending further analysis of the impacts of this contingency modeling enhancements feature based on simulations using the actual ISO software.

DMM understands that the ISO is attempting to pay congestion revenue rights as much of the congestion rent on the lines between sources and sinks as possible without exacerbating revenue inadequacy. However, because the post-contingency constraints are not included or priced in the congestion revenue right auction, DMM questions the rationale for settling rights as if their holders have purchased rights to congestion rents associated with these constraints. DMM suggests that an alternative would be to exclude congestion prices from the post-contingency constraints in congestion revenue rights settlement process. This would only pay for transmission rights actually purchased and would eliminate all potential revenue inadequacy for congestion revenue rights from post-contingency constraints.

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

11.7 Resource adequacy

Background

In 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 different resources toward meeting these requirements. These flexible capacity rules are widely viewed as an interim solution and will provide the ISO and CPUC with additional experience and time to develop a more comprehensive set of provisions. The process of addressing flexible capacity needs and other issues related to the evolving framework of resource adequacy in the ISO are also being addressed through the CPUC's joint reliability plan proceeding.[221]

The ISO is also 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 11.5 and 11.6. However, it is unclear how often these constraints will be binding and, therefore, whether they will provide significant market revenues. 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 of the timeline needed to bring new flexible capacity on-line.

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 adequate to meet actual operational ramping needs.** As previously noted in this chapter, the ISO is developing a 5-minute flexible ramping product and new capacity 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 requirements established for the resource adequacy process should be designed to ensure that day-to-day market requirements for these resource flexibility needs can be consistently met by the flexible capacity procured. However, flexible resource adequacy requirements are not based directly on these day-to-day operational requirements and do not account for many operational resource and system constraints. Therefore, flexible resource adequacy requirements and counting criteria require annual re-evaluation and adjustment to ensure capacity procured meets operational needs. The analysis of flexible ramping capacity during 2015 in Chapter 10 provides an example of this type of analysis.

- **Flexible capacity procurement should be directly linked with a must-offer obligation for operational ramping products.** DMM has also recommended that the ISO tariff should 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 bidding provisions may need to be modified to ensure this capacity can be utilized to meet requirements for ISO market products or operational constraints developed to meet flexibility and reliability needs.

The following sections summarize DMM's comments and recommendations on several ongoing initiatives relating to the resource adequacy program.

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221 For more information on the CPUC's joint reliability plan (JRP) see: http://www.cpuc.ca.gov/PUC/energy/Procurement/The_Joint_Reliability_Plan_Proceeding.htm.

Resource operating characteristics

The current ISO tariff requires that "all information provided to the CAISO regarding the operational and technical constraints … shall be accurate and actually based on physical characteristics of the resources …"[222] As noted in our 2014 annual report, DMM has expressed concerns that the maximum number of starts per day entered in the market software by participants are often lower than the actual physical capabilities of the units.[223]

Although this issue does not stem from resource adequacy rules, DMM believes this issue is relevant to the overall flexibility of the ISO's fleet of gas resources. For example, in 2015 DMM provided the ISO with an assessment of how multi-stage units with only one transition per day would often be unable to provide their full flexible capacity rating under the current counting criteria for flexible capacity.

As noted in Section 11.3, the ISO is proposing to provide generators flexibility to submit lower values to the market software for several key factors affecting units' flexibility: maximum daily starts, maximum multi-stage generator daily transitions, and ramp rates. DMM has noted that this change may reduce the overall flexibility of the ISO's fleet at a time when the ISO will likely need to rely on a smaller but more flexible gas fleet to integrate the growing volume of renewable resources on the ISO system.

Thus, DMM was not highly supportive of this aspect of the ISO's initial proposal. DMM strongly recommended that the ISO require resources to submit a minimum of two start-ups and two transitions per day unless this exceeds their physical operating limits. The ISO ultimately adopted this recommendation.

In practice, it is possible that the new rule requiring at least two starts and two transitions per day may help maintain overall resource flexibility relative to current practice, since many units currently enter only one start or transition per day. However, DMM recommends that the ISO continue to assess how resource operating characteristics used in the market software may limit the ability of resources to actually provide the flexibility needed by the ISO system.

Reliability services initiative

The reliability services initiative is a two-phase, multi-year effort to address the ISO's rules and processes surrounding resource adequacy resources. The initiative is part of the ISO's overall effort to work with the CPUC to ensure that sufficient resources with the right capabilities are available and offered into the ISO market to meet local, flexible, and system needs.

Phase 1

The ISO completed the first phase of this initiative in early 2015, which included a new availability incentive mechanism to encourage greater availability from resource adequacy resources.[224] DMM was supportive of this proposal as a step toward improving and streamlining resource adequacy requirements and processes to meet the need for increased operational flexibility to integrate new renewable energy resources.

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[222] See ISO tariff section 4.6.4.

[223] *2014 Annual Report on Market Issues and Performance*, p. 199.

[224] The proposal considered by the ISO Board can be found at: http://www.caiso.com/Documents/DraftFinalProposalAddendum-ReliabilityServices.pdf.

However, DMM noted that since the penalty for not meeting availability standards was set at 60 percent of the potential cost of procuring replacement capacity, it could be less costly for generating unit owners to pay the penalty rather than provide substitute capacity when supply conditions are tight. Consequently, DMM recommends that the ISO monitor this issue over time and adjust the penalty level so that it is sufficient to prevent this.[225]

Phase 2

As part of the second phase of this initiative, the ISO is working to improve the rules relating to the newly approved resource adequacy availability incentive mechanism (RAAIM).[226] While DMM views this mechanism as an improvement over the previous incentive mechanism (the *standard capacity product*), we still view the design of the mechanism as incomplete. DMM is recommending that the ISO incorporate an assessment of resources' performance when dispatched into its availability incentive mechanism, rather than basing performance solely on whether or not a resource submitted a bid.

DMM believes it is problematic to rely solely on market bids as a measure for compliance because a resource could offer into the market without necessarily having the ability to perform. The ISO, in consultation with local regulatory agencies, specifies the criteria for resource characteristics and locations that will ensure system reliability. However, if resource adequacy resources do not perform according to the characteristics the ISO assumes for the resources, the resource adequacy process may not ensure system reliability. Therefore, DMM encourages the ISO to consider performance based enhancements to this mechanism so that resources are penalized if they cannot consistently perform at the standards the ISO assumes for the resources in the ISO's reliability studies.

Flexible resource adequacy criteria and must-offer obligation

The ISO continues to assess and improve the newly implemented flexible resource adequacy program as part of the flexible resource adequacy criteria and must-offer obligation initiative. While this program is in its first stages, DMM encourages the ISO and CPUC to consider modifying the current framework. The analysis in Chapter 10 suggests that the 2015 requirements and must-offer hours were insufficient in reflecting actual ramping needs. This was not necessarily an issue in 2015 because the load-serving entities procured significantly more flexible capacity than required. However, if load-serving entities had only procured the minimum Category 1 and maximum Category 2 and 3 requirements, this capacity may have fallen short of the actual flexibility needed to meet ramping needs under some conditions.

The effectiveness of flexible resource adequacy requirements and must-offer rules hinge in part on the ability to predict the level of the maximum net load ramp as well as the time of day the ramp occurs over a year in advance. As shown in Section 10.2 of this report, the must-offer hours for flexible resources did not fully correspond with the actual maximum net load ramp for all but one month in 2015. This highlights the difficulty of projecting actual ramping needs one year in advance. DMM recommends that the ISO and local regulatory authorities consider broadening the must-offer obligations in order to accommodate the uncertainty underlying annual assessments.

[225] Memorandum to ISO Board of Governors, from Eric Hildebrandt, Director, Market Monitoring, March 19, 2015, pp.6-7: http://www.caiso.com/Documents/Department_MarketMonitoringReport-Mar2015.pdf.

[226] For more information on the second phase of this initiative see: http://www.caiso.com/informed/Pages/StakeholderProcesses/ReliabilityServices.aspx.

DMM is also concerned that a significant amount of procured flexible capacity in 2015 was from long-start or extra-long-start units that will not have a real-time obligation unless committed well in advance (see discussion in Section 10.7). This is because non-resource adequacy resources, which may be scheduled in the day-ahead market instead of the long-start resource adequacy resources, do not have a must-offer obligation in real time. These resources may self-schedule in real time or be of lower quality (for example, hourly-block resources), which will ultimately provide less flexibility to the market. DMM encourages the ISO and CPUC to consider whether flexible capacity from such resources should be limited in order to ensure the grid has sufficient real-time flexibility.

Non-resource specific resource adequacy imports

The ISO is currently assessing the ability for 15-minute inter-tie resources to be used to meet flexible resource adequacy requirements. Based on the ISO's initial assessment, the ISO proposed to allow 15-minute inter-tie resources that meet certain qualifications to provide flexible capacity.[227] These requirements include that imports be *resource specific* and must commit to providing firm energy to the ISO. Based on input from some stakeholders, the ISO is considering allowing non-resource specific resources to provide imported flexible capacity as well.

DMM is concerned that if imports are allowed to provide flexible capacity, additional criteria and even monitoring or reporting requirements may need to be developed to ensure that these imports are backed by available physical capacity that may be dispatched in the 15-minute market. Unlike resources within the ISO, the actual availability of resource specific imports cannot be directly monitored by the ISO. While resource adequacy imports are required to submit bids in the day-ahead market, these resources can meet this obligation by submitting bids at extremely high prices in the day-ahead market that would rarely if ever get dispatched. These resources then have no must-offer obligation in real time.

Requirements relating to the physical availability of imports used to meet resource adequacy requirements are also an issue in the regional resource adequacy initiative being conducted as part of the potential integration of PacifiCorp into the ISO. This initiative will evaluate resource adequacy tariff provisions appropriate for use in a regional ISO balancing authority area that encompasses multiple states. Currently, the integrated resource plans for utilities in other states, such as those in the PacifiCorp area, indicate that these entities rely on bilateral spot market purchases to meet a significant portion of the peak capacity needs. The ISO's April 13 paper on this issue indicates that imports used to meet resource adequacy requirements "are considered to be a firm monthly commitment to deliver those MWs to the ISO."[228]

DMM is recommending that the requirements and expectations relating to the physical availability of imports used to meet resource adequacy requirements be further discussed and clarified as part of this initiative. This is important since imports used to meet resource adequacy obligations are required to bid in the day-ahead market, but are not subject to any limits on bid price and do not have any must-offer obligation in real-time if not accepted in the day-ahead market.

[227] *Flexible Resource Adequacy Criteria and Must Offer Obligation – Phase 2 Straw Proposal,* December 11, 2015, pp. 12-14: http://www.caiso.com/Documents/StrawProposal-FlexibleResourceAdequacyCriteria-MustOfferObligationPhase2.pdf.

[228] *Regional Resource Adequacy Revised Straw Proposal*, April 13, 2016, p. 19: http://www.caiso.com/Documents/RevisedStrawProposal-RegionalResourceAdequacy.pdf.

Thus, DMM believes it is important for all stakeholders and the ISO to have a common understanding of what may constitute a “firm monthly commitment” for the purposes of meeting resource adequacy requirements. This is increasingly important as the ISO expands regionally to include additional load-serving entities that currently rely on established integrated resource planning processes subject to regulation by other states. This is also needed to provide a framework for any monitoring of the compliance of resource adequacy imports with market rules or expectations.