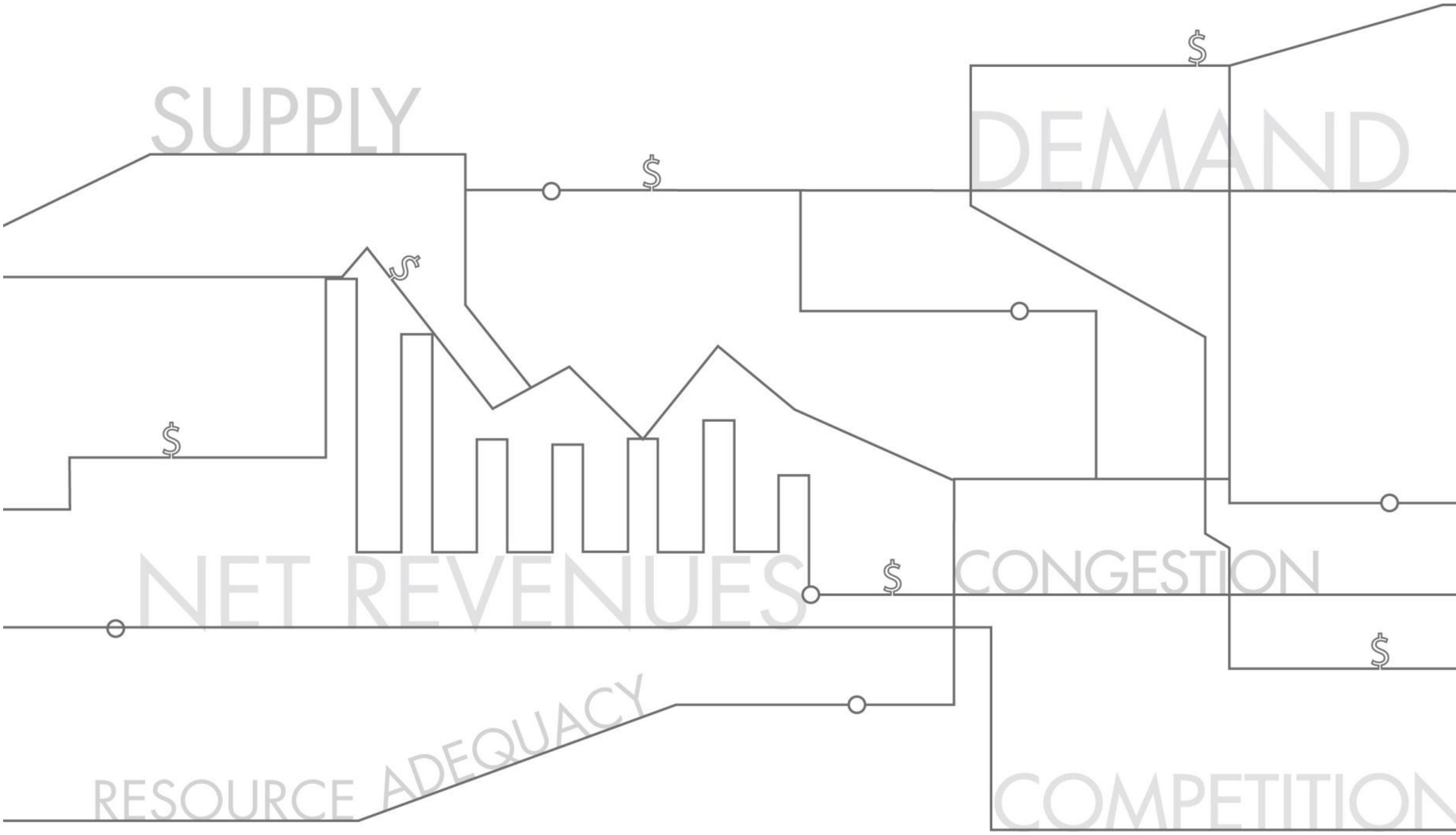
2011
ANNUAL REPORT ON MARKET ISSUES & PERFORMANCE

Department of Market Monitoring



California ISO
Shaping a Renewed Future

ACKNOWLEDGEMENT

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Executive summary

The California Independent System Operator Corporation (ISO) implemented a major redesign of California's wholesale energy markets in April 2009. In 2011, this design continued to facilitate efficient and competitive market performance:

- Total wholesale electric costs fell by 9 percent. This represents a 6 percent decrease after adjusting for lower natural gas prices. This decrease was driven by a significant increase in hydro-electric generation, an increase in low priced imports and moderate loads.

- Almost 100 percent of system load was scheduled in the day-ahead energy market, which continued to be highly efficient and competitive. Day-ahead prices continued to be about equal to prices we estimate would result under competitive conditions.

- Price spikes in the 5-minute real-time market decreased over the course of the year. This improved price convergence between the hour-ahead and real-time markets. The ISO made changes to procedures and software that reduced the incidence of real-time price spikes.

- Revenue imbalance offset costs associated with divergence of hour-ahead and real-time prices totaled about $166 million, up 15 percent from 2010. These costs increased significantly in the first few months of the year and were exacerbated by the introduction of virtual bidding in February 2011, which increased the volume of transactions clearing at these different market prices. These costs decreased by the end of the year as price convergence in these markets improved and virtual bidding on inter-ties was suspended.

- Ancillary services accounted for about 2 percent of total energy costs, up from about 1 percent of total wholesale costs in 2010. This increase was largely attributable to very high hydro conditions in the first half of the year, which decreased the availability of ancillary services from hydro resources as they provided energy instead of reserves.

- Bid cost recovery payments totaled about 1.5 percent of total energy costs in 2011, compared to less than 1 percent in 2010. This increase was primarily attributable to costs resulting from manipulative bidding behavior that was identified and corrected by June 2011.

- Exceptional dispatches, or out-of-market unit commitments and energy dispatches to meet constraints not reflected in the market software, remained relatively low. Energy from exceptional dispatches totaled approximately 0.3 percent of total system energy in 2011. However, the above-market costs associated with these commitments and dispatches increased from $25 million in 2010 to $43 million in 2011. This increase is attributable to a combination of increased volumes of exceptional dispatches, along with higher minimum load and energy bid prices for units receiving exceptional dispatches.

- About 300 MW of new gas-fired capacity came online in 2011, while over 350 MW of gas generation was retired. In 2012, another 450 MW of gas capacity is expected to be retired, while about 650 MW of new gas generation is projected to come online. Beyond 2012, significant reductions in total gas-fired capacity are possible due to the state's restrictions on use of once-through cooling technology.

- Meanwhile, the amount of new renewable generation coming online has begun to increase dramatically. About 650 MW of nameplate capacity from renewable sources came online in 2011, including about 540 MW of wind projects. Because of the relatively low peak summer capacity value of wind resources, this 650 MW of new renewable capacity represents about 195 MW of potential summer peak capacity. In 2012, about 3,000 MW of new renewable nameplate capacity is expected to come online, including over 2,000 MW of solar capacity. As more renewable generation comes online, the ISO has highlighted the need to backup and balance renewable generation with the flexibility of conventional generation resources to maintain reliability.

- The state's resource adequacy program continued to work well as a short-term capacity procurement mechanism. However, in 2011 it became increasingly apparent that the state's current process for longer-term procurement may not ensure the investment and revenues needed to support sufficient new or existing gas-fired capacity required to integrate the increased amount of intermittent renewable energy coming online. The ISO and the California Public Utilities Commission are addressing this issue through several initiatives in 2012. This represents a major market design challenge facing the ISO and state policy makers.

Total wholesale market costs

Total estimated wholesale costs of serving load in 2011 were $8.2 billion or just over $36/MWh. This represents a decrease of about 9 percent from a cost of $40/MWh in 2010. This is also the lowest nominal wholesale cost since 1999.

Much of the decrease in costs was driven by lower gas prices. Spot market gas prices decreased by about 4 percent.[1] After accounting for lower gas prices, total wholesale energy costs decreased from $35/MWh in 2010 to $33/MWh in 2011, a decrease of 6 percent in gas-normalized prices.

Figure E.1 shows total estimated wholesale costs per MWh from 2007 to 2011. Wholesale costs are provided in nominal terms, as well as after normalization for changes in average spot market prices for natural gas. The green line representing the annual average natural gas price shows the high correlation between the cost of natural gas and the total wholesale costs.

In addition to lower gas prices, other factors contributed to the decrease in wholesale costs in 2011. As highlighted in Chapter 1, other demand and supply conditions contributing to lower prices included:

- increased hydro-electric generation;
- increased imports, particularly from the northwest; and
- lower summer peak loads.

Other factors contributing to lower prices discussed in the following sections of this report include:

- high day-ahead scheduling of load relative to actual loads;
- competitive bidding levels in the day-ahead and real-time energy markets; and
- low congestion.

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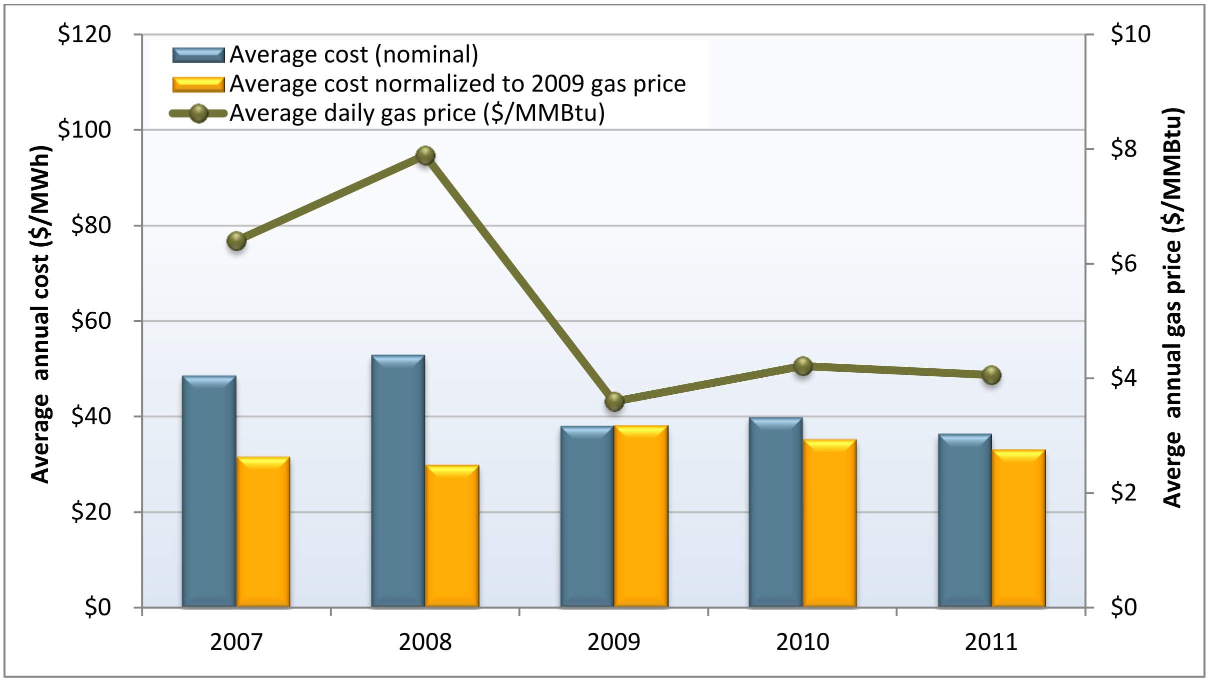
[1] In this report, we calculate average annual gas prices by weighting daily spot market prices by the total ISO system loads. This results in a price that is more heavily weighted based on gas prices during summer months when system loads are higher than winter months, during which gas prices are often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

Figure E.1 Total annual wholesale costs per MWh of load: 2007-2011



Energy market prices

A key measure of overall market performance is the degree of price convergence between the day-ahead, hour-ahead and real-time markets. Price convergence is an indicator of market efficiency, since it suggests that resource commitment and dispatch decisions are being optimized across the day-ahead and real-time markets. Price divergence can also create revenue imbalances in the real-time energy market that must be allocated to load-serving entities.

Figure E.2 and Figure E.3 show average prices in the energy markets by quarter for the Pacific Gas and Electric area during peak and off-peak hours. As shown in these figures, average hour-ahead prices tended to be lower than day-ahead and real-time prices in many periods. Average day-ahead prices were higher than hour-ahead prices in 2011 during all periods except peak hours in the third quarter. Real-time prices during peak periods were higher than day-ahead prices in the first quarter, but remained lower than day-ahead prices from the second quarter through the end of 2011. During off-peak hours, average real-time prices were well above day-ahead and hour-ahead prices during the first and second quarters, but were much closer to day-ahead and hour-ahead prices during the second half of the year. The trend toward higher real-time prices during some periods was driven by very short but extreme price spikes in the 5-minute real-time market. These price spikes generally reflect short-term modeling and forecasting limitations, rather than fundamental underlying supply and demand conditions. In most cases, these price spikes lasted for only a few 5-minute intervals.

As the frequency of these price spikes fell in 2011, hour-ahead and real-time price convergence improved. As shown in Figure E.4, the frequency of price spikes at or above $1,000/MWh increased after the price cap was raised to $1,000/MWh in April 2011. However, the overall frequency of price spikes dropped significantly after the first quarter of 2011, improving price convergence.

Figure E.2 Comparison of energy market prices (PG&E area – peak hours)

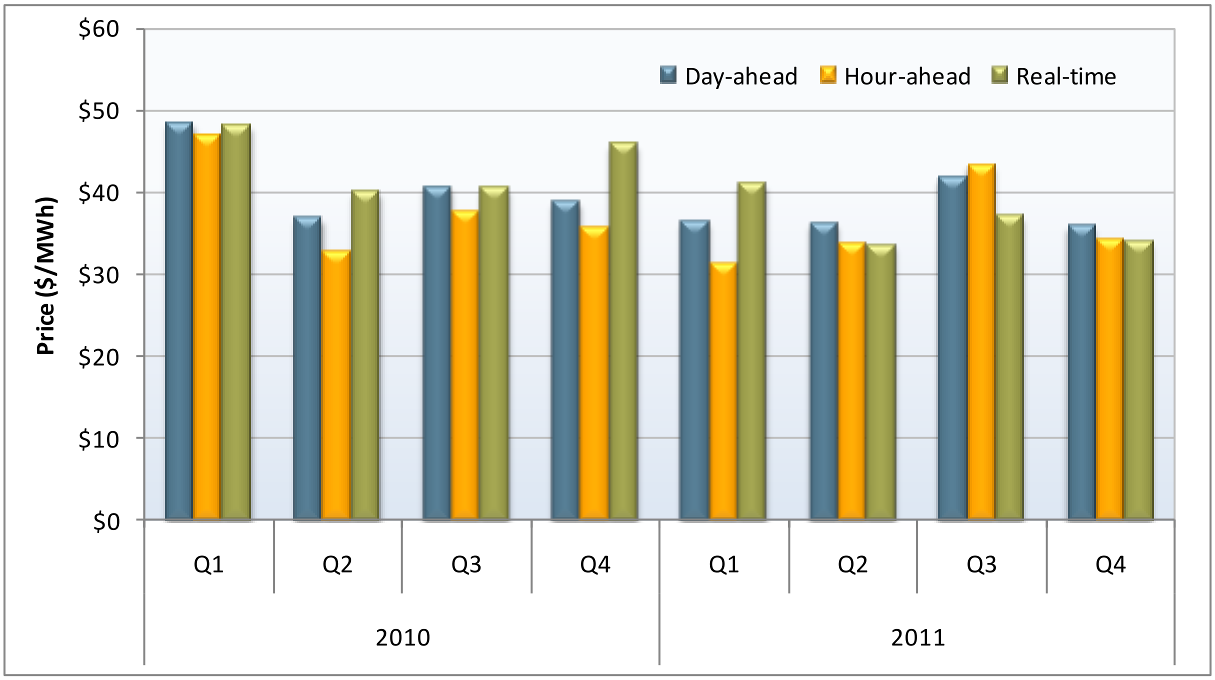


Figure E.3 Comparison of energy market prices (PG&E area – off-peak hours)

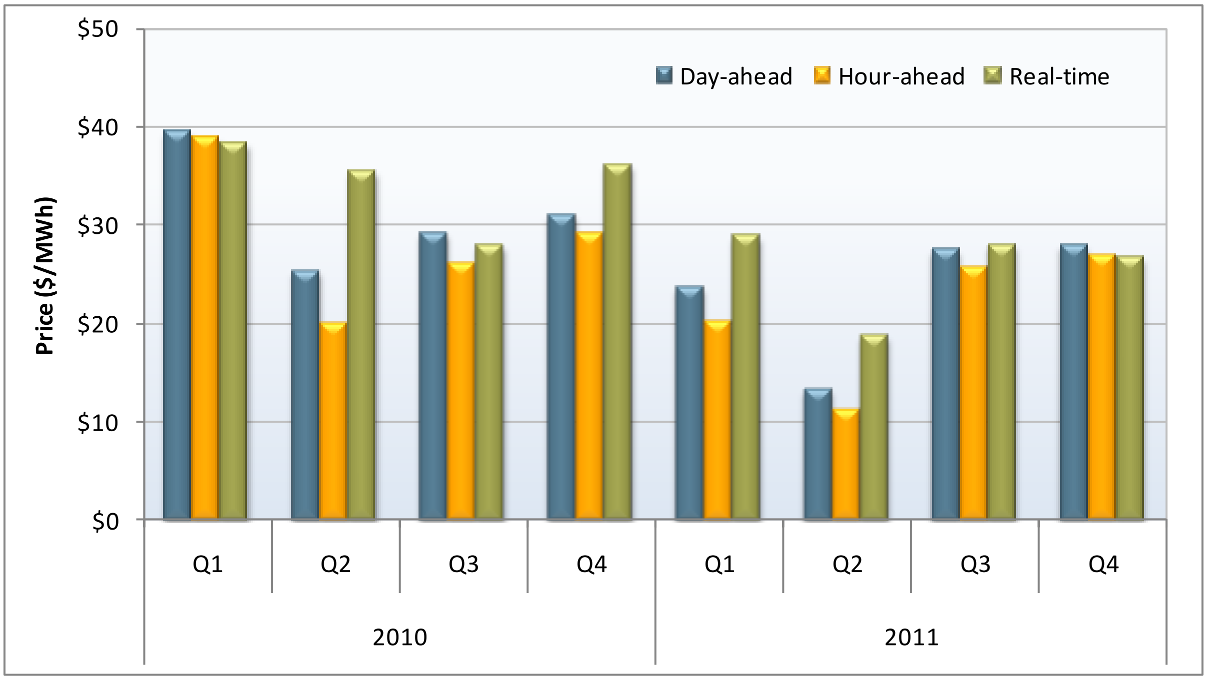
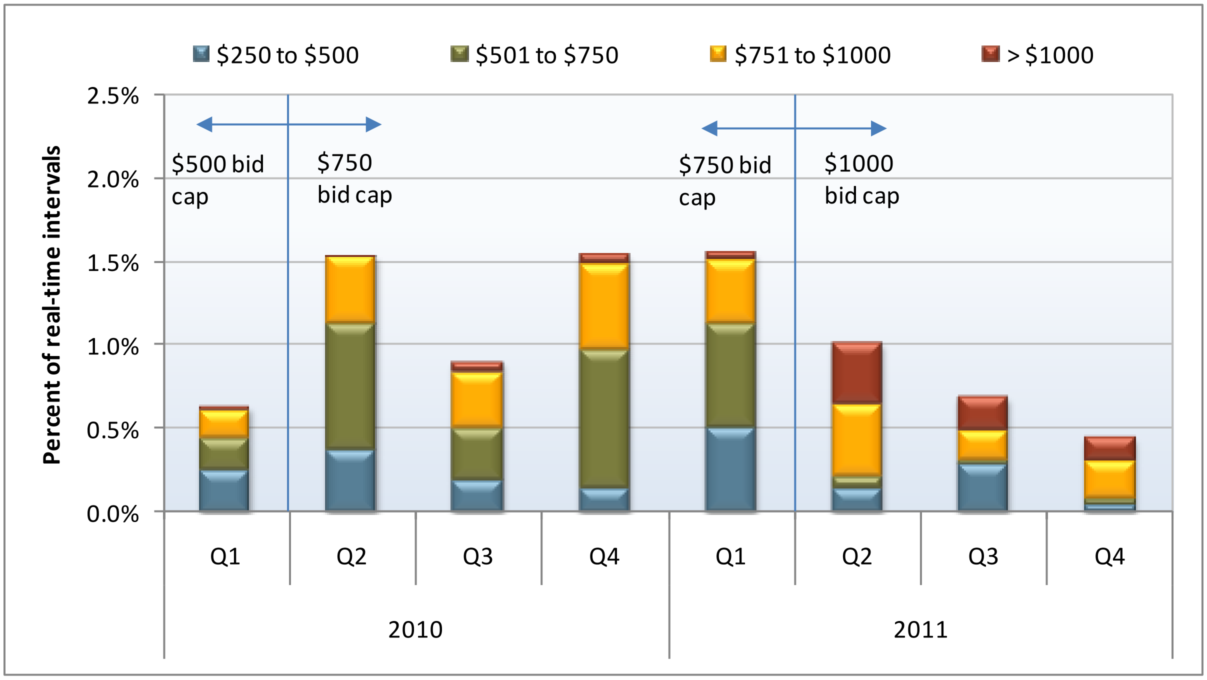


Figure E.4 Price spike frequency by quarter



Price divergence between the hour-ahead and 5-minute real-time markets has contributed to uplifts known as real-time imbalance offset costs.[2] These costs are usually incurred when the ISO sells physical or virtual energy in the hour-ahead market at low prices and then re-purchases additional energy in the 5-minute real-time market at higher prices.

Total real-time imbalance offset costs in 2011 were about $166 million, up 15 percent from $144 million in 2010. These costs represent a significant source of inefficiency under the nodal market design. However, as seen in Figure E.5, real-time imbalance offset costs decreased in the fourth quarter as price convergence improved following the suspension of convergence bidding on the inter-ties.

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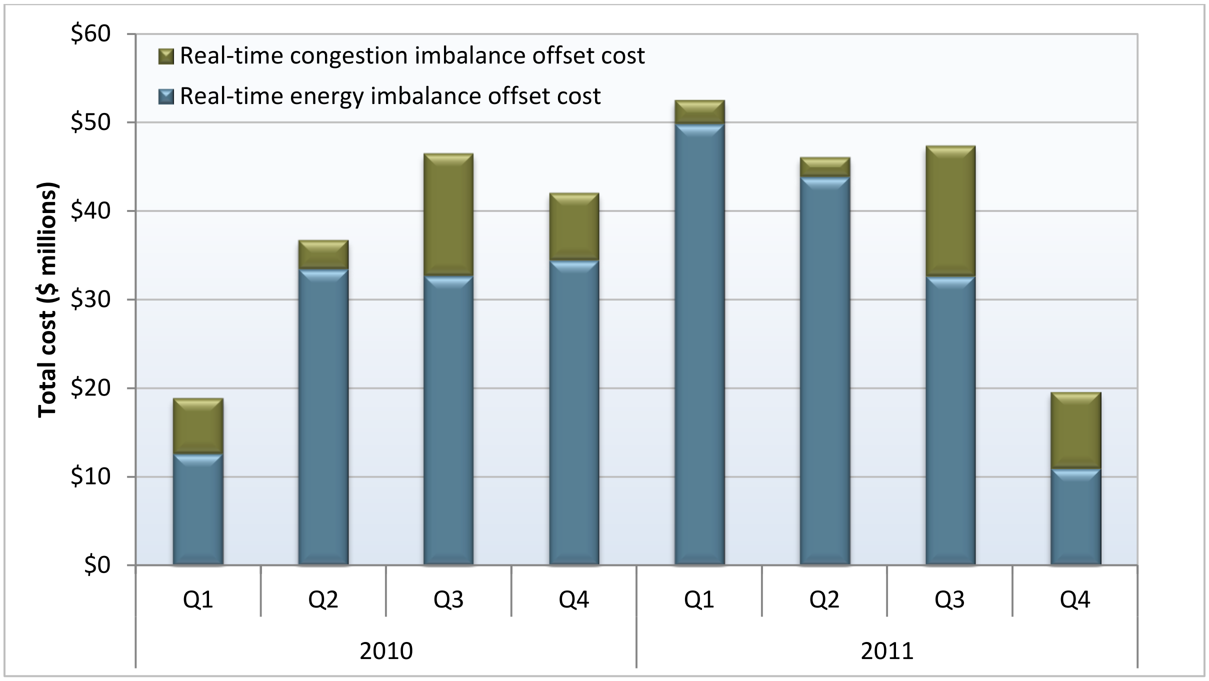
[2] Other factors that contribute to real-time imbalance offset costs include uninstructed deviations and unaccounted for energy.

Figure E.5 Real-time imbalance offset costs



Convergence bidding

The ISO implemented convergence (or virtual) bidding in the day-ahead market on February 1, 2011. Convergence bidding allows participants to place financial bids to buy power and offers to sell power into the day-ahead market, regardless of whether or not the bidders own physical load or generation. Virtual bids are automatically liquidated in the hour-ahead and real-time markets. These markets clear based on a physical re-dispatch of the system and not the purely financial convergence bids.

Convergence bidders profit by taking advantage of differences between day-ahead, hour-ahead and real-time prices. In theory, if participants successfully profit from virtual bidding, this activity should drive day-ahead, hour-ahead and real-time prices closer. However, this theoretical impact of virtual bidding may not occur because of a market feature that makes the California market design different from most other ISOs.

California's market design re-optimizes imports and exports in an hour-ahead scheduling process based on bid prices and projected conditions within the ISO for the following operating hour. Unlike other ISOs, the ISO settles inter-tie transactions based on hour-ahead market clearing prices rather than 5-minute real-time prices. Virtual bids on inter-ties are also settled based on hour-ahead prices rather than the 5-minute real-time prices.

The financial settlement of inter-tie convergence bids based on hour-ahead prices has led to additional uplifts, known as imbalance offset costs, which can occur when prices diverge between the hour-ahead and real-time markets. Virtual bidding on inter-ties increased these imbalance offset costs by increasing the volume of transactions clearing at these different market prices.

When convergence bidding was implemented, numerous individual participants profited from systematic differences between hour-ahead and real-time prices by placing large volumes of virtual imports at inter-ties along with equal volumes of offsetting virtual demand at internal nodes. This enabled participants to profit from the tendency for average real-time prices to exceed hour-ahead prices. However, these offsetting virtual supply and demand bids provided no net virtual demand or supply in the day-ahead market and therefore did not contribute to the primary goal of convergence bidding: to help improve convergence of day-ahead and real-time prices. This bidding practice declined in the third quarter as differences between hour-ahead and real-time prices decreased and became less predictable.

Net profits paid to virtual bidding participants totaled $41 million in 2011. About $28 million of these profits came from virtual bids at inter-tie schedules, compared to $13 million from bids at internal locations. An estimated $26 million of these profits were received as a result of virtual supply bids on inter-ties offset by virtual demand bids within the ISO during the same hour placed by the same market participant.

Figure E.6 shows the estimated monthly effect of offsetting convergence bids on real-time imbalance offset charges compared to total real-time imbalance offset charges. The estimated real-time imbalance offset costs associated with offsetting virtual positions were highest in the first months after implementation, totaling $44 million from February through June. In the second half of the year, the costs associated with offsetting virtual transactions fell to about $13 million between July and November.[3] The decline was associated with improved price convergence and a corresponding decrease in volumes of offsetting transactions.

To address the issues created by virtual bidding on inter-ties, the ISO requested the Federal Energy Regulatory Commission to allow it to suspend convergence bidding on the inter-ties. Convergence bidding at inter-ties was suspended effective November 28, 2011, pending further consideration through a FERC technical conference and written comments.

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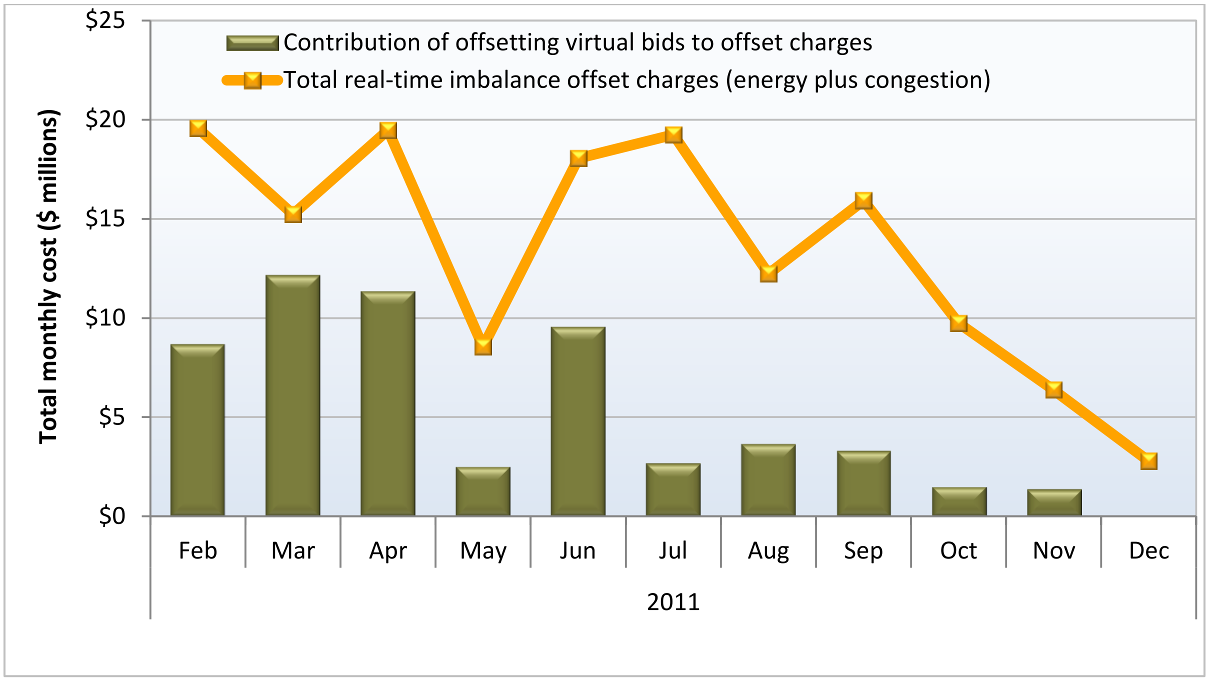
[3] There were no imbalance costs for offsetting virtual positions in December as convergence bidding at the inter-ties was suspended in late November.

Figure E.6 Contribution of offsetting virtual supply and demand to real-time imbalance charges



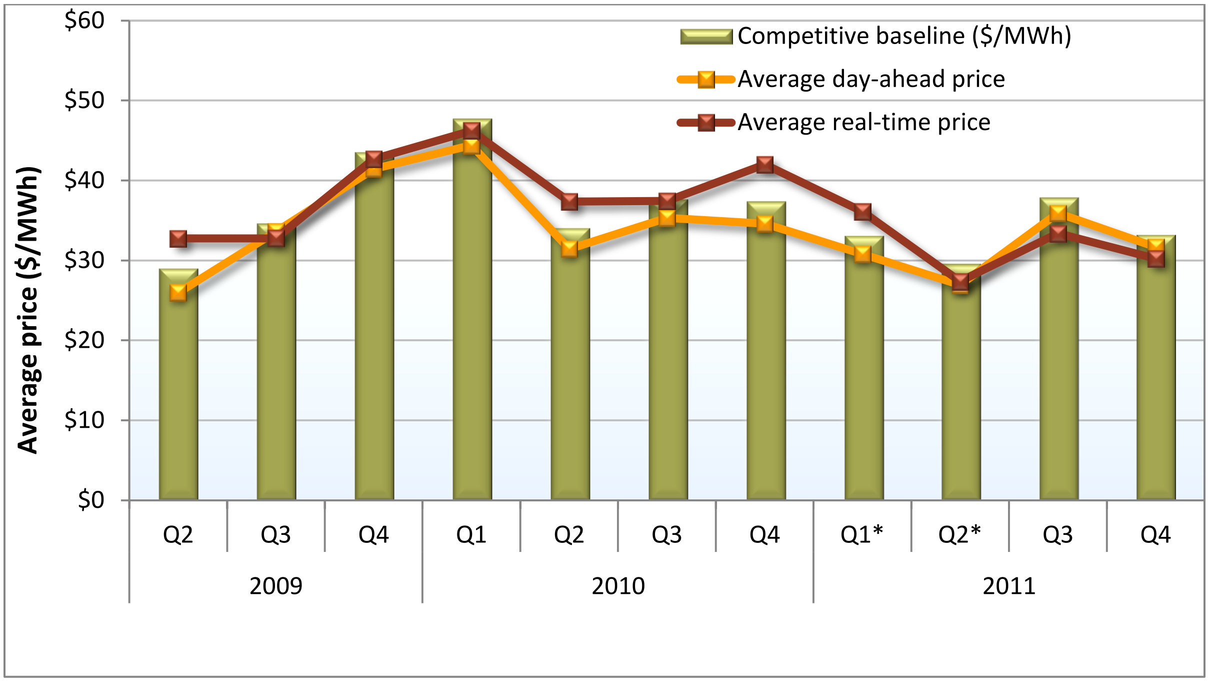
Market competitiveness and mitigation

Overall wholesale energy prices were about equal to competitive baseline prices the Department of Market Monitoring (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.7 compares this price to actual average system-wide prices in the day-ahead and 5-minute real-time markets.

As shown in Figure E.7, prices in the day-ahead market have consistently been about equal to these competitive baseline prices since the start of the nodal market. Average system-wide real-time prices in 2011 were below this competitive baseline by about 3 percent. This was a significant reduction from 2010 when average real-time prices were 12 percent above the competitive baseline. The drop resulted primarily from the decreased frequency of extremely high real-time prices associated with ramping limitations and other modeling constraints.

A key factor driving the competitiveness of these markets continues to be the high degree of forward energy contracting by load-serving entities. The high level of forward contracting significantly limits the ability and incentive for suppliers to exercise market power in the day-ahead and real-time markets. Bids for the additional supply needed to meet remaining demand in the day-ahead and real-time energy markets have generally been highly competitive.

Figure E.7 **Comparison of competitive baseline with day-ahead and real-time prices**[4]



During each quarter in 2011, an average of about 3.5 units out of over 500 units were subject to bid mitigation per hour in the day-ahead market.[5] When units are subject to bid mitigation, they are often not dispatched at a higher level as a result. This occurs because mitigation often results in minor changes in bids and market prices that often exceed a unit's unmitigated bid.

The ISO will in 2012 phase in new local market power mitigation features.[6] This approach targets units that can relieve congestion on specific constraints found to be non-competitive based on a more dynamic assessment of actual market conditions. This approach is to ensure that bid mitigation is applied under non-competitive conditions, while avoiding unnecessary mitigation when congestion does not occur or market conditions are competitive.

Ancillary services

Ancillary service costs increased to about $139 million in 2011, representing a 61 percent increase over 2010. This increase was driven primarily by a drop in ancillary services from hydro-electric generation during the spring and early summer periods. During this period, high runoff required that many hydro resources provide energy instead of ancillary services. This required increased reliance on higher-priced

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[4] As a result of technical difficulties, DMM had difficulty loading and re-running save cases in the months of February, March and April. Unfortunately, the current market model is too different to replicate enough useful market results for this period.

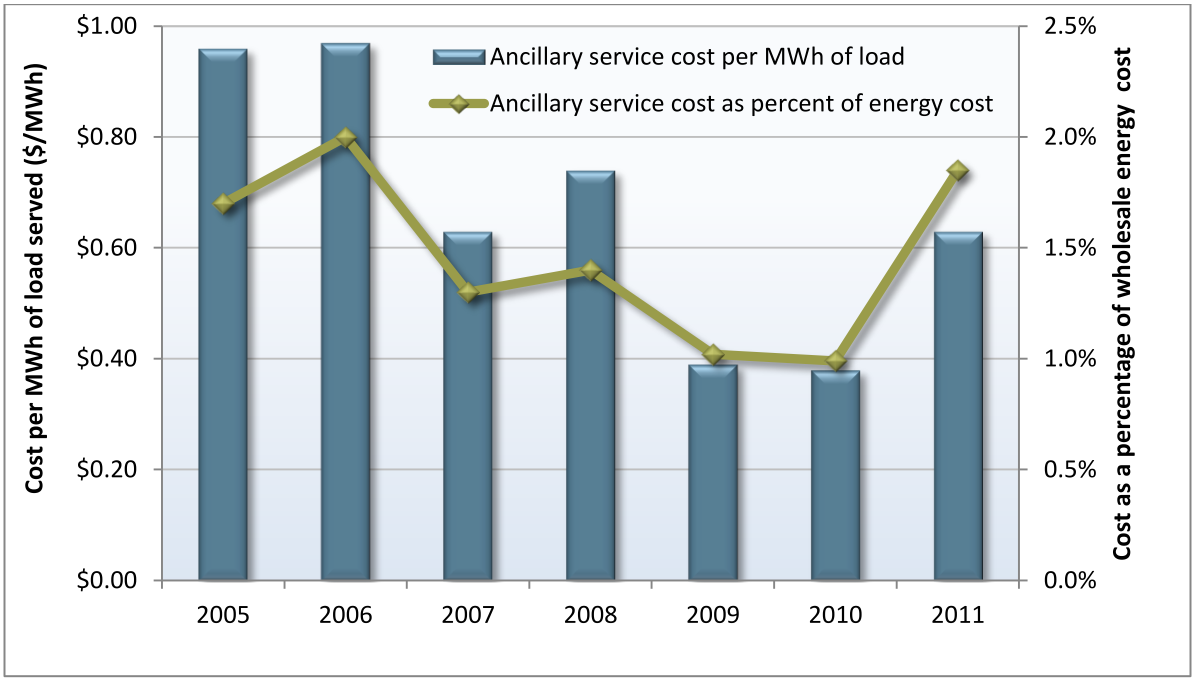
[5] DMM has determined that many of the units subject to mitigation were included as a result of issues in the mitigation process. Further analysis of this issue was included as part of the FERC filing to amend the tariff for the new local market power mitigation procedure. For more information, see the following documentation: http://www.caiso.com/Documents/2011-11-16_ER12-423_LMPMAmend.pdf.

[6] *Draft Final Proposal – Local Market Power Mitigation Enhancements*, May 2012: http://www.caiso.com/Documents/DraftFinalProposal-LocalMarketPowerMitigationEnhancements.pdf.

ancillary services from thermal units and more capacity not owned or contracted by load-serving entities.

As shown in Figure E.8, ancillary service costs increased from $0.37/MWh of load in 2010 to $0.63/MWh in 2011. This represents an increase in ancillary service costs to about 1.9 percent of total energy costs in 2011 from 1 percent of total energy cost in 2010.

Figure E.8 Ancillary service cost as a percentage of wholesale energy cost



Exceptional dispatches

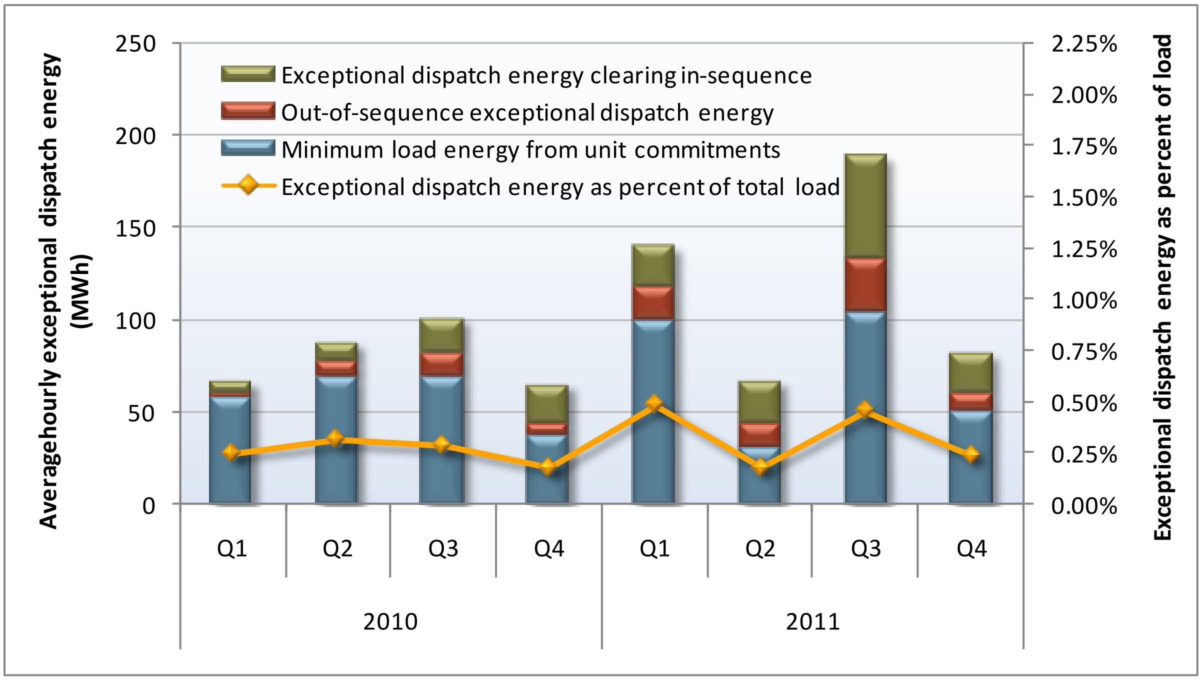
Exceptional dispatches (also known as out-of-market dispatches) are instructions issued by grid operators when the automated market optimization is not able to address particular reliability requirements or constraints. The ISO has made an effort to reduce exceptional dispatches by refining operational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

Total energy from all exceptional dispatches increased slightly in 2011, rising from 0.26 percent in 2010 to 0.34 percent of system load in 2011. The above-market costs of all exceptional dispatches in 2011 totaled around $43 million. As shown in Figure E.9:

- The majority of energy from exceptional dispatches represents minimum load energy from units committed to operate by exceptional dispatches. This minimum load energy averaged almost 72 MW per hour in 2011, up from 58 MW in 2010.
- Almost two-thirds of the energy above minimum load from exceptional dispatches cleared in-sequence, meaning that their bid prices were less than the market clearing prices.

- Exceptional dispatches resulting in out-of-sequence real-time energy with bid prices higher than the market prices accounted for an average of only 18 MW per hour in 2011, up from 8 MW in 2010. This increase was primarily the result of more exceptional dispatches made to position units at a level where they could provide more upward ramping capacity.

Figure E.9 Average hourly energy from exceptional dispatches



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 bids accepted by the ISO. This calculation includes bids for start-up, minimum load, day-ahead energy, ancillary services, residual unit commitment availability and real-time energy.

Units committed by the market software or exceptional dispatches may have higher bid cost recovery payments if they have very high bid costs or are not dispatched for significant amounts of additional energy above minimum load. Thus, excessively high bid cost recovery payments can be indicative of inefficient unit commitment or dispatch.

Figure E.10 provides a summary of total estimated bid cost recovery payments in 2010 and 2011.[7] These payments in 2011 are projected to total $126 million or about 1.5 percent of total energy costs. This compares to a total of $68 million or about 0.8 percent of total energy costs in 2010. This increase in bid cost recovery payments was driven by two factors:

- In the last quarter of 2010 and first six months of 2011, day-ahead bid cost recovery payments were inflated by a design flaw in combination with manipulative market behavior. In March and June, the

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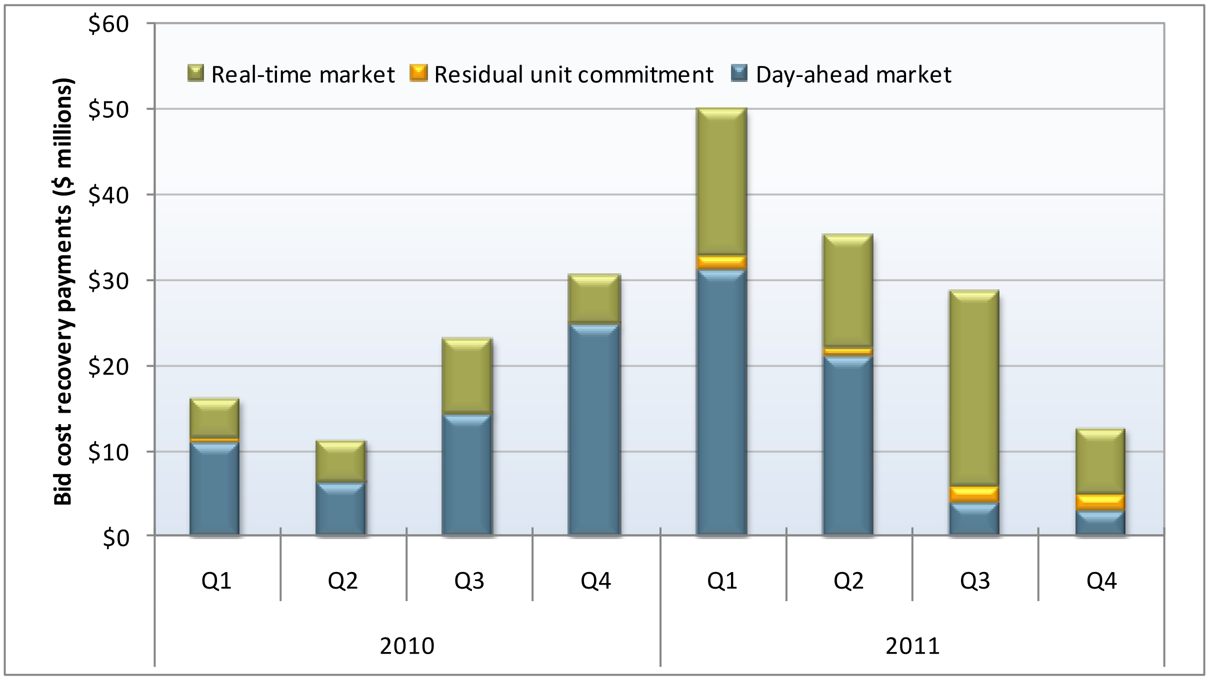
[7] Estimates in this report include estimated adjustments to bid cost recovery data still pending in the settlement system.

ISO made two emergency filings with the FERC to modify bid cost recovery rules to mitigate this behavior.[8] As a result, bid cost recovery payments associated with the day-ahead market dropped by 86 percent in the second half of 2011.

- Bid cost recovery payments associated with real-time market dispatches were considerably higher in the third quarter of 2011. Higher real-time payments were mainly from exceptional dispatches that were made by the ISO to commit additional capacity after the day-ahead market for system and local reliability needs. A decrease in commitment of units within the ISO through the market resulted from relatively low energy prices and increased imports.

Figure E.10 Bid cost recovery payments



Resource adequacy

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

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[8] California Independent System Operator Corporation, Tariff Revision and Request for Expedited Treatment, March 18, 2011, http://www.caiso.com/2b45/2b45d10069e0.pdf. Tariff Revision and Request for Waiver of Sixty Day Notice Requirements, June 22, 2011, http://www.caiso.com/Documents/2011-06-22_Amendment_ModBCRrules_EDEnergySettRules_ER11-3856-000.pdf.

Chapter 9 of this report provides an analysis of the amount of resource adequacy capacity actually available in the ISO market during peak hours of 2011. This analysis shows that the availability of resource adequacy capacity was relatively high during the highest load hours of each month. During the peak summer load hours, about 91 percent of resource adequacy capacity was available to the day-ahead energy market. This is approximately equal to the target level of availability incorporated in the resource adequacy program and similar to the results in 2010.

Capacity under the resource adequacy program was sufficient to meet virtually all system-wide and local area reliability requirements in 2011. As a result, the ISO placed very limited reliance on the two alternative capacity procurement mechanisms provided under the tariff: reliability must-run contracts and the capacity procurement mechanism.

The state's resource adequacy program continued to work well as a short-term capacity procurement mechanism. However, in 2011 it became increasingly apparent that the state's current process for longer-term procurement may not ensure the investment and revenues needed to support gas-fired resources that will be needed to integrate the increased amount of intermittent renewable energy coming online. This issue is discussed in the following section.

Generation addition and retirement

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

Figure E.11 summarizes the quarterly trends in summer capacity additions in 2011 and planned additions in 2012. Almost 1,000 MW of new nameplate generation began commercial operation within the ISO system in 2011, contributing to over 500 MW of additional summer capacity. This included over 300 MW of new gas-fired capacity and about 650 MW of nameplate renewable generation, which added almost 200 MW of summer capacity.

The ISO anticipates construction of about 7,400 MW of new nameplate generation by the end of 2012, with almost 90 percent coming from renewable resources. About 3,950 MW of this new capacity is from wind resources, which is likely to provide about 650 MW of peak summer capacity.[9] After taking the summer peak capacity ratings of new resource types into account, this represents about 4,000 MW of additional summer capacity. The ISO also anticipates 450 MW of existing generation to be retired in 2012.

The proposed addition of new gas-fired generation in 2012 is mostly offset by the retirement of older gas-fired generation. As a result, non-renewable generation capacity has not grown significantly in the last few years, while renewable generation increases to meet the state's renewable requirements. As more renewable generation comes online, the ISO has highlighted the need to backup and balance renewable generation with the flexibility of conventional generation resources to maintain reliability.[10]

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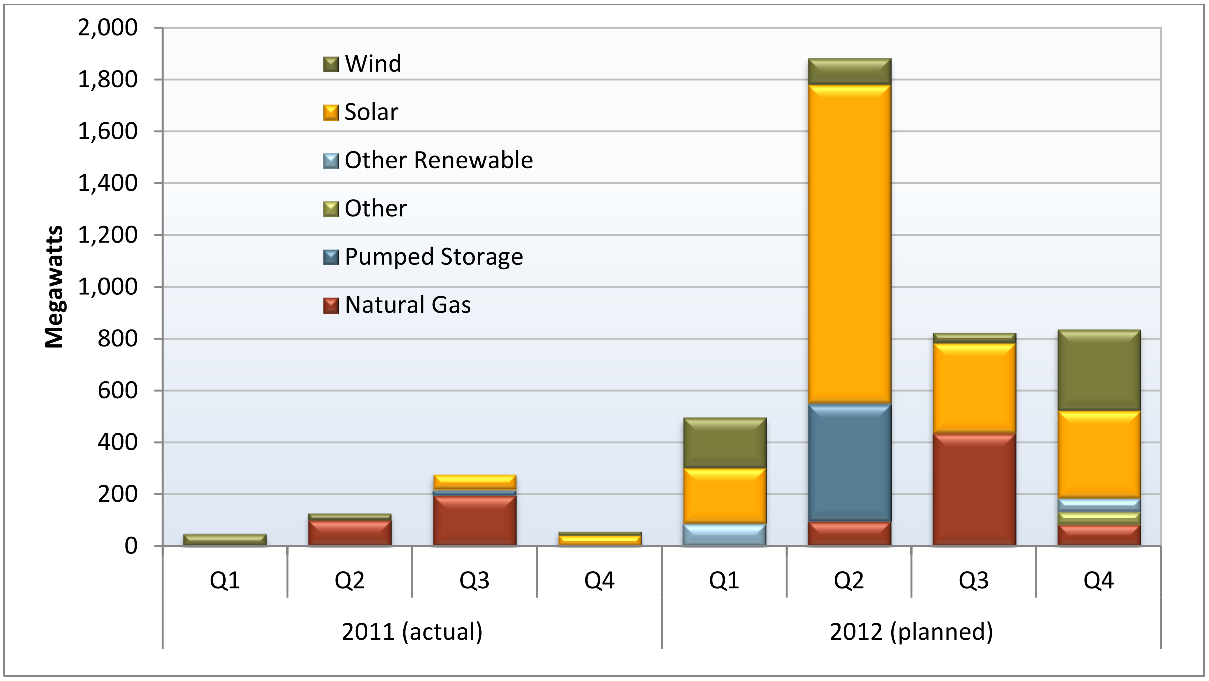
[9] The summer capacity factors used for wind and solar resources are 16 percent and 92 percent respectively.

[10] More information on renewable integration can be found here: http://www.caiso.com/informed/Pages/StakeholderProcesses/IntegrationRenewableResources.aspx.

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



Under California's 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 in 2011 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 2011 prices for gas and electricity show a decrease in net operating revenues for hypothetical new gas units compared to 2010. The 2011 net revenue estimates for hypothetical combined cycle and combustion turbine units both 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 2011 are estimated at about $23/kW-year, compared to estimated annualized fixed costs of $191/kW-year.

Under current market conditions additional new generic gas-fired capacity does not appear to be needed at this time. However, a substantial portion of the state's 15,000 MW of older gas-fired capacity is located in transmission constrained load pockets and is needed to meet local reliability requirements. Much of this capacity is also needed to provide the operational flexibility needed to integrate the large volume of intermittent renewable resources coming online. This capacity is increasingly uneconomic to keep available without some form of capacity payment and will need to be retrofitted or replaced to eliminate use of once-through cooling technology over the next decade.

Investment necessary to maintain, retrofit or replace this capacity could be addressed through long-term bilateral contracting under the CPUC's long-term procurement and resource adequacy proceedings. However, as noted in DMM's last annual report, this capacity is located in areas where one or two entities own most of the generation needed to meet the local reliability requirements. Potential competition from new generation and transmission in these areas is severely limited because of siting and other regulatory limitations. Thus, DMM has continued to emphasize the need for a mechanism to mitigate local market power that may be exercised in the bilateral market for local capacity.

In 2011 another potential gap or limitation between the state's current long-term procurement planning and resource adequacy programs became increasingly apparent. In late 2011, Calpine Corporation informed the ISO of its intent to retire a 550 MW combined cycle unit (Sutter Energy Center) in 2012 unless the unit received a resource adequacy contract or was contracted by the ISO through the capacity procurement mechanism. The ISO determined that the Sutter unit was not needed in 2012, but that the unit is likely to be needed in 2017-2018 because of the retirement of other existing gas-fired capacity subject to the state's once-through cooling regulations. The ISO found that the Sutter unit was specifically needed because it can provide flexible ramping capabilities that will be needed to integrate the large volume of intermittent renewable resources coming online in the next few years.[11]

This case has highlighted several key limitations of the state's current long-term procurement planning and resource adequacy programs.

- Neither of these processes incorporates any specific capacity or operational requirements for the flexible capacity characteristics that will be needed from a large portion of gas-fired resources to integrate the large volume of intermittent renewable resources coming online in the next few years.
- The resource adequacy program and the capacity procurement mechanism in the ISO tariff are based on procurement of capacity only one year in advance. This creates a gap between these procurement mechanisms and the multi-year timeframe over which some units at risk of retirement may need to be kept online to meet future system flexibility or local reliability requirements.

In response to these issues, the ISO has taken several specific steps:

- The ISO is working with the CPUC and stakeholders to integrate requirements for new categories of flexible resource characteristics into the current resource adequacy program.[12]
- The ISO is also proposing that the CPUC establish a multi-year resource adequacy requirement, including flexibility requirements, in the next resource adequacy proceeding that would establish resource adequacy requirements starting in 2014.
- Finally, the ISO has initiated a stakeholder process to develop a mechanism in the ISO tariff to ensure the ISO has sufficient backstop procurement authority to procure any capacity at risk of retirement not contracted under the resource adequacy program that the ISO identifies as needed up to five years in the future to maintain system flexibility or local reliability.[13]

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[11] For a detailed discussion see California Independent System Operator Corporation Petition for Waiver of Tariff Revisions and Request for Confidential Treatment, January 25, 2012: http://www.caiso.com/Documents/2012-01-26_ER12-897_Sutter_Pet_TariffWaiver.pdf.

[12] For further details see the Flexible Capacity Procurement stakeholder process site: http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleCapacityProcurement.aspx.

[13] For further details see *Flexible Capacity Procurement Market and Infrastructure Policy Straw Proposal*, March 7, 2012: http://www.caiso.com/Documents/StrawProposal-FlexibleCapacityProcurement.pdf.

Recommendations

In our prior annual and quarterly reports, DMM has provided a variety of specific recommendations for short-term market improvements. DMM also works closely with ISO staff and stakeholders to provide recommendations on new market design initiatives on an ongoing basis. While the ISO has already taken steps responsive to many of these recommendations, continued emphasis on these issues is warranted in 2012. This section summarizes DMM recommendations on selected key issues, along with steps that have been taken or are being taken to address these issues.

Improve price convergence

Recommendation: In many of its reports for the last couple of years, DMM highlighted the lack of price convergence in the ISO markets. In particular, DMM stressed the difference between the hour-ahead and real-time markets as problematic. In its 2010 annual report, DMM warned that continued divergence in prices would pose an increasing problem after the implementation of convergence bidding.[14] Price divergence and the resulting real-time imbalance costs remained a significant issue for much of 2011.

Resolution: Starting in the summer of 2011, price convergence began to improve significantly as the frequency of 5-minute real-time price spikes fell. As discussed in Chapter 3, the ISO has taken numerous actions, including modifying operator procedures and enhancing the software, that have ultimately improved price convergence. At the end of the year, the ISO also implemented the flexible ramping constraint. While these changes have helped to improve price convergence, they are not likely to resolve all limitations contributing to price divergence. Therefore, DMM recommends that the ISO remain committed to addressing the underlying causes of price divergence between the hour-ahead and 5-minute real-time markets. This includes addressing factors that may cause real-time prices to be systematically higher or *lower* than day-ahead or hour-ahead prices for sustained periods.

Convergence bidding on inter-ties

Issue: Within the first few months after virtual bidding was implemented, DMM noted that large volumes of virtual supply at inter-ties were offsetting virtual demand bids clearing at internal locations. These offsetting virtual supply and demand bids allowed some participants to profit from price divergence between the hour-ahead and 5-minute real-time markets. However, these offsetting bids provided little or no increase in efficiency or reliability by improving day-ahead unit commitment. In many cases, these virtual import bids completely offset the impact that internal virtual bidding could otherwise have on helping to converge day-ahead and real-time prices. In addition, these offsetting bids created significant revenue imbalances that are imposed on other participants. Based on these findings, DMM supported the suspension of inter-tie convergence bidding while modifications to settlement provisions for virtual inter-tie bids are assessed.

Resolution: In September, the ISO filed with FERC to suspend convergence bidding at the inter-ties. In late November, FERC temporarily suspended convergence bidding at the inter-ties, pending further comments from interested parties and consideration by the Commission. In 2012, the ISO continued its stakeholder process to assess modifications to the hour-ahead and real-time markets that will facilitate re-implementation of virtual bidding on inter-ties.

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[14] *2010 Annual Report on Market Issues and Performance*, April 2011, p. 12: http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf.

Re-implementing convergence bidding on inter-ties

Recommendation: DMM has been actively involved in working with ISO staff and stakeholders to identify various market design changes that would facilitate re-implementation of virtual bidding on inter-ties. However, DMM believes that virtual bidding on inter-ties should only be re-implemented in conjunction with market design changes that will ensure it will be beneficial to overall market efficiency and will not impose significant costs on other participants.

Many participants agree that virtual bidding on inter-ties should not be reinstated until fundamental market design and inter-control area seams issues underlying problems with the hour-ahead and real-time markets are addressed. DMM believes developing and implementing such changes will take time. Extreme care must be taken to avoid introducing inefficiencies or other unintended consequences into the physical markets that are more critical to system reliability and overall market performance.

Resolution: In 2012, the ISO is continuing its stakeholder process to assess modifications to the hour-ahead and real-time markets that might facilitate re-implementation of virtual bidding on inter-ties. Options being proposed by the ISO appear to provide reasonable assurance that the problems previously observed with convergence bidding on inter-ties will not reoccur. However, DMM continues to recommend that the details of various options be thoroughly reviewed and that proper safeguards be incorporated into any market design changes made in conjunction with re-implementation of virtual bidding on inter-ties.

Modify local market power mitigation procedures

Recommendation: The local market power mitigation provisions of the new energy market design have proven to be effective without imposing an excessive level of mitigation. However, prior to implementation of virtual bidding in 2011, DMM recommended that current local market power mitigation procedures be modified to ensure that virtual bids do not undermine the effectiveness of these procedures. DMM also recommended that the ISO implement a more dynamic process for assessing the competiveness of transmission constraints using the actual market software based on actual system and market conditions.

Resolution: In 2011, the ISO and DMM worked with stakeholders to develop a package of modifications to make local market power mitigation procedures more dynamic, and therefore more reflective of actual system and market conditions. In addition, modifications will be made to ensure that bid mitigation is targeted at individual units that can relieve congestion on uncompetitive constraints. DMM believes these modifications will help ensure that mitigation is applied when appropriate, while avoiding bid mitigation in cases when local market power does not exist.

Flexible generation characteristics

The ISO has proposed spot market and forward procurement products that will provide additional generation dispatch flexibility to improve reliability as more variable energy resources are integrated. The flexible ramping product may provide significant revenue opportunities for more flexible generating resources on the margin. The ISO has also proposed incorporating specific requirements for flexible unit operating characteristics in the state's year-ahead resource adequacy requirements and eventually into a five year forward capacity procurement process. As the requirements for such characteristics increase over time it will be increasingly important that forward capacity procurement also include flexible ramping characteristics. The ISO has deferred pursuing forward procurement of flexible ramping capacity; however, it does intend to develop a mechanism to evaluate the risk of unit retirement in the context of future ramping requirements and have in place a compensation mechanism to bridge the time between potential retirement and when the resource will provide needed ramping capacity.

Recommendation: For the spot product, DMM has recommended that the ISO provide further clarification on how the requirements will be set. We have also recommended that the ISO pursue cost allocation during this initiative and do so in a way that most closely adheres to cost causation principles. For the forward procurement, DMM has recommended a clear linkage between the target requirement for forward procurement and anticipated needs.

Resolution: The ISO is currently in the process of more clearly defining the requirements for the spot product, but has not yet indicated a final form or expected magnitude during different circumstances. It is difficult to anticipate potential scarcity or market power issues without this information; however, DMM is optimistic that more development and empirical work will be done this year. For the forward procurement, the ISO has elected not to pursue incorporating flexible ramping characteristics into the existing forward capacity procurement process. We note that while there may appear to be sufficient flexible ramping capacity over the next few years, including this characteristic and requirement in the long-term procurement process is the most likely means to providing a price signal that will ensure adequate flexible ramping capacity further out in time.

Cost allocation

Recommendation: As noted in 2009 and 2010 annual reports, DMM continues to recommend the costs of any additional products needed to integrate different resources should also be allocated in a way that reflects the reliability and operational characteristics of different resources. This will help ensure proper price signals for investment in different types of new resources. For example, if new ancillary services or other products are specifically procured to mitigate the impacts of intermittent renewable resources, the cost of these additional products should be allocated to these intermittent resources. Currently, the cost of all ancillary services is allocated to load.

Resolution: The ISO is conducting a process to define principles that will be applied in determining cost allocation for specific market and non-market items going forward. The proposed principles include cost causation, along with providing proper incentives, rationality (e.g., the cost of implementation relative to the cost to be allocated), and alignment with public policy. DMM has recommended that cost causation should be the driving principle of cost allocations.[15] Allocating costs to participants whose actions directly cause the cost provides a direct incentive to modify actions when this is cost-effective and reduces the associated cost. DMM believes this will ultimately be the most efficient and effective way to manage the overall costs associated with renewable integration, which in turn will help achieve the state public policy goals for increased reliance on renewable energy at a reasonable cost.

The first product the ISO will apply these principles regards procuring a new flexible ramping product in the spot market. The initial proposal allocated these costs entirely to load. However, a revised proposal proposes allocating these costs in a manner that reflects the contribution of each individual resource to the real-time variability that ultimately influences the quantity and cost of procurement. This revised

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[15] See DMM comments at http://www.caiso.com/Documents/DMM_Comments-CostAllocationGuidingPrinciplesStrawProposal.pdf.

approach should provide an incentive for resources to reduce variability which will, over time, reduce the procurement requirement and cost associated with this product.

Review effectiveness of the 200 percent cap for registered costs

Recommendation: In 2011, DMM observed that the majority of bids for both start-up and minimum load costs for units under the registered cost option have approached the current cap of 200 percent of fuel-costs.[16] DMM recommended that the ISO reevaluate the appropriateness and effectiveness of the current cap. If this cap is lowered, DMM also continues to support consideration of the inclusion of a fixed component for non-fuel costs associated with any verifiable start-up and minimum load costs.

Resolution: The ISO has included this item to be considered as part of its commitment cost refinement stakeholder process.[17] DMM also continues to recommend that the ISO revise the caps for transition cost bids for multi-stage generating units as part of this initiative.

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 2011. 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 2011.
- **Real-time market performance.** Chapter 3 provides an analysis of real-time market performance, including reasons for extreme positive prices and negative prices in the real-time market.
- **Convergence bidding.** Chapter 4 analyzes the convergence bidding feature that was added in 2011 and its effects on the market.
- **Ancillary services.** Chapter 5 reviews performance of the ancillary service markets.
- **Market competitiveness and mitigation.** Chapter 6 assesses the competitiveness of the energy market, along with the impact and effectiveness of market power mitigation provisions.
- **Congestion.** Chapter 7 reviews congestion and the market for congestion revenue rights.
- **Market adjustments.** Chapter 8 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 9 assesses the short-term performance of California’s resource adequacy program in 2011.
- **Recommendations.** Chapter 10 highlights DMM recommendations on several key issues and initiatives.

Chapter 1 of DMM’s 2010 annual report provides a summary of the nodal market design implemented in 2009 and key design enhancements that have been added in 2010 and 2011.[18] This chapter of our

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[16] *Quarterly Report on Market Issues and Performance*, November 8, 2011, pp. 41-44.

[17] See http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostsRefinement2012.aspx.

2010 annual report also highlights various state policies and requirements closely linked to the design and performance of the ISO markets.

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[18] *2010 Annual Report on Market Issues and Performance*, April 2011, pp. 17-32. http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf.

1 Load and resources

Overall load and supply conditions were very favorable in 2011. Key trends highlighted in this chapter include:

- The average price of natural gas in the daily spot markets decreased about 4 percent from 2010.[19] This was the primary driver of the 9 percent decrease in the annual wholesale energy cost per MWh of load served in 2011.
- Average loads during summer peak hours increased by about 1.5 percent. The system peaked at 45,545 MW, or almost 4 percent lower than peak load in 2010 due to mild summer conditions.
- Hydro-electric energy production increased by 25 percent in 2011 compared to 2010 and was at its highest level since 2006. The increase in hydro-electric generation lasted well into the summer and early fall months when loads are highest.
- Net imports increased by 10 percent in 2011, driven by a 60 percent increase in low priced imports from the Northwest. This increase reflected abundant hydro-electric supplies and increases in wind generation in that region.
- Demand response programs operated by the major utilities continued to meet over 5 percent of the ISO’s overall system resource adequacy capacity requirements. Activation of these programs continued to be very limited in 2011 because of the favorable supply and demand conditions. Nearly two-thirds of demand response capacity continues to be comprised of reliability-based programs that can only be activated under extreme system conditions. However, price-responsive programs that can be dispatched during the operating day in response to real-time conditions provided about 26 percent of demand response capacity in 2011, compared to 15 percent in 2010. The remaining 10 percent of demand response capacity came from price-responsive programs that could only be dispatched on a day-ahead basis in response to expected market or system conditions.
- About 195 MW of peak generating capacity from renewable generation was added in 2011. Energy from wind and solar currently provides only about 4 percent of system energy, but energy from new wind and solar resources is expected to increase at a much higher rate in the next few years as a result of projects under construction to meet the state’s renewable portfolio standards.
- Over 300 MW of new gas-fired generation was added in 2011. The estimated net operating revenues for typical new gas-fired generation in 2011 fell substantially below the annualized fixed cost of new generation. This analysis does not include revenues earned from resource adequacy contracts or other bilateral contracts. However, these findings continue to emphasize the critical importance of long-term contracting as the primary means for investment in any new generation needed under California’s current market design.
- Analysis by DMM also indicates that net operating revenues of many existing gas-fired generating units in 2011 may not even cover going forward fixed costs of these units. While the overall level of

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

gas-fired capacity may not need to increase in the next few years, a substantial portion of the state's existing fleet of gas-fired resources will need to be maintained or replaced to ensure that enough capacity is available to meet peak loads and provide the operational flexibility needed to integrate the large volume of intermittent renewable resources coming on-line. Again, this emphasizes the importance of the state's annual resource adequacy program and longer-term contracting under California's current market design.

1.1 Load conditions

1.1.1 System loads

System loads were moderate in 2011, likely because of a combination of moderate summer weather and a slowly recovering economy. Table 1.1 summarizes annual system peak loads and energy use over the last five years, which includes:

- Average daily peak loads during the summer months rose by only 1.5 percent, while average loads during all hours increased by just 0.4 percent.
- Summer loads peaked at 45,545 MW on September 7 at 4:30 p.m. This represents a 4 percent drop from 2010 and the lowest annual peak level since 2005.

Table 1.1 Annual system load: 2007 to 2011

Year	Annual total energy (GWh)	Average load (MW)	% change	Annual peak load (MW)	% change
2007	242,880	27,644		48,615	
2008	241,128	27,526	-0.4%	46,897	-3.5%
2009	230,754	26,342	-4.3%	46,042	-1.8%
2010	224,922	25,676	-2.5%	47,350	2.8%
2011	226,087	25,791	0.4%	45,545	-3.8%

Figure 1.1 summarizes load conditions during summer peak hours (June to August, hours 7 to 22) since 2001. Average hourly peak loads have remained relatively flat since 2003. However, system demand during the single highest load hour has varied substantially from year to year because of summer heat waves. The potential for such heat-related peak loads drives many of the ISO's reliability planning requirements. This also creates a continued threat of operational reliability problems under extreme weather conditions.

Figure 1.2 shows load duration curves for the years 2009 through 2011. While overall energy consumption was higher in 2011 compared to 2010, peak demand dropped in 2011. System load exceeded 40,000 MW during only 61 hours, or about 0.6 percent of all hours. In 2010, load exceeded 40,000 MW during 88 hours, or about 1 percent of all hours.

The ISO in coordination with the CPUC and other local regulatory authorities sets system level resource adequacy requirements based on the 1-in-2 year forecast of peak demand. Resource adequacy requirements for local areas are based on the 1-in-10 year peak forecast for each area. As shown in Figure 1.3, summer peak demand in 2011 was about 2,270 MW lower than the 1-in-2 year forecast, representing a difference of 4.7 percent. In 2009 and 2010, peak loads slightly exceeded the 1-in-2 year forecast.

Figure 1.1 Summer load conditions (2001 to 2011)

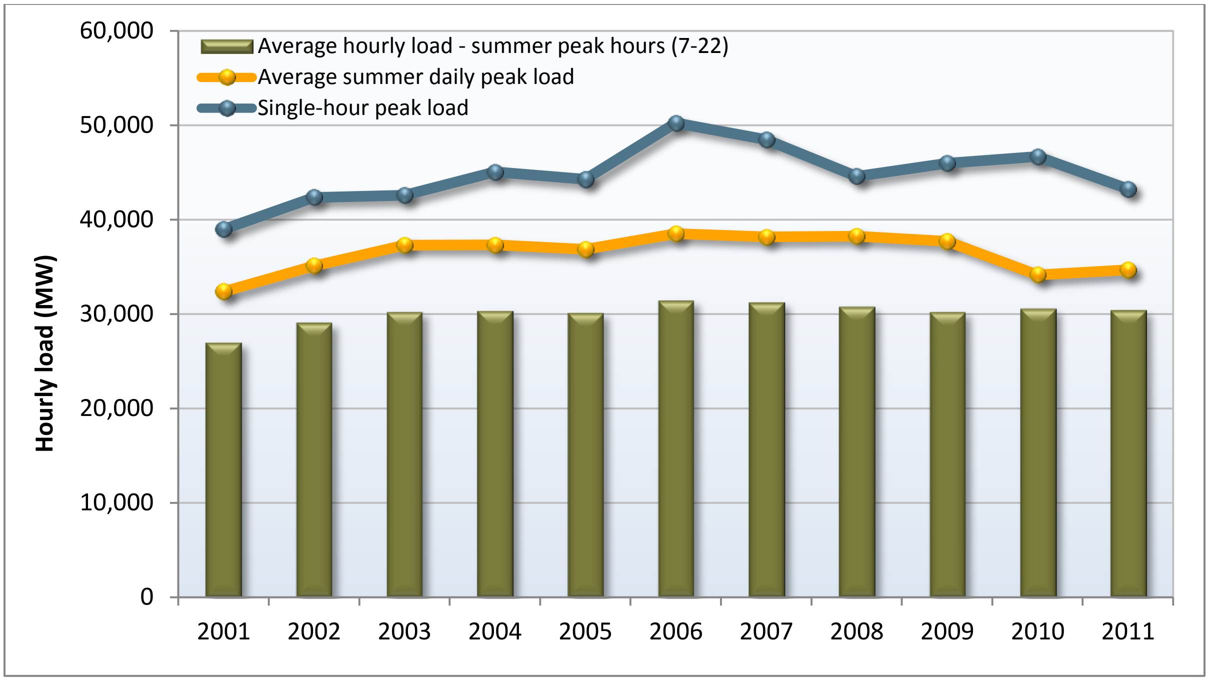


Figure 1.2 System load duration curves (2009 to 2011)

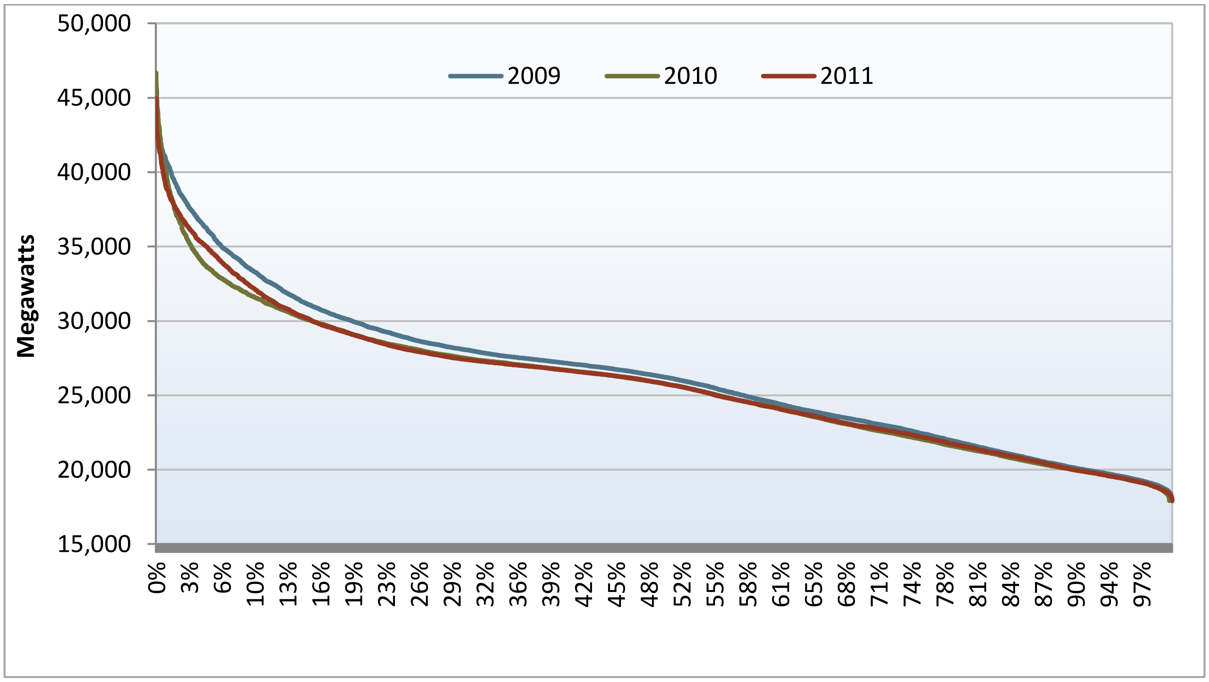
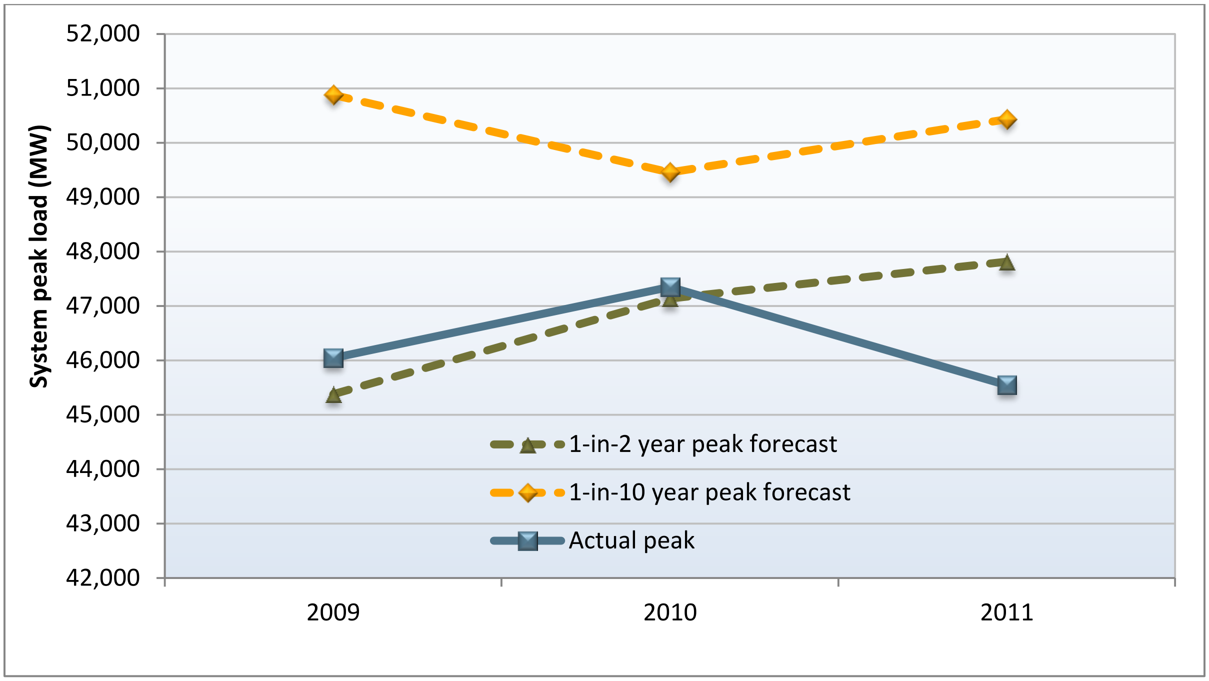


Figure 1.3 Peak load vs. planning forecasts



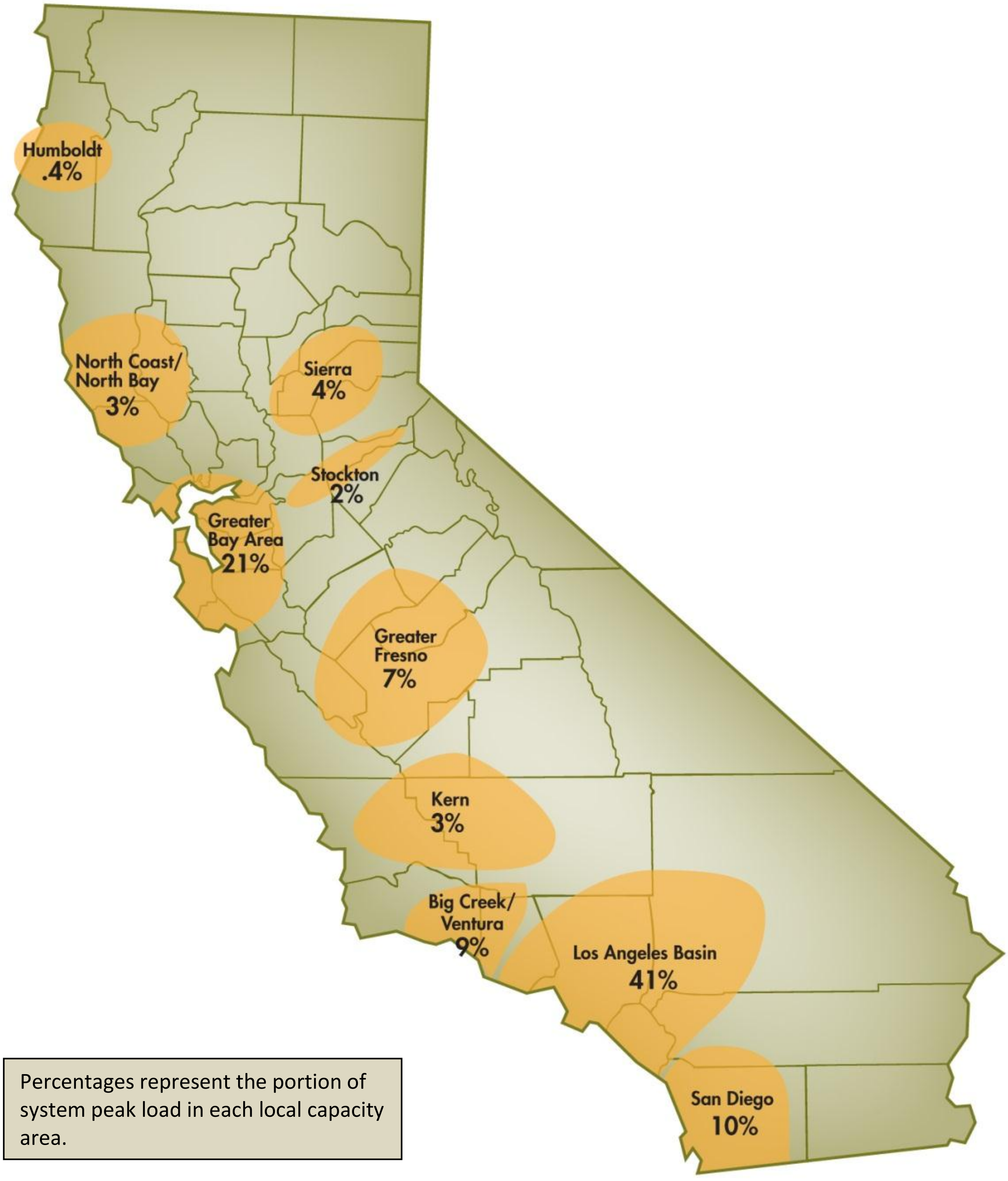
1.1.2 Local transmission constrained areas

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

- The Pacific Gas and Electric area accounts for about 39 percent of total local capacity area loads under the 1-in-10 year forecast. Loads in the Greater Bay Area account for around half of the potential peak load in the PG&E area.
- The Southern California Edison area accounts for around 51 percent of total local capacity area loads under the 1-in-10 year forecast. Loads in the Los Angeles Basin account for around 80 percent of the potential peak load in the SCE area.
- The San Diego Gas and Electric area is comprised of a single local capacity area, which accounts for about 10 percent of total local capacity area loads.

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

Figure 1.4 Local capacity areas



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

Table 1.2 Load and supply within local capacity areas in 2011

		Peak Load (1-in-10 year)		Dependable Generation	Local Capacity Requirement	Requirement as Percent of
Local Capacity Area	**LAP**	**MW**	**%**	**(MW)**	**(MW)**	**Generation**
Greater Bay Area	PG&E	10,322	21%	6,506	4,878	75%*
Fresno	PG&E	3,306	7%	2,919	2,448	84%*
Sierra	PG&E	1,977	4%	1,816	2,082	115%*
North Coast/North Bay	PG&E	1,574	3%	861	734	85%
Stockton	PG&E	1,163	2%	526	682	130%*
Kern	PG&E	1,387	3%	708	447	63%*
Humboldt	PG&E	206	0.4%	223	205	92%*
LA Basin	SCE	20,223	41%	12,309	10,589	86%
Big Creek/Ventura	SCE	4,648	9%	5,306	2,786	53%
San Diego	SDG&E	5,036	10%	3,421	3,207	94%*
Total		**49,842**		**34,595**	**28,058**	**80%**

Source: *2012 Local Capacity Technical Analysis: Final Report and Study Analysis*, April 29, 2011. See Table 6 on page 22. http://www.caiso.com/2b6f/2b6f8be32da20.pdf

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

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

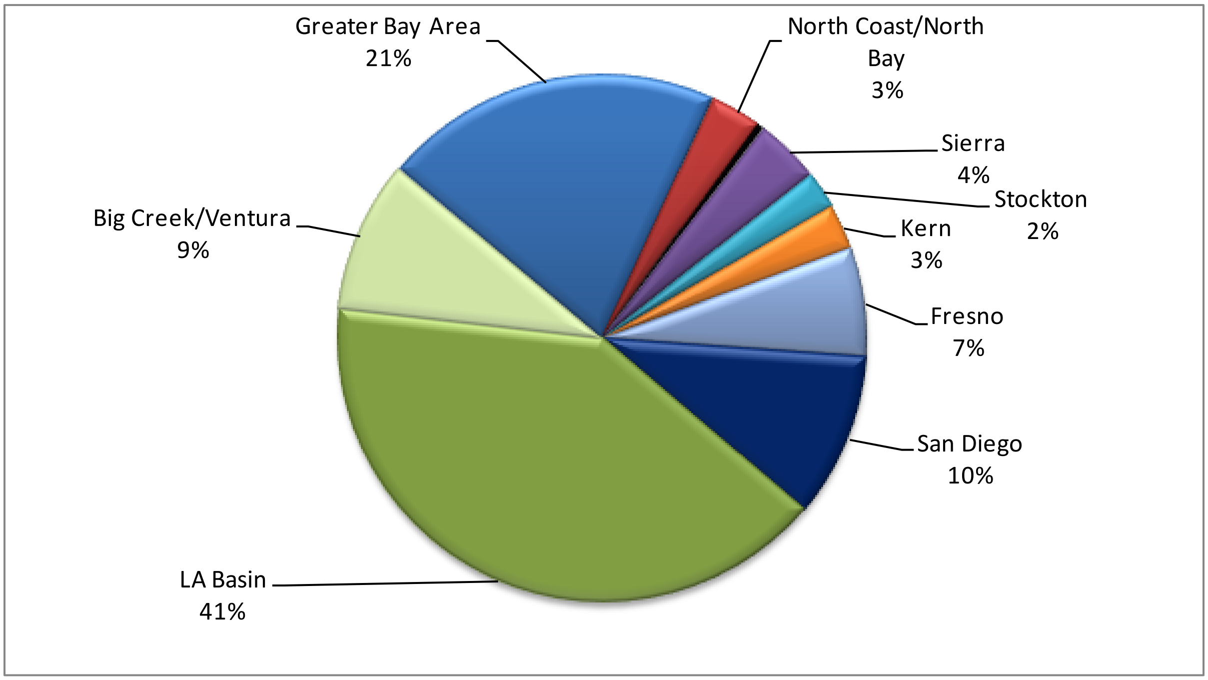
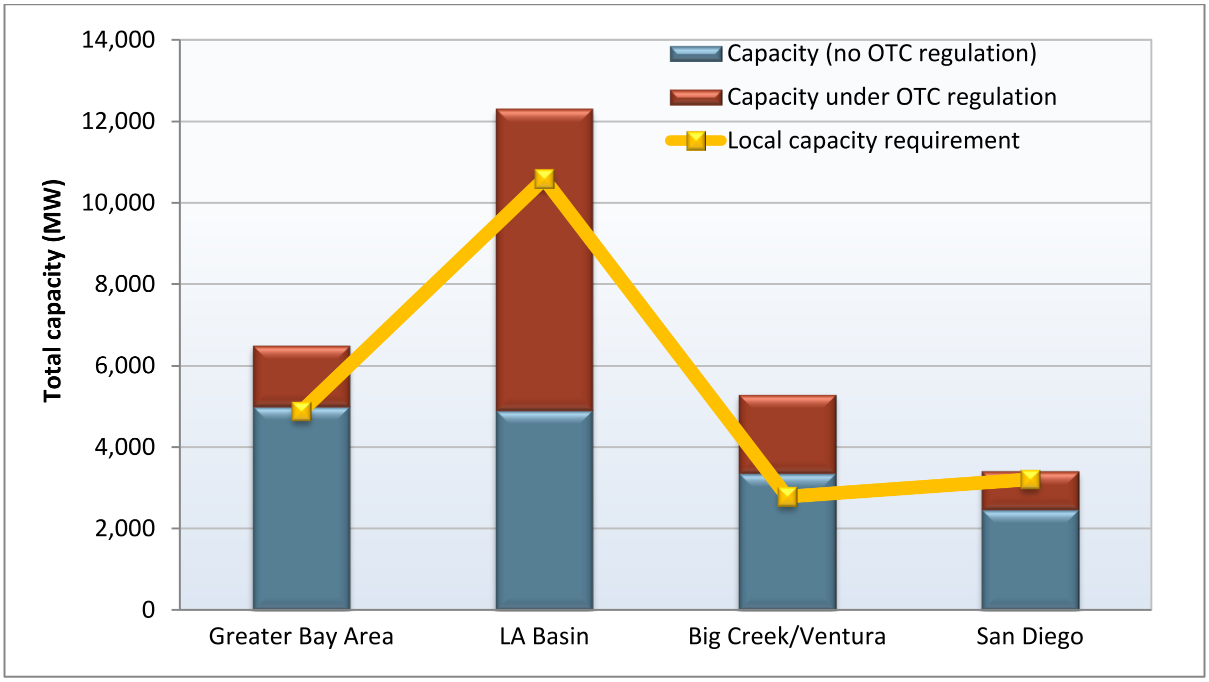


Table 1.2 also shows the total amount of generation in each local capacity area, along with the total amount of capacity required for local reliability requirements for these areas used in the state resource adequacy program. Table 1.2 shows that, in most of these areas, a very high portion of the available capacity is needed to meet peak reliability planning requirements. One or two entities own the bulk of generation in each of these areas. As a result, the potential for locational market power in these load pockets is significant.

Figure 1.6 shows how the four major local capacity areas are affected by the state's once-through cooling (OTC) regulations.[20] Regulations affect around 19,600 MW of generation capacity (net qualifying capacity) on the California coast. About 11,160 MW of this capacity is located in these four local capacity areas. As shown in Figure 1.6:

- A significant portion of existing capacity needed to meet local capacity requirements in each of these areas are subject to once-through cooling regulations.
- In two of these areas (the LA Basin and San Diego), 2011 local capacity requirements could not be met without repowering or replacing some of the capacity affected by once-through cooling.
- In the remaining areas (the Greater Bay Area and Big Creek/Ventura), virtually all capacity not subject to once-through cooling regulations would be needed to meet local capacity requirements when compared to 2011 requirements.[21]

Figure 1.6 Capacity affected by once-through cooling regulations



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[20] For more information on once-through cooling, please see the following link to the State Water Resource Control Board: http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/.

[21] The ISO conducted a detailed transmission analysis on local capacity requirements and the impact of once-thorough cooling regulations. See pages 212-216 at http://www.caiso.com/Documents/RevisedDraft-2011-2012TransmissionPlan.pdf.

1.1.3 Demand response

Overview

Demand response plays an important role in meeting California's capacity planning requirements for peak summer demand. During the peak summer months, demand response programs operated by the state's three investor-owned utilities met over 5 percent of overall system resource adequacy capacity requirements. Non-utility entities, such as independent curtailment service providers, provide demand response by participating in utility sponsored programs. These utility demand response programs are not dispatched directly by the ISO. Currently, demand response provided directly to the ISO is primarily limited to water pumping loads.[22]

In August 2010, the ISO implemented a proxy demand resource product. This market enhancement also allows aggregators of end-use loads to bid directly into the energy and ancillary service markets. This was designed to increase direct participation in the energy and ancillary service markets by utility demand response programs, as well as aggregated end-use or independent curtailment service providers. However, only about 12 MW of proxy demand resource capacity was registered in 2011 and no bids from these resources were dispatched.

In 2011, the ISO also completed development of a reliability demand response resource product planned for implementation in 2012. This product is designed to be similar to the proxy demand resource product, but is tailored to allow retail emergency-triggered demand response programs (such as interruptible load, air conditioning and agricultural pumping load programs) to be integrated into day-ahead and real-time energy markets. These resources would be able to bid into the day-ahead energy market like other resources, regardless of whether emergency operating conditions have been met. However, the resources would only be dispatched by the ISO in real-time during a system emergency or a warning notice period. However, in early 2012, the FERC rejected the ISO's reliability demand response proposal on the grounds that the proposal does not meet the payment and cost allocation principles outlined in FERC's Order 745.[23]

Utility demand response programs

Almost all of California's current demand response consists of load management programs operated by the state's three investor-owned utilities. These programs are triggered by criteria set by the utilities. The programs are not necessarily tied to market prices. Notification times required by the retail programs are also not well synchronized with market operations. This limits the programs' ability to reduce electricity prices in the market. This is because the demand response resources cannot necessarily be called on to reduce load at times of high prices or low reserve margins that do not result in an actual system emergency.

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

[23] February 16, 2012 Order rejecting tariff revisions in docket nos. ER11-3616-000, et al. http://www.caiso.com/Documents/2012-02-16_ER11-3616_order.pdf.

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

From the perspective of market performance and system reliability, day-of price responsive demand programs are significantly more valuable than price-responsive programs that can only be triggered on a day-ahead basis.

Table 1.3 summarizes total demand response capacity for each of the three major utilities during the peak summer month of August, as reported to the CPUC since 2007. As shown in Table 1.3, there is a notable drop in reported demand response capacity from 2009 to 2010. This was due to a change in the way that demand response capacity is assessed and reported, as explained below.

Demand response capacity was reported until 2009 based on planning estimates of the potential load reductions from total loads enrolled under each program. Then the CPUC established standard protocols for measuring and reporting demand response programs for utilities under its jurisdiction.[24] Estimates of load reductions under these new protocols are generally based on statistical analysis of actual metered data and tend to be lower than prior estimates used in program planning.

Protocols in effect since 2010 required monthly reporting of *ex post* estimates of program impacts based on results of these prior studies combined with the actual number of participants in each program. Totals in Table 1.3 for 2010 and 2011 are based on these *ex post* estimates of program impacts in monthly reports filed by each utility with the CPUC.[25] As a result, estimated values reported for 2010 and 2011 are lower relative to capacity reported in previous years.

The bottom two rows of Table 1.3 show the amount of capacity from utility demand response programs used to meet resource adequacy requirements. The amount of this capacity used to meet resource adequacy requirements is determined by the CPUC based on its estimate of demand response capacity that can be expected under peak summer conditions. The decrease in demand response used to meet

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

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

resource capacity requirements in 2010 and 2011 reflects the use of the more stringent standard protocols for measuring and reporting demand response programs that took effect in 2010.

As shown in Table 1.3, demand response capacity used to meet the 2010 and 2011 resource adequacy requirements tracked closely with estimates of actual demand response capacity reported in these years under the more advanced protocols for measuring and reporting of these programs. In both these years, *ex post* estimates of the combined impact of all utility demand response programs for August 2011 equaled about 95 percent of the resource adequacy capacity requirements that the CPUC allowed to be met by these resources.

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 reductions reduce the amount of capacity needed to meet the 15 percent supply margin used in setting resource adequacy requirements.

Table 1.3 Utility operated demand response programs (2007-2011)

Utility/type	2007 Enrolled MW	2008 Enrolled MW	2009 Enrolled MW	2010 Estimated* MW	2011 Estimated* MW
Price-responsive					
SCE	256	381	498	407	331
PG&E	623	752	508	272	451
SDG&E	121	154	89	66	60
Sub-total	999	1,287	1,095	746	842
Reliability-based					
SCE	1,305	1,458	1,577	1,038	1,167
PG&E	323	466	533	325	253
SDG&E	98	83	62	13	8
Sub-total	1,726	2,007	2,172	1,376	1,428
Total	2,725	3,294	3,267	2,122	2,270
Resource adequacy allocation	2,226	2,670	2,637	2,221	2,421
With 15 percent adder	2,560	3,071	3,033	2,554	2,784

* Capacity for 2007-2009 based on planning projections of program enrollment and impacts.
Capacity for 2010-2011 based on *ex post* assessment of program enrollment and impacts.

Figure 1.7 Utility operated demand response programs (2007-2011)

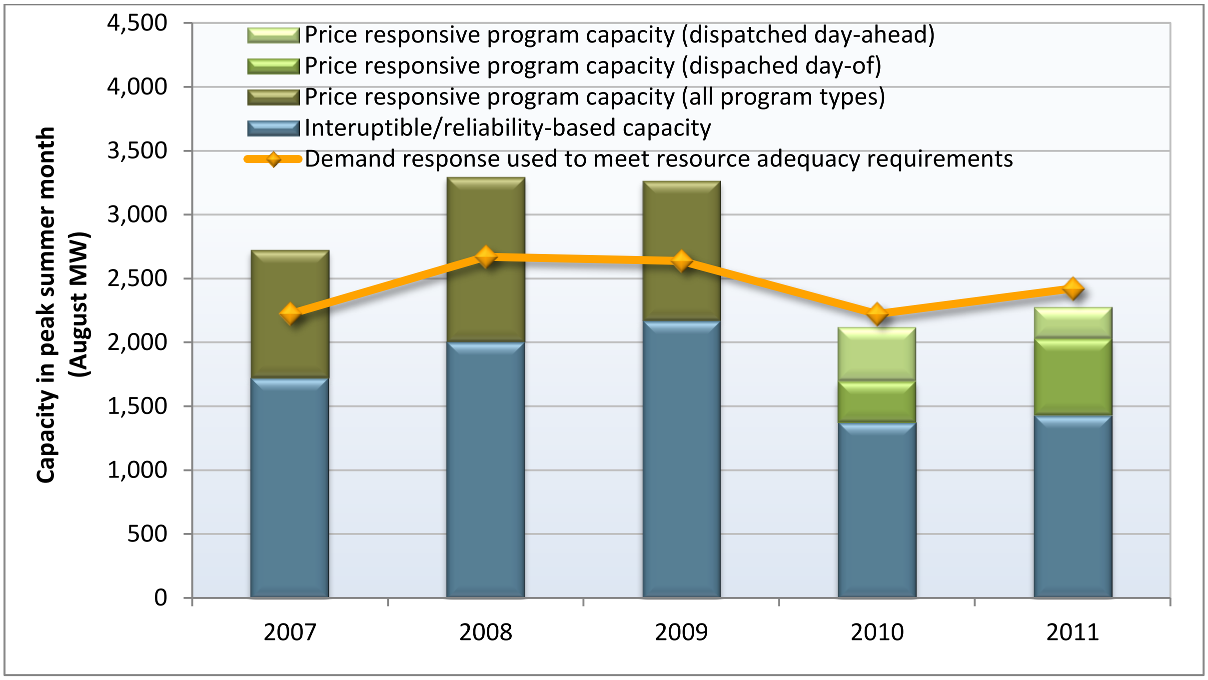

Figure 1.7 summarizes data in Table 1.3, but provides a further breakdown of the portion of price-responsive capacity that can be dispatched on a day-ahead and day-of basis in 2010 and 2011.[26] As shown in Figure 1.7:

- Reliability-based programs account for about 64 percent of the capacity from utility-managed demand response resources.
- Price-responsive programs account for around 36 percent of this capacity.
- In 2011, price-responsive programs that can be dispatched on a day-of basis grew to about 26 percent of all demand response capacity compared to about 15 percent in 2010.

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

Use of demand response programs

Demand response resources continue to be dispatched by utilities on a very limited basis. The low use of demand response programs reflects the relatively low market prices, moderate peak loads and favorable supply conditions in 2011. Figure 1.8 shows the annual total amount of demand response operated by the three largest utilities in 2011 by operating hour.

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

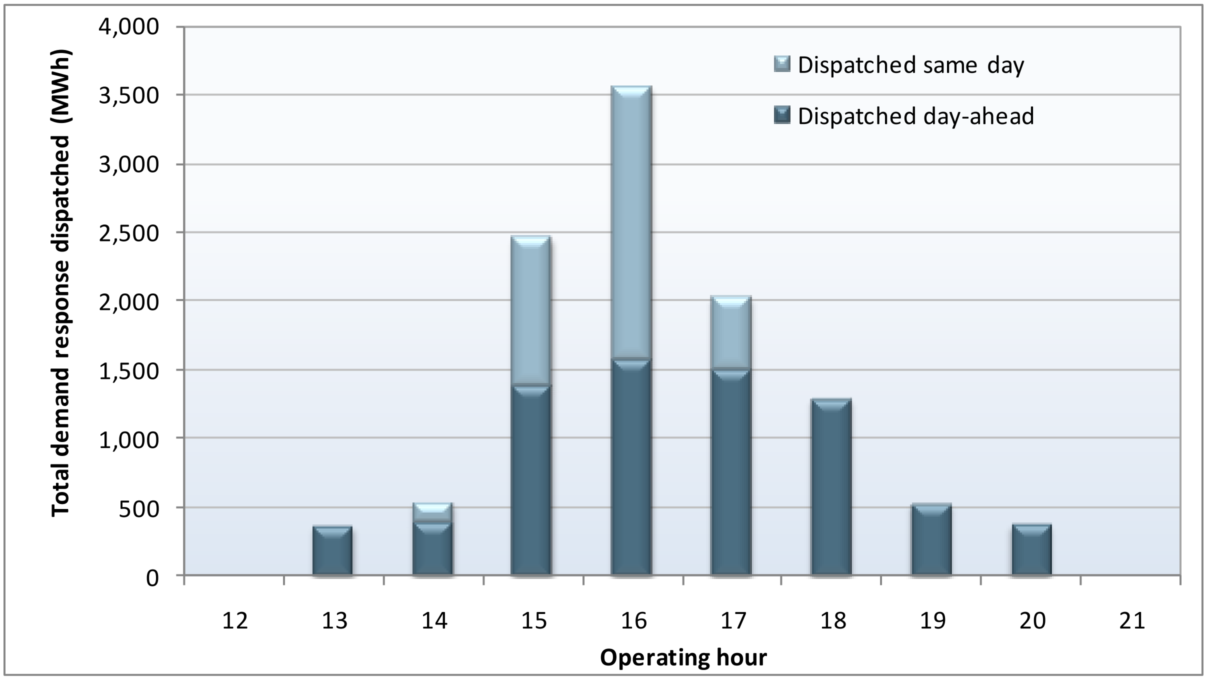
- About two-thirds of demand response dispatched was from price-responsive programs triggered on a day-ahead basis. About 5 percent of this day-ahead demand response was triggered for measurement and evaluation purposes, with the remaining 95 percent being dispatched due to projected market conditions the following operating day.

- About one-third of demand response was from price-responsive programs that are dispatched during the same operating day that load is curtailed. About 80 percent of this demand response was triggered for measurement and evaluation purposes, with the remaining 20 percent being dispatched due to actual market or system conditions.

- The most demand response dispatched during any hour in 2011 was only about 350 MW. This occurred on the peak load day from the prior year in August (August 25) and again on the overall annual peak day of September 7. Together these two days accounted for about 30 percent of all demand response dispatched in 2011.

Under the CPUC monitoring and evaluation protocols, the actual performance of demand response is re-assessed on an annual basis based on actual metered data. However, results of these evaluations are not available until spring of the following year. Under the current market design, the ISO does not have the data or responsibility for assessing the performance of these utility programs. When these programs are bid and dispatched directly in the ISO market as proxy demand resources, the ISO will play a role in assessing the impact of these resources based on metering data as part of its settlement process. This assessment will involve the use of a relatively simple statistical approach to estimate a baseline level of consumption from which load reductions will be estimated.

Figure 1.8 Total amount of demand response programs dispatched in 2011



1.2 Supply conditions

1.2.1 Generation mix

Figure 1.9 provides a profile of average hourly generation by month and fuel type. Figure 1.10 shows an hourly average profile of energy supply by fuel type for the peak summer months, July through September. These figures show the following:

- Natural gas and hydro-electric production increased most during the higher load months (August and September) of the year and the higher load hours of the day (7 through 22). These resources are most often marginal in the system.
- In 2011, natural gas generators provided 28 percent and hydro-electric generators provided 14 percent of supply. This indicates a significant decline in the share of natural gas, which provided 35 percent in 2010. Natural gas generation was replaced by hydro-electric generation, imports and nuclear generation.
- Net imports represented around 29 percent of total supply and base load nuclear production represented around 16 percent of supply in 2011.
- Non-hydro renewable generation accounted for 9 percent of total supply, staying around the same as the 2010 share.

Figure 1.11 provides a more detailed breakdown of non-hydro renewable generation in 2010 and 2011. Generation from wind resources increased significantly in 2011, while generation from biomass and solar resources only increased slightly.

- Geothermal provided approximately 38 percent of renewable energy.
- Wind provided approximately 35 percent of renewable energy in 2011, up from 30 percent in 2010.
- Biogas, biomass, and waste generation provided another 22 percent of renewable energy.
- Solar power provided about 5 percent of the total renewable generation.

Figure 1.12 compares average monthly generation from hydro, wind and solar resources. Both hydro-electric and wind generation peaked in the second quarter (April through June), when system loads are moderate and the supply portfolio is limited. The combination of these conditions contributes to the potential for negative price spikes due to over-generation during these months (see Section 3.4 for further discussion). Hydro-electric and wind generation declined in the third quarter (July through September) when loads reached peak levels. Figure 1.12 also shows that generation from solar resources peaked in the summer months. Currently, the share of generation from solar resources relative to the hydro and wind resources is significantly smaller. However, solar is expected to provide an increasing portion of supply from new renewable resources.

Figure 1.9 Average hourly generation by month and fuel type in 2011

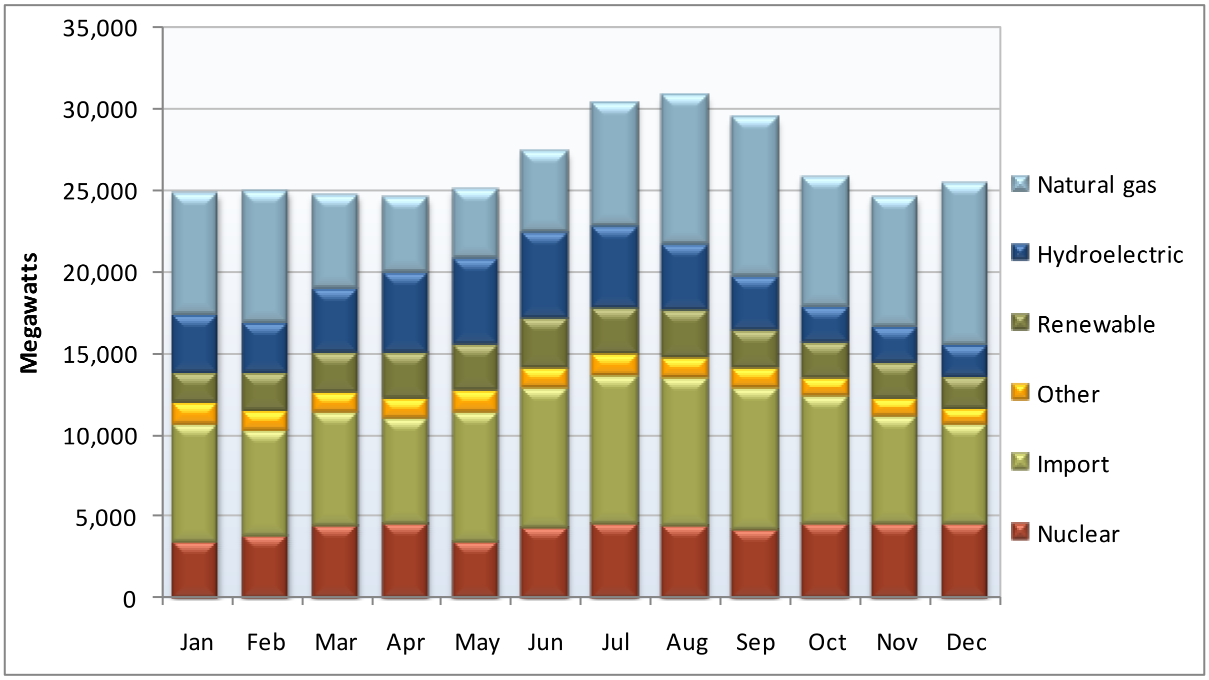


Figure 1.10 Average hourly generation by fuel type in Q3 2011

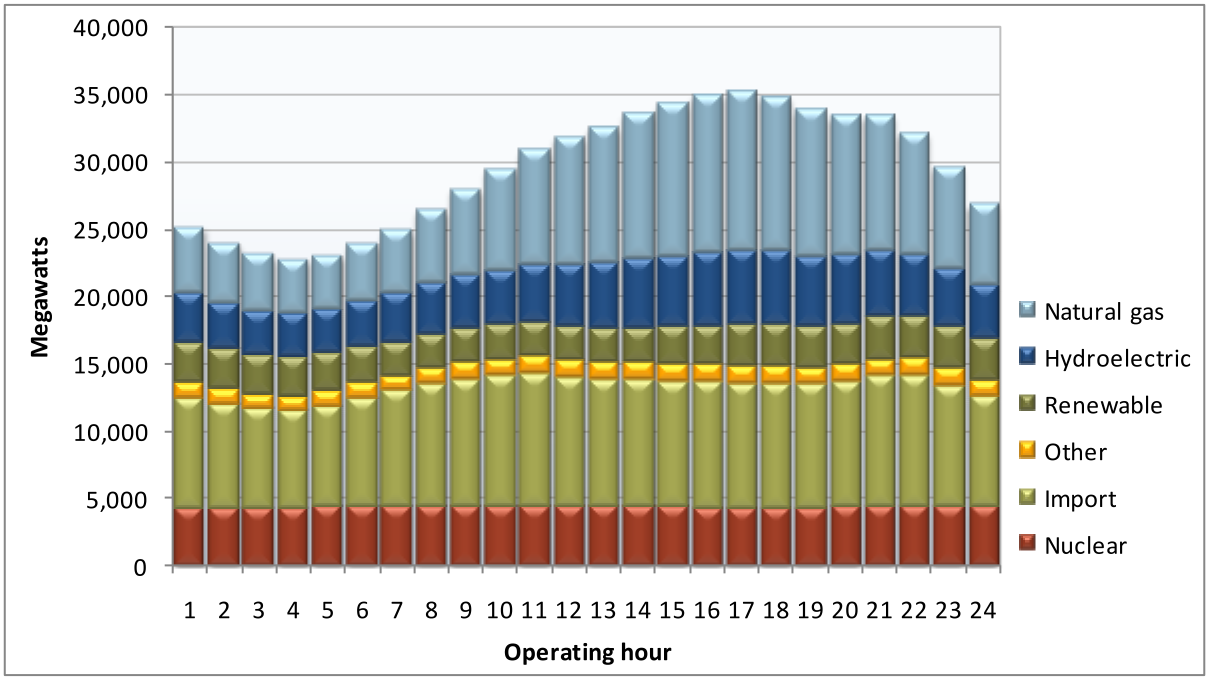


Figure 1.11 Total renewable generation by type (2009-2011)

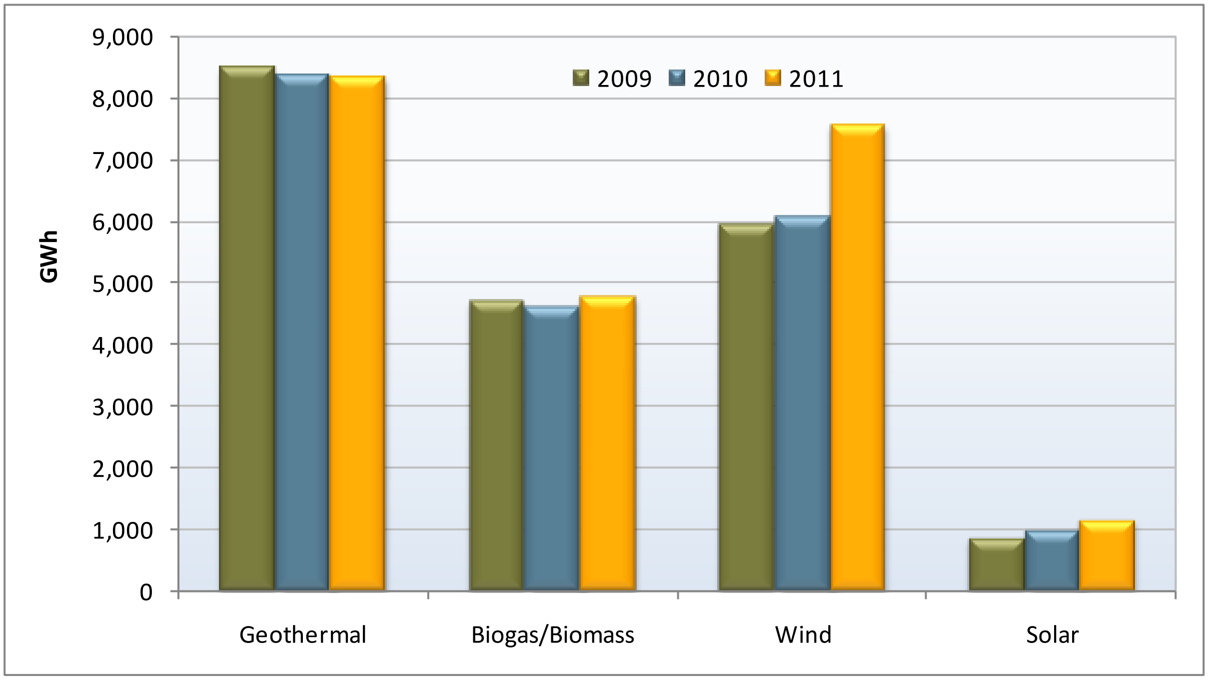
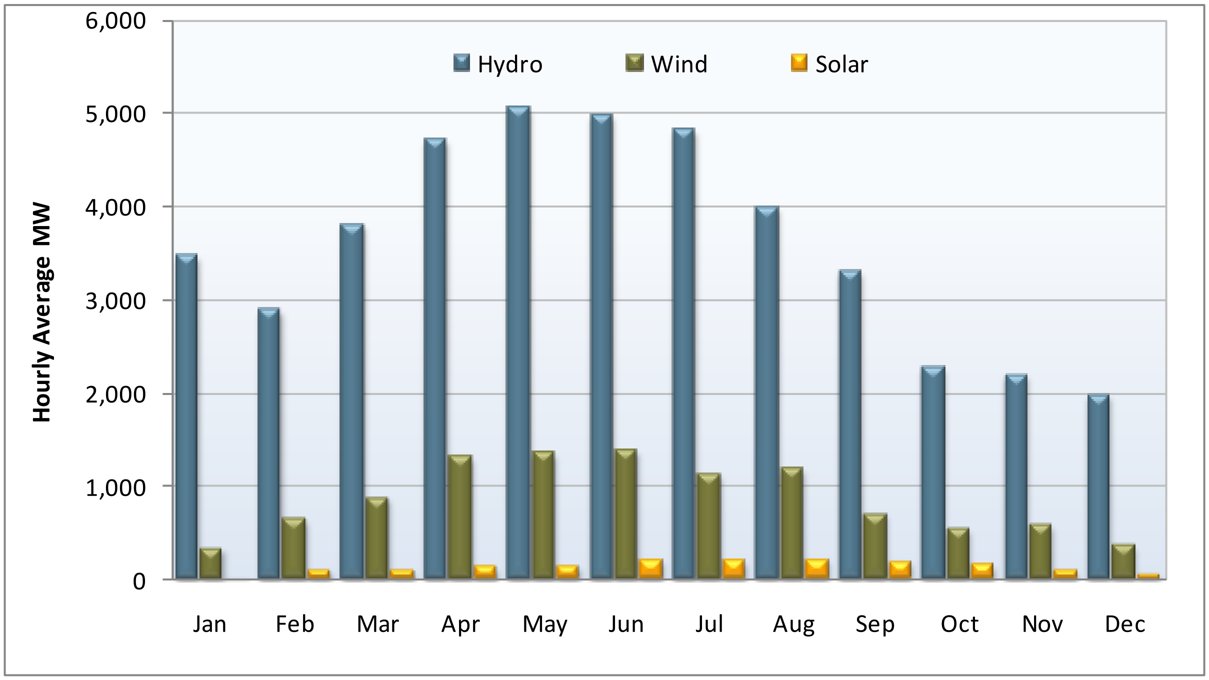


Figure 1.12 Monthly comparison of hydro, wind and solar generation (2011)



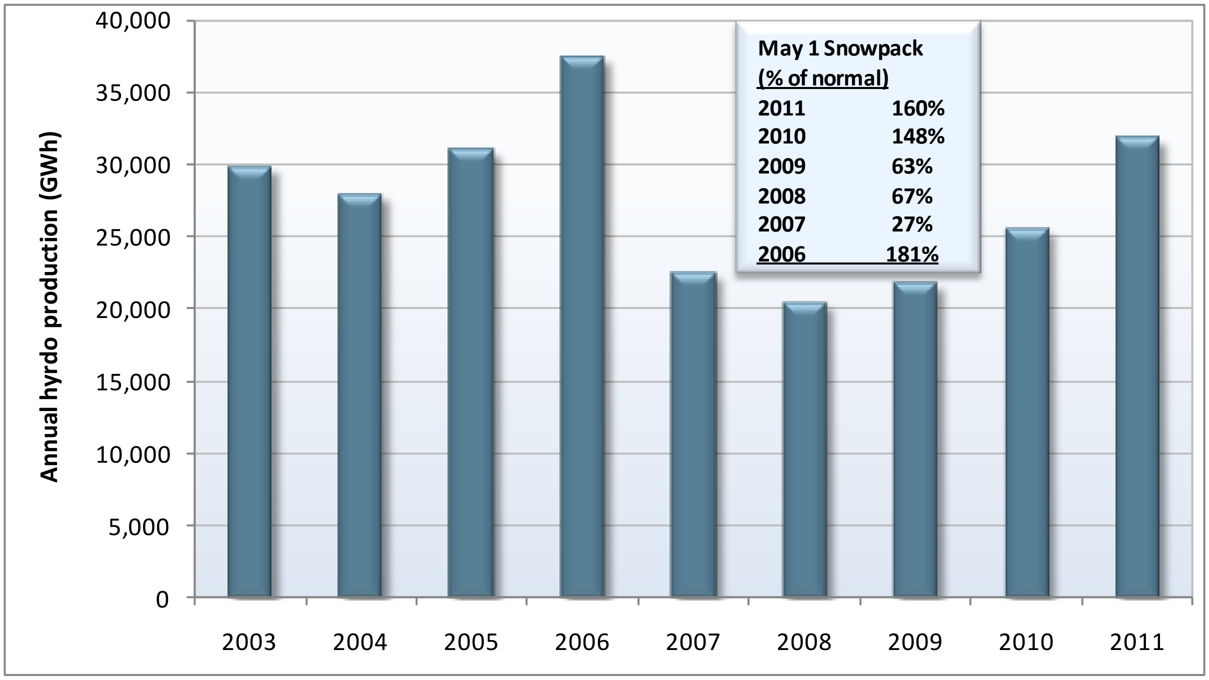
Hydro-electric supplies

Year-to-year variations in hydro-electric power supply in California have 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 base load 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 resources in the ISO are owned by load-serving entities that are net buyers of electricity. They therefore seek to manage these resources in a way that moderates overall energy and ancillary service prices.

As shown in Figure 1.13, overall hydro-electric production in 2011 was second only to 2006 over the past 9 years. Overall snowpack in the Sierra Nevada mountains on May 1, 2011, was about 160 percent of the long-term average, indicating much better-than-average hydro conditions.

Figure 1.14 compares monthly hydro-electric output from resources within the ISO for each of the last three years. Hydro production in 2011 was 25 percent higher than in 2010. During the peak load months of July and August, hydro production was about 16 percent higher than in 2010. During the fourth quarter, hydro-electric generation dropped below 2010 levels due to unusually low precipitation. This lack of precipitation continued into the first quarter of 2012 and hydro conditions in 2012 are expected to be well below average within California.

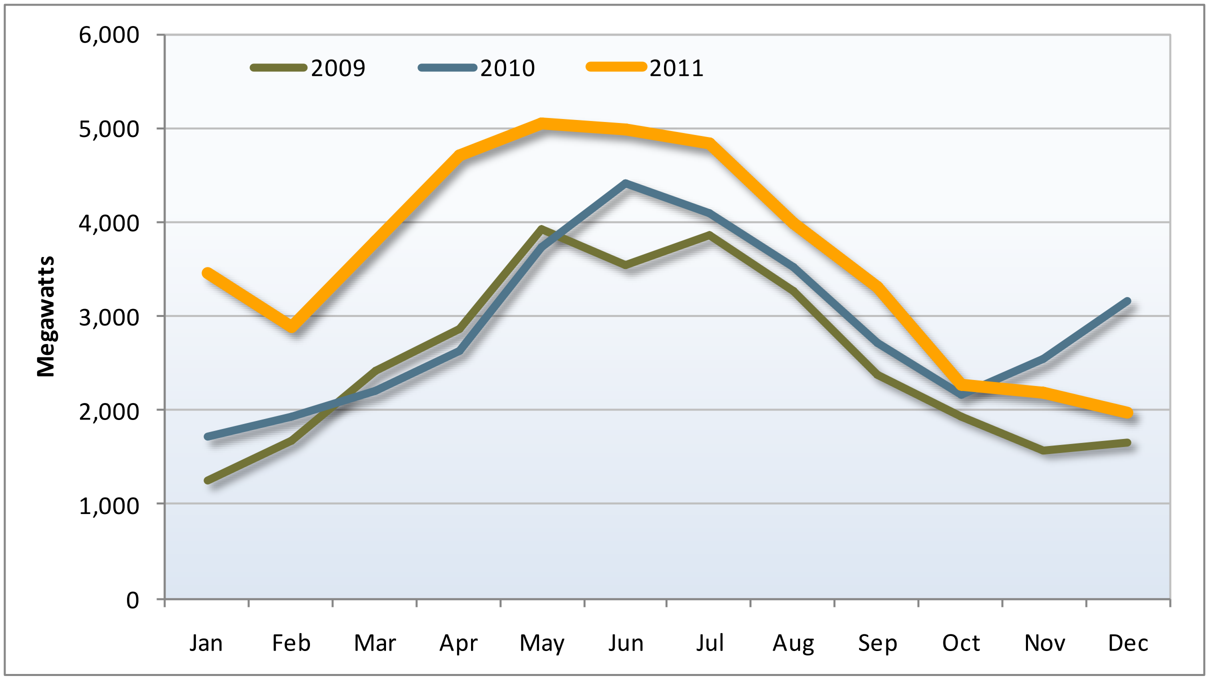
Figure 1.13 Annual hydroelectric production (2003-2011)



May 1 Snowpack
(% of normal)

2011	160%
2010	148%
2009	63%
2008	67%
2007	27%
2006	181%

Figure 1.14 Average hourly hydroelectric production by month (2009-2011)



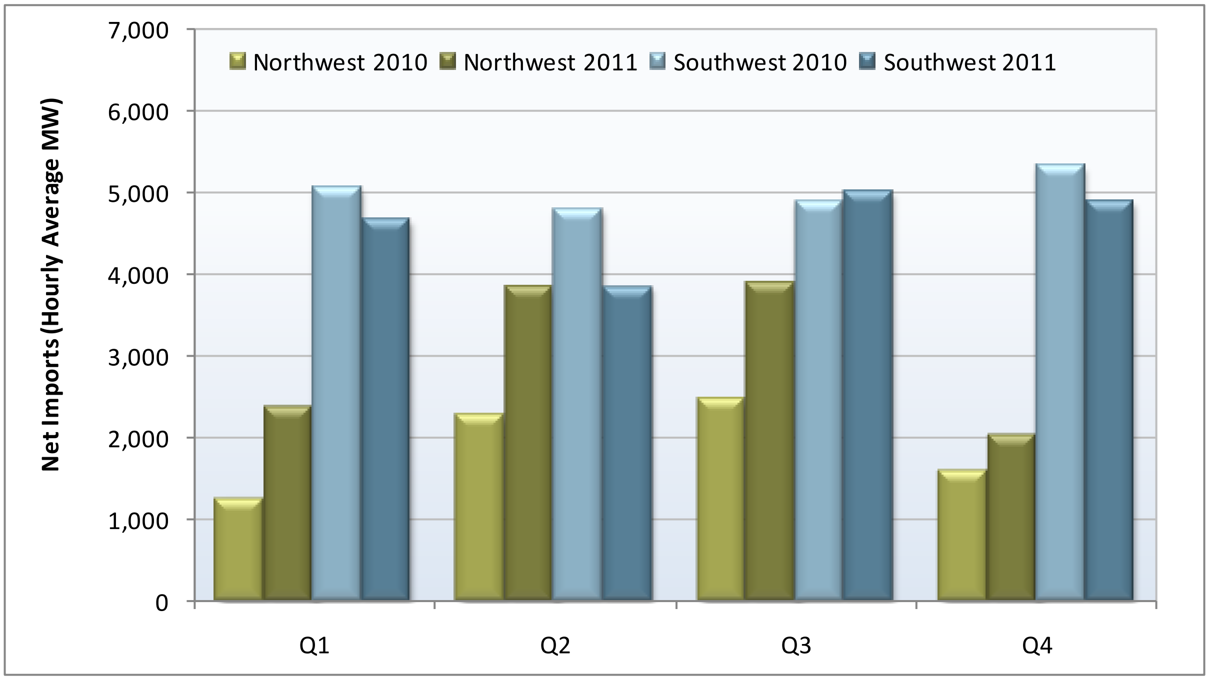
Net imports

Net imports increased by 10 percent in 2011 over 2010. Net imports from the Northwest increased about 60 percent, while net imports from the Southwest dropped about 8 percent. Figure 1.15 compares net imports by region for each quarter of 2010 and 2011.

Overall, the main reason for this increase was a substantial increase in hydro-electric and wind generation in the Northwest in 2011. This additional supply helped lower Mid-Columbia trading hub prices significantly. As a result, the 2011 price differential between the NP15 and Mid-Columbia trading hub prices increased for both on-peak and off-peak periods when compared to 2010.

The decrease in imports from the Southwest was likely due to changes in the relative price differentials between California and Southwestern trading hubs. The price differential between the SP15 and the Palo Verde trading hub prices fell slightly in both on-peak and off-peak periods in 2011 when compared to 2010.

Figure 1.15 Net imports by region (2010-2011)



1.2.2 Natural gas prices

Electric prices in the western states typically follow natural gas price trends because natural gas units are usually the marginal source of generation in California and other regional markets. In 2011, the average weighted price of natural gas in the daily spot markets decreased about 4 percent from 2010. This was one of the main drivers of the 9 percent decrease in the annual wholesale energy cost per MWh of load served in 2011.

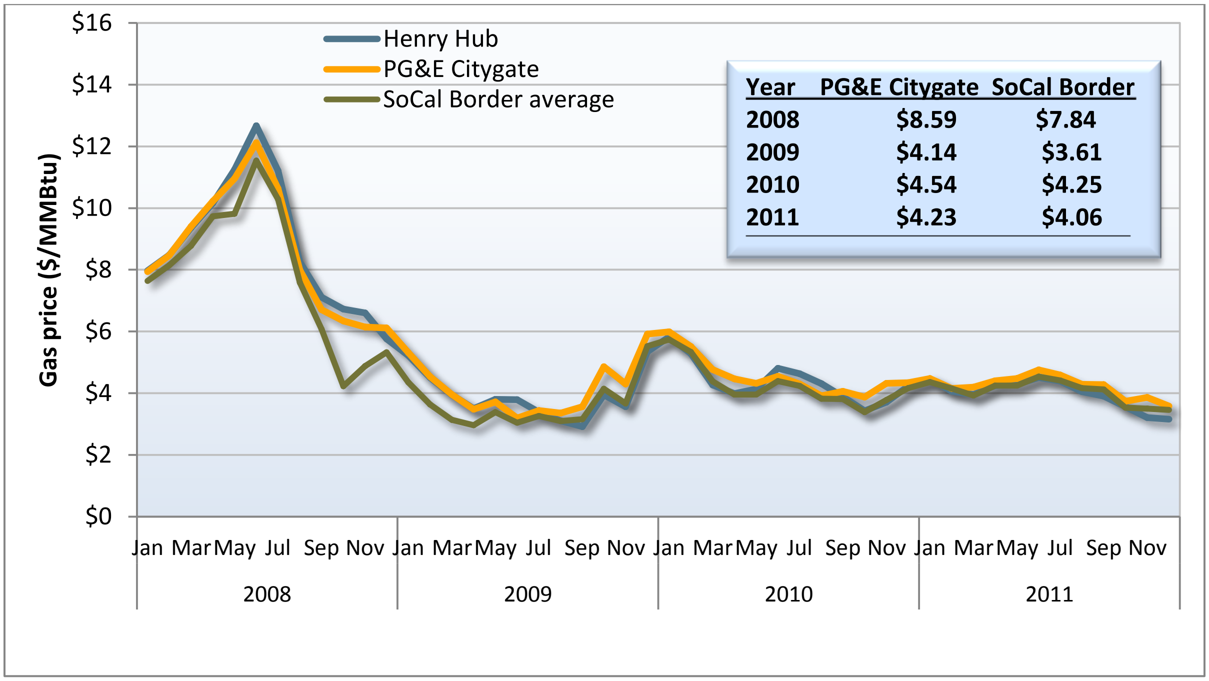
Figure 1.13 shows monthly average natural gas prices for 2008 through 2011 at key delivery points in Northern California (PG&E Citygate) and in Southern California (SoCal Border). Prices for the national Henry Hub trading point are also provided as a point of reference.

Natural gas prices in California tend to follow national trends, with differences that reflect gas pipeline transportation congestion. Because Northern and Southern California are served by different gas producing regions and transportation systems, natural gas prices within California periodically diverge, with prices in Northern California tending to be higher than in Southern California. However, the difference between natural gas prices in Northern and Southern California continued to decline in 2011.

- In 2011, average daily natural gas prices in Northern California exceeded prices in Southern California by about $0.19/MMBtu, or 4 percent. In 2010, natural gas prices in Northern California exceeded prices in Southern California by about $0.29/MMBtu, or 7 percent.
- For the first time over the past few years, Southern California prices were slightly higher than Northern California prices, on average, in the month of February. This was a result of unusually cold weather in the Southwest, which affected natural gas deliveries and increased prices into Southern California.

- The overall decline in the difference between Northern and Southern California prices was a result of changes in increased production and transportation capacity and lower costs from sources in the northern Rocky Mountain area and Canada to Northern California. Specifically, the Ruby Pipeline, which takes low cost natural gas from the Rockies to the Northwest, went into service in late July. Furthermore, increased hydro-electric and renewable production in the Northwest reduced natural gas demand.

Figure 1.16 Monthly weighted average natural gas prices in 2008-2011



Year	PG&E Citygate	SoCal Border
2008	$8.59	$7.84
2009	$4.14	$3.61
2010	$4.54	$4.25
2011	$4.23	$4.06

1.2.3 Generation addition and retirement

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

Figure 1.17 summarizes trends in the addition and retirement of generation from 2002-2011. It also includes planned capacity additions and retirements in 2012.[27] Table 1.4 also shows generation additions and retirements since 2002. It includes projected 2012 changes and totals across the 11-year period (2002-2012).

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[27] Capacity values in 2011 and 2012 are calculated summer peak capacity values. The values in 2010 and before are nominal capacity values.

Figure 1.18 and Figure 1.19 show additional generation capacity by generator type. As the figures indicate, most of the additional units are wind, solar and natural gas units. The vast majority of the new renewable capacity is expected to come from wind and solar generators.

Generation additions and retirements in 2011

Approximately 516 MW of new generation (peak summer capacity) began commercial operation within the ISO system in 2011. About 115 MW of this capacity was installed in the PG&E area and 401 MW came online in the SCE and SDG&E areas. A more detailed listing of these is provided in Table 1.5. There were 362 MW of capacity retirements in 2011.

Anticipated additions and retirements in 2012

The ISO anticipates 4,042 MW of new generation (peak summer capacity) in 2012. Around 2,929 MW of this capacity will come from renewable resources. Table 1.6 provides more detailed information on these projects. The ISO expects about 1,944 MW of this new capacity to be commercially available before the anticipated summer peak season. The ISO also anticipates 452 MW of existing generation to be retired in 2012.

Over the past couple years, new gas-fired generation has been mostly offset by the retirement of older gas-fired generation. As a result, non-renewable generation capacity has not grown significantly in the last few years, while renewable generation increases to meet the state's renewable requirements. Beyond 2012, significant reductions in total gas-fired capacity are possible due to the state's restrictions on use of once-through cooling technology. Meanwhile, the amount of new renewable generation coming online has begun to increase dramatically. As more renewable generation comes online, the ISO has highlighted the need to backup and balance renewable generation with the flexibility of conventional generation resources to maintain reliability.[28]

The state's resource adequacy program continued to work well as a short-term capacity procurement mechanism. However, in 2011 it became increasingly apparent that the state's current process for longer-term procurement may not ensure the investment and revenues needed to support sufficient new or existing gas-fired capacity to integrate the increased amount of intermittent renewable energy coming online. The ISO and CPUC are addressing this issue through several initiatives in 2012. This represents a major market design challenge facing the ISO and state policy makers.

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[28] More information on renewable integration can be found here: http://www.caiso.com/informed/Pages/StakeholderProcesses/IntegrationRenewableResources.aspx.

Figure 1.17 Generation additions and retirements: 2002-2012

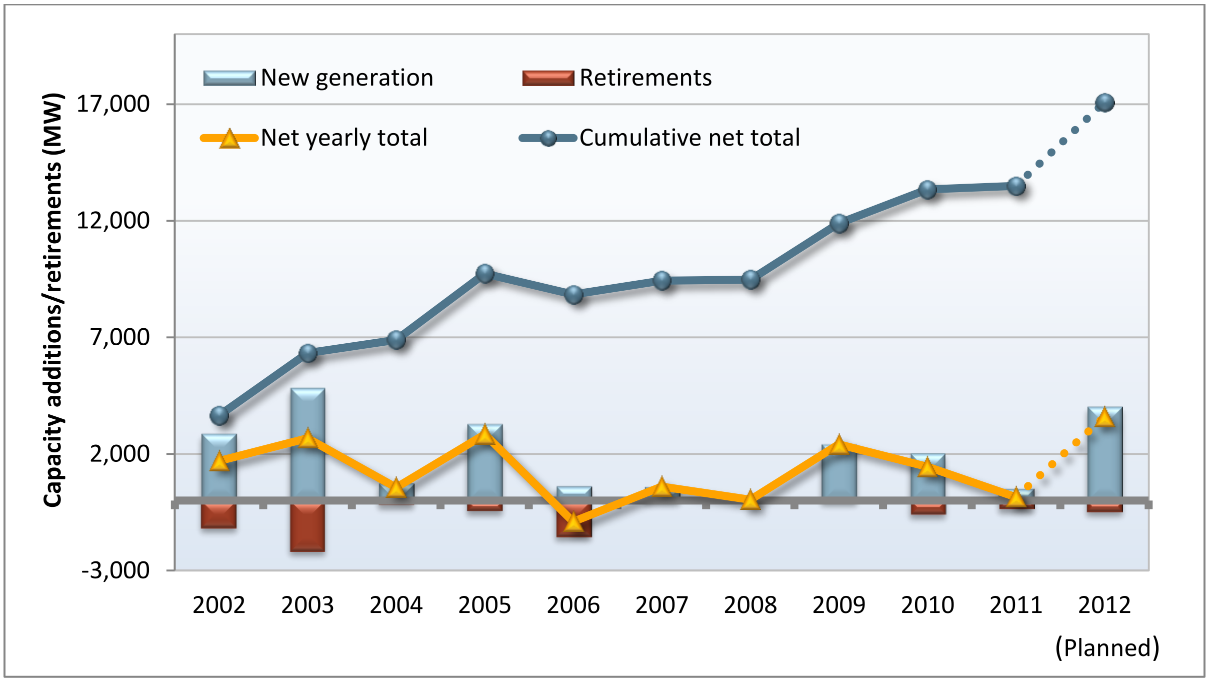

Table 1.4 Changes in generation capacity since 2002

	2002-2006	2007	2008	2009	2010	2011	Projected 2012	Total through 2012
SCE and SDG&E								
New Generation	6,280	485	45	1,107	1,042	401	2,757	12,118
Retirements	(4,280)	0	0	0	(414)	0	(452)	(5,146)
Net Change	**2,000**	**485**	**45**	**1,107**	**628**	**0**	**1,075**	**5,340**
PG&E								
New Generation	6,104	112	0	1,329	1,002	115	1,285	9,947
Retirements	(1,207)	0	0	(26)	(175)	(362)	0	(1,770)
Net Change	**4,897**	**112**	**0**	**1,303**	**827**	**0**	**1,009**	**8,148**
ISO System								
New Generation	12,384	598	45	2,436	2,044	516	4,042	22,065
Retirements	(5,487)	0	0	(26)	(589)	(362)	(452)	(6,916)
Net Change	**6,897**	**598**	**45**	**2,410**	**1,455**	**154**	**3,590**	**15,149**

Figure 1.18 Generation additions by resource type (nameplate capacity)

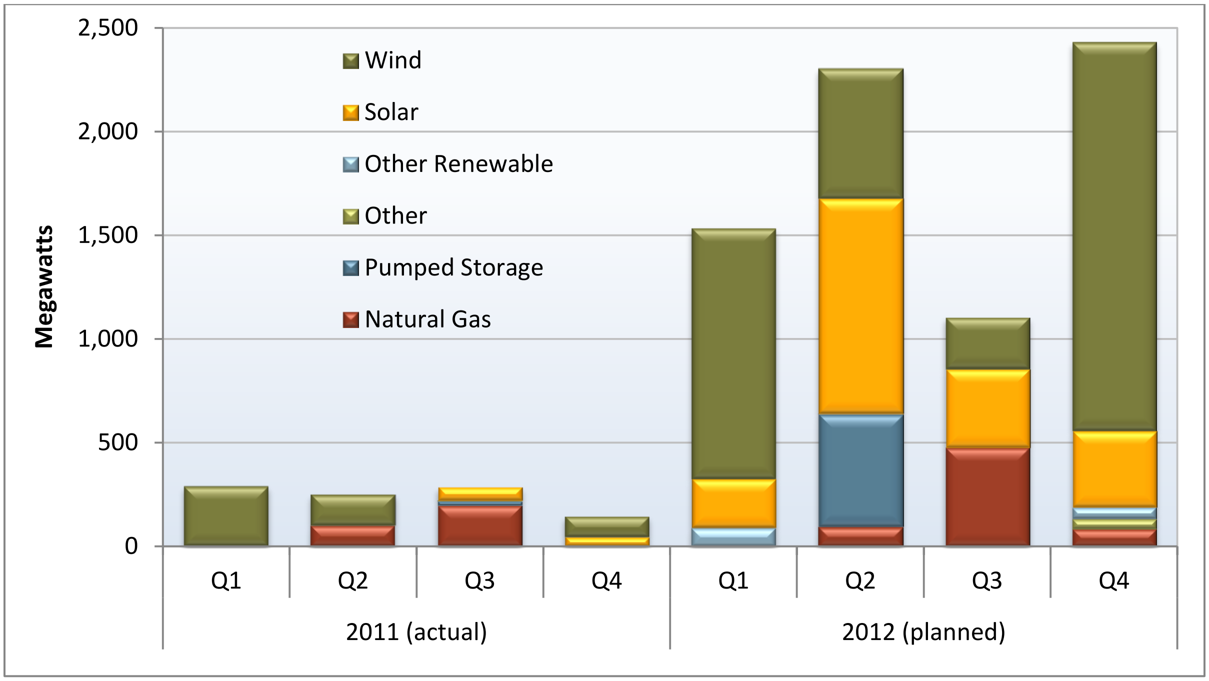

Figure 1.19 Generation additions by resource type (summer peak capacity)

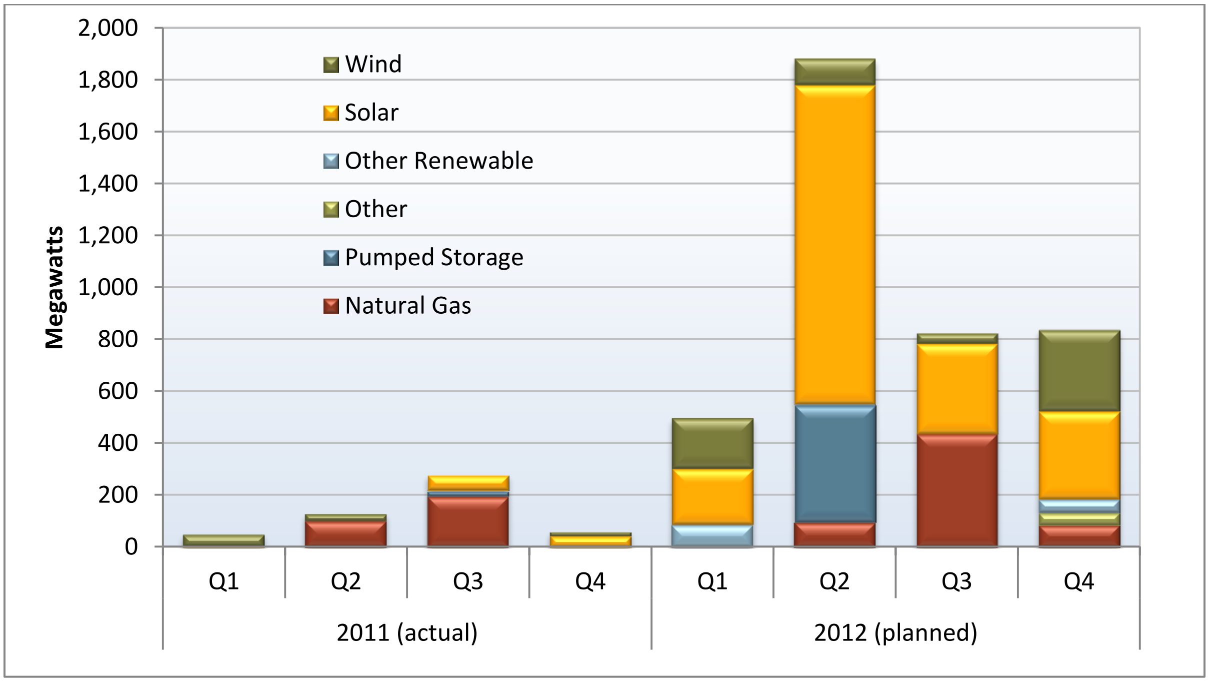

Table 1.5 New generation facilities in 2011

Generating unit	Unit type	Resource capacity (MW)	Summer capacity (MW)	Commercial operation date	Area
FPL Energy Montezuma Wind*	Wind	37	6	25-Jan-11	PG&E
Avenal Park Solar Project *	Solar	6	6	5-Aug-11	PG&E
Sun City Solar Project *	Solar	20	18	5-Aug-11	PG&E
Sand Drag Solar Project *	Solar	19	17	5-Aug-11	PG&E
Westside Solar Station*	Solar	15	14	13-Sep-11	PG&E
SF State Fuel Cell Station	Fuel Cell	2	2	27-Sep-11	PG&E
CSUEB Fuel Cell Station	Fuel Cell	2	2	27-Sep-11	PG&E
Stroud Solar Station *	Solar	20	18	4-Oct-11	PG&E
Five Points Solar Station*	Solar	15	14	7-Oct-11	PG&E
Three Forks Water Power Project	Pumped Storage	2	2	1-Nov-11	PG&E
Shiloh III - Phase A*	Wind	100	16	22-Dec-11	PG&E
PG&E Actual New Generation in 2011		**237**	**115**		
CPC West - Alta Wind III*	Wind	150	24	12-Feb-11	SCE
Rialto Roof Top Solar Project*	Solar	1	1	1-Mar-11	SCE
CPC East - Alta Wind IV*	Wind	102	17	12-Mar-11	SCE
SPVP022 Redlands RT Solar *	Solar	3	2	23-Mar-11	SCE
Riverside Energy Resource Center (RERC) Unit 3	Gas Unit	50	48	1-Apr-11	SCE
Riverside Energy Resource Center (RERC) Unit 4	Gas Unit	50	49	1-Apr-11	SCE
CPC East - Alta Wind V*	Wind	150	27	21-Apr-11	SCE
Sycamore Energy 1	Gas Unit	2	2	19-May-11	SDG&E
San Marcos Energy	Gas Unit	2	2	20-May-11	SDG&E
Canyon Power Plant Unit 3	Gas Unit	50	48	30-Jul-11	SCE
Canyon Power Plant Unit 4	Gas Unit	50	50	30-Jul-11	SCE
Ontario RT Solar *	Solar	6	5	25-Aug-11	SCE
Lake Hodges Pump Station 1 - Unit 1	Pumped Storage	20	20	8-Sep-11	SDG&E
Canyon Power Plant Unit 1	Gas Unit	50	49	16-Sep-11	SCE
Canyon Power Plant Unit 2	Gas Unit	50	48	16-Sep-11	SCE
CM10 Pseudo-Tie*	Solar	10	9	3-Oct-11	SCE
SCE and SDG&E Actual New Generation in 2011		**742**	**401**		
Total Actual New Generation in 2011		**979**	**516**		
Total Renewable Generation in 2011*		**653**	**195**		

Source: California ISO Interconnection Resources Department

Table 1.6 Planned generation additions in 2012

Generating unit	Number of projects	Resource capacity (MW)	Summer capacity (MW)	Commercial operation date	Area
Biogas-biomass Project*	2	28	26	Jan-12	PG&E
Solar Project*	6	105	97	Jan-12	PG&E
Wind Project*	1	78	13	Jan-12	PG&E
Solar Project*	2	40	37	Feb-12	PG&E
Solar Project*	1	20	18	Mar-12	PG&E
Wind Project*	1	128	21	Mar-12	PG&E
Solar Project*	3	60	55	Apr-12	PG&E
Wind Project*	1	30	5	Apr-12	PG&E
Biogas-biomass Project*	1	4	3	May-12	PG&E
Solar Project*	2	40	37	May-12	PG&E
Gas Project*	2	45	45	Jun-12	PG&E
Solar Project*	3	60	55	Jun-12	PG&E
Gas Project	2	476	435	Jul-12	PG&E
Solar Project*	3	60	55	Aug-12	PG&E
Solar Project*	1	20	18	Sep-12	PG&E
Solar Project*	1	20	18	Nov-12	PG&E
Wind Project*	1	250	51	Nov-12	PG&E
Biogas-biomass Project*	1	16	16	Dec-12	PG&E
Small Hydro Project*	2	12	10	Dec-12	PG&E
Solar Project*	9	234	215	Dec-12	PG&E
Wind Project*	4	336	54	Dec-12	PG&E
PG&E Total New Generation in 2012		**2,062**	**1,285**		
Solar Project*	1	20	18	Jan-12	SCE
Wind Project*	2	102	17	Jan-12	SCE
Geothermal Project*	1	62	60	Feb-12	SCE
Solar Project*	1	50	46	Feb-12	SCE
Wind Project*	1	550	89	Feb-12	SCE
Wind Project*	2	351	57	Mar-12	SCE
Solar Project*	1	20	18	May-12	SCE
Wind Project*	1	300	49	May-12	SCE
Pumped Storage Project	2	540	451	May-12	SDG&E
Solar Project*	2	600	828	May-12	SDG&E
Gas Project	1	50	50	Jun-12	SCE
Solar Project*	3	258	237	Jun-12	SCE
Wind Project*	1	297	48	Jun-12	SCE
Solar Project*	2	214	197	Aug-12	SCE
Solar Project*	1	20	18	Aug-12	SDG&E
Solar Project*	1	66	61	Sep-12	SCE
Wind Project*	1	250	41	Sep-12	SCE
Wind Project*	1	201	33	Nov-12	SDG&E
Gas Project	1	85	85	Dec-12	SCE
Nuclear Project	1	48	47	Dec-12	SCE
Solar Project*	6	115	106	Dec-12	SCE
Wind Project*	2	789	128	Dec-12	SCE
Biogas-biomass Project*	1	27	26	Dec-12	SDG&E
Wind Project*	1	299	48	Dec-12	SDG&E
SCE and SDG&E Total New Generation in 2012		**5,314**	**2,757**		
Total Planned New Generation in 2012		**7,376**	**4,042**		
Total New Renewable Generation in 2012*		**6,465**	**2,929**		

1.3 Net market revenues of new gas-fired generation

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

Each year, DMM examines the extent to which revenues from the spot markets would contribute to the annualized fixed cost of typical new gas-fired generating resources. This represents an important market metric tracked by all ISOs. Costs used in the analysis are based on a 2009 (most recent) report by the California Energy Commission.[29]

Hypothetical combined cycle unit

Key assumptions used in this analysis for a typical new combined cycle unit are shown in Table 1.7. The increase in new generation costs from 2009 are primarily attributable to increases in capital and financing costs and taxes, according to the California Energy Commission report used in this analysis.

Table 1.7 Assumptions for typical new combined cycle unit[30]

Technical Parameters	
Maximum Capacity	500 MW
Minimum Operating Level	150 MW
Startup Gas Consumption	1,850 MMBtu/start
Heat Rates	
Maximum Capacity	7,100 MBtu/MWh
Minimum Operating Level	7,700 MBtu/MWh
Financial Parameters	
Financing Costs	$134.4 /kW-yr
Insurance	$7.2 kW-yr
Ad Valorem	$9.4 kW-yr
Fixed Annual O&M	$10.1 /kW-yr
Taxes	$29.6 kW-yr
Total Fixed Cost Revenue Requirement	**$190.7/kW-yr**
Variable O&M	$3.7/MWh

Results for a typical new combined cycle unit are shown in Table 1.8 and Figure 1.15. The 2011 net revenue results show a decrease in net revenues compared to 2010. The 2011 net revenue estimates

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[29] 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.

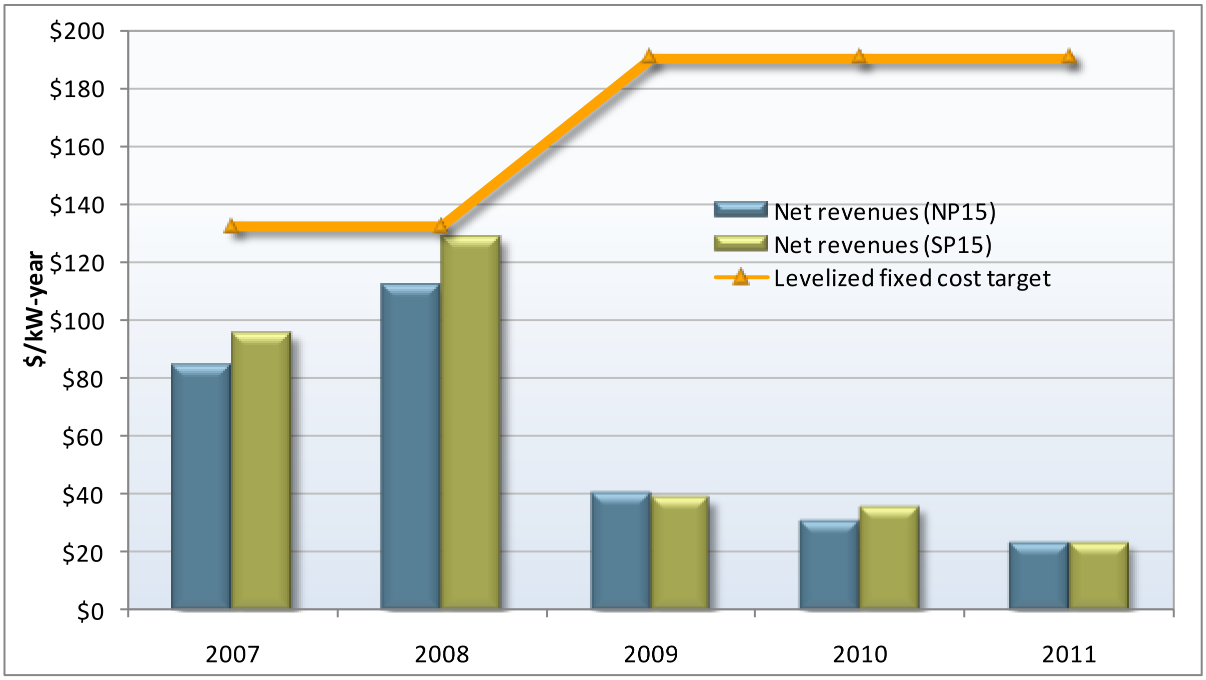
[30] The financing costs, insurance, ad valorem, fixed annual O&M and tax costs for a typical unit in this table were derived directly from the data presented in the CEC's *2009 Comparative Costs of California Central Station Electricity Generation Technologies* report which can be found at: http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SF.PDF.

for a hypothetical combined cycle unit in NP15 and SP15 both fall substantially below the $191/kW-year estimate of annualized fixed costs provided in the CEC report.

Table 1.8 Financial analysis of new combined cycle unit (2007–2011)

Components	2007		2008		2009		2010		2011	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	69%	76%	74%	81%	57%	57%	67%	74%	53%	66%
DA Energy Revenue ($/kW - yr)	$369.59	$389.41	$489.17	$505.42	$172.67	$169.61	$137.95	$142.65	$101.62	$94.27
RT Energy Revenue ($/kW - yr)	$36.20	$41.98	$47.41	$51.98	$21.27	$15.50	$34.89	$37.31	$28.62	$30.84
A/S Revenue ($/kW – yr)	$0.37	$0.42	$0.41	$0.42	$0.76	$0.85	$1.01	$1.25	$1.71	$2.29
Operating Cost ($/kW - yr)	$321.86	$337.82	$425.16	$428.39	$154.57	$147.48	$143.25	$145.69	$108.65	$104.41
Net Revenue ($/kW – yr)	$84.30	$95.23	$111.82	$128.25	$40.14	$38.48	$30.60	$35.52	$23.30	$22.99
5-yr Average ($/kW – yr)	*$58.03*	*$64.10*								

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 1.16 show estimated net revenues that a hypothetical combustion turbine unit would have earned by participating in the real-time energy and non-spinning reserve markets. These results show a decrease in the net revenues in 2011. Estimated net revenues for a hypothetical combustion turbine also fell well short of the $212/kW-year estimate of annualized fixed costs in the CEC report.

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

Table 1.9 Assumptions for typical new combustion turbine[31]

Technical Parameters	
Maximum Capacity	100 MW
Minimum Operating Level	40 MW
Startup Gas Consumption	180 MMBtu/start
Heat Rates	
Maximum Capacity	9,300 MBtu/MWh
Minimum Operating Level	9,700 MBtu/MWh
Financial Parameters	
Financing Costs	$146.6 /kW-yr
Insurance	$7.9 kW-yr
Ad Valorem	$10.4 kW-yr
Fixed Annual O&M	$20.3 /kW-yr
Taxes	$26.5 kW-yr
Total Fixed Cost Revenue Requirement	**$211.7/kW-yr**
Variable O&M	$5.1/MWh

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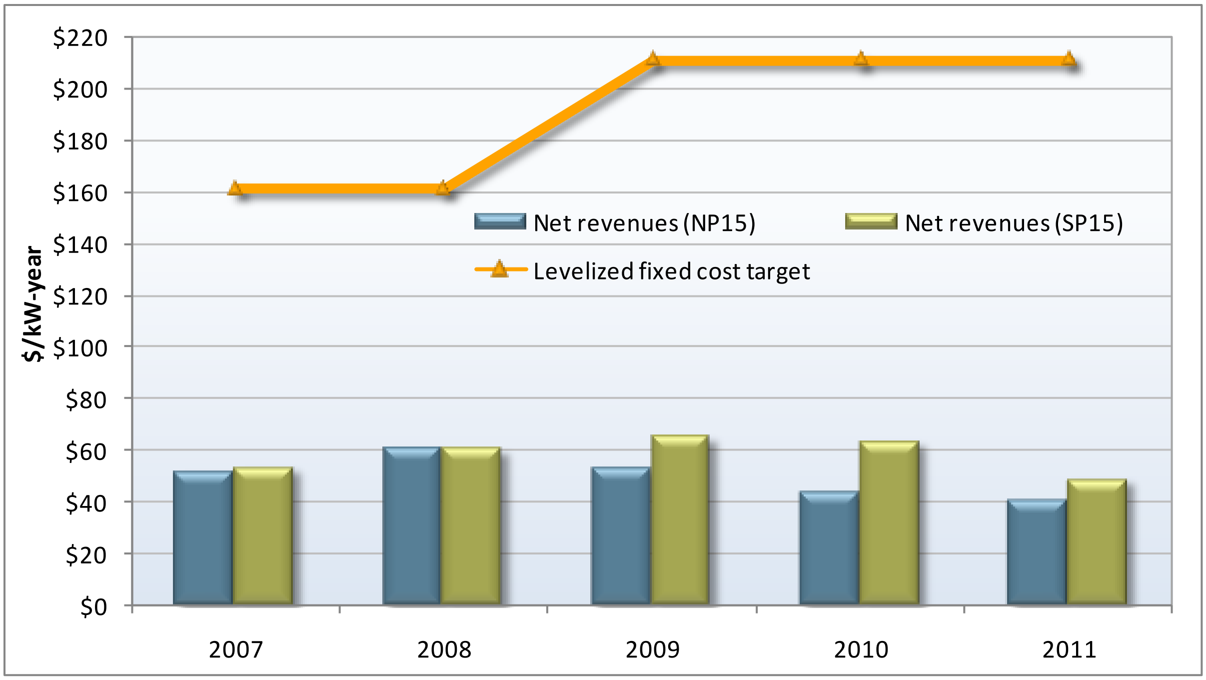
[31] The financing costs, insurance, ad valorem, fixed annual O&M and tax costs for a typical unit in this table were derived directly from the data presented in the CEC's *2009 Comparative Costs of California Central Station Electricity Generation Technologies* report which can be found at: http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SF.PDF.

Table 1.10 Financial analysis of new combustion turbine (2007-2011)

Components	**2007**		**2008**		**2009**		**2010**		**2011**	
	NP15	**SP15**	**NP15**	**SP15**	**NP15**	**SP15**	**NP15**	**SP15**	**NP15**	**SP15**
Capacity Factor	8%	9%	11%	12%	6%	6%	7%	10%	6%	7%
Energy Revenue ($/kW - yr)	$97.54	$104.99	$155.58	$158.98	$70.50	$84.62	$64.97	$95.94	$57.60	$69.57
A/S Revenue ($/kW - yr)	$13.30	$12.83	$5.50	$5.53	$8.64	$8.37	$3.36	$2.97	$6.06	$5.98
Operating Cost ($/kW - yr)	$59.18	$64.63	$100.12	$104.09	$25.85	$27.70	$24.80	$35.60	$23.23	$26.88
Net Revenue ($/kW - yr)	$51.66	$53.19	$60.96	$60.43	$53.29	$65.29	$43.54	$63.32	$40.43	$48.67
5-yr Average ($/kW - yr)	*$49.98*	*$58.18*								

Figure 1.21 Estimated net revenues of new combustion turbine



2 Overview of market performance

In April 2009, the ISO implemented a major redesign of California's wholesale energy markets. In 2011, this new design continued to effectively facilitate efficient and competitive market performance.

- Total wholesale electric costs fell by 9 percent. This represents a 6 percent decrease after adjusting for lower natural gas prices. This 6 percent decrease was driven by a significant increase in hydro-electric generation, an increase in low priced imports and moderate loads.
- About 98 percent of system load was scheduled in the day-ahead energy market, which continued to be highly efficient and competitive. Day-ahead prices continued to be about equal to prices we estimate would result under highly competitive conditions.
- Price spikes in the 5-minute real-time market decreased over the course of the year, improving price convergence between the hour-ahead and real-time markets.
- Revenue imbalance costs associated with divergence of hour-ahead and real-time prices increased significantly in the first few months of the year and were exacerbated by the introduction of convergence bidding in February. However, these costs fell by the end of the year as price convergence in these markets improved.
- Ancillary services accounted for about 2 percent of total energy costs, up from about 1 percent of total wholesale costs in 2010. This increase was largely attributable to abundant hydro conditions in the first half of the year, which decreased the availability of ancillary services from hydro resources.
- Bid cost recovery payments totaled about 1.5 percent of total energy costs in 2011, compared to less than 1 percent in 2010. This increase was primarily attributable to increased costs associated with manipulative bidding behavior that was identified and corrected by June 2011.

Several aspects of market performance have improved or have shown signs of improving toward the end of 2011.

- The frequency of real-time price spikes decreased over the year. The ISO made changes to both procedures and software that helped reduce the incidence of these price spikes. The frequency of price spikes began to fall starting in the spring and continued to fall through the end of the year.
- The consistency of prices in the hour-ahead and real-time markets improved significantly in the second half of the year. Hour-ahead prices were systematically lower than both day-ahead and real-time markets in the first half of 2011. This pattern created substantial revenue imbalances that were allocated to load-serving entities. These revenue imbalance costs were exacerbated by the introduction of virtual bidding on inter-ties, which increased the volume of transactions clearing at these different market prices. These costs decreased over the course of the year as the ISO implemented procedural and software changes which improved price convergence in these different energy markets.

2.1 Total wholesale market costs

Total estimated wholesale costs of serving load in 2011 were $8.2 billion or just over $36/MWh. This represents a decrease of about 9 percent from a cost of $40/MWh in 2010, and the lowest estimated nominal wholesale cost since 1999.

Gas prices also decreased in 2011, with spot market gas prices decreasing by about 4 percent.[32] Much of this decrease occurred in the first quarter of the year. After accounting for lower gas prices, total wholesale energy costs decreased from $35/MWh in 2010 to $33/MWh in 2011, representing a decrease of almost 6 percent in gas-normalized prices.[33]

A variety of factors contributed to the decrease in gas-normalized total wholesale costs in 2011. As highlighted in Chapter 1, fundamental demand and supply conditions favorable to lower prices in 2011 included:

- Increased hydro-electric generation;
- Increased imports, particularly from the Northwest; and
- Lower summer peak loads.

Other factors contributing to lower prices discussed in the following sections and chapters of this report include the following:

- High day-ahead scheduling of load relative to actual loads;
- Competitive bidding levels in the day-ahead and real-time energy markets; and
- Low congestion.

Figure 2.1 shows total estimated wholesale costs per MWh from 2007 to 2011. Wholesale costs are provided in nominal terms, as well as after normalization for changes in average spot market prices for natural gas. The green line representing the annual average of daily natural gas prices is included to illustrate the correlation between the cost of natural gas and the total wholesale cost estimate.

Table 2.1 provides annual summaries of nominal total wholesale costs by category for years 2007 through 2011. Under the nodal market design, which began in 2009, total wholesale market costs are estimated based on prices and quantities cleared in each of the three energy markets: day-ahead, hour-ahead and 5-minute real-time markets. This estimate also includes costs associated with ancillary services, convergence bidding, residual unit commitment, bid cost recovery, reliability must-run contracts, the capacity procurement mechanism, the flexible ramping constraint and grid management charges.[34]

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

[33] Gas prices are normalized to 2009 prices.

[34] 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. DMM has made a few modifications to this methodology to accommodate costs associated with convergence bidding and the flexible ramping constraint. The net convergence bidding costs are calculated as noted in Section 4.2 of this report. The flexible ramping costs are added to the real-time energy costs. The real-time energy costs are further adjusted to account for the re-dispatch of real-time energy associated with the liquidation of net convergence bidding positions.

Figure 2.1 Total annual wholesale costs per MWh of load: 2007-2011

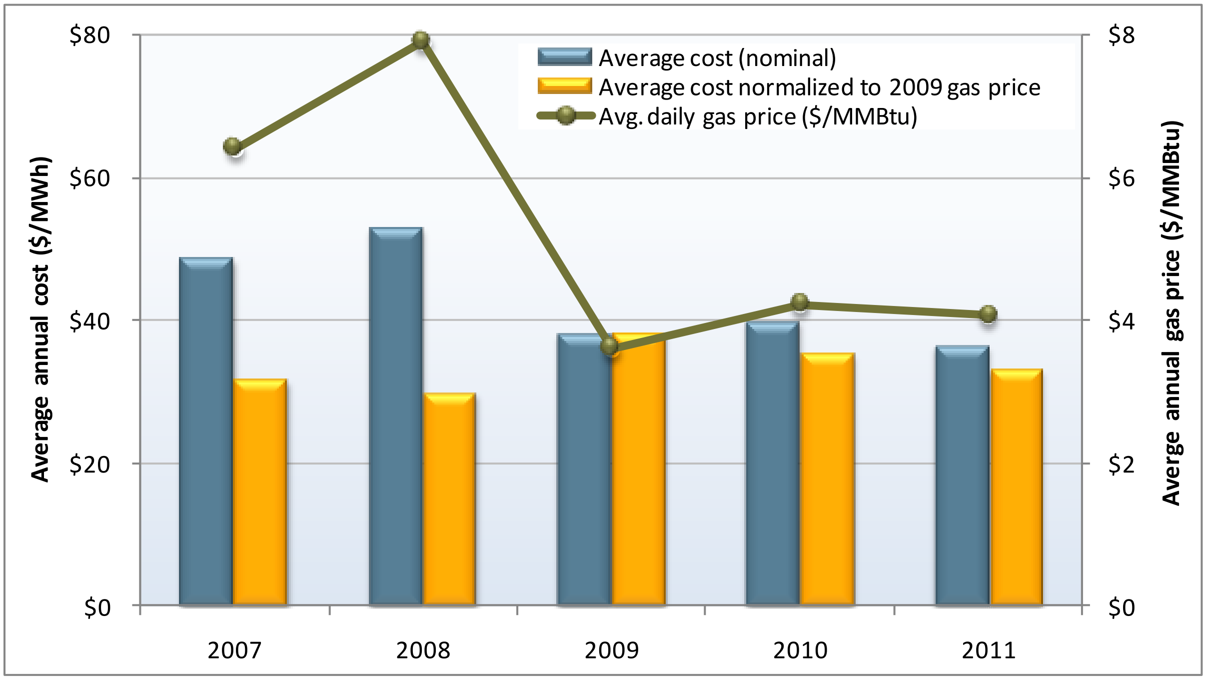

Table 2.1 Estimated average wholesale energy costs per MWh (2007-2011)

	2007	2008	2009	2010	2011	Change '10-'11
Day-Ahead Energy Costs (excl. GMC)	$ 44.74	$ 47.48	$ 35.57	$ 37.37	$ 33.23	$ (4.13)
Real-Time Energy Costs (incl. Flex Ramp)	$ 0.25	$ 0.81	$ 0.81	$ 0.73	$ 0.97	$ 0.25
Grid Management Charge	$ 0.76	$ 0.76	$ 0.78	$ 0.79	$ 0.79	$ (0.00)
Bid Cost Recovery Costs	$ 0.23	$ 0.41	$ 0.29	$ 0.37	$ 0.56	$ 0.19
Net Convergence Bidding Costs	N/A	N/A	N/A	N/A	$ 0.18	$ 0.18
Reliability Costs (RMR and CPM)	$ 1.64	$ 2.80	$ 0.25	$ 0.27	$ 0.03	$ (0.24)
Average Total Energy Costs	**$ 47.62**	**$ 52.26**	**$ 37.70**	**$ 39.53**	**$ 35.78**	**$ (3.76)**
Reserve Costs (AS and RUC)	$ 0.97	$ 0.63	$ 0.39	$ 0.38	$ 0.62	$ 0.24
Average Total Costs of Energy and Reserve	**$ 48.59**	**$ 52.89**	**$ 38.09**	**$ 39.91**	**$ 36.39**	**$ (3.52)**

In 2011, the decrease in nominal wholesale costs is primarily due to a decrease in day-ahead energy costs, while most other cost categories increased. The majority of the decrease in day-ahead energy costs occurred in the first quarter and was largest in January. The two factors causing this decrease are the decrease in gas prices (4 percent) and a significant increase in hydro-electric generation (25 percent). Real-time costs increased primarily as a result of increased real-time generation to offset virtual supply that cleared the day-ahead market and was replaced in the real-time market.

Prior to implementation of the nodal market design in 2009, the ISO did not have a day-ahead energy market. Virtually all supply was provided through self-supply or bilateral trading and supply arrangements. This required DMM to estimate wholesale energy costs on various sources of bilateral market data and estimated costs of self-supply. Thus, as noted in our 2009 and 2010 annual reports, comparisons of costs under the nodal market design with previous years should be viewed with caution given the different sources of data used to estimate wholesale costs in prior years.

2.2 Day-ahead scheduling

The portion of load clearing the day-ahead market continued to be consistently very high, averaging 98 percent of total forecast demand and about 100 percent of actual loads in 2011. This left a relatively small volume of demand to be met by the residual unit commitment process and real-time market.[35]

Figure 2.2 compares the average level of load clearing in the day-ahead market to the forecast of demand. The percentage of the forecasted load met in the day-ahead market has stayed relatively constant during each quarter, with day-ahead scheduled loads averaging about 98 to 99 percent of forecasted load.

As shown in Figure 2.3, the ISO's load forecast tends to exceed actual loads all hours of the day. During the evening peak hours, average scheduled load was approximately equal to or just below actual load. During the early morning off-peak hours and morning ramping hours, load schedules tended to slightly exceed actual loads. This pattern reflects the fact that during off-peak and lower load peak hours, additional energy is available from minimum load generation and imports that are purchased in standard multi-hour blocks (i.e., all 8 off-peak hours or all 16 peak hours).

Self-scheduling of loads and generation

- The high level of scheduling in the day-ahead market is due largely to a very high level of self-scheduling of loads and generation. Figure 2.4 shows the portion of load clearing the day-ahead market comprised of self-schedules and price-taking demand bids, as opposed to price-sensitive demand bids.[36] Self-scheduled and price-taking demand bids accounted for an average of 95 to 97 percent of load clearing the day-ahead market in 2011.

- Figure 2.5 shows the portion of supply clearing the day-ahead market comprised of self-scheduling and price-taking bids.[37] Self-scheduled and price-taking supply bids have accounted for an average of about 65 to 85 percent of supply clearing the day-ahead market. Self-scheduling of supply was most pronounced in the second quarter as hydro-electric generation increased.

- Extremely high levels of self-scheduled supply can decrease market efficiency by reducing the degree to which the market software is free to optimize supply resources based on their bid costs. High levels of self-scheduling can also hinder the ability to manage congestion in the most cost-effective manner. As shown in Figure 2.5, the total amount of self-scheduled and price-taking supply increased in the second quarter as hydro-electric generation increased, but dropped significantly in the final two quarters.

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[35] Real-time imbalance energy averaged about 2.5 percent of total load in 2011. These imbalances were a result of changes in both demand and supply in real-time.

[36] In this analysis, DMM classified load bids within $5/MWh of the maximum bid cap as price-taking because these bids are virtually certain to clear the day-ahead market. The energy bid cap was $500/MWh April 1, 2009 to March 31, 2010 and $750/MWh from April 1, 2010 to March 31, 2011. The energy bid cap increased to $1,000/MWh on April 1, 2011.

[37] In this analysis, DMM classified supply bids between the energy bid floor and $0/MWh as price-taking supply because these bids are virtually certain to clear the day-ahead market. The energy bid floor was -$30/MWh in 2010 and 2011.

Figure 2.2 Day-ahead cleared load versus forecast in 2010 and 2011

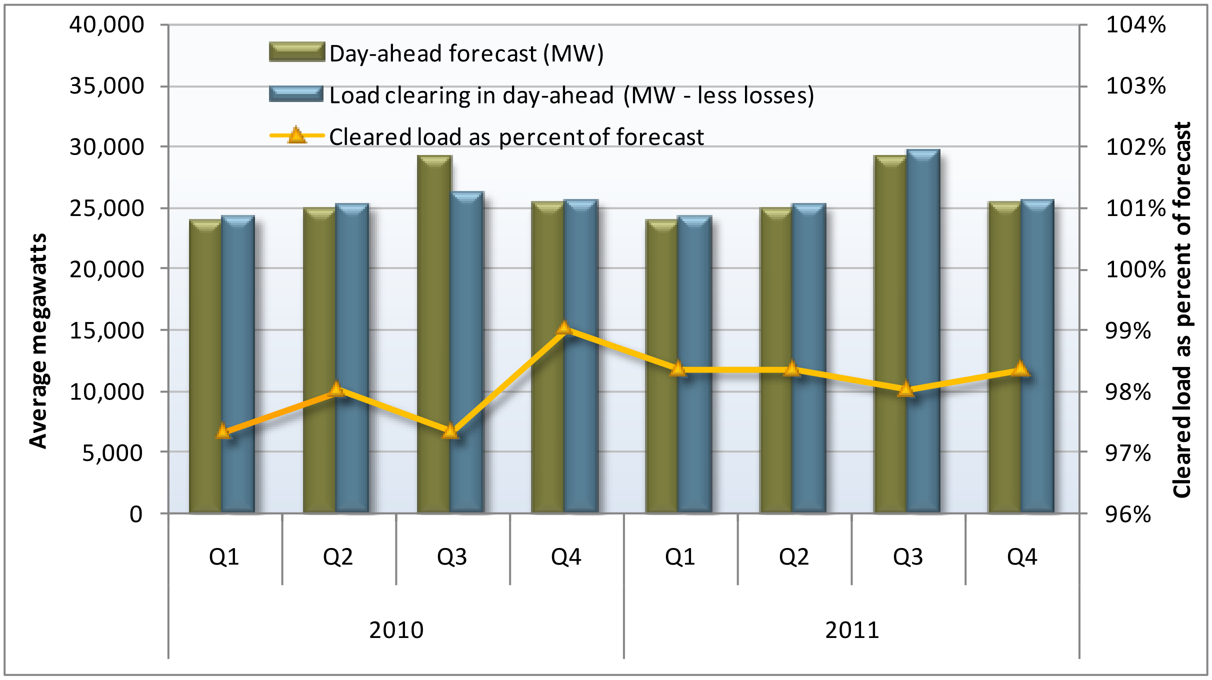


Figure 2.3 Day-ahead schedules, forecast and actual load 2011

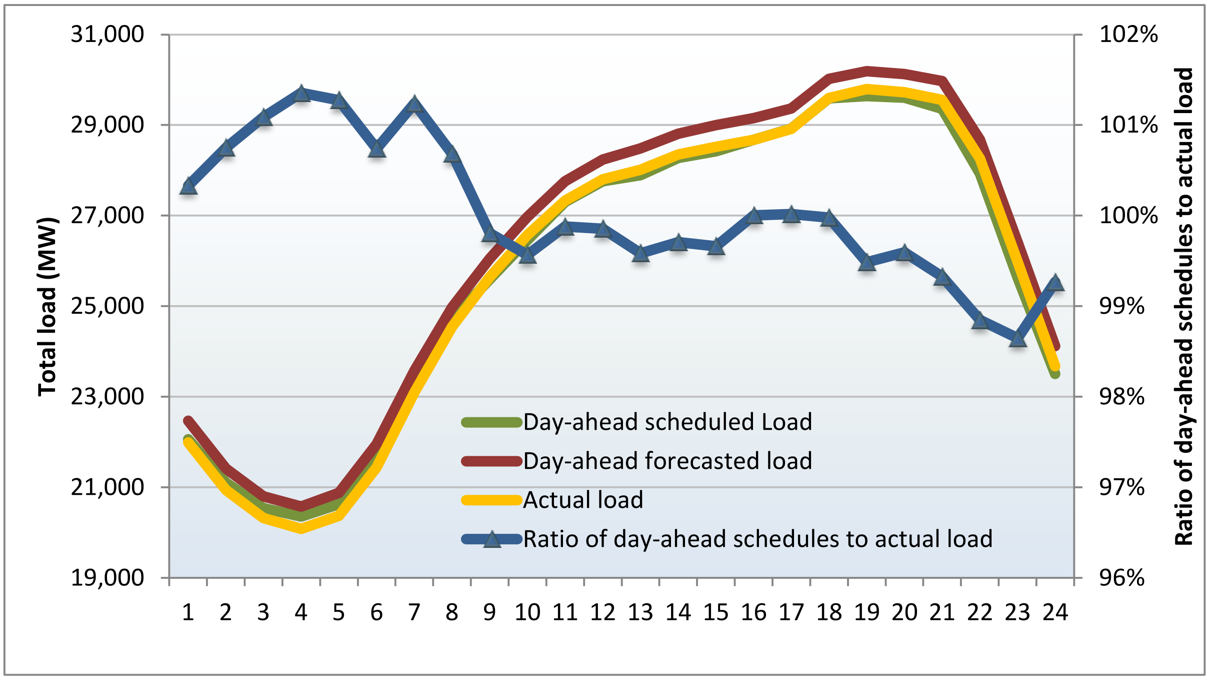


Figure 2.4 Average self-scheduled load versus load cleared in day-ahead market

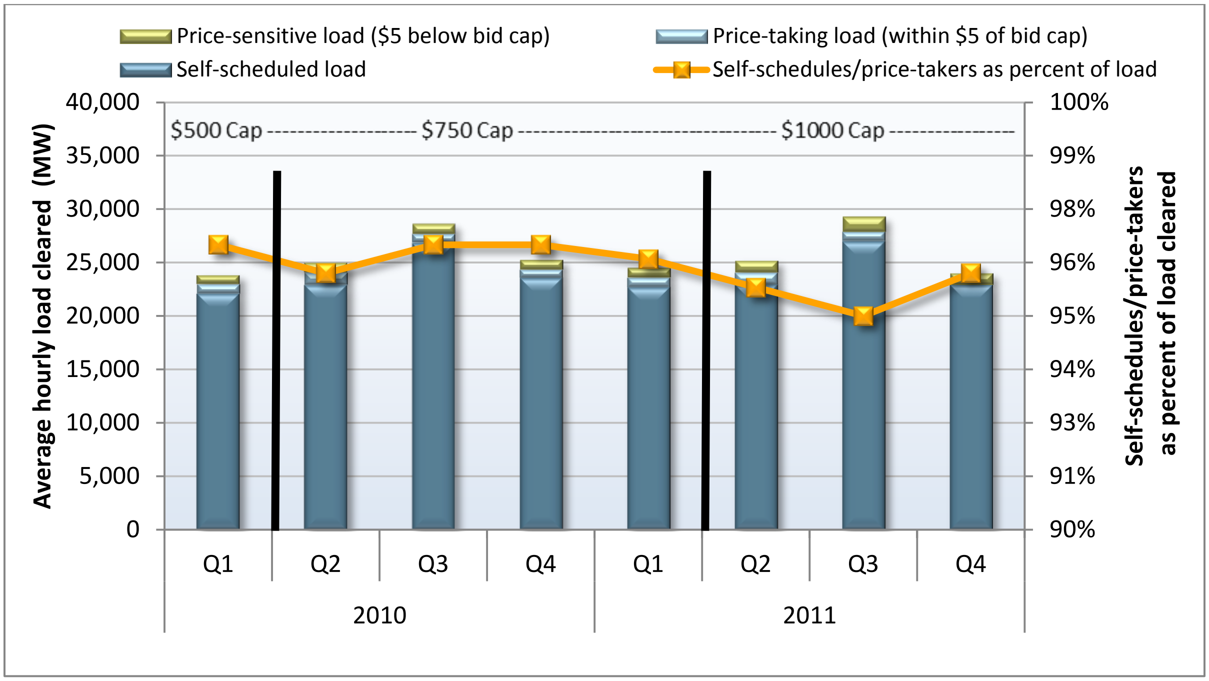
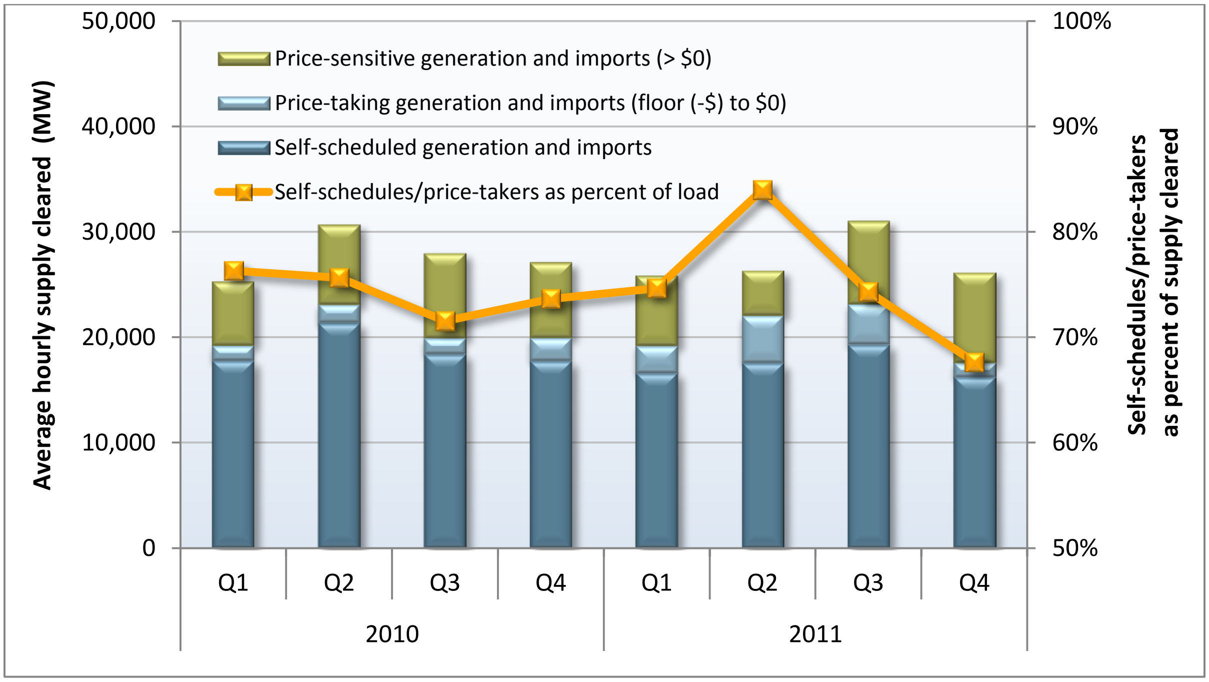


Figure 2.5 Average self-scheduled supply versus supply cleared in day-ahead market



Hour-ahead market

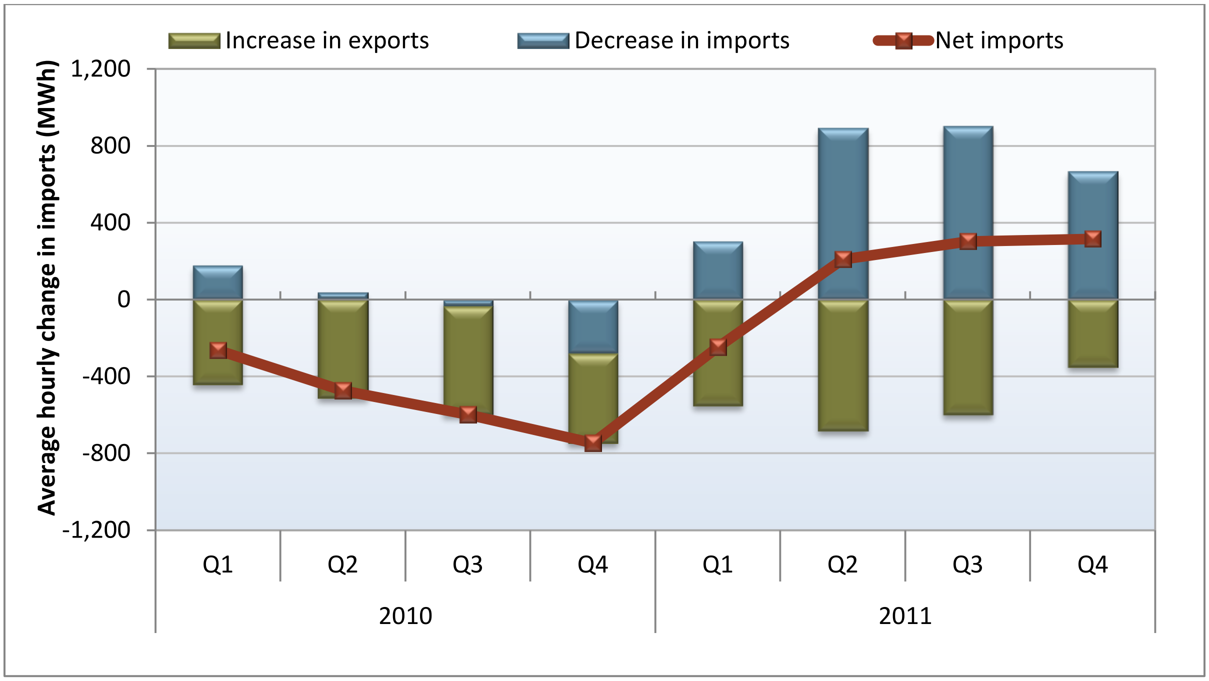
The hour-ahead market allows day-ahead inter-tie schedules to be modified through a re-optimization of the entire market. Market participants with accepted day-ahead imports or export bids can either self-schedule their energy in the hour-ahead market, or re-bid day-ahead scheduled quantities at the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

In 2010 through the first quarter of 2011, the net import schedules clearing the hour-ahead market were systematically lower than net import schedules clearing the day-ahead market. As shown in Figure 2.6:

- During each quarter through the first quarter of 2011, net imports clearing the hour-ahead market averaged 250 to 800 MW less than net day-ahead import schedules.
- Most of this decline was due to an increase in net exports in the hour-ahead market, which averaged over 400 MW per hour during this period.

As noted in prior DMM quarterly and annual reports, these trends reflected the fact that hour-ahead prices tended to be systematically lower than day-ahead prices during many hours, especially during off-peak periods.

Figure 2.6 Change in net day-ahead imports after hour-ahead market



The trend of reduced net physical imports in the hour-ahead market reversed during the second quarter of 2011 after virtual bidding was implemented in February. As discussed in Chapter 4, the tendency for hour-ahead prices to be relatively low during many hours made large volumes of virtual import bids profitable. These virtual import bids are paid the day-ahead price and then liquidated at the hour-ahead price. With significant quantities of this virtual supply being liquidated in the hour-ahead market, physical imports began to increase in the hour-ahead market. As shown in Figure 2.6, the increase in imports usually more than offset the increase in exports, causing net imports to increase in the hour-ahead market.

2.3 Energy market prices

Overall, energy market prices were lower in 2011 than 2010. Figure 2.7 and Figure 2.8 show average quarterly prices in the three energy markets for the PG&E area for peak and off-peak hours, respectively.[38] As shown in these figures:

- Prices decreased in the first half of the year – particularly during off-peak hours. As noted in Chapter 1, this is primarily attributable to decreased natural gas prices and increased hydro-electric generation.

- As shown in Figure 2.7, after the first quarter, price convergence between the day-ahead and hour-ahead markets during on-peak hours improved in 2011 compared to 2010. On-peak real-time prices decreased significantly in 2011.

- As shown in Figure 2.8, in 2011, off-peak prices showed signs of improved convergence in all markets, particularly in the second half of the year.

While price convergence in these three markets improved substantially from the first quarter of 2011, price convergence remained volatile during the year. The improvement in price convergence is partly due to the decrease in the frequency of real-time price spikes over the course of the year. Figure 2.9 shows the frequency of different levels of price spikes on a quarterly basis over the past two years. As shown in Figure 2.9:

- The total frequency of price spikes decreased in each of the last three quarters of the year.

- The total frequency of price spikes at or near $1,000/MWh increased in the second quarter after the bid cap was raised to $1,000/MWh on April 1, 2011. However, the frequency of these extremely high price spikes dropped substantially in each of the last two quarters.

Many of the price spikes in the third quarter consisted of intervals with prices between $250/MWh to $500/MWh that were due to the ISO setting an administrative real-time price of $250/MWh during the power outage in San Diego on September 8, 2011. A more detailed analysis of price convergence and real-time price spikes is provided in Chapter 3.

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[38] The average PG&E prices were often similar to prices at the other areas. However, there were times when the other points were more congested than the PG&E price, and therefore were less reflective of overall system conditions than the PG&E price.

Figure 2.7 Comparison of quarterly prices – PG&E area (peak hours)

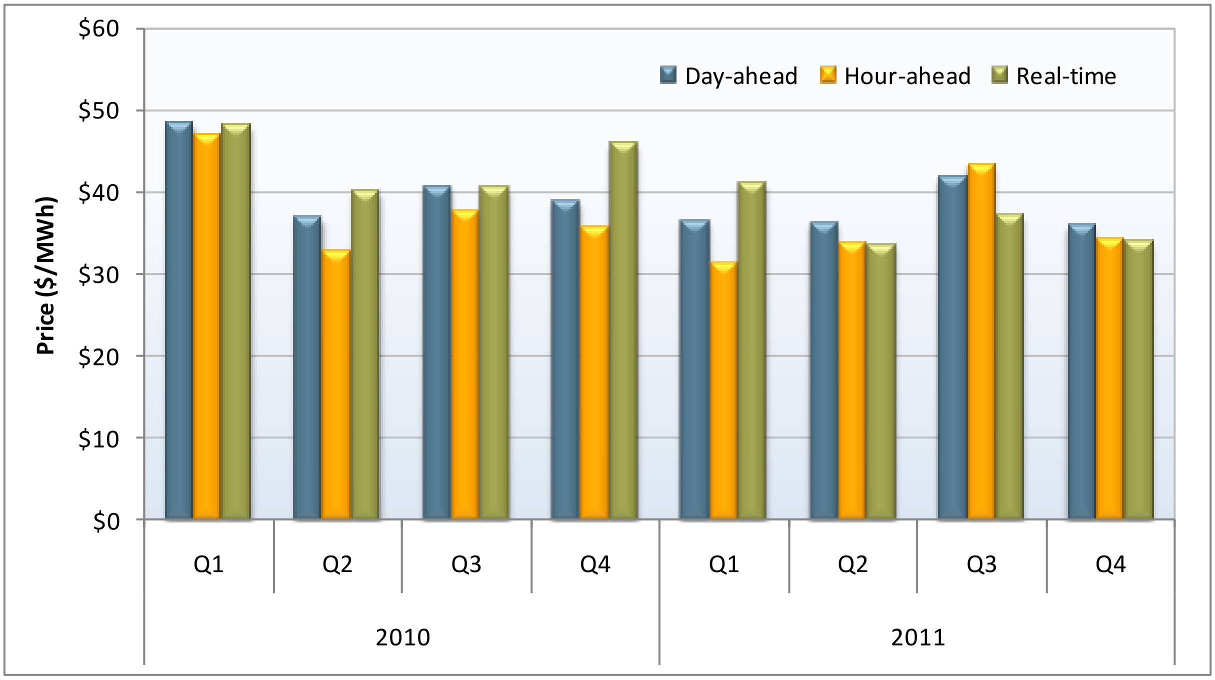


Figure 2.8 Comparison of quarterly prices – PG&E area (off-peak hours)

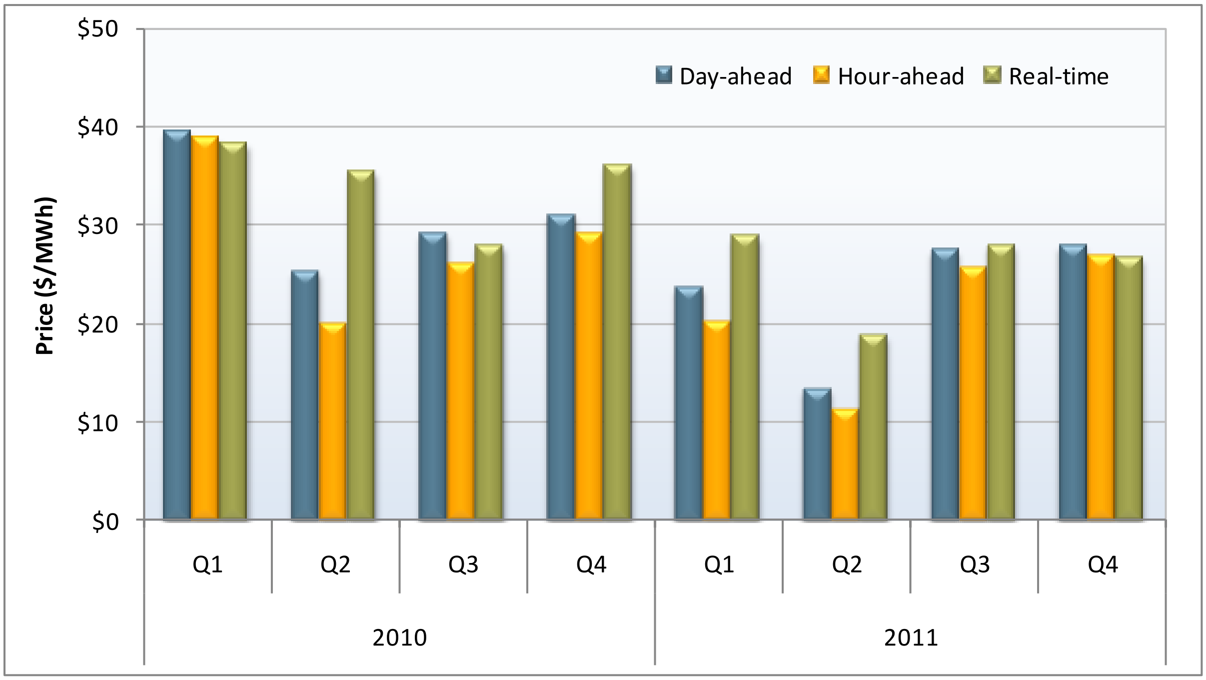
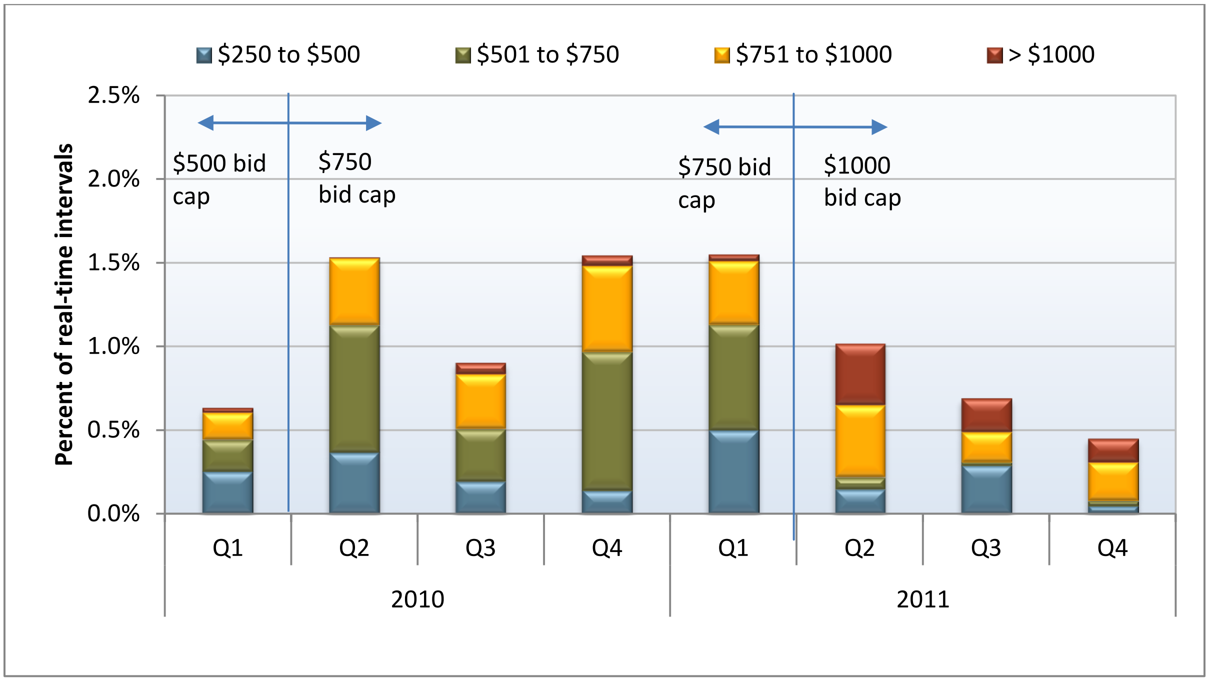


Figure 2.9 Price spike frequency by quarter



Price convergence, particularly between the hour-ahead and 5-minute real-time markets, has been a reoccurring problem since the start of the new market design in 2009. Figure 2.10 and Figure 2.11 show the difference in hour-ahead and real-time prices for each quarter over the last two years for peak hours and off-peak hours, respectively. In both peak and off-peak hours, average real-time prices were significantly higher than hour-ahead prices from the second quarter of 2010 into the first quarter of 2011. During off-peak hours, this trend continued in the second and third quarters of 2011.

This trend of higher average real-time prices relative to hour-ahead prices during many periods has been driven by relatively short but extreme price spikes in the 5-minute real-time market. These price spikes generally reflect short-term modeling and ramping limitations, rather than fundamental underlying supply and demand conditions. In most cases, these price spikes lasted for only a few 5-minute intervals.

The difference in these prices have contributed to uplifts, known as real-time imbalance offset costs, which are paid by load-serving entities.[39] These uplifts occur when generation decreases in the hour-ahead or 5-minute real-time market at a low price, only to be offset by generation in the other market at a higher price.[40]

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[39] DMM first highlighted this issue in detail in its *Quarterly Report on Market Issues and Performance*, Department of Market Monitoring, Revised December 23, 2009: http://www.caiso.com/Documents/QuarterlyReportonMarketIssuesandPerformance-October2009.pdf. The issue was also highlighted in several subsequent quarterly and annual reports.

[40] Other factors that contribute to real-time imbalance offset costs include uninstructed deviations and unaccounted for energy.

Figure 2.10 Difference in hour-ahead and real-time pries – PG&E area (peak hours)

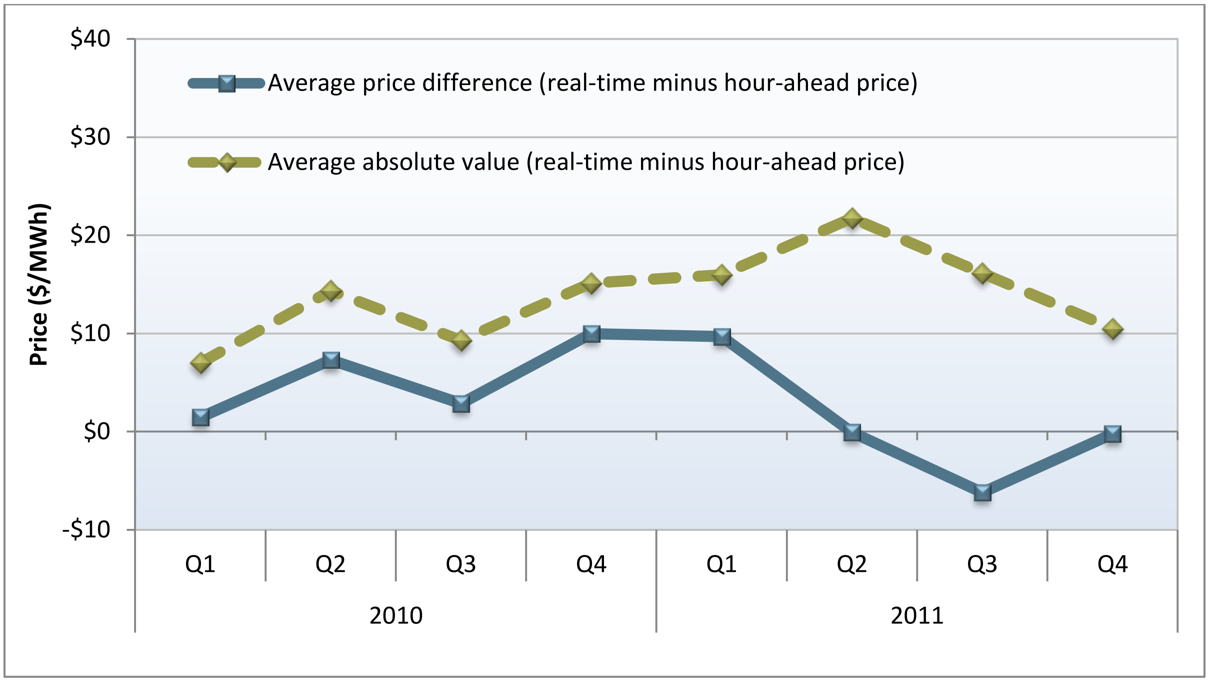
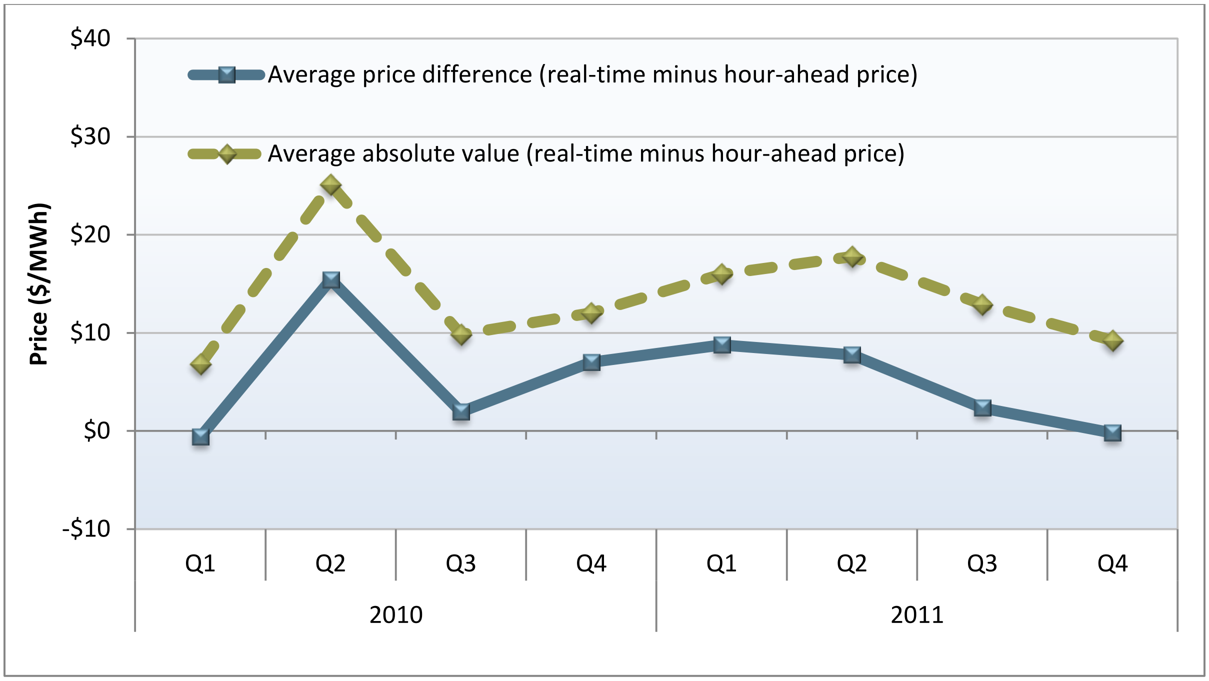
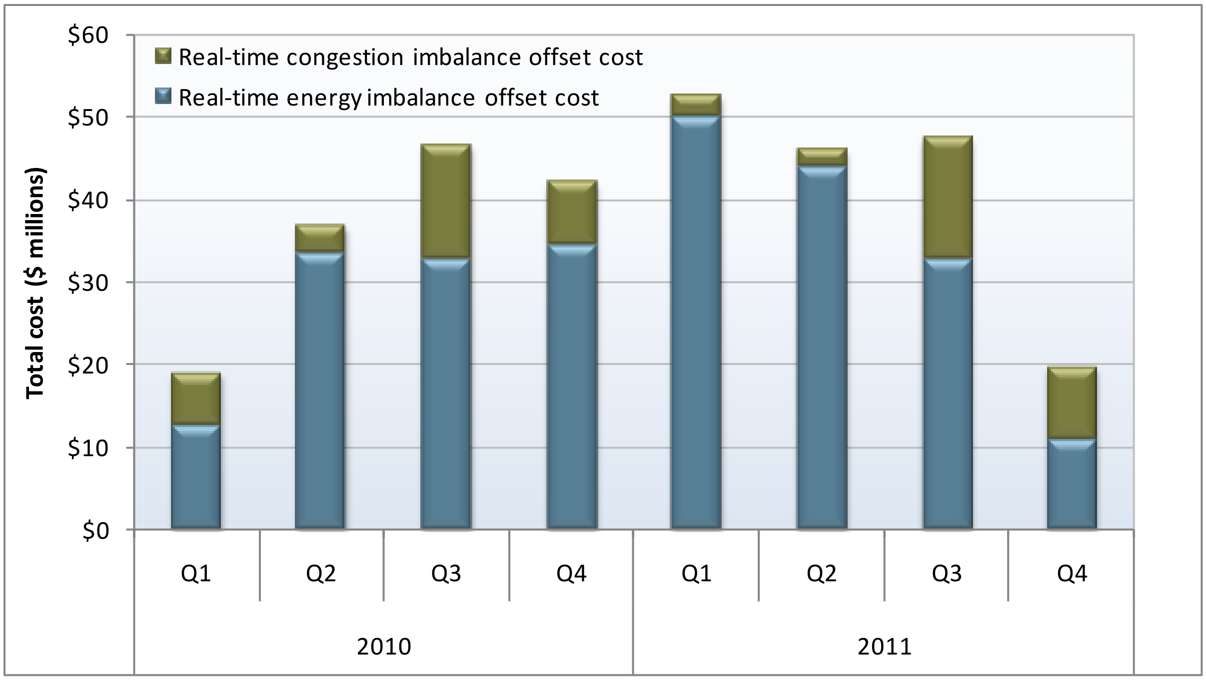


Figure 2.11 Difference in hour-ahead and real-time prices – PG&E area (off-peak hours)



In 2011, total real-time imbalance offset costs were about $166 million, up 15 percent from $144 million in 2010. At the beginning of 2011, these uplifts increased to their highest level since the very beginning of the nodal market in 2009 (see Figure 2.12). By the end of 2011, these uplifts fell to the second lowest levels since the new market began. The reduction in these uplifts can be primarily attributed to improvements in price convergence. These costs were also somewhat lower due to the suspension of convergence bids at the inter-ties.

Figure 2.12 Real-time imbalance offset costs



2.4 Residual unit commitment

The direct cost of procuring capacity through the residual unit commitment process was around $1.1 million in 2011 compared to $83,000 in 2010. After the implementation of convergence bidding in February, the direct residual unit commitment costs increased notably. For much of 2011, cleared virtual supply outweighed cleared virtual demand.[41] As a result, more residual unit commitment capacity was needed to replace the net virtual supply with physical supply. This increased both the direct capacity procurement costs and bid cost recovery payments associated with residual unit commitment.

In 2011, units committed in the residual unit commitment process accounted for around $6.1 million in bid cost recovery payments, or about 5 percent of total bid cost recovery payments. In 2010, these costs accounted for $1.4 million. This increase can also be attributed to net virtual supply positions in the day-ahead market. When cleared virtual supply outweighs cleared virtual demand, minimum load capacity can be committed through the residual unit commitment process. If the units providing the

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[41] This pattern was prevalent for most of 2011. After virtual bidding was suspended on the inter-ties in late November, the initial bidding pattern shifted and cleared virtual demand outweighed cleared virtual supply. By mid-December, cleared virtual supply again outweighed cleared virtual demand. See Chapter 4 for more detail.

minimum load capacity generate in the real-time market, their start-up and minimum load costs become eligible for the bid cost recovery payments.

DMM also identified two settlement problems related to residual unit commitment bid cost recovery payments in 2011:

- First, the residual unit commitment process incorrectly backed down multi-stage generating units due to an issue with the implementation of multi-stage generating unit functionality in the software. As a result, DMM estimated inappropriate bid cost recovery payments of approximately $1 million. The ISO indicated that the root cause was fixed in early 2011 as part of a software patch.

- Second, a flaw in the ISO tariff resulted in inappropriate bid cost recovery payments. Typically, resources do not receive bid cost recovery payments if they do not perform in real-time, except when their performance falls within a tolerance band. The tariff gap occurred when units with small minimum capacity values and short start-up times were committed in the residual unit commitment process but did not run in real-time. The source of the issue was that a zero actual value may fall within the tolerance band for units with very small minimum capacities. Therefore, such units could receive residual unit commitment bid cost recovery payments without generating any energy in the real-time. This issue resulted in estimated payments of about $300,000 in 2011. In February 2012, the California ISO Board of Governors approved a tariff change to fix this flaw.

2.5 Bid cost recovery payments

Generating units are eligible to receive bid cost recovery payments if total market revenues earned over the course of a day do not cover the sum of all the unit's accepted bids. This calculation includes bids for start-up, minimum load, ancillary services, residual unit commitment availability and day-ahead and real-time energy. Excessively high bid cost recovery payments can indicate inefficient unit commitment or dispatch.

Figure 2.13 provides a summary of total estimated bid cost recovery payments in 2011.[42] As reflected in this figure:

- In 2011, bid cost recovery payments are calculated to total $126 million or about 1.5 percent of total energy costs. This compares to a total of $68 million or about 0.8 percent of total energy costs in 2010.

- In the last quarter of 2010 and first six months of 2011, bid cost recovery payments were high. In that period, the ISO had identified flaws in the calculation of these payments which led to excessively high bid cost recovery payments when exploited by certain manipulative bidding behaviors. In March and June, the ISO made two emergency filings with the FERC to modify bid cost recovery rules to mitigate this behavior.[43] As a result, bid cost recovery payments associated with the day-ahead market dropped by 86 percent in the second half of 2011.

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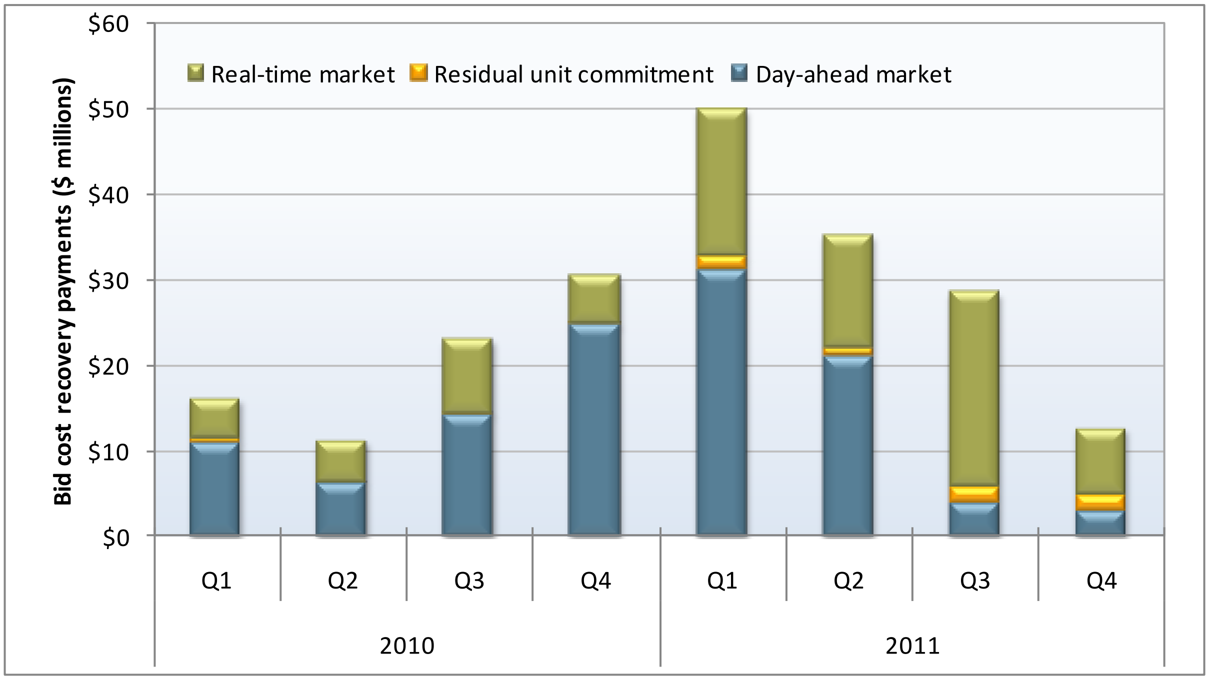
[42] Estimates provided in this report include estimated adjustments to bid cost recovery data which are still pending in the ISO settlement system.

[43] California Independent System Operator Corporation, Tariff Revision and Request for Expedited Treatment**,** March 18, 2011, http://www.caiso.com/2b45/2b45d10069e0.pdf. Tariff Revision and Request for Waiver of Sixty Day Notice Requirements**,** June 22, 2011, http://www.caiso.com/Documents/2011-06-22_Amendment_ModBCRrules_EDEnergySettRules_ER11-3856-000.pdf.

DMM estimates that bid cost recovery payments from minimum online constraints totaled $12 million, or about 10 percent of total bid cost recovery payments in 2011.[44] This is down from an estimated $17 million or 25 percent of bid cost recovery payments in 2010.

Figure 2.13 Bid cost recovery payments



Bid cost recovery payments associated with real-time market dispatches were considerably higher in the third quarter of 2011. Higher real-time payments were mainly from exceptional dispatches that were made by the ISO to commit additional capacity after the day-ahead market for two reasons. First, exceptional dispatches for system capacity help to meet generation capacity requirements for the entire ISO region. These additional unit commitments are made after the day-ahead market to protect the system from voltage collapse and potential thermal overloads on critical inter-ties should worst-case contingencies occur. Second, additional online capacity located south of Path 26 that can be ramped up in 30 minutes to meet a contingency such as an outage of the Nevada-Oregon Border (NOB) transmission path, also known as the Pacific DC Inter-tie (PDCI), and for other local capacity needs.[45]

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[44] These constraints are set in the day-ahead and residual unit commitment markets. They make sure that the system has enough longer start capacity on-line to meet locational voltage requirements and respond to contingencies that cannot be directly modeled. See Section 8.1 for further detail.

[45] *Quarterly Report on Market Issues and Performance*, Department of Market Monitoring, November 8, 2011, p. 17, http://www.caiso.com/Documents/QuarterlyReport-MarketIssues_Performance-November2011.pdf.

3 Real-time market performance

The consistency of prices in hour-ahead and real-time markets has been problematic since the start of the nodal market design in 2009. During many periods, average hour-ahead prices have been systematically lower than average real-time prices. These higher average real-time prices have often been driven by very high price spikes during a relatively small number of 5-minute intervals. As noted in prior reports by DMM, most of these price spikes have been caused by brief shortages of 5-minute upward ramping capacity in the market model, which require that the system energy balance constraint be relaxed.[46]

This chapter highlights changes in factors that caused extreme positive and negative prices in 2011.

- While shortages of upward ramping capacity continued to play a role in setting high prices, the frequency of such price spikes decreased over the course of the year as the result of improvements in manual operating procedures, forecasting capability and the market software.
- As the incidence of these extreme 5-minute real-time prices decreased, price convergence improved, particularly towards the end of the year.
- While the incidence of extremely high prices decreased, the frequency of negative prices increased in 2011. The occurrence of negative prices increased most notably in the second quarter and during the early morning hours.
- One of the major factors that led to the increase in negative prices was an increase in the volumes of inflexible self-scheduled hydro-electric generation. Other factors, including load and wind forecast deviations, also contributed to the increase in negative prices.
- Most negative real-time prices in 2011 were set by negative priced bids dispatched by the ISO. In 2010, most negative prices occurred when the power balance constraint needed to be relaxed in the market software due to shortages of downward ramping capacity.

3.1 Background

The ISO market includes an energy bid cap and bid floor to limit the effect volatile energy prices may have on market outcomes. Currently, the bid cap is set at $1,000/MWh; the bid floor is set at -$30/MWh.[47] This bid cap and floor affect prices directly and indirectly:

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

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[46] This issue was highlighted in DMM's *2010 Annual Report on Market Issues and Performance* as well as in its *Quarterly Market Issues and Performance Reports* in 2011. These reports can be found here: http://www.caiso.com/market/Pages/MarketMonitoring/MarketIssuesPerfomanceReports/Default.aspx.

[47] The -$30/MWh floor is really a "soft floor." Bids below -$30/MWh can be submitted, but do not set the market price. Also, bids below -$30/MWh are subject to cost justification if the participant seeks to be paid more than -$30/MWh.

Prices have rarely reached the bid cap or floor because of the market dispatching energy bids at these bid limits. Most prices that have hit these bid limits are caused by relaxing the power balance or transmission capacity constraints, as discussed below.

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

- When insufficient incremental energy is available for 5-minute dispatch, this constraint is relaxed in the scheduling run of the real-time software. In the scheduling run, the software assigns a penalty price of $1,000/MW for the first 350 MW that this constraint is relaxed. Any relaxation above 350 MW is assigned a penalty price of $6,500/MW in the scheduling run.[48] In the pricing run, a penalty price of $1,000/MW is used. This causes prices to spike to the $1,000/MWh bid cap or above.

- When insufficient decremental energy is available for 5-minute dispatch, the software relaxes this constraint in the scheduling run using a penalty price of -$35/MW for the first 350 MW. After this, self-scheduled energy may be curtailed at a penalty price of -$1,800/MW. In the pricing run, a penalty price of -$35/MW is used. This causes prices to drop down to or below the -$30/MWh floor for energy bids.

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

3.2 System power balance constraint

Figure 3.1 shows the percentage of intervals that the power balance constraint was relaxed during each operating hour in 2011. As shown in this figure:

- Shortages of upward ramping capacity caused the system power balance constraint to be relaxed most frequently during morning and evening load ramping hours when system loads were changing at a relatively high rate.

- The constraint was relaxed because of shortages of upward ramping in about 0.9 percent of intervals in 2011. During the system peak load hours of 18 through 21, prices spiked because of shortages of upward ramping in around 1.6 percent of intervals, almost double the average for all hours.

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[48] The bid cap was raised from $750/MWh to $1,000/MWh on April 1. As a result, the penalty price also increased from $750 to $1,000 in April.

- The system power balance constraint was relaxed due to shortages of downward ramping capacity primarily during the off-peak hours, when periods of excess energy tend to occur. The constraint was also relaxed nearly 8 percent of intervals during hour ending 7. This is the first hour of the 16 hour block used in standard contracts for peak period energy. Excess energy often occurs in these hours as generating units and inter-tie schedules ramp up from off-peak levels to peak levels.

- The constraint was relaxed because of shortages of downward ramping in about 1.8 percent of intervals in 2011. About 83 percent of these intervals occurred in hours ending 1 through 8, during which the constraint was relaxed about 4.5 percent of the time.

Most of these shortages were very short-lived. About 86 percent of shortages of upward ramping capacity persisted for only one to three 5-minute intervals (or 5 to 15 minutes). About 65 percent of shortages of downward ramping capacity lasted for only one to three 5-minute intervals.[49]

Figure 3.1 Relaxation of power balance constraint by hour (2011)

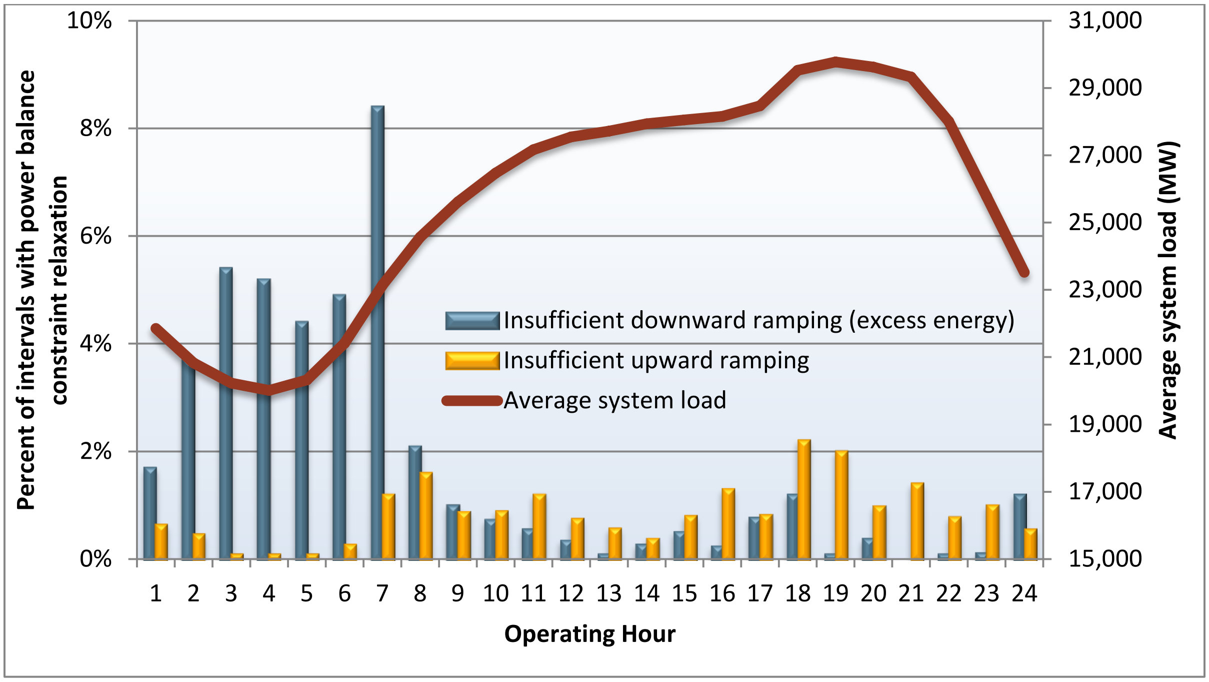

Figure 3.2 and Figure 3.3 show the frequency with which the power balance constraint was relaxed in the 5-minute real-time market software each quarter since 2010. This constraint has never been relaxed in the day-ahead or the hour-ahead markets as self-schedules are cut first.

- As shown in Figure 3.2, the constraint was relaxed because of insufficient incremental energy in about 1 percent of the 5-minute intervals starting in the first and second quarter of 2011. However, the frequency decreased to about 0.6 percent of all 5-minute intervals during the fourth quarter of 2011.

- As shown in Figure 3.3, the constraint was relaxed due to insufficient decremental energy less consistently, but more frequently than for upward insufficiencies. When the constraint is relaxed

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[49] See details in *Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2011, p. 162, http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf.

under these conditions, the downward impact on average prices is also less significant because prices only drop towards or to the -$30/MWh bid floor.

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

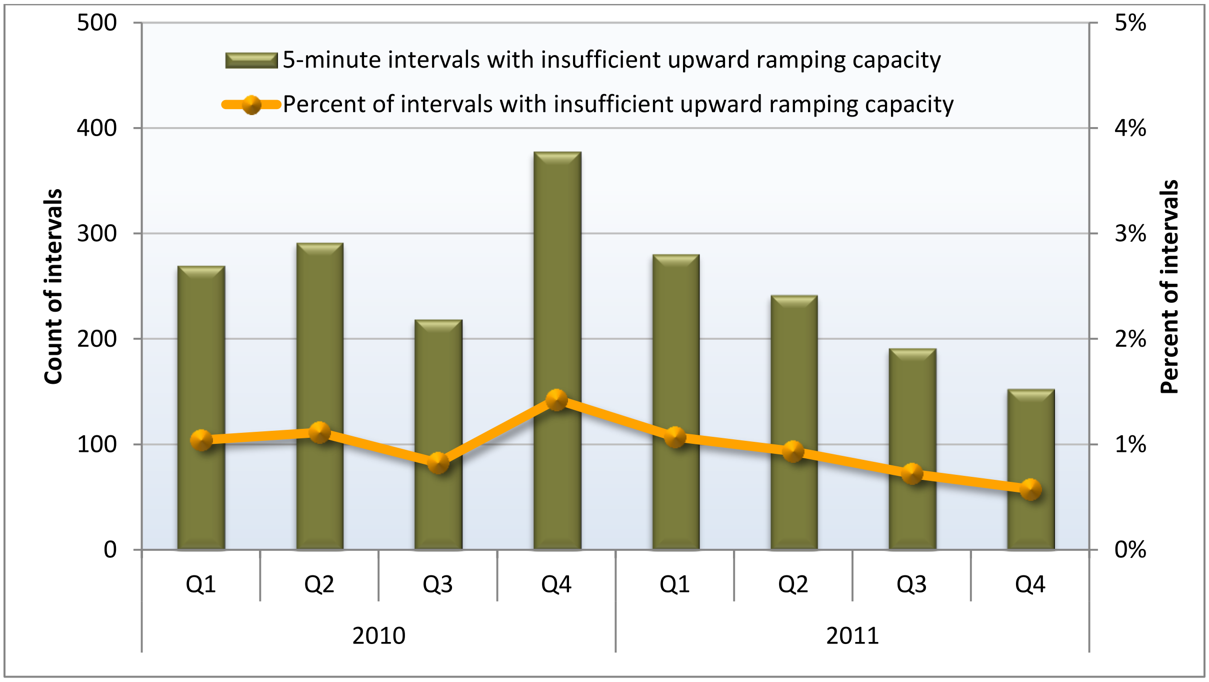
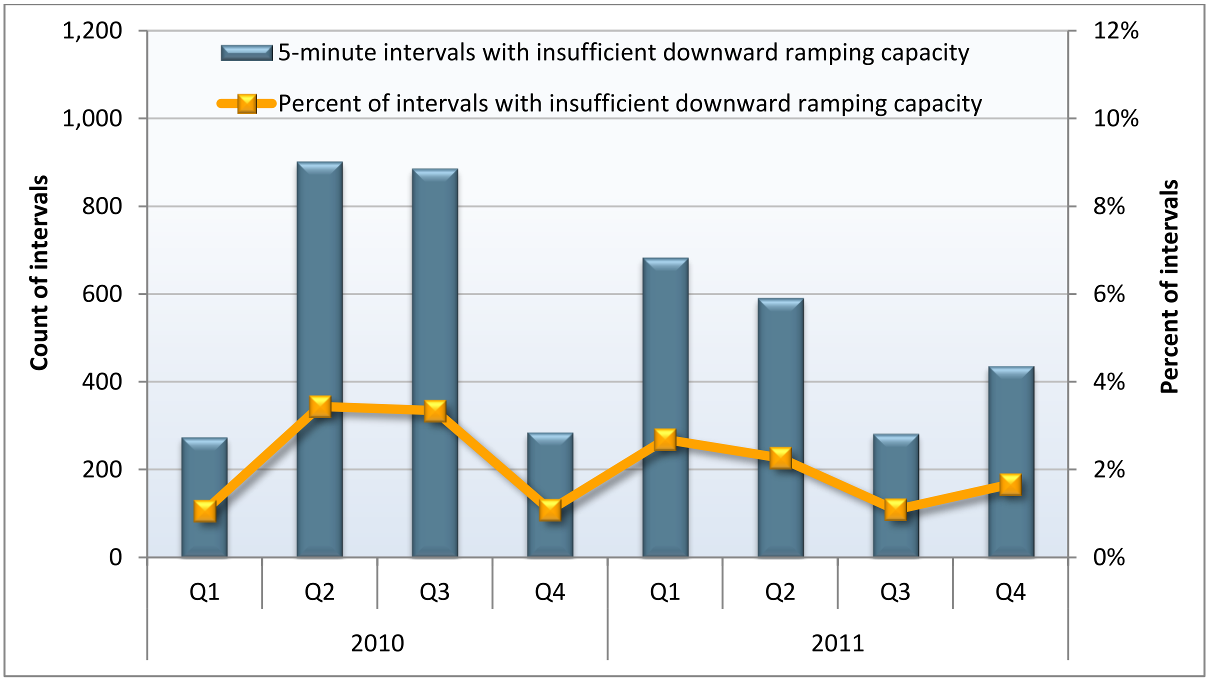


Figure 3.3 Relaxation of power balance constraint due to insufficient downward ramping capacity

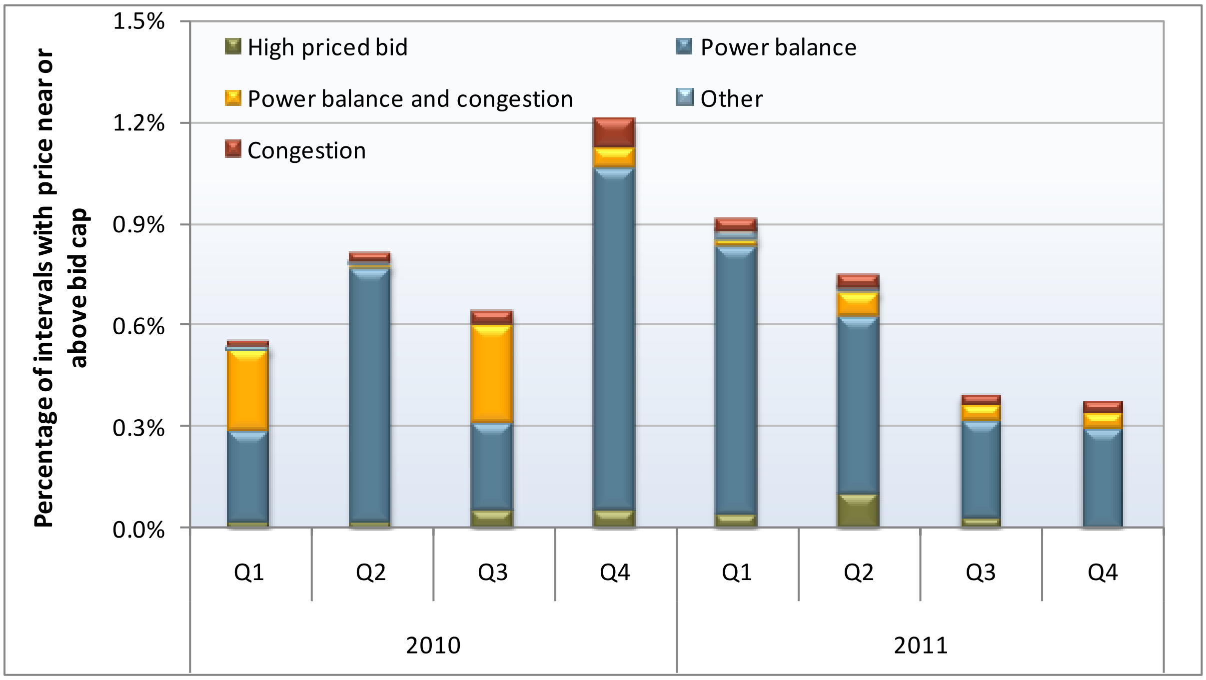


3.2.1 Causes of extremely high prices

Figure 3.4 shows the approximate frequency of different factors driving high real-time prices for each load aggregation point. For purposes of this analysis, high prices are defined as including all intervals in which the real-time price for a load aggregation point was at or near the bid cap in effect.[50] The primary reasons for each of these high load aggregation point prices are identified based on the following categories:

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

Figure 3.4 Factors causing high real-time prices



Results of this analysis show that almost all of the extremely high prices in the real-time market continue to occur in intervals when the power balance constraint is relaxed. As shown in Figure 3.4:

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[50] During the first quarter of 2011, this included all prices at or above $750/MWh. Starting in April, the analysis included all prices at or above $1,000/MWh.

- Over 78 percent of all high prices at load aggregation points in 2011 were due to relaxing the power balance constraint during an interval when congestion did not have a significant impact on price. Starting in the fourth quarter of 2010, this category has accounted for the largest percentage of the price events.
- Starting in the fourth quarter of 2010, congestion has played a much lower secondary role in causing high load aggregation point prices. In 2011, about 6 percent of all high price events were due to pure congestion and 8 percent were due to a combination of congestion and the power balance constraint.
- There were relatively few instances where the dispatch of high priced bids could have caused a high load aggregation point price. Overall, these intervals represented about 7 percent of all high price events during the year.

3.2.2 Causes of negative prices

Real-time energy prices become negative for various reasons. Figure 3.5 summarizes an analysis of the causes of real-time prices less than $0/MWh at load aggregation points. The causes for low prices are categorized as follows:

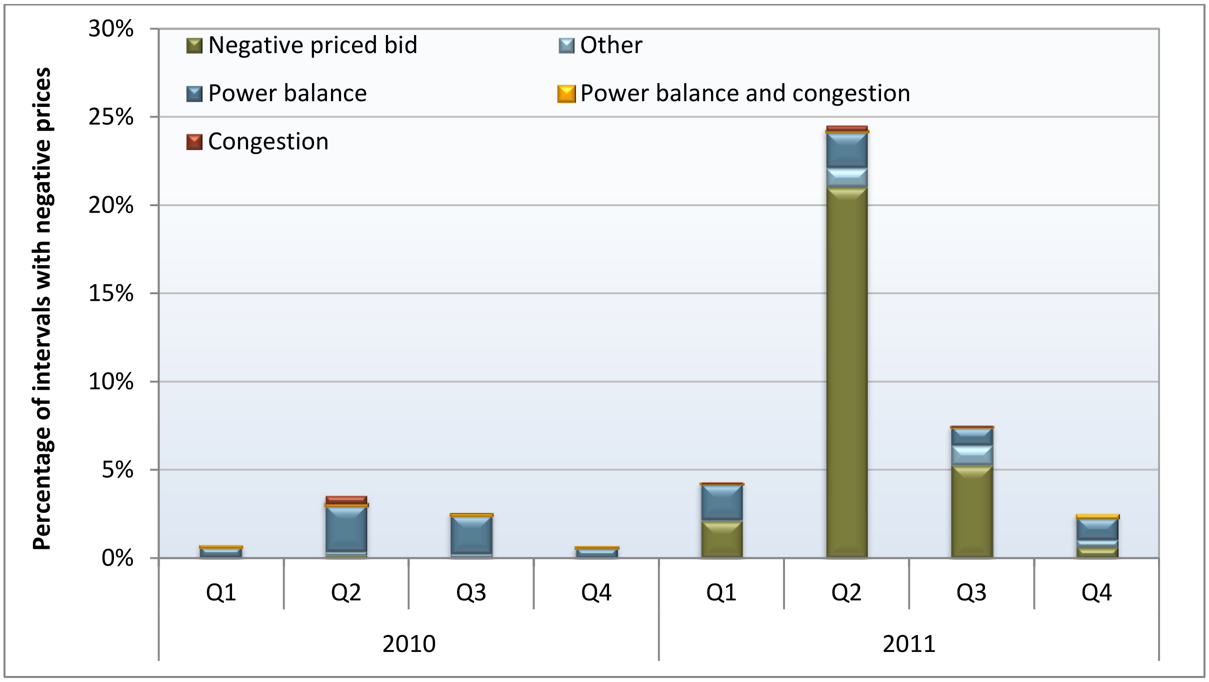
- **Power balance constraint** – During these intervals the power balance constraint was relaxed and the congestion component was less than 50 percent of the price.
- **Power balance constraint and congestion** – These prices occurred when the power balance constraint was relaxed and the congestion component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

Results of this analysis show that during most intervals when negative prices occur, there are sufficient negatively priced bids. As seen in Figure 3.5:

- In the second quarter of 2011, almost 86 percent of negative prices were due to the dispatch of negatively priced bids. The trend continued in the third quarter of the year, with negatively priced bids setting prices in about 70 percent of intervals with negative prices.
- About 16 percent of negative prices in 2011 occurred when the power balance constraint was relaxed. Most of these negative prices occurred during the first half of 2011. The percentage of intervals the power balance constraint was relaxed due to excess energy remained fairly consistent from 2010 to 2011. However, since the total number of negatively priced intervals increased, the percentage of negatively priced intervals in which the power balance constraint was relaxed dropped from about 80 percent in 2010 to about 16 percent in 2011.

- Only about 7 percent of negative prices were due to other model parameters. Most of these negative prices had energy components between -$30/MWh and -$35/MWh, but the power balance constraint was not relaxed.
- Congestion was a significant cause of only about 2 percent of negative prices for load aggregation points.

Figure 3.5 Factors causing negative real-time prices



3.3 Increase of negative real-time prices

When there is an oversupply of scheduled energy in the real-time market, the ISO reduces generation below scheduled levels based on bid prices offered by those units that do not self-schedule generation to meet their full day-ahead schedule. Prices are typically lower in these circumstances, signaling a surplus of supply.

There are typically sufficient positive-priced bids for backing down generation. This represents the willingness of generators to pay a positive price less than their marginal operating cost to avoid incurring the cost associated with that production. However, generators can submit bid prices to -$30/MWh (the bid price floor), indicating they require payment to reduce output. If there are insufficient positive-priced bids to reduce energy output in the real-time market, negative bids must be accepted and the real-time energy price will be negative.

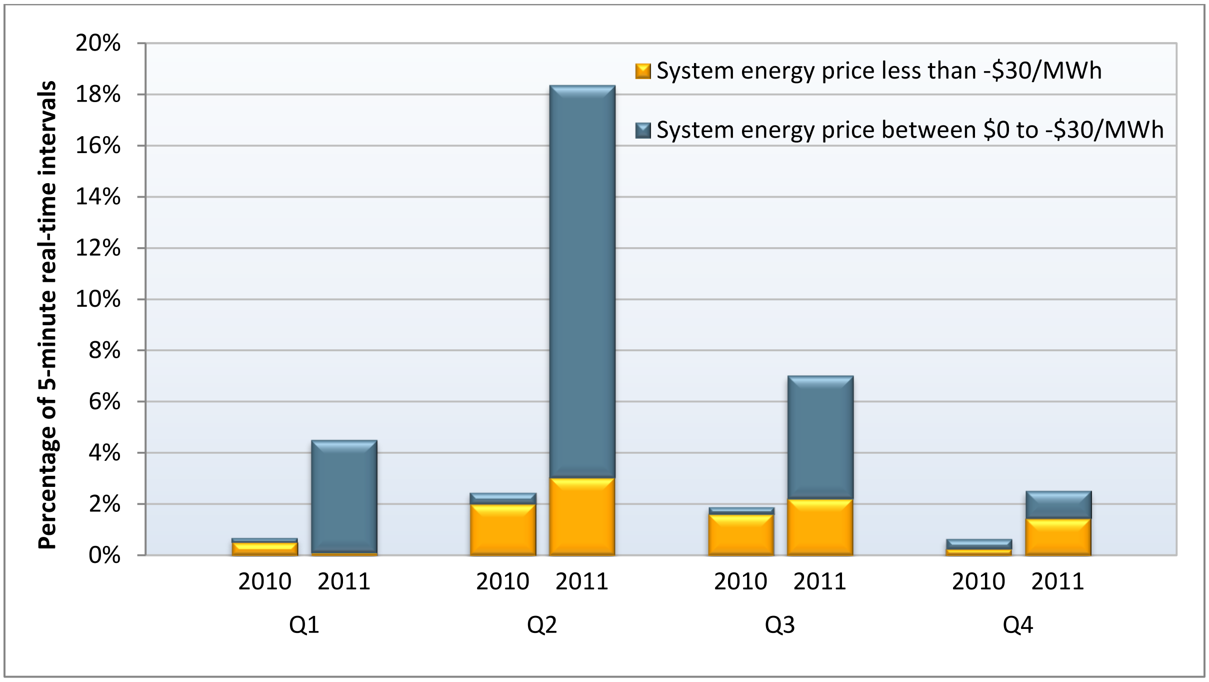
The ISO experienced a significant increase in negative real-time prices in 2011 compared to 2010. As shown in Figure 3.6:

- Most of the increase in negative prices involved prices between $0/MWh and -$30/MWh. Many of these occurred in the second quarter, when hydro runoff was extremely high. Negative system energy prices in this range indicate sufficient capacity bid at negative prices to economically clear the real-time market and resolve the over-supply.

- The frequency of prices less than -$30/MWh increased only slightly in 2011. Prices below the bid floor of -$30/MWh indicate that there was not sufficient dispatchable downward capacity offered to relieve over-supply. When this happens the market may curtail self-scheduled resources, relax the power balance constraint, and/or utilize additional downward regulation to mitigate over-supply.[51]

Despite the increase in over-supply conditions in 2011, the needed reductions in generation were usually resolved with market bids so that the prices remained greater than -$30/MWh. Analysis by DMM indicates the increase in negative prices above -$30/MWh resulted from an increase in negatively priced decremental energy bids.

Figure 3.6 Negatively priced 5-minute real time intervals (2010 vs 2011)



As shown in Figure 3.7, one of the key drivers of negative real-time prices during these hours is the very large portion of online capacity comprised of minimum load energy from online units and self-scheduled energy.

- Together, minimum load energy and self-scheduled energy accounted for about 94 percent of online capacity during hours with negative prices (during hours ending 1 to 10). Thus, only about 6 percent of capacity during these hours could be dispatched down based on market bids.

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[51] The power balance constraint is a constraint in the market optimization that requires supply to equal demand. In cases of over-supply where the power balance constraint is relaxed, the market software is not able to reduce supply sufficiently to equal demand. When the power balance constraint is relaxed, a penalty price becomes effective in setting prices. More details on the power balance constraint are in Section 3.2. Figure 3.6 reflects a pricing run analysis and therefore will differ from the pure power balance constraint analysis in Section 3.2, which uses scheduling run prices to determine when the constraint was relaxed.

- Minimum load energy during these hours decreased slightly in 2011 (see red bars in Figure 3.7). However, this was offset by an increase in self-scheduled energy compared to 2010 (see blue bars in Figure 3.7). The increase in self-scheduled energy was driven by a significant increase in hydro-electric generation and also a small increase in wind generation.

Figure 3.8 provides a more detailed summary of the capacity during these hours that could be dispatched down based on market bids. As highlighted in this figure:

- During the first three quarters of 2011, the amount of downward capacity bid at positive prices was comparable to 2010 (see green bars in Figure 3.8).
- However, during each quarter, there was a significant increase in negatively priced downward capacity (see yellow bars in Figure 3.8). This shift in bidding may at least in part be attributable to the increased frequency of negative prices and the ISO's policy emphasis on the need for additional downward capacity.

Figure 3.7 Downward ramping capacity in real-time market during hours with negative prices (hours 1 – 10)

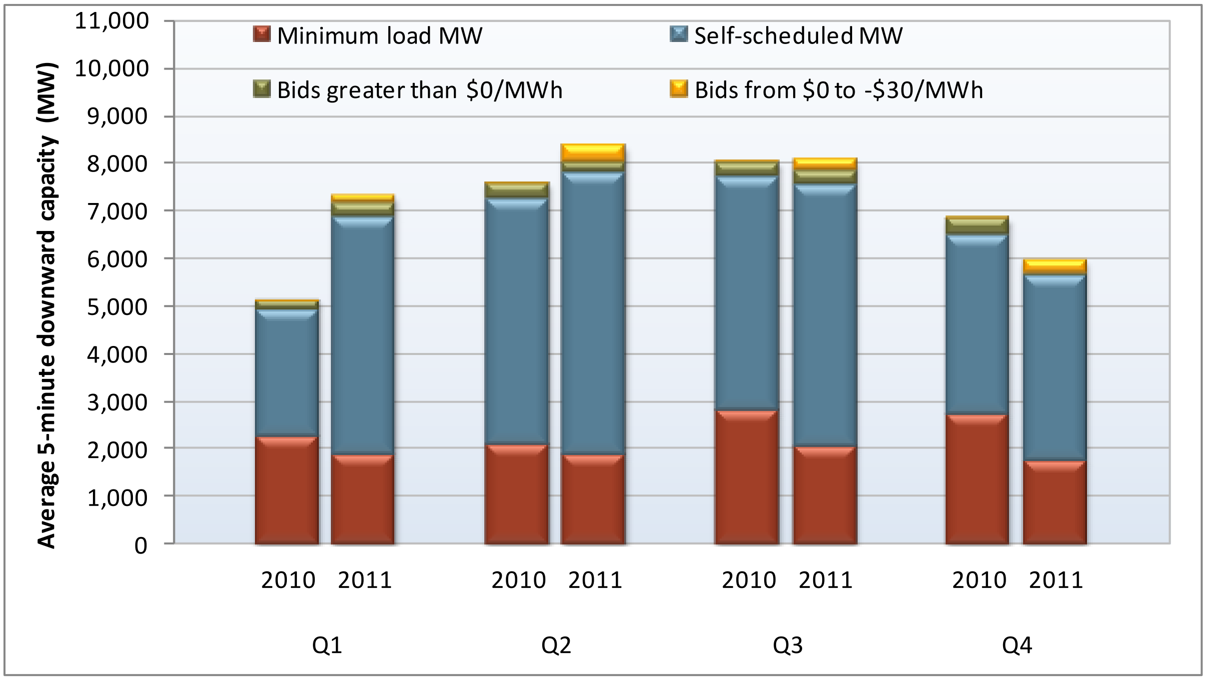
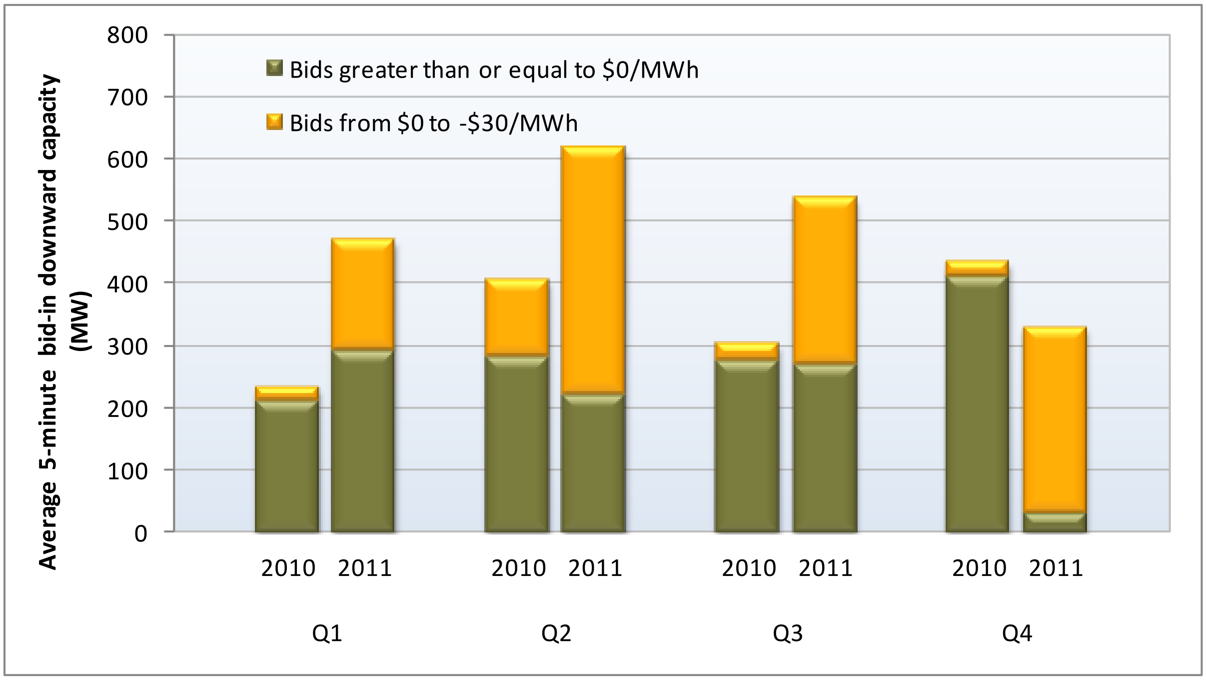


Figure 3.8 Downward ramping capacity bid into real-time market during hours with negative prices (hours 1 – 10)



3.4 Hydro and wind resources

One of the primary causes of the increase of negative prices and over-supply conditions in 2011 was the high level of hydro generation. However, negative prices often occur when high hydro generation is exacerbated by other factors, including high wind production and variability. As seen in Figure 3.9, in both 2010 and 2011 the peak month in hydro-electric production coincided with the peak month of negatively priced intervals. Figure 3.10 shows that while wind production does not perfectly coincide with the peak month of negatively priced intervals, wind output is on average higher during months with greater levels of negative intervals.

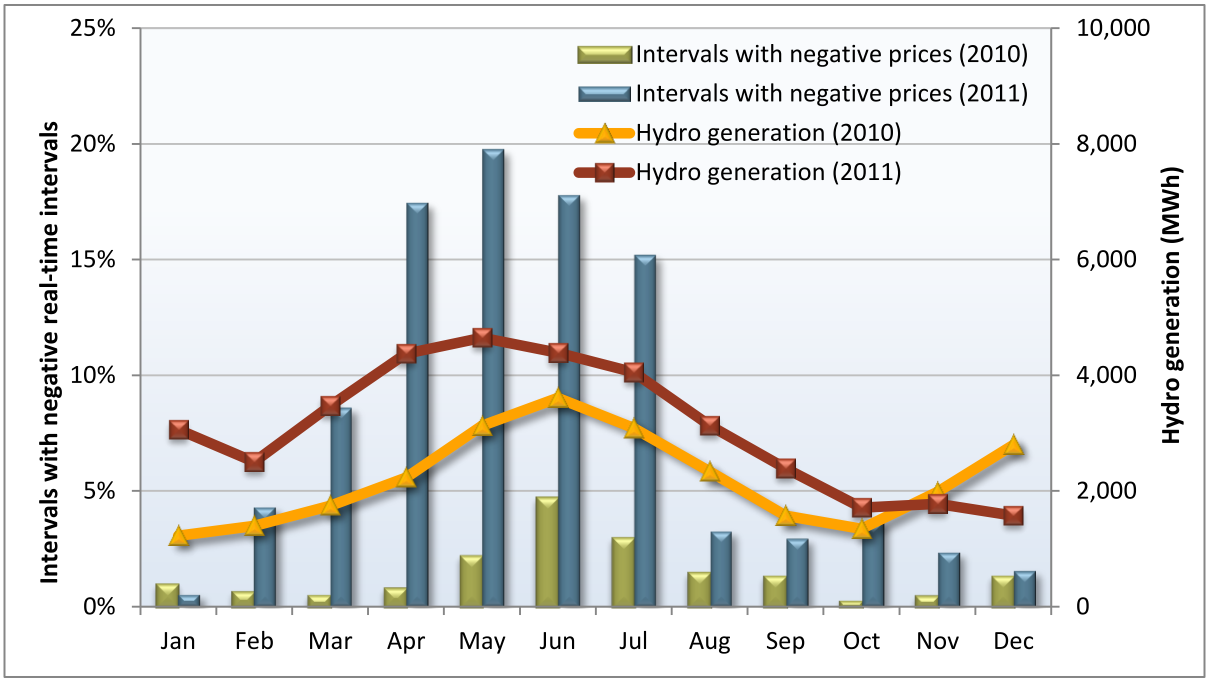
The large increase in hydro-electric generation in 2011 led to large amounts of hydro-electric power being self-scheduled in the off-peak hours. This contributed to the overall increase in self-scheduling during the first through third quarters seen in Figure 3.7. The market optimization will only curtail self-scheduled resources in the event of over-supply after all economic bids are accepted. Thus, large amounts of self-scheduled energy add to the inflexibility of the real-time market.

Wind resources are not required to schedule in the day-ahead market and instead submit forecasts in the hour-ahead market. Forecasting wind generation in off-peak hours remains a challenge, particularly on a day-ahead basis and in the early morning hours when wind output is generally at its highest.

The green bars in Figure 3.11 show the average difference between actual wind output and the day-ahead and hour-ahead forecasts of wind output during hours between 1 and 10 with negative real-time prices in 2010 and 2011. The positive values represent the average amount by which the ISO over-forecast actual wind output during these hours. Under-forecasting of wind output may lead to over-scheduling of traditional resources in the day-ahead market compared to real-time needs. Traditional resources then have to be backed down in real-time so the ISO can accommodate the unexpected additional amounts of wind on the system that cannot be economically curtailed.

The relationship between unexpected real-time wind generation and increased negative intervals is reflected in the positive correlation in the frequency of negative real-time prices during each month shown in Figure 3.10 and the average amount of under-forecast wind output each quarter shown in Figure 3.11.[52] The increase in under-forecasting of wind output in the first few quarters of 2011 compared to 2010 shown in Figure 3.11 is due to increased amounts of wind on the system rather than a decrease in wind forecasting accuracy by the ISO. However, this illustrates that wind is likely to have an increased impact on the potential for negative prices as the amount of wind energy increases even more dramatically in the coming years.

Figure 3.9 Hydro-electric generation and frequency of negatively priced intervals (hours 1 – 10)



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[52] In the second quarter of 2011, when negative real-time prices were most frequent, prices were coincidently negative in the hour-ahead market a majority of the time. Overall, hour-ahead and real-time prices were negative at the same time in about 30 percent of these intervals in 2011 compared to about 8 percent in 2010.

Figure 3.10 Wind generation compared to incidence of negatively priced intervals (hours 1 – 10)

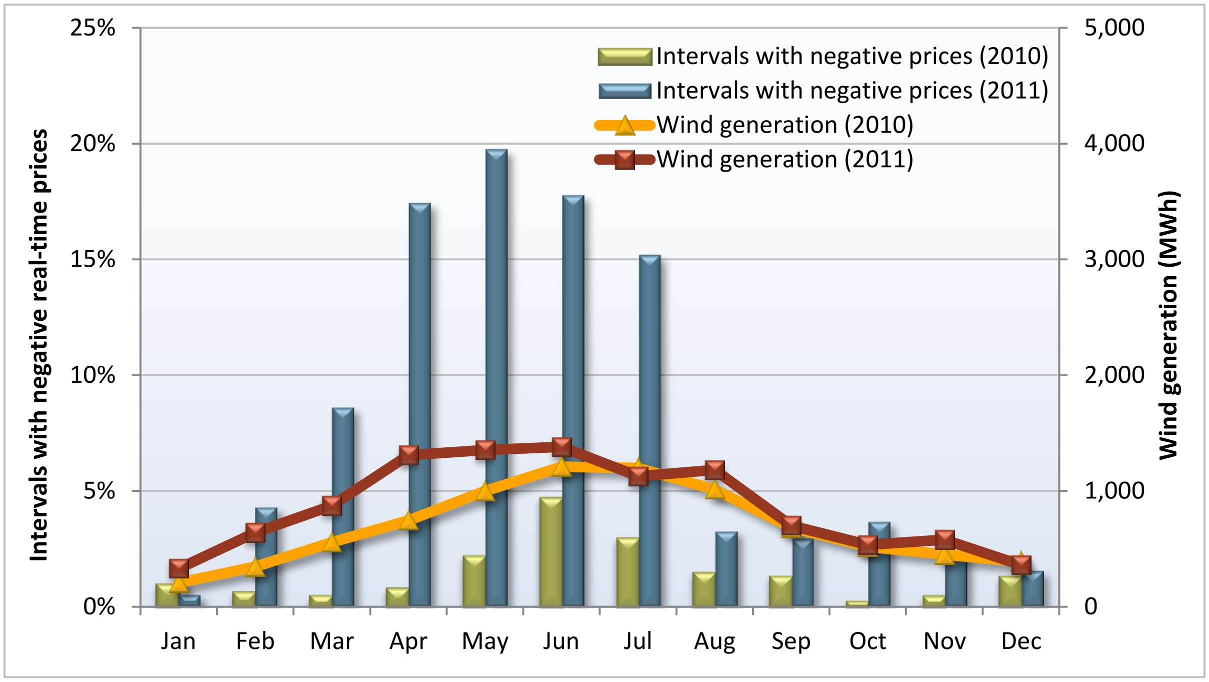
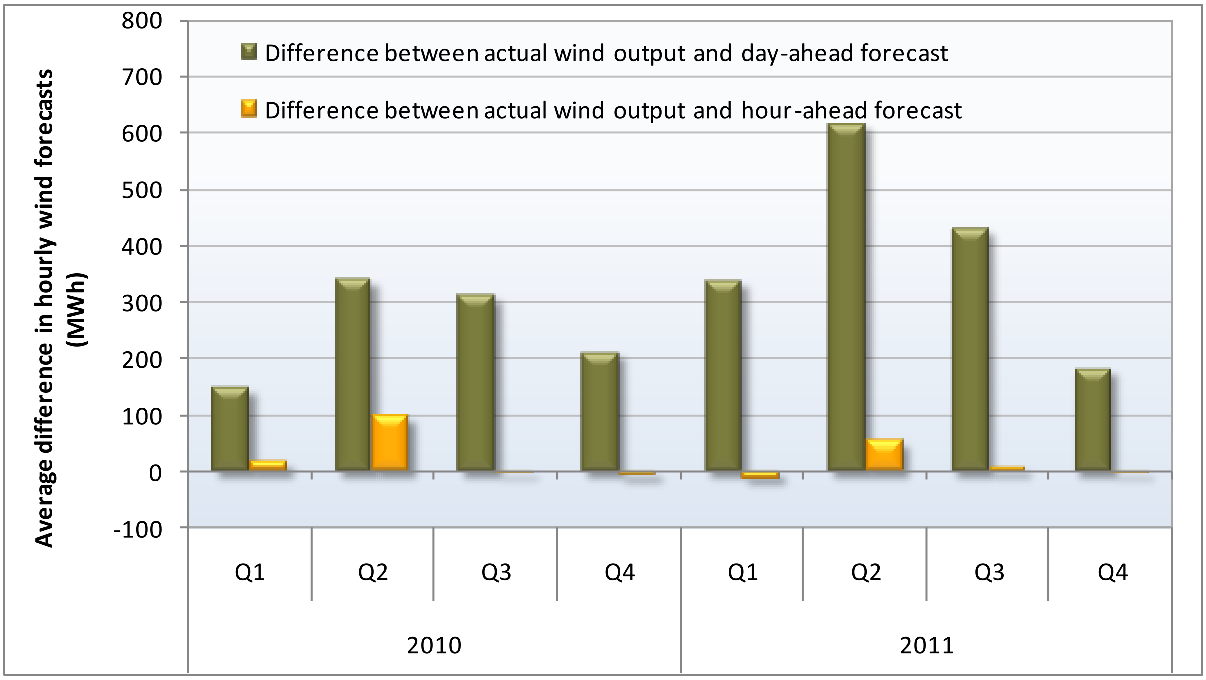


Figure 3.11 Average difference in wind generation forecasts during hours with negative prices (hours 1 – 10)



3.5 Real-time flexible-ramping constraint

In December 2011, the ISO began enforcing the upward flexible ramping constraint in both the 15-minute real-time pre-dispatch and in the 5-minute real-time dispatch markets. The constraint is applied to internal generation resources as well as to proxy demand response resources and not to external resources.[53]

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

Although the FERC has approved the implementation of the flexible ramping constraint in the 5-minute real-time market, the methodology to allocate the associated cost has not yet been approved by FERC.[54] The total system cost since the implementation of the flexible ramping constraint in mid-December through February was around $6.8 million. This compares with a total cost of $3.1 million for spinning reserve during the same timeframe.

The ISO enforces a constraint that attempts to ensure 10-minute dispatchable capacity is available from the set of resources procured in the 15-minute real-time pre-dispatch run. If there is sufficient capacity already online, the ISO does not commit additional resources in the system, which often leads to a low (or sometimes zero) shadow price for the procured flexible ramping capacity. During intervals when there is not enough 15-minute dispatchable capacity available among the committed units, the ISO commits additional resources (mostly short-start units) for energy to free up capacity from the existing set of resources. The short-start units can be eligible for bid cost recovery payments for commitment costs in real-time.[55]

Analysis of the flexible ramping constraint

The ISO determines the amount of needed flexible ramping capacity on an hourly basis. When the flexible ramping constraint was first implemented, the ISO utilized a fixed flexible ramping requirement of 700 MW for each hour of the day. The flexible ramping capacity requirement was set at this level as a conservative number to allow the ISO to gain experience with how the constraint affected unit commitment in the 15-minute real-time pre-dispatch and ramping needs in the 5-minute real-time dispatch. As the ISO gained experience with the implementation, the requirement was subsequently adjusted gradually downward to a maximum of around 450 MW and a low of around zero depending on the hour of the day. Beginning in January, operators have been instructed to adjust the hourly requirement levels based on the prevailing system conditions and actual utilization experience. When

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

[54] FERC held a technical conference on January 31, 2012 to address the cost allocation of the flexible ramping constraint.

[55] Further detailed information on the flexible ramping constraint implementation and related activities can be found here: http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/FlexibleRampingConstraint.aspx.

the constraint binds, the shadow price of the constraint in the 15-minute real-time pre-dispatch run reflects the opportunity cost associated with a marginal resource meeting the constraint.

4 Convergence bidding

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

Total net profits paid to entities as a result of their convergence bids were around $41 million in 2011.

- Most of these net profits ($28 million) came from virtual supply on inter-ties, which are settled based on the difference in day-ahead and hour-ahead prices. Virtual imports averaged 1,760 MW per hour, while virtual exports averaged only 180 MW per hour.
- About $13 million in profits were received by virtual bids at points within the ISO. Most of these profits were for internal virtual demand bids. At internal locations, virtual supply averaged 660 MW while virtual demand averaged 1,570 MW per hour.[56]

In theory, profitable virtual bids may help market efficiency by improving unit commitment decisions and price convergence between these markets. In practice, however, several aspects of the ISO's market design and performance prevented convergence bidding from working as intended in 2010.

- The tendency for real-time prices to exceed day-ahead prices made virtual demand profitable at scheduling points within the ISO. Meanwhile, the tendency for hour-ahead prices to be predictably lower than day-ahead prices during many periods made it profitable for participants to submit large volumes of virtual imports. During most hours, these virtual imports completely offset the volume of accepted virtual demand within the ISO. This negated or greatly reduced the impact that virtual bids within the ISO would otherwise have on helping to converge day-ahead and real-time prices.
- Virtual bidding also exacerbated real-time energy imbalance offset costs by increasing the volume of transactions settled at these different hour-ahead and real-time prices. These costs are ultimately allocated to load-serving entities. Virtual bidding increased these imbalance offset costs, but often provided little or no benefits in terms of the primary objective of virtual bidding: to help improve convergence of day-ahead and real-time prices.

In response to these issues, the ISO filed with FERC in September to suspend convergence bidding on the inter-ties. Convergence bidding at inter-tie scheduling points was suspended effective November 28, 2011, pending further consideration of this issue by FERC.[57]

Although price convergence improved significantly over the course of 2011, analysis by DMM does not indicate this was attributable to convergence bidding. This is evidenced in part by the fact that virtual bidding volumes tended to decrease as priced convergence increased, and vice versa. Thus, while virtual bidders were responding to price divergences, this did not appear to have significant net effect

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[56] Inter-tie averages are calculated from February 1 through November 27, while internal locations are averaged from February 1 through December 31. Inter-tie convergence bids were suspended by FERC on November 28.

[57] See 137 FERC ¶ 61,157 (2011) accepting and temporarily suspending convergence bidding at the inter-ties subject to the outcome of a technical conference and a further commission order.

on improving price convergence due to the large volumes of offsetting virtual supply and demand bids. Instead, the improved price convergence appears to be primarily the result of improvements in market software, modeling and operational practices.

Background

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

- Participants with virtual demand bids accepted in the day-ahead market pay the day-ahead price for this virtual demand. Virtual demands at points within the ISO are then paid the real-time price for these bids. Virtual demand bids at inter-ties – representing virtual exports – are paid the hour-ahead price.
- Participants with accepted virtual supply bids are paid the day-ahead price for this virtual supply. Virtual supply at points within the ISO is then charged the real-time price. Virtual supply bids at inter-ties – representing virtual imports – are charged the hour-ahead price.

Thus, virtual bidding allows participants to profit by arbitraging the difference between day-ahead, hour-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. For instance:

- If prices in the real-time market tend to be higher than day-ahead market prices, convergence bidders will seek to arbitrage this price difference by placing virtual demand bids. Virtual demand will raise load in the day-ahead market and thereby increase prices. This increase in load and prices could also lead to commitment of additional physical generating units in the day-ahead market, which in turn could tend to reduce average real-time prices. In this scenario, virtual demand could help improve price convergence by increasing day-ahead prices and reducing real-time prices.
- If real-time market prices tend to be lower than day-ahead market prices, convergence bidders will seek to profit by placing virtual supply bids. Virtual supply will tend to lower day-ahead prices by increasing supply in the day-ahead market. This increase in virtual supply and decrease in day-ahead prices could also reduce the amount of physical supply committed and scheduled in the day-ahead market.[58] 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.

In practice, several aspects of the ISO's market design and performance prevented convergence bidding from working as intended in 2010:

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

- First, the way that imports and exports are dispatched and settled under the California market design is different from all other ISOs. In the hour-head market, the ISO re-optimizes hourly import and export schedules based on bid prices and projected conditions within the ISO the following operating hour. Unlike other ISOs, the ISO also settles these hourly inter-tie dispatches at prices resulting from the hour-ahead market rather than at 5-minute real-time prices.

- Second, during many time periods, average hour-ahead prices often tend to be predictably different than average real-time prices as a result of modeling and operational differences in these two markets. During many periods, net imports have often been reduced in the hour-ahead market at relatively low prices, while additional generation within the ISO has been dispatched at higher prices in the real-time market.[59] This pattern of "selling low and buying high" causes a revenue imbalance that is recovered from load-serving entities through the real-time imbalance offset charge.

As previously noted, these aspects of the ISO's market design and performance created two problems when convergence bidding was implemented in February 2010:

- The tendency for real-time prices to exceed day-ahead prices made virtual demand profitable at scheduling points within the ISO. Meanwhile, the tendency for hour-ahead prices to be predictably lower than day-ahead prices during many periods made it profitable for participants to submit large volumes of virtual imports. These virtual imports negated or greatly reduced the impact virtual bids within the ISO would otherwise have on helping to converge day-ahead and real-time prices.

- Virtual bidding also exacerbated real-time energy imbalance offset costs by increasing the volume of transactions settled at these different hour-ahead and real-time prices.

In response to these issues, the ISO filed with FERC in September to suspend convergence bidding on the inter-ties. Convergence bidding at inter-tie scheduling points was suspended effective November 28, 2011, pending further consideration of this issue by FERC.

4.1 Convergence bidding trends

Convergence bidding volumes increased steadily from the start of convergence bidding on February 1 until mid-April. After dropping in mid-April, convergence bidding volumes stabilized at a lower level until late November when convergence bidding volumes dropped sharply due to the suspension of convergence bidding at inter-tie nodes. Figure 4.1 shows the quantities of both virtual demand and supply offered and cleared in the market. As shown in Figure 4.1:

- On average, 55 percent of virtual supply and demand bids offered into the market cleared in 2011.

- Cleared volumes of virtual supply outweighed cleared virtual demand during most hours over the first ten months of convergence bidding. Virtual imports accounted for the bulk of virtual supply clearing the market, while virtual demand at scheduling points within the ISO accounted for almost all virtual demand.

- Starting in December, convergence bidding only occurred at scheduling locations within the ISO. During the first half of December, cleared virtual demand continued to exceed virtual supply clearing within the ISO. However, this bidding trend became unprofitable as real-time prices began

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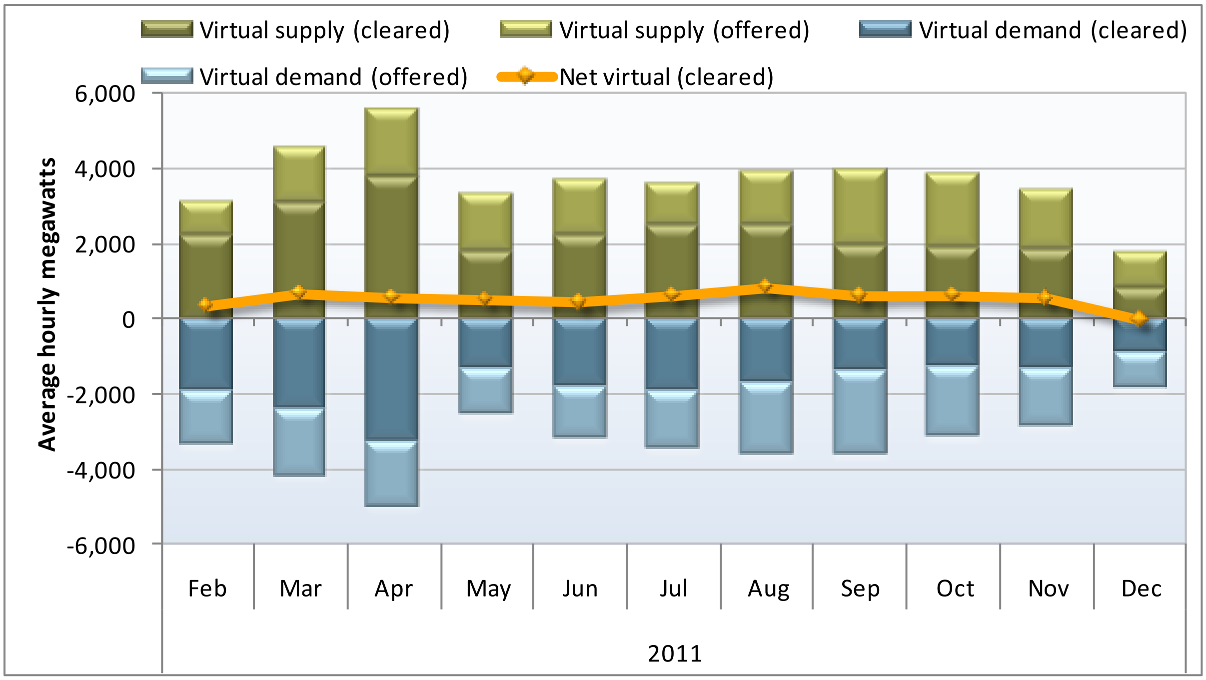
[59] As discussed in Section 2.2, this results from a combination of increased exports and decreased imports in the hour-ahead market.

to fall below day-ahead prices at the start of December. By mid-December, the amount of net cleared virtual bids within the ISO shifted from a demand position to net virtual supply. For the month, the virtual supply and demand positions were balanced on average.[60]

- Prior to suspension of inter-tie convergence bidding, the net amount of all accepted virtual bids averaged 58 MW of net virtual imports. After inter-tie virtual bids were suspended in late November, the net virtual position averaged 33 MW of internal demand.

Figure 4.1 Monthly average virtual bids offered and cleared



Offsetting virtual bids at internal and inter-tie scheduling points

Virtual supply at inter-ties and virtual demand at internal nodes made up 75 percent of the total gross virtual trading volumes in 2011. Figure 4.2 and Figure 4.3 show the average net cleared virtual positions on inter-ties and internal locations for each operating hour. As shown in these figures:

- From February through July, net cleared virtual bids on inter-ties represented virtual supply during most hours, particularly in off-peak hours (see Figure 4.2). At internal locations net cleared positions were predominantly virtual demand.

- During all hours, most or all of the virtual demand at locations within the ISO were offset by virtual imports. These are referred to as *offsetting* virtual positions since the impact of this internal virtual demand on day-ahead and real-time prices is completely offset by the impact of these virtual imports.

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[60] See details in *Quarterly Report on Market Issues and Performance*, Department of Market Monitoring, February 2012, p. 21, http://www.caiso.com/Documents/QuarterlyReport_Market%20Issues_Performance-February2012.pdf.

Figure 4.2 Average net cleared virtual bids at internal points and inter-ties (February-July)

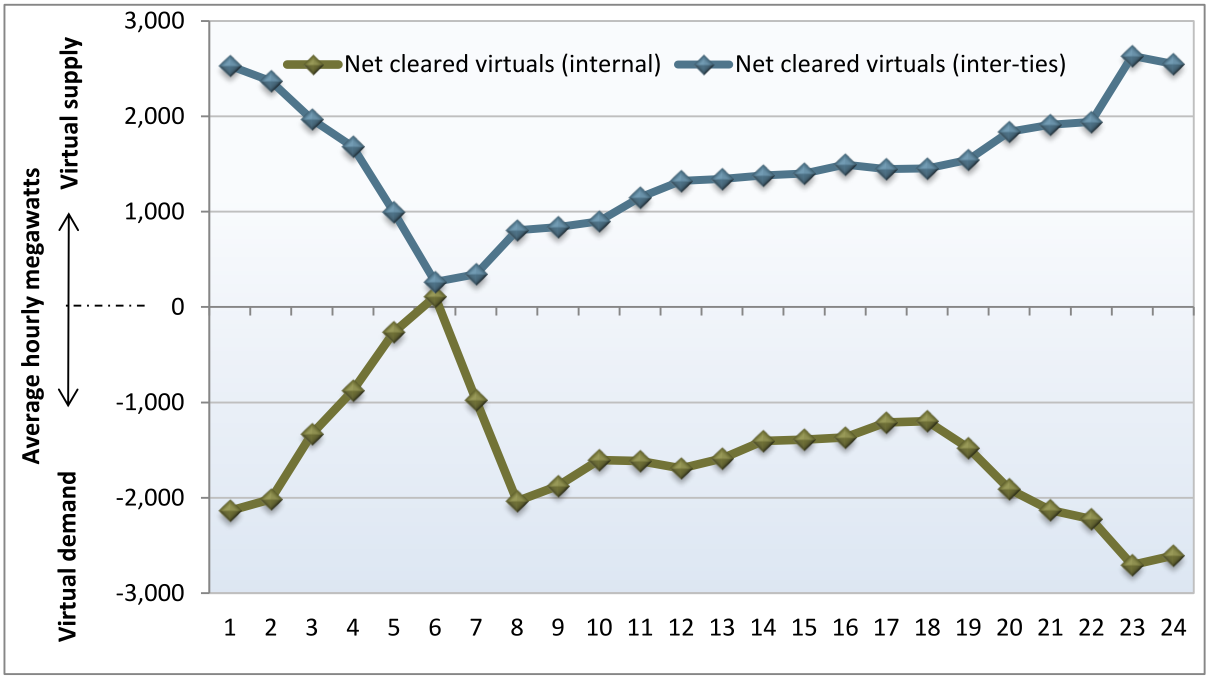
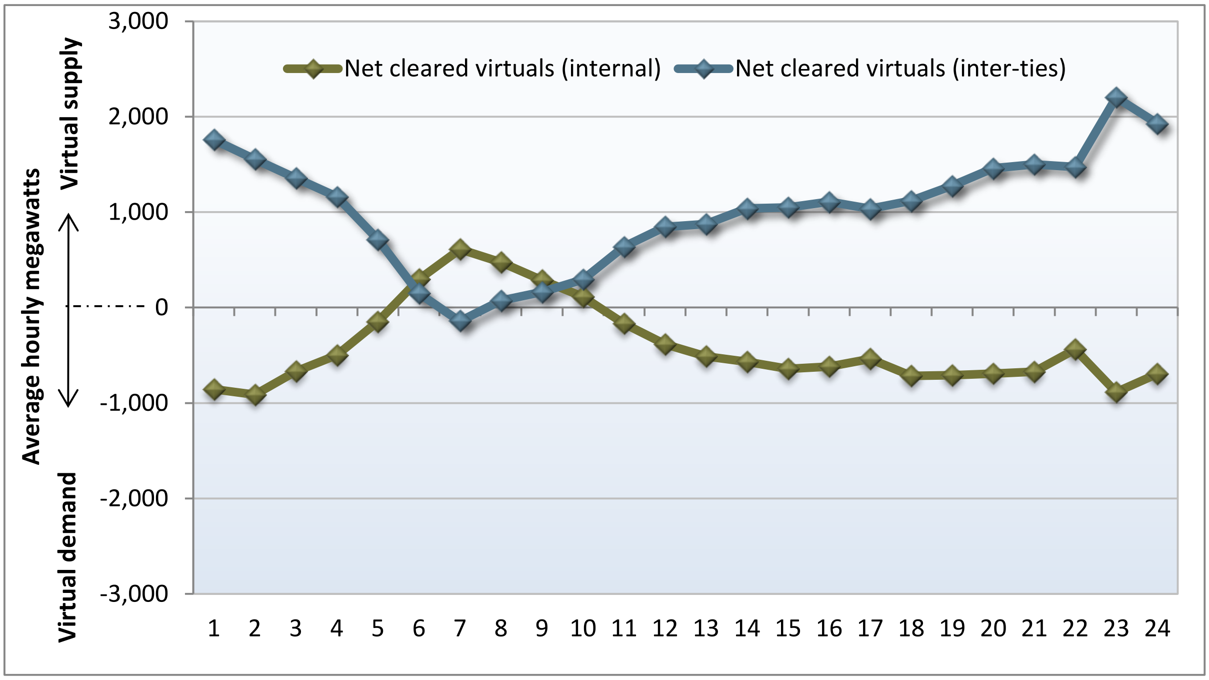


Figure 4.3 Average net cleared virtual bids at internal points and inter-ties (August-December)[61]



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[61] Inter-tie convergence bidding was suspended on November 28. Thus, the figure represents the inter-tie convergence bids through November 27. The figure represents internal convergence bidding through December.

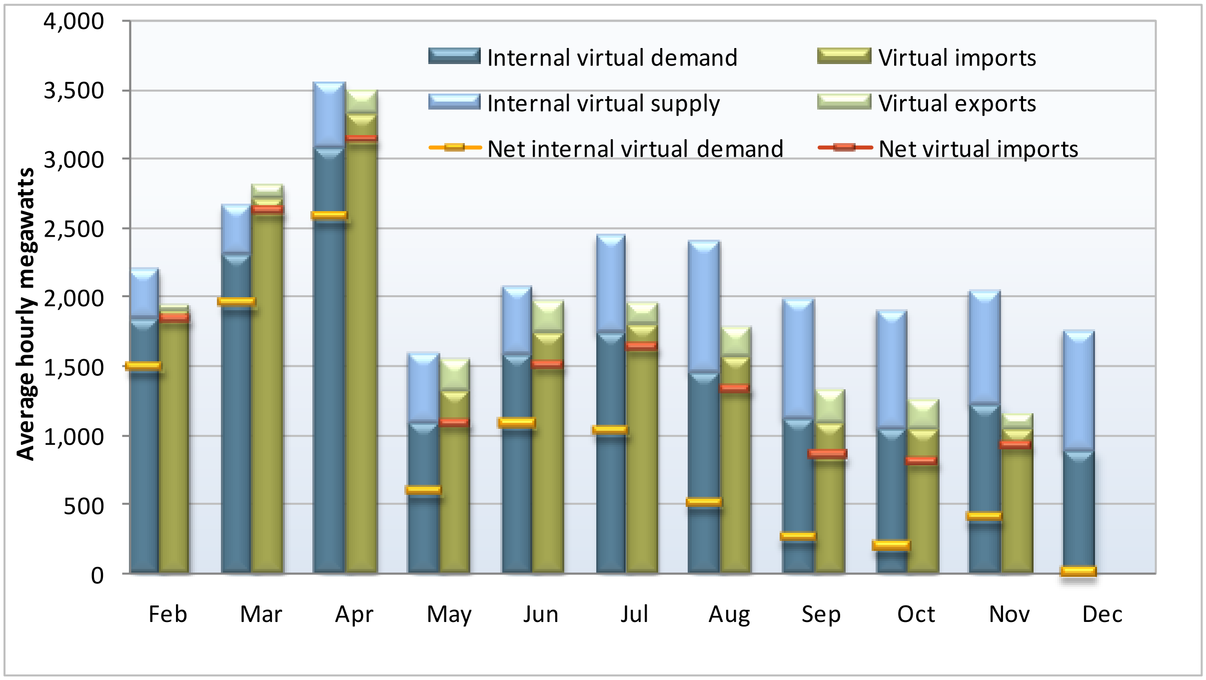
- In the second half of the year, the trend of net virtual supply on inter-ties and net virtual demand continued but the volumes of these offsetting virtual positions decreased (see Figure 4.3). Virtual imports dropped, but the trend of significant net virtual imports continued during all hours except for the morning ramping period (hours ending 6 to 10). Meanwhile, the net volume of cleared virtual bids within the ISO also dropped, but significant net internal virtual demand continued except in the morning ramping hours.

As shown in Figure 4.2 and Figure 4.3, during most hours the average net amount of virtual demand clearing within the ISO was slightly lower than the average amount of net virtual imports. These offsetting virtual positions tended to be profitable due to systematic divergences in day-ahead, hour-ahead and real-time prices, but provided little or no improvement in convergence of day-ahead and real-time prices. The potential benefit of internal virtual demand is to improve price convergence between the day-ahead and real-time markets by increasing prices and unit commitment in the day-ahead market. However, these potential benefits of internal virtual demand were negated in most hours by the larger volume of net virtual import bids clearing the market.

Figure 4.4 provides a direct comparison of accepted virtual supply and demand bids at internal points with virtual imports and exports clearing the market during each month. As shown in this figure:

- Convergence bidding on inter-ties (shown in green) consistently resulted in net virtual supply in the day-ahead market.
- Convergence bidding on internal locations (shown in blue) typically resulted in additional virtual demand.
- The average hourly volume of net virtual imports exceeded net demand within the ISO in all months until virtual bidding on inter-ties was suspended in December 2011. This illustrates how virtual imports consistently offset the impact of net virtual demand within the ISO in the day-ahead market during most hours until virtual bidding on inter-ties was suspended.
- The volume and portion of virtual supply at internal nodes increased gradually after the first three months of virtual bidding. Analysis by DMM indicates that most virtual supply at internal scheduling points was directly offset by virtual demand at a different internal scheduling point by the same participant. These offsetting virtual supply and demand bids at internal points reflect use of virtual bidding to hedge or profit from internal congestion within the ISO.
- Starting in December, convergence bidding only occurred at scheduling locations within the ISO. During the first half of December, cleared virtual demand continued to exceed virtual supply clearing within the ISO. However, this bidding trend became unprofitable as real-time prices began to fall below day-ahead prices at the start of December. By mid-December, the amount of net cleared virtual bids within the ISO shifted from a demand position to net virtual supply. For the month, the virtual supply and demand positions were balanced.

Figure 4.4 Average monthly cleared convergence bids at inter-ties and internal locations



From the start of convergence bidding until the suspension of virtual bidding on inter-ties, numerous market participants placed virtual supply bids at the inter-ties in combination with an equal virtual demand position at internal locations. These are referred to as *offsetting* virtual positions by the same participant. In this case, the impact of the participant's internal virtual demand on day-ahead and real-time prices is completely offset by the impact of the participant's virtual imports. However, this bidding pattern enables the participant to profit from the tendency for hour-ahead prices to be predictably lower than real-time prices during many periods.[62]

Figure 4.5 shows the weekly volume of offsetting virtual positions on inter-ties and scheduling points within the ISO. The blue bars represent the average cleared virtual bids associated with offsetting positions by the same market participant. The green bars represent the remaining aggregate level of offsetting virtual positions at inter-ties and internal locations attributable to different market participants placing offsetting positions.[63]

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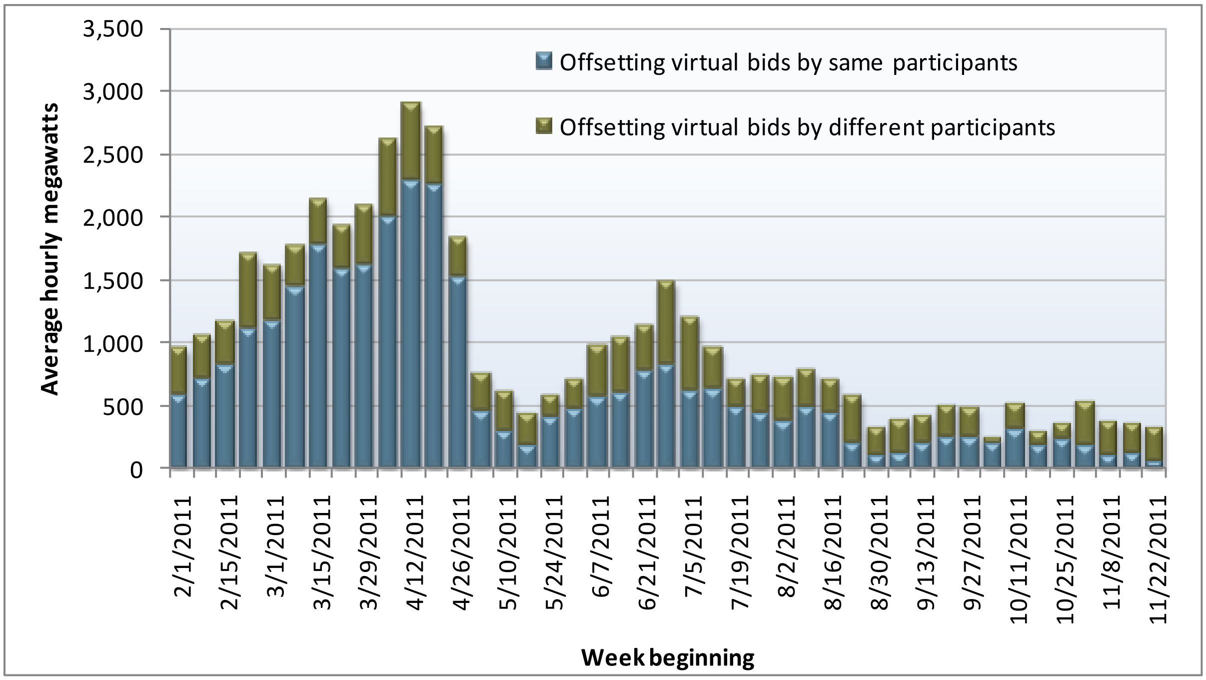
[62] For example, assume that a participant employing this bidding strategy has bids accepted for 100 MW of virtual imports and 100 MW of virtual demand within the ISO at the day-ahead price of $50/MW. The cost paid by the participant for this 100 MW of virtual demand ($5,000) is equal to the revenues received for the 100 MW of virtual imports. As previously noted, these offsetting virtual supply and demand bids also have no impact on the net supply or demand in the day-ahead market. However, the participant then profits whenever the hour-ahead price is lower than the real-time price. For instance, if the hour-ahead price is $45/MW and the real-time price is $55/MW, the participant receives $5,500 for its internal virtual demand (100 MW x $55/MW), and is charged $4,500 for its virtual import bids (100 MW x $45/MW). Thus, the participant earns a profit of $1,000 when these virtual bids are liquidated at these different hour-ahead and real-time prices.

[63] Substantial amounts of offsetting virtual positions also occurred when different market participants place virtual demand bids within the ISO that were offset by virtual import bids placed by different participants. These bids can result from the market activity of different participants seeking to profit. These positions are independent of one another and are not a direct strategy to profit from offsetting bids.

- Offsetting virtual positions by the same participant have accounted for the bulk of all offsetting virtual positions occurring since the start of convergence bidding. Almost all of these offsetting positions consisted of virtual imports that offset internal virtual demand.
- There was a sharp drop in offsetting positions in mid-April. This decrease corresponds to two events. At this time, the ISO expressed concern about the volume of offsetting virtual demand and imports bids and initiated a stakeholder process to address this issue. In addition, systematic predictable differences in day-ahead, hour-ahead and real-time prices began to decrease.
- The use of offsetting virtual positions by individual market participants increased slightly in June and July, but continued to decline until the suspension of the inter-ties in late November.

As shown in Figure 4.5, substantial amounts of offsetting virtual positions also occurred when different market participants placed virtual demand bids within the ISO that were offset by virtual import bids placed by different participants. These offsetting virtual bids can result from the market activity of different participants independently responding to differences between day-ahead prices and prices in the hour-ahead and real-time markets. However, the impact of these offsetting bids on overall market outcomes is the same: these offsetting bids do not add any net supply or demand to the day-ahead market, but can exacerbate real-time imbalance offset charges when hour-ahead prices diverge from real-time prices.

Figure 4.5 Average hourly virtual imports offsetting virtual internal demand



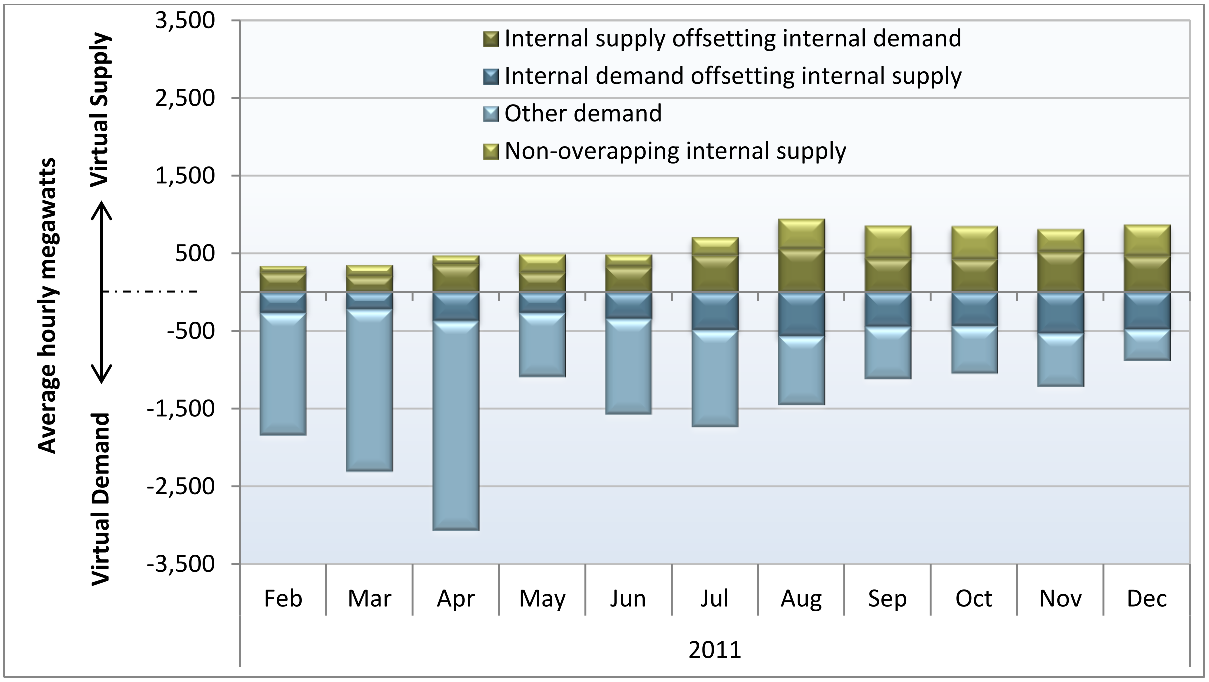
Offsetting virtual supply and demand bids at internal points

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

Figure 4.6 shows the average hourly volume of offsetting virtual supply and demand positions at internal locations. The dark blue and dark green represent the average hourly overlap between internal demand and internal supply by the same participants.[64] The light blue bars represent the remaining portion of internal virtual supply that were not offset by internal virtual demand by the same participants. The light green bars represent the remaining portion of internal virtual demand that was not offset by internal virtual supply by the same participants. As shown in Figure 4.6:

- During the first five months of convergence bidding, this type of offsetting virtual position at internal locations accounted for about 27 percent of all cleared internal virtual bids. During this period, most of the other internal virtual demand clearing the market was offset by virtual imports submitted by the same participant, as previously depicted in Figure 4.5. The amount of virtual supply at internal locations that was not paired with internal virtual demand by the same participant was minimal.
- Over the course of the year, the amount of such offsetting internal virtual bidding positions taken by participants grew in volume and as a share of total internal virtual bids. For July through the rest of the year, the share of offsetting internal virtual positions increased to 61 percent of the internal positions. This suggests that virtual bidding was increasingly used to hedge or profit from internal congestion.

Figure 4.6 Average hourly offsetting virtual supply and demand positions at internal points



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[64] When calculating the overlap between each participant's accepted virtual supply and demand bids at internal points each hour, we did not include the portion (if any) of the participant's internal virtual demand bids that were offset by accepted virtual import bids by that participant (as shown in Figure 4.5). This was done to avoid any potential double counting of internal virtual demand as offsetting virtual imports and virtual supply within the ISO during the same hour.

Other uses of virtual bidding on interties

Some participants opposing the suspension of virtual bidding on inter-ties have contended that this market feature can be used in two ways to hedge risks associated with physical imports scheduled into the ISO. However, analysis by DMM indicates that use of virtual bidding at inter-ties for these purposes has been non-existent or minimal.

- **Hedging delivery risks for imports scheduled in day-ahead market**. After a supplier schedules an import in the day-ahead market, the intended source of this import may become unavailable prior to the hour-ahead market (e.g., due to a transmission or generation outage or de-rate). Under this scenario, the supplier may need to buy back this schedule in the hour-ahead market. If the supplier is concerned that hour-ahead prices may be higher than day-ahead prices, they could schedule the import in the day-ahead market but also place a virtual export bid on that same inter-tie. The net effect of this is to allow the import to be scheduled in the day-ahead market, but earn the hour-ahead price. However, analysis by DMM did not identify any virtual inter-tie bids that appear to have been utilized in this manner.

- **Facilitating imports of intermittent renewables.** One participant has indicated that they have used virtual bidding on inter-ties to facilitate imports of renewable energy. Under this scenario, a supplier would submit a virtual import in the day-ahead market equal to the expected output of an intermittent renewable resource. In the hour-ahead market, the participant would then schedule the revised forecast of the expected output from the intermittent renewable resource as a physical import. This allows the supplier to earn the day-ahead inter-tie price for most of the actual output of the renewable resource, but to wait and purchase transmission based on the revised hour-ahead forecast of the output of the renewable resource being imported into the ISO. However, analysis by DMM indicates that any use of virtual inter-tie bids for this purpose was minimal.

4.2 Convergence bidding profits

Figure 4.7 shows total monthly net profits paid for accepted virtual supply and demand bids. As shown in this figure:

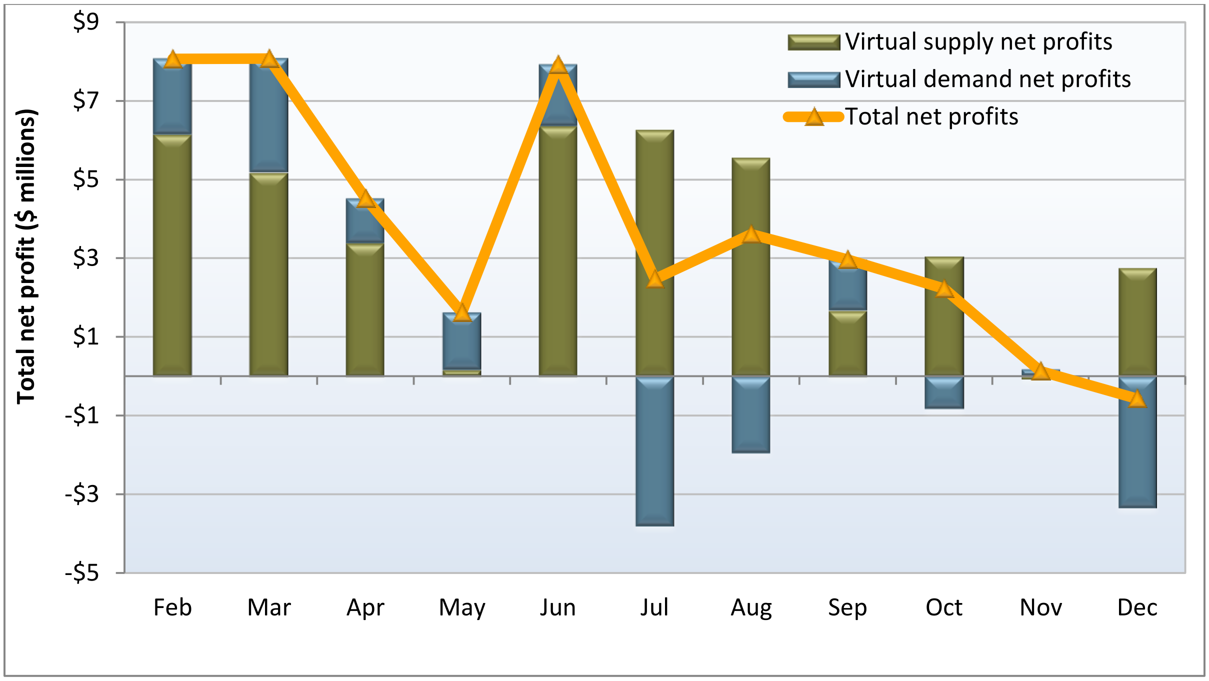
- Virtual supply positions have resulted in net profits in all months. This trend reflects the fact that virtual imports account for most virtual supply, and that virtual imports have been highly profitable because hour-ahead prices have been predictably lower than day-ahead prices in many hours.

- Virtual demand positions were consistently profitable for the first five months of convergence bidding, but have since varied from being profitable or unprofitable from one month to the next. This trend reflects how real-time prices were predictably higher than day-ahead prices during the first half of 2011, but have been much more consistent with day-ahead prices in the second half of the year.

- Total profits paid to virtual bidders tended to decrease over the course of the year. Total net profits were near zero in November and negative in December. This reflects the reduction in predictable differences between day-ahead, hour-ahead and real-time markets that occurred in the second half of the year.

- Over the course of the year, net profits paid to convergence bidding entities totaled around $41 million. Most of the profits ($28 million) came from virtual supply on inter-ties, or virtual imports. About $13 million in profits were received by virtual bids at internal locations. Most of these profits were for virtual demand bids at locations within the ISO.

Figure 4.7 Total monthly net profits from convergence bidding



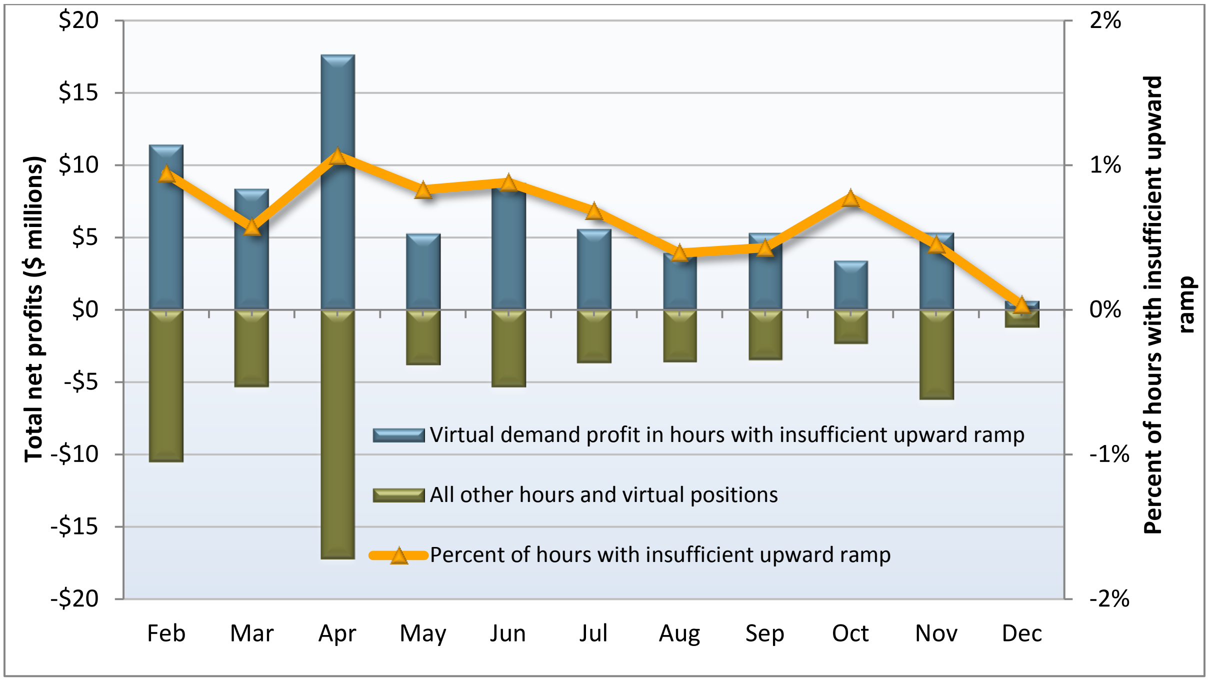
Net profits at internal scheduling points

Since the start of convergence bidding in February, virtual demand accounted for about 70 percent of cleared bids at internal locations. Virtual demand bids at internal nodes are profitable when real-time prices spike in the 5-minute real-time market. Almost all profits from these internal virtual demand positions have resulted from a relatively small portion of intervals when the system power balance constraint becomes binding due to insufficient upward ramping capacity.

Figure 4.8 compares total profits from internal virtual bids during hours when the power balance constraint was binding due to short-term shortages of upward ramping capacity with the overall profitability of internal virtual bids during all other hours. As shown in Figure 4.8:

- Although upward ramping capacity was insufficient during less than 1 percent of hours each month, these hours accounted for all net profits from internal virtual demand. Profits from virtual demand during these brief but extreme price spikes can be high enough to outweigh losses when the day-ahead price exceeds the real-time market price. In fact, having a single 5-minute interval price spike can yield enough aggregate income to compensate for losses in the remaining hours of the day.
- During the other 99 percent of hours when sufficient ramping capacity was available, virtual demand bids were highly unprofitable. In December, the frequency of real-time price spikes decreased significantly. As result, the profitability of internal virtual bids decreased to about zero.

Figure 4.8 Convergence bidding profits from internal scheduling points



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

- As discussed in prior sections of this chapter, the impact of virtual internal demand in the day-ahead market was completely offset during most hours by virtual imports.
- Any additional capacity available to convergence bidding may not be enough to address the short-term ramping limitations.

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

Improvements in operational practices, market software and implementation of the flexible ramping constraint helped decrease the frequency of extreme price spikes in December. As a result, virtual demand positions became less profitable and ultimately participants shifted to a virtual supply position during the second half of December.

Figure 4.9 and Figure 4.10 compare cleared convergence bidding volumes with the volume weighted average price differences at which these virtual bids were settled. The difference between day-ahead and real-time prices shown in Figure 4.9 represents the average price difference weighted by the amount of virtual bids clearing at different internal locations. As shown in Figure 4.9:

- During months when the red line in Figure 4.9 is negative, this indicates that the weighted average price charged for internal virtual demand in the day-ahead market was lower than the weighted average real-time price paid for this virtual demand. Internal virtual demand volumes were consistent with weighted average price difference for the hours in which this virtual demand cleared the market in all months except July, August, October and December. On average, these virtual demand positions were profitable most months.

- During months when the yellow line in Figure 4.9 is positive, this indicates that the weighted average price paid for internal virtual supply in the day-ahead market was higher than the weighted average real-time price charged when this virtual supply was liquidated in the real-time market. Beginning in May and continuing through most of the rest of the year, virtual supply at internal locations was consistently profitable.
- As previously noted, a large portion of the internal virtual supply clearing the market was paired with internal demand bids at different internal locations by the same market participant. Such offsetting virtual supply and demand bids are likely used as a way of hedging or profiting from internal congestion within the ISO. When virtual supply and demand bids are paired in this way, one of these bids may be unprofitable independently, but the combined bids may break even or are profitable due to congestion.

The difference between day-ahead and hour-ahead prices in Figure 4.10 shows the average price difference weighted by the amount of virtual imports and exports clearing on different inter-ties. As shown in Figure 4.10:

- During months when the yellow line in Figure 4.10 is positive, this indicates that the weighted average price paid for virtual imports in the day-ahead market was lower than the weighted average hour-ahead price paid when these virtual imports were liquidated in the hour-ahead market. In every month, the weighted average price difference for virtual imports was positive, which is consistent with large virtual supply positions at inter-ties. These virtual supply positions were consistently profitable.
- With the exception of May and September, the weighted average price difference for virtual export bids was also positive. These virtual demand positions were unprofitable on average. However, as shown in Figure 4.10, the volume of accepted virtual export bids was extremely low.

Figure 4.9 and Figure 4.10 help to reinforce two points.

- First, structural differences in the hour-ahead and 5-minute real-time markets can create situations where virtual supply at inter-ties and virtual demand positions at internal locations can both be profitable at the same time. These structural differences can lead to uplifts, known as real-time imbalance offset charges, which are allocated to load-serving entities (see Section 4.4).
- Second, participants will take advantage of differences in price convergence by switching from virtual supply to virtual demand positions depending on the hour, as highlighted in Figure 4.2 and Figure 4.3.

Figure 4.9 Convergence bidding volumes and weighted price differences at internal locations

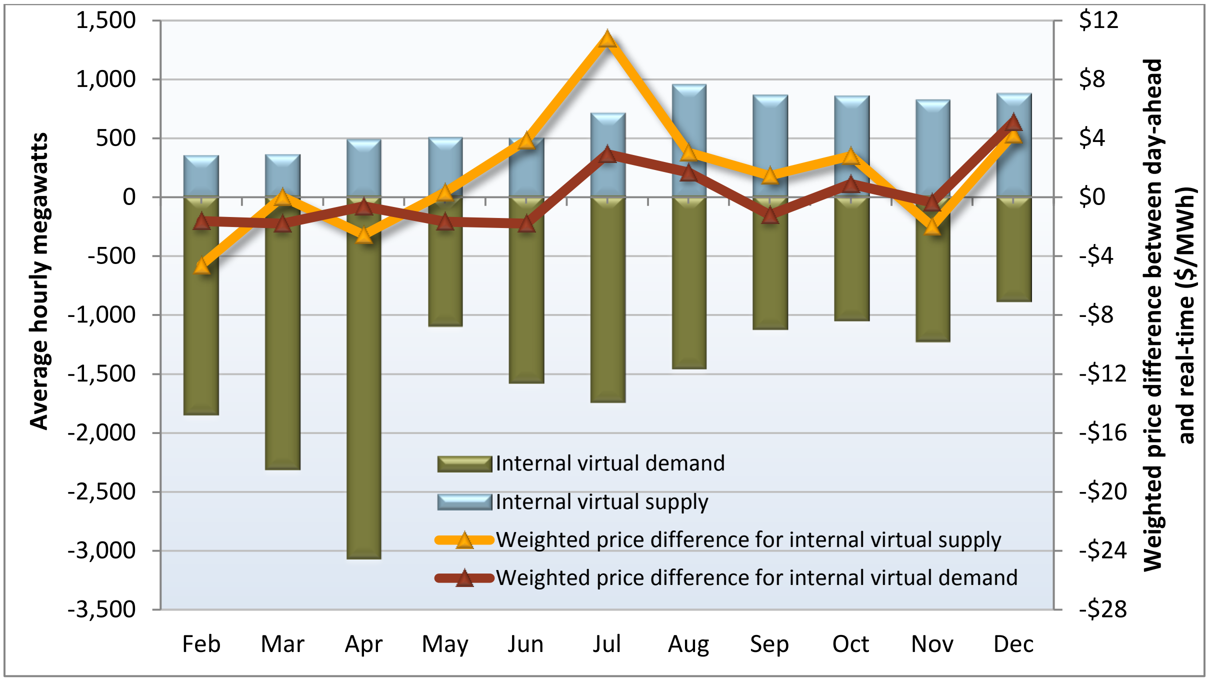
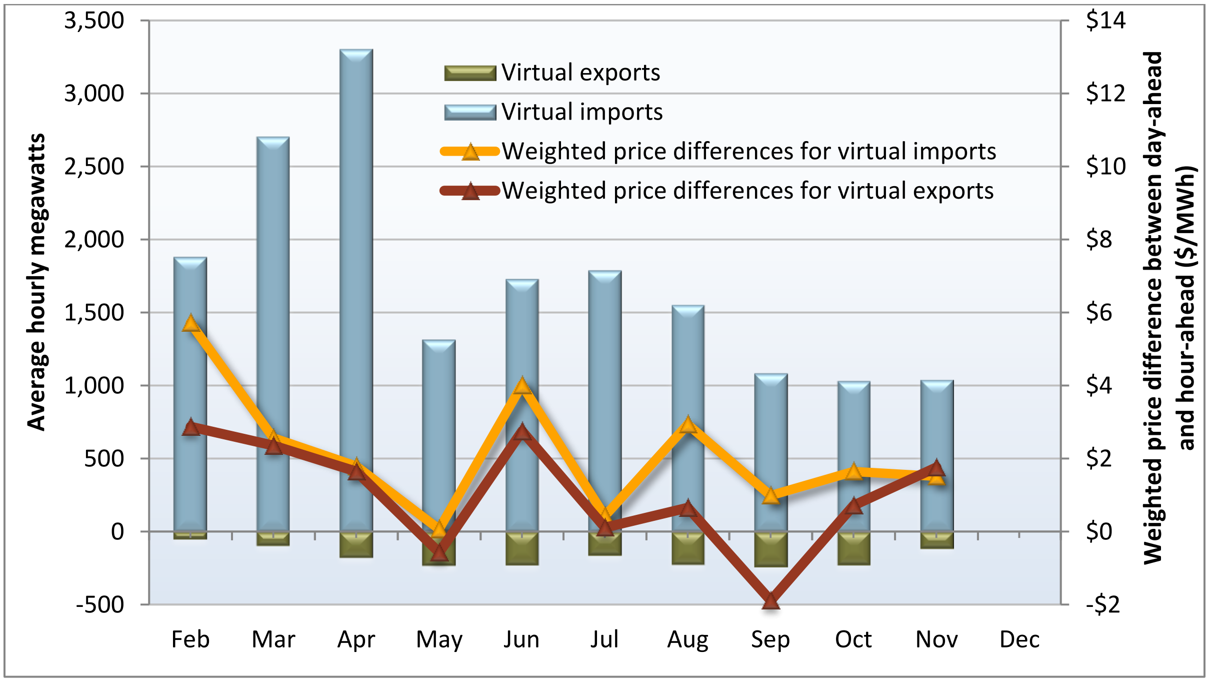


Figure 4.10 Convergence bidding volumes and weighted price differences at inter-ties



4.3 Changes in unit commitment

If physical generation resources clearing the day-ahead energy market are less than the ISO's forecasted demand, the residual unit commitment ensures that enough additional capacity is available to meet the forecasted demand. As previously shown, virtual supply clearing the day-ahead energy market consistently exceeded virtual demand. As a result, more residual unit commitment capacity was needed to replace the net virtual supply with physical supply. This is likely to have increased both the direct capacity procurement costs and bid cost recovery payments associated with residual unit commitment. As noted in Section 2.4, total direct residual unit commitment costs reached $1.1 million in 2011, up from $83,000 in 2010. Bid cost recovery payments for capacity committed in the residual unit commitment process were also up in 2011, totaling $6.1 million compared to $1.4 million in 2010.

4.4 Real-time imbalance offset charges

Real-time imbalance offset charges are a form of market uplift that have been exacerbated by price differences and convergence bidding. Imbalance offset charges arise when the amount collected from virtual supply in one market is insufficient to cover the payments to virtual demand in the other market. This occurs because prices in the hour-ahead and 5-minute real-time markets have historically been different. The resulting uplift costs are made up by load-serving entities.

When virtual supply and virtual demand positions offset each other, net profits paid for these revenues are determined by the difference between real-time and hour-ahead price differences.[65] At the start of the convergence bidding market, 5-minute real-time prices were higher on average than hour-ahead prices. The volume of offsetting virtual positions also increased dramatically at the start of the convergence bidding market, as shown in Figure 4.5. Over the course of the year, the volumes of balanced offsetting positions decreased as 5-minute real-time prices converged closer with hour-ahead prices. Furthermore, as price convergence improved, real-time imbalance offset costs also decreased.

Figure 4.11 shows the estimated real-time imbalance cost associated with virtual supply on inter-ties that offset virtual demand at internal locations, along with total real-time imbalance offset charges.

- DMM estimates that charges associated with offsetting virtual positions totaled $57 million in 2011, or about 40 percent of the total imbalance offset costs. These costs totaled about $44 million from February through June, and fell to about $13 million between July and November.[66]
- Total real-time imbalance offset costs were $88 million between February and June. These costs decreased to $66 million in the second half of 2011.

The decrease in these real-time imbalance offset costs reflects an improvement in price convergence in the second half of 2011, as well as decrease in offsetting virtual supply and demand bids settling at different hour-ahead and real-time prices.

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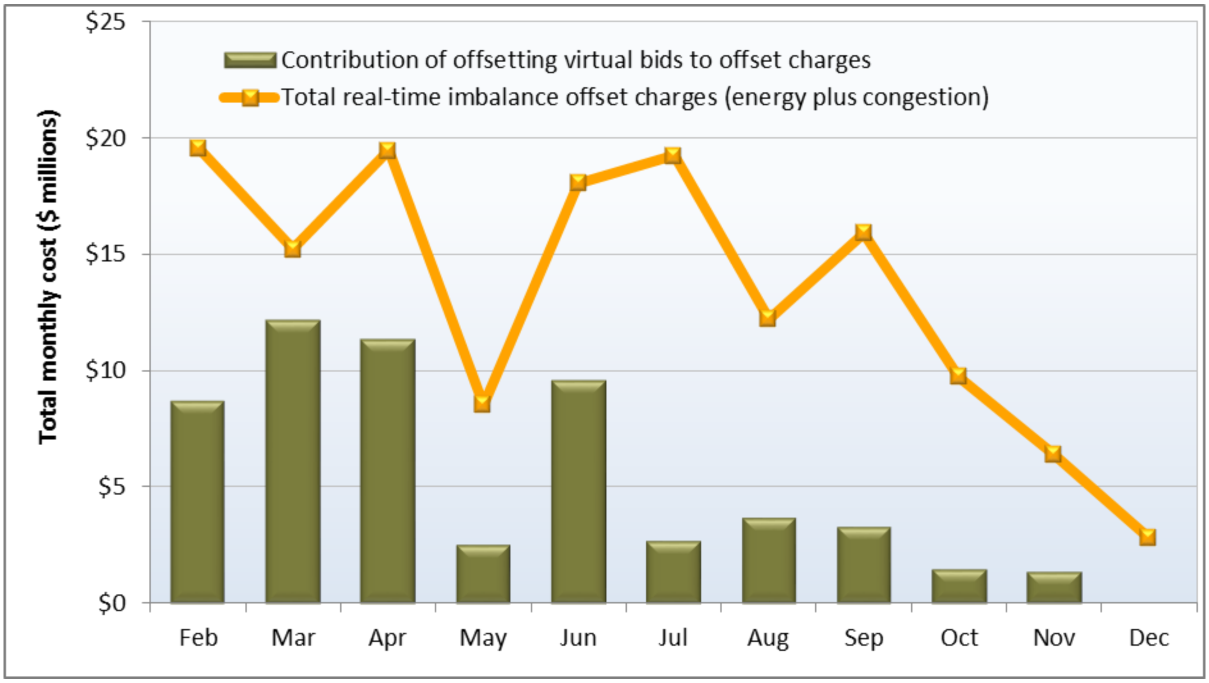
[65] For the most part, the day-ahead component is offset by virtual demand and virtual supply schedules as what they receive and pay are essentially the same. The only difference in net day-ahead revenues created from offsetting virtual supply and demand bids results from differences in congestion and losses, which have typically been minor.

[66] There were no imbalance costs for offsetting virtual positions in December as convergence bidding at the inter-ties was suspended in late November.

Figure 4.11 Contribution of offsetting virtual supply and demand to real-time imbalance charges



5 Ancillary services

The ancillary service market continued to perform efficiently and competitively in 2011, despite an increase in ancillary service market costs:

- Ancillary service costs increased to about $139 million, representing a 61 percent increase over 2010. Ancillary service costs were up from about 1 percent of total wholesale energy costs to about 1.9 percent of total energy costs.
- This increase was driven primarily by a drop in ancillary services from hydro-electric generation during the spring and early summer periods. During this period, high runoff required that many hydro resources provide energy instead of ancillary services. This required increased reliance on higher priced ancillary services from thermal units and more capacity not owned or contracted by load-serving entities.
- The value of self-provision of ancillary services accounted for about $33 million in 2011 compared to only $13 million in 2010.[67] This reflects how load-serving entities are somewhat hedged from higher ancillary service costs by the hydro-electric and gas resources they control.
- There were a total of 24 intervals with ancillary service scarcity pricing events in 2011. In total, DMM estimates that the direct cost of these events were minimal, about $60,000.
- In August, the ISO implemented a process to dynamically award ancillary services in the day-ahead and real-time markets based on an optimization of operational ramp rate segments compared to single fixed ancillary service ramp rates. This process was designed to make day-ahead ancillary services feasible with day-ahead energy schedules and ramp rates.

A detailed description of the ancillary service market design implemented in 2009 is provided in DMM's 2010 annual report.[68] This market design includes co-optimization of energy and ancillary service bids provided by each resource. Co-optimization considers the lost opportunity cost of providing one product (energy or ancillary service) over the other when determining prices.

5.1 Ancillary service costs

As shown in Figure 5.1, ancillary service costs increased to about $0.63/MWh of load served in 2011, up from $0.37/MWh of load served in 2010. This represents ancillary service costs of about 1.9 percent of total wholesale energy market costs, compared to about 1 percent over the last two years since the ISO's new market design has been in place.

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[67] 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. This value is calculated at the cost loads would have paid for the self-provided ancillary services.

[68] *2010 Annual Report on Market Issues and Performance*, April 2011, pp. 139-142: http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf.

Figure 5.1 Ancillary service cost as a percentage of wholesale energy cost (2006 – 2011)

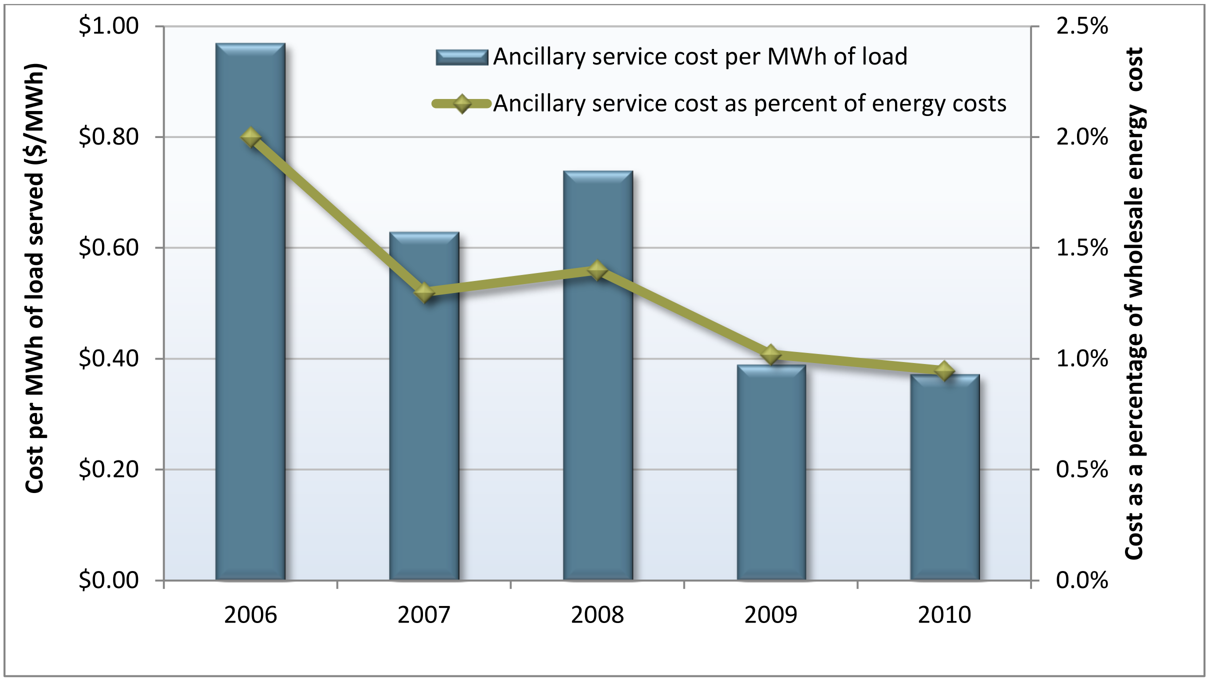


Figure 5.2 shows the cost of ancillary services by quarter during 2011. During the second quarter of 2011, ancillary services cost per MW load served reached about $1/MW – the highest level since the implementation of the nodal market design in April 2009. This represents about 3.5 percent of total energy costs during the second quarter. By the fourth quarter, ancillary service costs fell to $0.40/MWh, representing a little over 1 percent of total wholesale energy costs.

The increase was driven primarily by the high level of hydro runoff during the spring and early summer months, which required hydro-electric generation to produce electricity rather than provide ancillary services. This resulted in high overall ancillary service prices in both the day-ahead and real-time markets.

Historically, ancillary service costs have peaked in the spring and summer months. Figure 5.3 shows that ancillary service costs in the first two quarters of 2011 were close to costs during the last three years prior to implementation of the new market design (2006 to 2008). A sharp decline in costs after the second quarter brought the overall cost closer to the level of ancillary service costs incurred during these months over the last two years the nodal market design has been in place.

Figure 5.2 Ancillary service cost by quarter

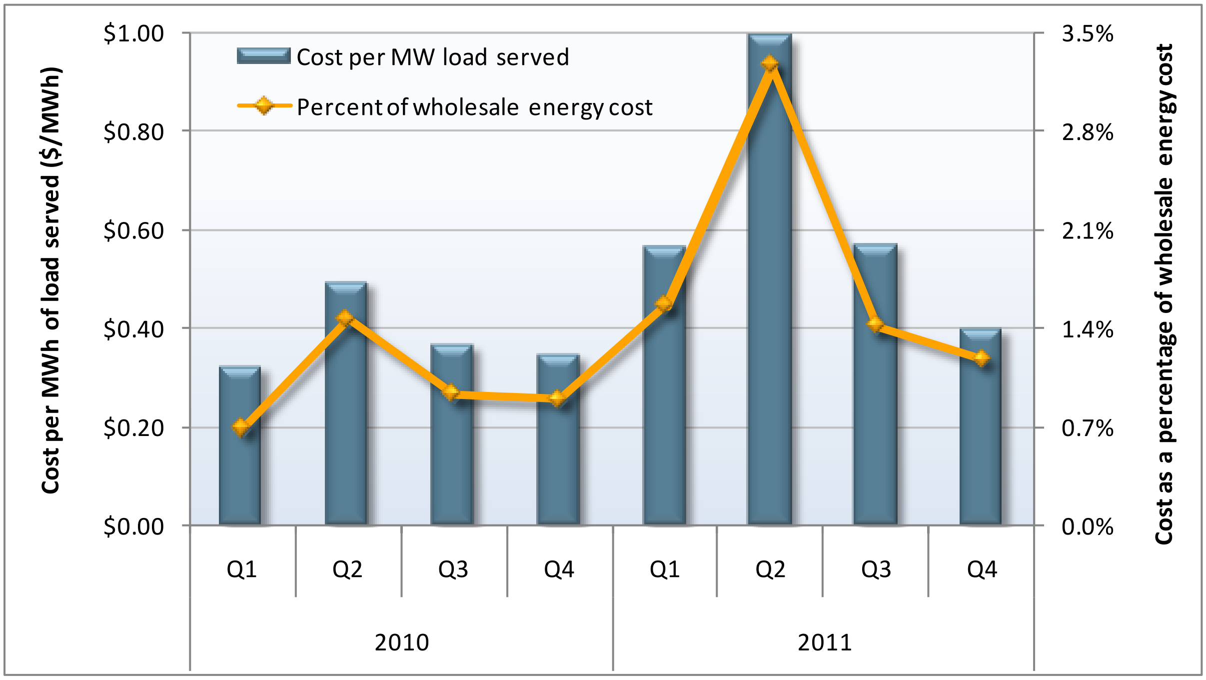
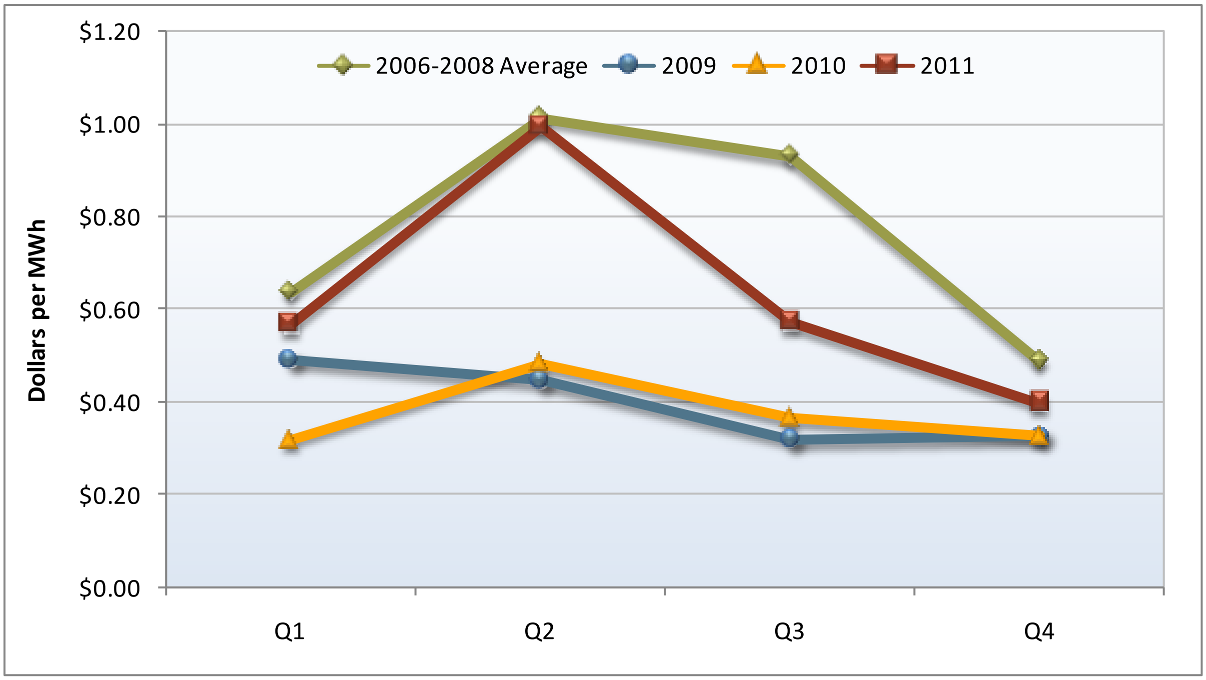


Figure 5.3 Ancillary service cost per MWh of load (2006 – 2011)



5.2 Procurement

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

The average hourly real-time operating reserve requirement was 1,617 MW in 2010 and 1,712 MW in 2011, which is about a 6 percent increase from the 2010 level. This requirement is typically set by 5 percent of forecasted demand met by hydro-electric resources plus 7 percent of forecasted demand met by thermal resources.[69] Thus, the requirements follow a seasonal load pattern with higher requirements during the peak load months.

The average hourly requirement for regulation up and regulation down was slightly lower in 2011. The requirement for regulation up and down is implemented by an algorithm based on inter-hour forecast and schedule changes. The average hourly real-time regulation down requirement was 341 MW in 2011, compared to 330 MW in 2010. The average hourly real-time regulation up requirement was 339 MW, compared to 356 MW in 2010.

Figure 5.4 shows the portion of ancillary services procured from different types of resources. Ancillary service requirements can be met by a combination of internal resources and imports. However, ancillary service imports are indirectly limited by minimum requirements set for procurement of ancillary services from within the ISO. As shown in Figure 5.4, imports and internal natural gas resources provided a slightly larger portion of ancillary services in 2011:

- Total imports, which include dynamic transfers, for all ancillary services increased from 349 MW in 2010 to 433 MW in 2011.
- In 2011, 29 percent of the regulation up resources came from imports, down from 33 percent in 2010.
- Imports accounted for 14 percent of spinning and non-spinning reserve capacity in 2011, compared to 8 percent in 2010.
- The contribution of hydro resources towards ancillary services decreased from 2010 to 2011. This decrease occurred as above average hydro generation was used to provide energy rather than ancillary services. Overall, average ancillary service procurement from hydro units decreased by around 14 percent in 2011 compared to 2010.
- The decline in the contribution of hydro resources for ancillary services was most prominent in the late spring months. In the second quarter of 2011, the contribution of ancillary services from hydro units declined by around 19 percent compared to the same quarter in 2010. Correspondingly, gas-fired ancillary services increased by 12 percent for the same period. Most gas fired ancillary services are non-spin. When reviewing the increase in the other ancillary services, gas-fired reserves increased by almost 60 percent in the second quarter of 2011 relative to the same period in 2010.

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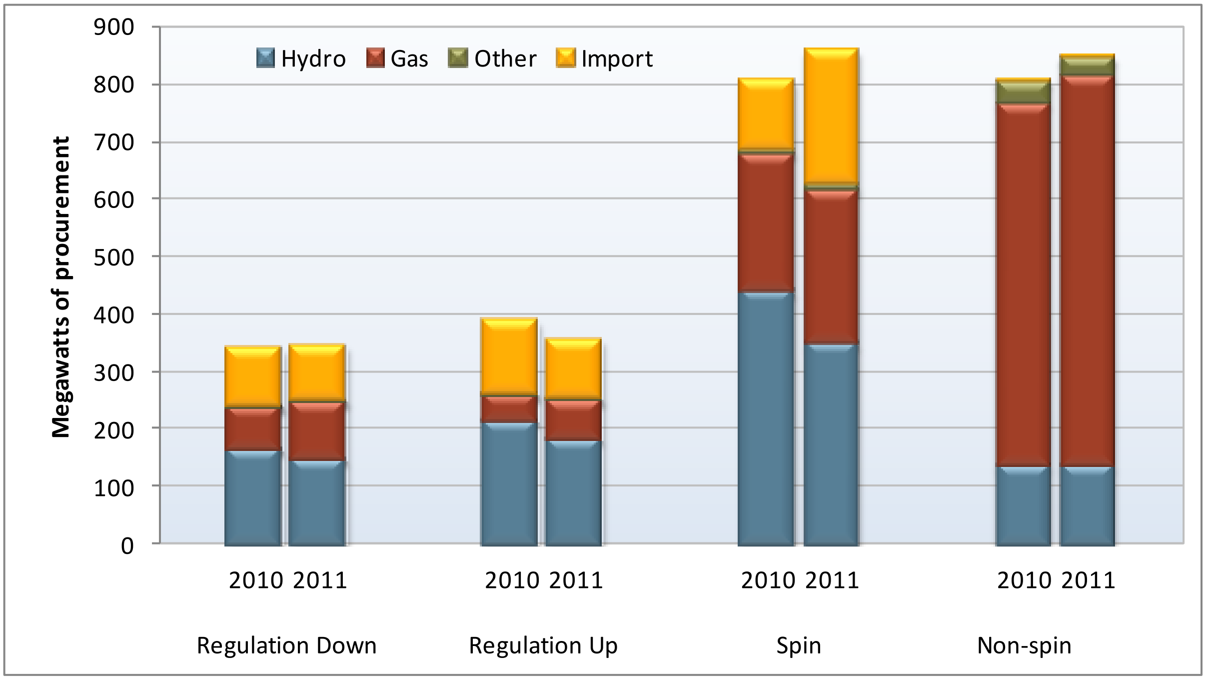
[69] Because of the magnitude of demand, the 5 and 7 percent are typically larger than the single largest contingency, which can also set the requirement.

- For all ancillary services other than spin, gas-fired reserves filled the ancillary service deficit created by hydro generation by increasing 11 percent in 2011 compared to 2010. For spin, imports offset the reduction in hydro-electric spinning reserves.

With respect to imports, ancillary services bid across the inter-ties have to compete for transmission capacity with energy. If an inter-tie becomes congested, the scheduling coordinator awarded ancillary services will be charged the congestion rate. As noted above, requirements also put limitations on ancillary service procurement from imports. Thus, most ancillary service requirements continue to be met by ISO resources.

Figure 5.4 Procurement by internal resources and imports



5.3 Ancillary services pricing

Resources providing ancillary services receive a capacity payment, or market clearing price, in both the day-ahead and real-time markets. Capacity payments in the real-time market are only for incremental capacity above the day-ahead award. Figure 5.5 and Figure 5.6 below show the weighted average market clearing prices for each ancillary service product by quarter in the day-ahead and real-time markets in 2010 and 2011.

Overall, 2011 average quarterly day-ahead prices ranged from approximately $0.50/MW to $18.50/MW, peaking during the second quarter. As noted, high hydro conditions caused the high prices from April to June. This occurred as reserve capacities from hydro units that typically bid relatively low prices were reduced when hydro units provided energy instead. Therefore, more ancillary service capacity needed to be procured from non-hydro units at a higher price.

Figure 5.5 Day-ahead ancillary service market clearing prices

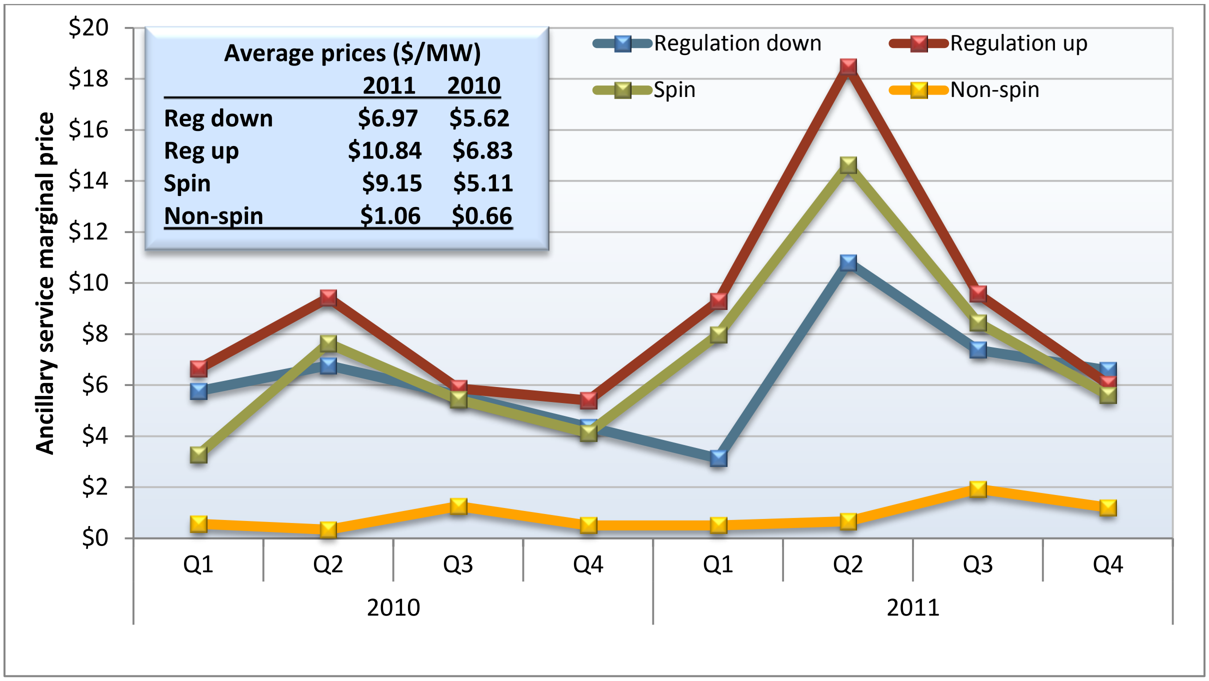
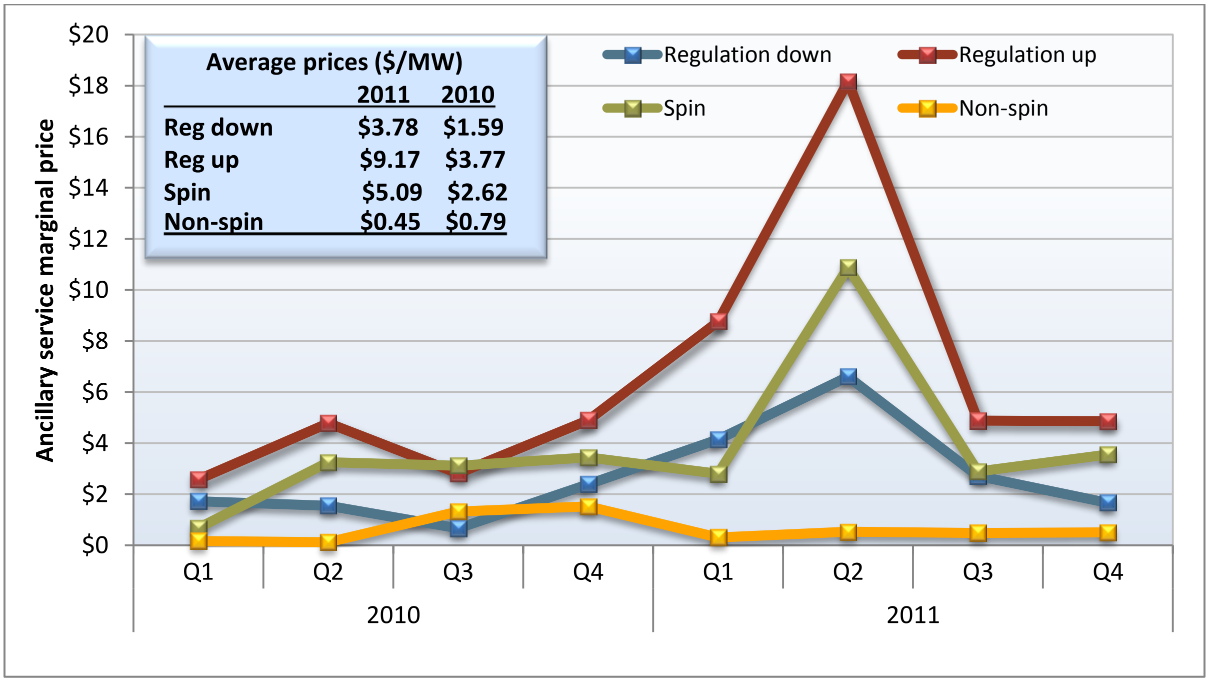


Figure 5.6 Real-time ancillary service market clearing prices



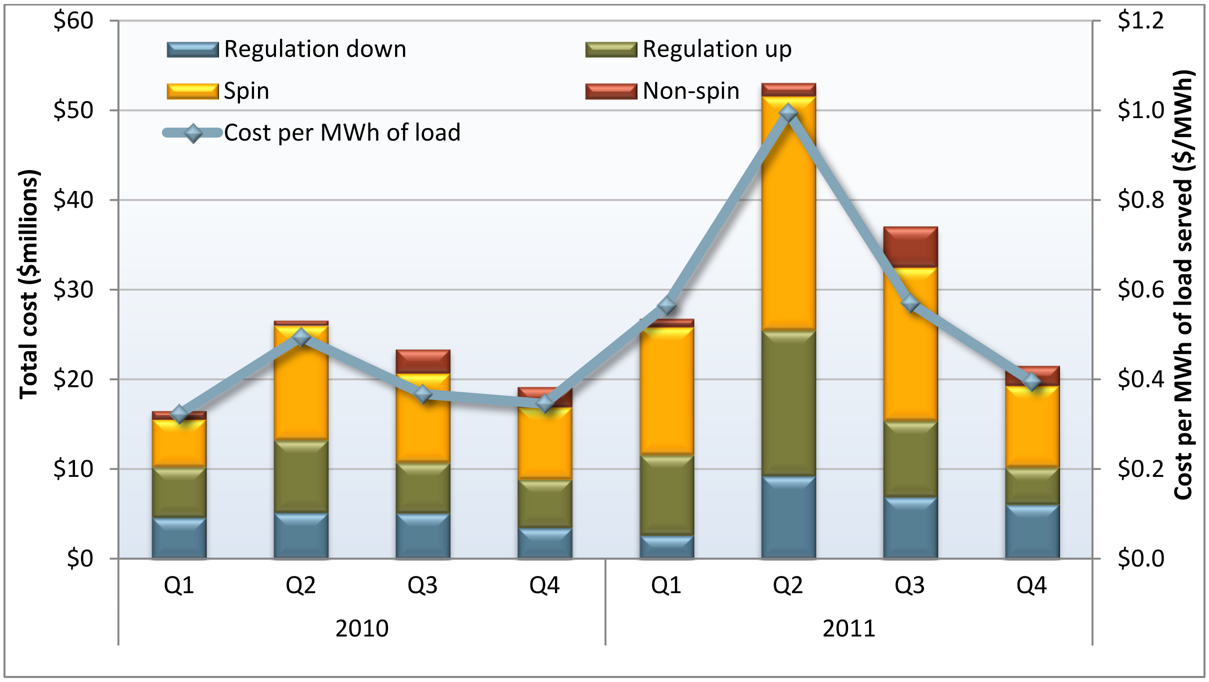
In Figure 5.6, real-time ancillary service prices generally reflect similar pricing trends. Monthly average real-time prices ranged from $0.30/MW to $18.20/MW. During some 15-minute intervals, high real-time ancillary service price spikes, reaching almost $1,000/MW, were mostly the result of high opportunity costs from 15-minute real-time energy price spikes. The volume of procurement in the real-time market is very limited, accounting for less than 1 percent of the total procurement. Consequently, these real-time ancillary service price spikes do not affect overall ancillary service costs significantly.

5.4 Ancillary service costs

Ancillary service costs totaled $139 million, representing an increase of 61 percent over 2010. The value of self-provision of ancillary service by load resources contributed $33 million to the final amount.

Figure 5.7 shows the total cost of procuring ancillary service products by quarter along with the total ancillary service cost for each MWh of load served. Total ancillary service cost peaked during the second quarter of the year. As discussed previously, above average snow-pack causing hydro-electric generation to provide energy instead of ancillary services contributed to this increase in cost.

Figure 5.7 Ancillary service cost by product



5.5 Ancillary service scarcity pricing

Scarcity pricing of ancillary services occurs when there is insufficient supply to meet reserve requirements specified in the market model. In 2011, there were a very limited number of intervals during the year when the ancillary service requirements were not met in the hour-ahead scheduling process (HASP) and 15-minute pre-dispatch real-time market (RTPD). Most of these ancillary service scarcity events were in June and July. Table 5.1 shows the number of intervals during each month that scarcity of ancillary services occurred in these markets, along with the average amount of ancillary service capacity shortage during these scarcity events.

In total, there were 15 valid 15-minute real-time pre-dispatch intervals where scarcity pricing of ancillary services was triggered during the year.[70] There were an additional 9 ancillary service scarcity intervals on the inter-ties in the hour-ahead market. These scarcity events were restricted to upward ramping ancillary services with most of them being for spinning reserve scarcity in the SP26 and SP26 expanded regions.

The overall direct market effect of these scarcity events on ancillary service costs was about $60,000. As a result of these events, there is also likely to have been additional unit commitment in the 15-minute real-time pre-dispatch process that may not have occurred otherwise.[71]

Table 5.1 Ancillary service scarcity events

Month	Market	Ancillary Service	Scarcity Intervals	Average MW shortfall	Ancillary service region
April	RTPD	Spin	1	7.1	SP 26
May	RTPD	Spin	3	11.5	SP 26/SP 26 Exp
June	RTPD	Regulation Up	8	19.9	SP 26 Exp
July	HASP	Regulation Up	2	0.9	CAISO
July	HASP	Spin	2	13.8	CAISO
July	HASP	Non-spin	9	112.7	CAISO
November	RTPD	Spin	1	12.3	SP 26
November	RTPD	Regulation Up	2	10	SP 26

5.6 Dynamic ramp rates for ancillary services

In August, the ISO implemented a software enhancement to ensure that ancillary services procured in the day-ahead market could be fully delivered in real-time if needed.[72] The new software uses the operational ramp rates that are a function of a resource's generation level in conjunction with each unit's day-ahead energy bids to ensure that ancillary services procured in the day-ahead market could be delivered in real-time.

The ISO software allows units to submit operational ramp rates that vary at different levels of output in conjunction with their energy bid curves. These variable operational ramp rates are referred to as dynamic ramp rates. However, prior to this enhancement, generating units were required to submit a

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[70] There were 17 15-minute real-time pre-dispatch scarcity intervals that were corrected as part of the price correction process in 2011.

[71] Since the market models co-optimize energy and ancillary services, scarcity of ancillary services can also increase the energy price in the 15-minute pre-dispatch process. This may cause additional units to be committed in the 15-minute process. However, real-time energy is financially settled based on prices in the 5-minute real-time market. Therefore, these scarcity events do not directly impact real-time energy prices.

[72] See technical bulletin on dynamic ramp functionality for further detail: http://www.caiso.com/Documents/TechnicalBulletin-DynamicRampRate_AncillaryServiceProcurement.pdf.

single fixed ramp in conjunction with their ancillary service bids.[73] In addition, resource adequacy units are required to offer their full certified ancillary service capacity into the day-ahead market.

In some cases, this allowed units to be scheduled to provide energy at which their operational ramp rates would be insufficient to provide the full amount of 10-minute spinning or non-spinning reserve capacity they were awarded.

If ancillary services were unable to perform in real-time because of ramp rate limitations, the ISO sometimes needed to re-procure more ancillary services in the real-time market – often at higher prices. In other cases, operators may have exceptionally dispatched units to a higher energy level at which their operational ramp rates were fast enough to provide the unit's full ancillary service schedule.

To address these concerns, the ISO enhanced the day-ahead and real-time software to evaluate each unit's energy operational ramp rate, in conjunction with the fixed ancillary service ramp rate in the day-ahead ancillary service procurement. Specifically, the software sets the unit's ancillary service ramp to the lower of the operational ramp rate submitted with the unit's energy bids or the fixed ramp rate associated with its ancillary service bids. The ISO refers to this as a dynamic ramp rate for ancillary services. By implementing this modification, the co-optimization will ensure that the resource is awarded ancillary services consistent with its 10 minute ramping capability, which is a function of the resource's energy schedule and its operational ramp rate.

The ISO does not track or log when specific actions are taken in response to infeasible ancillary service schedules in a manner that would allow the impact of this software enhancement on re-procurement in real-time to be assessed directly. However, analysis by DMM provides some indications of lower re-procurement of ancillary services in real-time after this enhancement was implemented.

Figure 5.8 shows the average amount of additional megawatts procured in real-time during intervals of incremental ancillary service procurement. The incremental procurement dropped after the implementation of the dynamic ramp feature. In addition, the percentage of 15-minute real-time intervals with at least 1 MW of additional ancillary service procured also dropped following the implementation.[74] Furthermore, scarcity pricing of ancillary services only occurred three times since deployment of the new dynamic ramp rate feature. However, since many other factors also affect procurement of ancillary services in real-time, these data do not provide a definitive indication of the impact of this software enhancement.

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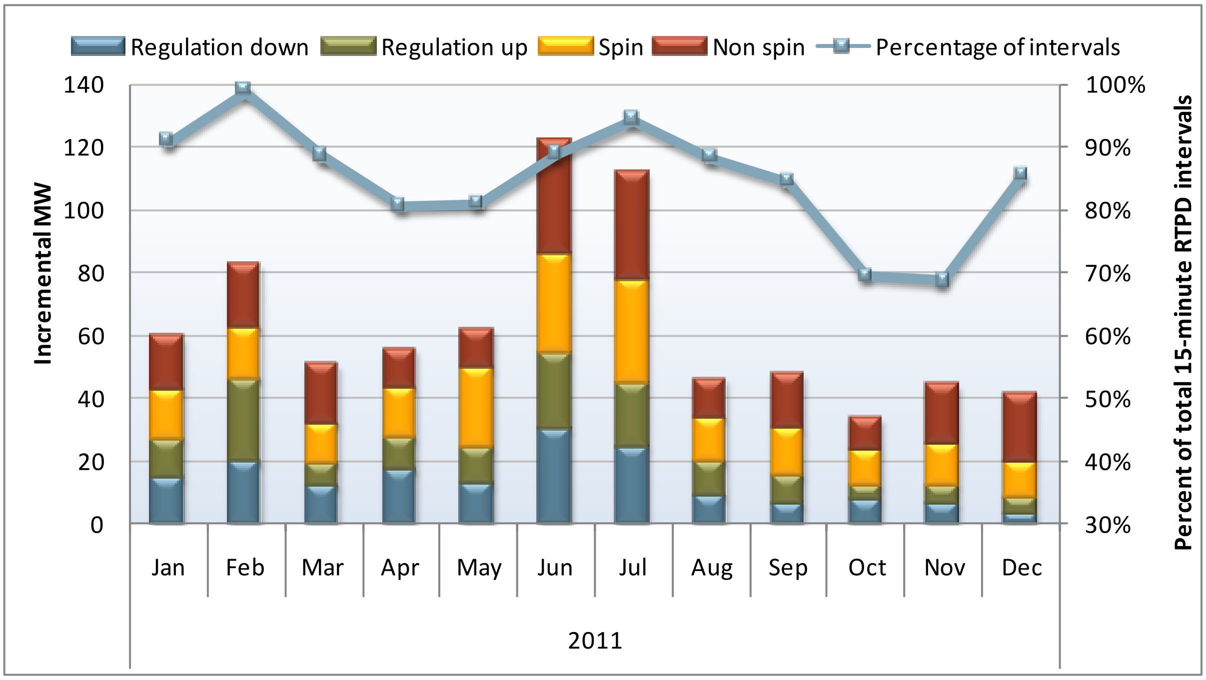
[73] The ramp rate submitted was required to be equal to or less than the unit's maximum ramp rate established as part of ancillary service certification testing.

[74] Real-time ancillary service procurement occurred In most real-time 15-minute intervals as small volumes of ancillary services were often needed to provide reserves in a particular ancillary service region.

Figure 5.8 Monthly average additional ancillary service megawatts procured in real-time



6 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 day-ahead integrated forward market has continued to be stable and competitive with virtually all loads and supply being scheduled in the day-ahead market.
- A key driver of the market competitiveness is the high degree of forward contracting by load-serving entities. This significantly limits the ability and incentive to exercise market power in the day-ahead and real-time markets.
- Bids for additional supply needed to meet remaining demand in the day-ahead and real-time markets have generally been highly competitive.
- Prices in the day-ahead market during each quarter were consistently about equal to competitive baseline prices we estimate would result under highly competitive conditions. DMM estimates competitive baseline prices as a benchmark for assessing actual market prices by re-simulating the market using the day-ahead market software with bids reflecting the actual marginal cost of gas-fired units.
- Prices in the 5-minute real-time market were lower than competitive baseline prices by about 3 percent in 2011. This is attributable to the lower frequency of extreme real-time price spikes due to brief shortages of upward ramping capacity, as discussed in detail in Chapter 3.
- Under current load and supply conditions, the system-wide energy market is structurally competitive. However, since ownership of resources within different areas of the ISO grid is highly concentrated, local reliability requirements and transmission limitations give rise to local market power in many areas of the system.
- Local market power mitigation provisions have continued to be triggered on a very limited basis. An average of only 1.3 units per hour had bids lowered due to mitigation in the day-ahead market. In the real-time market, bids for an average of about 3.8 units were lowered as a result of mitigation.
- When units are subject to bid mitigation, they are often not dispatched at a higher level as a result of this mitigation. This occurs since mitigation often results in a minor change in bids and market prices often exceed a unit’s unmitigated bid.
- Although the mitigation provisions have not had a significant direct impact on market results, this does not mean that these provisions are unneeded or did not have a more significant indirect impact. Effective local market power mitigation provisions in the day-ahead and real-time markets encourage forward contracting and deter attempts to exercise market power in all of these markets.

6.1 Overall market competitiveness

To assess the competitiveness of the day-ahead market, DMM compares actual market prices to competitive benchmark prices that we estimate would result under highly competitive conditions. DMM estimates competitive baseline prices by re-simulating the market using the day-ahead market software with bids reflecting the actual marginal cost of gas-fired units.[75] Figure 6.1 compares this competitive baseline price to average system-wide prices in the day-ahead and 5-minute real-time markets. As shown in Figure 6.1:

- Prices in the day-ahead market have consistently been about equal to the competitive baseline prices. Since June, the competitive baseline prices exceeded average prices for the ISO system by about 3 percent. Since May, average real-time prices have been closer to both average day-ahead prices and the competitive baseline than in 2010 and in January 2011.[76]

- Except for January 2011, average system-wide real-time prices were approximately equal to the competitive baseline in 2011.

Most of the differences in real-time prices and the competitive baseline were caused by one of two factors: extremely high price spikes during a small portion of 5-minute real-time intervals or intervals of over-generation when prices were negative. As discussed in Chapter 3, these price spikes generally reflect short-term modeling limitations, rather than fundamental underlying supply and demand conditions. These real-time price spikes are not attributable to uncompetitive bidding or other anti-competitive behavior, but rather often reflect structural modeling limitations.

DMM also calculates an overall price-cost mark-up by comparing competitive baseline prices to total average wholesale energy costs.[77] Total costs used in this analysis represent a weighted average of all energy transactions in the day-ahead, hour-ahead and real-time markets.[78] Thus, this analysis includes energy procured at higher prices in the real-time market, as well as net energy sales in the hour-ahead market at lower prices.

Figure 6.1 compares this competitive baseline price to average system-wide prices in the day-ahead and 5-minute real-time markets. As seen in Figure 6.1, prices in the day-ahead market have consistently been about equal to the competitive baseline prices. Since June, the competitive baseline prices exceed the state-wide average prices by about 3 percent. Since May, average real-time prices have been closer to both average day-ahead prices and the competitive baseline than in 2010 and January 2011. This

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[75] A more detailed description of the methodology used to estimate competitive baseline prices and the price cost mark-up is provided in DMM's *Quarterly Report on Market Issues and Performance*, February 13, 2012, p. 14, http://www.caiso.com/Documents/QuarterlyReport_Market%20Issues_Performance-February2012.pdf.

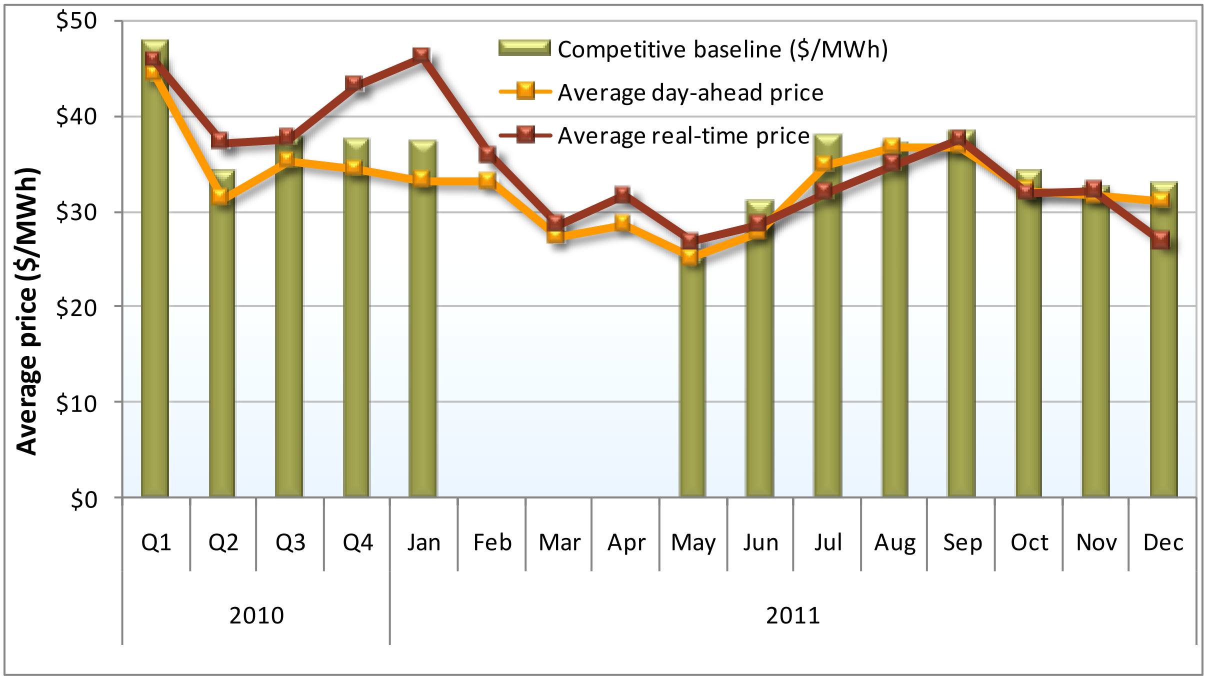
[76] Default energy bids used in calculating benchmark prices include a 10 percent adder above fuel and variable costs. The fact that market prices are slightly below this competitive benchmark reflects that many gas units bid below these default energy bids.

[77] DMM calculates the price-cost markup 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, but the competitive baseline price was $50/MWh, this would represent a price-cost markup of 10 percent. DMM considers a market to be generally competitive if this index is no more than a 10 percent mark-up over the competitive baseline on a monthly and annual basis.

[78] These costs are based on the same data and methodology used in the analysis of total wholesale energy costs provided in Chapter 2.

change has mainly been the result of the decreased frequency of penalty prices associated with ramping limitations influencing real-time market prices (see Section 3.2).

Figure 6.1 Comparison of competitive baseline with day-ahead and real-time prices



In 2010 and 2011, the overall price-cost mark-up was slightly negative, about -2 percent and -4 percent, respectively.[79] In 2009, DMM estimated the overall price-cost mark-up to be about 1.5 percent. The lower price-cost mark-up in 2011 can be attributed to day-ahead market prices that were somewhat lower in 2011 relative to the competitive baseline prices calculated using the day-ahead market software.

DMM has analyzed the price-cost mark-up for California's wholesale market since the beginning of the ISO in 1998. Figure 6.2 summarizes the results published in DMM's prior annual reports. As shown in Figure 6.2, DMM has concluded that California's wholesale market has been competitive since 2002, with a price-cost mark-up generally ranging from 5 to 10 percent.

The price-cost mark-up and other analysis in this report indicate that prices under the nodal market design have been extremely competitive. However, as discussed in our 2009 annual report, direct comparisons reported in previous years are difficult due to the significantly different way in which DMM calculated price-cost mark-up.[80]

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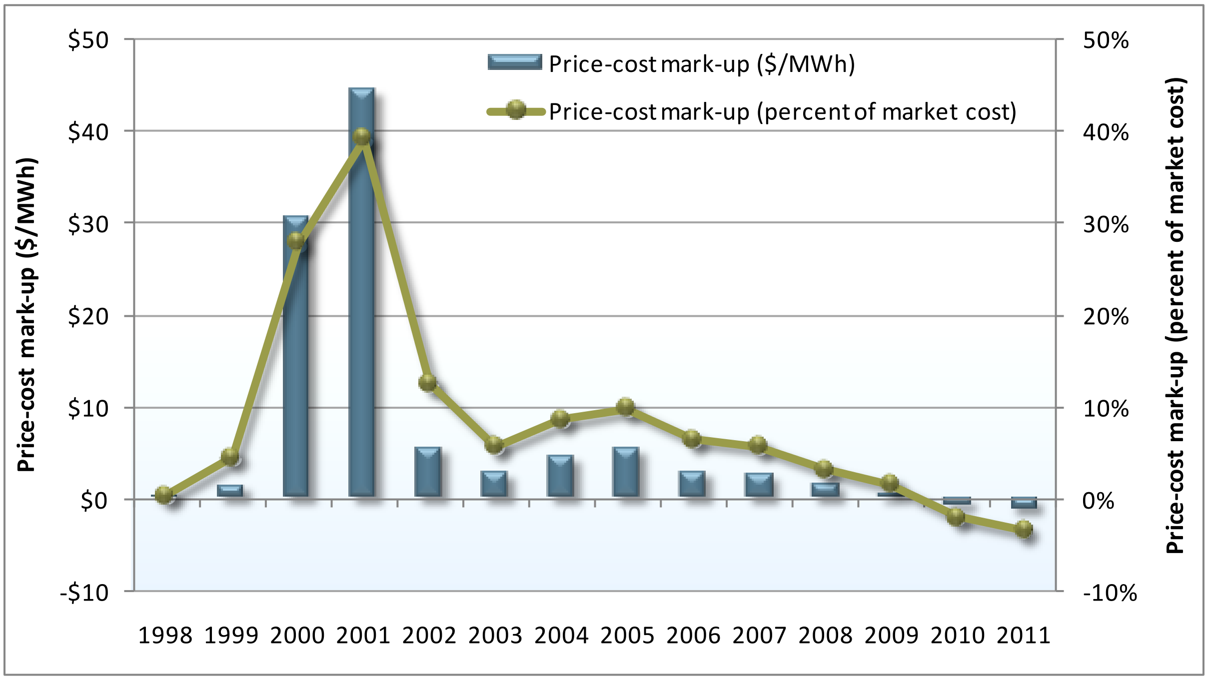
[79] As a result of technical difficulties, DMM had difficulty loading and re-running save cases in the months of February, March and April. Unfortunately, the current market model is too different to replicate enough useful market results for this period.

[80] See *2009 Annual Report on Market Issues and Performance*, April 2010, pp. 3.1-3.3 and 4.46-4.47: http://www.caiso.com/2777/27778a322d0f0.pdf.

Figure 6.2 Price-cost mark-up: 1998-2011



6.2 Structural measures of competitiveness

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

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

- **Residual supply index.** The residual supply index is the ratio of supply from non-pivotal suppliers to the demand.[81] A residual supply index less than 1.0 indicates an uncompetitive level of supply when the largest suppliers' shares are excluded.

In the electric industry, measures based on two or three suppliers in combination are often used because of the potential for oligopolistic bidding behavior by multiple suppliers. 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.

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[81] 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.

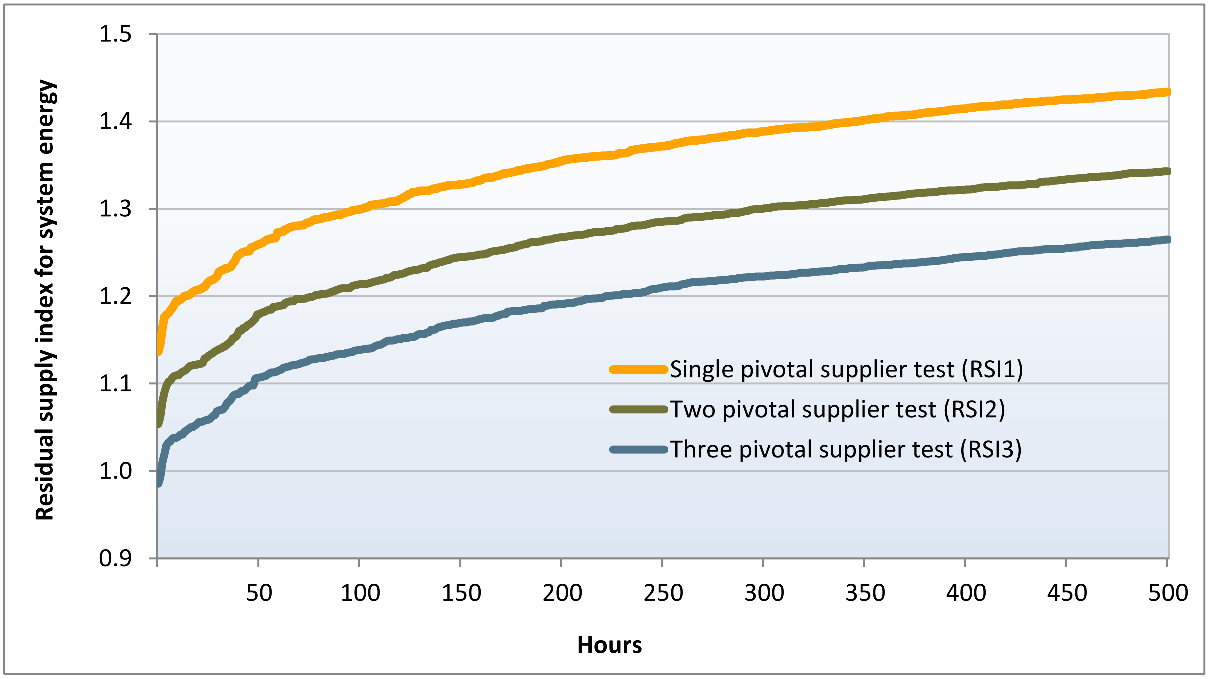
In this report, when the residual supply index is calculated by excluding the largest supplier, we refer to this measure as the RSI_1. With the two or three largest suppliers excluded, we refer to these results as the RSI_2 and RSI_3, respectively. A detailed description of the residual supply index was provided in Appendix A of DMM's 2009 annual report.

6.2.1 Day-ahead system energy

Figure 6.3 shows the hourly residual supply index for the day-ahead energy market in 2011. This analysis is based on system energy only and ignores potential limitations due to transmission limitations.[82] Results are only shown for the 500 hours when the residual supply index was lowest. These hours generally correspond to the highest load hours. As shown in Figure 6.3, the residual supply index with the three largest suppliers removed (RSI_3) was less than 1.0 during only 2 hours.

These findings reflect the favorable overall system supply and moderate load conditions. Under these conditions, the underlying structure of the overall energy market fosters competitive behavior and outcomes in the system-wide energy market. However, as discussed in the following sections, since ownership of resources within different areas of the ISO grid is highly concentrated, local reliability requirements and transmission limitations give rise to local market power in many areas of the system.

Figure 6.3 Residual supply index for day-ahead energy



6.2.2 Local capacity requirements

The ISO has defined ten 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

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

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 6.1 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 6.1, the total amount of supply owned by non-load-serving entities meets or exceeds the additional capacity needed by load-serving entities to meet these requirements in most areas. However, in most areas, one or more suppliers are individually pivotal for meeting the remainder of the capacity requirement. In other words, some portion of these suppliers' capacity is needed to meet local requirements. This is indicated by RSI_1 values less than 1.0 and RSI_2 values of 0.24 or lower in each of these areas.

Table 6.1 Residual supply index for major local capacity areas based on resource adequacy requirements

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	3,927	4,479	1.14	0.49	0.03	0.01	2
North Coast/North Bay	601	707	1.18	0.03	0.01	0.00	1
SCE area							
LA Basin	5,853	6,162	1.05	0.39	0.23	0.12	3
Big Creek/Ventura	232	2,902	12.51	3.33	0.24	0.07	0
San Diego	1,448	1,323	0.91	0.12	0.05	0.01	3

In addition to the capacity requirements for each local capacity area used in this analysis, additional reliability requirements exist for numerous sub-areas within each local capacity area. Some of these require that capacity be procured from specific individual generating plants. Others involve complex combinations of units which have different levels of effectiveness at meeting the reliability requirements. These sub-area requirements are not formally included in local capacity requirements incorporated in the state's resource adequacy program. However, these additional sub-area requirements represent an additional source of local market power. If a unit needed for a sub-area requirement is not procured in the resource adequacy program and that resource does not make itself available to the ISO in the spot market, the ISO may need to procure capacity from the unit using the backstop procurement authority (the capacity procurement mechanism).

As discussed in Chapter 9, in 2011 load-serving entities continued to procure all capacity needed to meet local resource adequacy requirements through bilateral contracts. As a result, the ISO has not needed to procure capacity through reliability must-run contracts or the capacity procurement mechanism in the ISO tariff. However, having this authority in the tariff serves as a backstop that helps to mitigate the potential for local market power in bilateral markets for this capacity.

In the energy markets, the potential for local market power is mitigated through bid mitigation procedures, as discussed in Section 6.4. These procedures require that each transmission constraint be pre-designated as either competitive or non-competitive based on seasonal planning studies performed several months in advance. The following section examines the actual structural competiveness of transmission constraints when congestion has occurred in the day-ahead and real-time markets.

6.3 Competitiveness of transmission constraints

Background

Local market power mitigation provisions require that each constraint be pre-designated as either competitive or non-competitive. Generation bids are subject to mitigation if that unit is committed or dispatched to relieve congestion on a constraint pre-designated as non-competitive. For these provisions to be effective, it is important that constraints designated as competitive are in fact competitive under actual market conditions.

The methodology used to designate transmission constraints as competitive or non-competitive is the competitive path assessment. This methodology incorporates a 3-pivotal supplier test.[83] The competitive path assessment evaluates if a feasible power flow solution of a full network model can be reached with the supply of any three suppliers excluded from the market.[84]

Starting in April 2010, the ISO performed competitive path assessment studies on a seasonal basis four times per year and updated constraint designations based on these results.[85] Under this process, the competitiveness of constraints under actual market and operating conditions may vary from results of the study for a variety of reasons:

- The assessment must currently be performed on a network model combining a typical day-ahead model and a typical congestion revenue rights model. This network model may differ from the model used in the actual market software, which is frequently updated to reflect new constraints, transmission outages or ratings, or other adjustments.
- The assessment does not incorporate any generation or transmission outages.
- The assessment is run for a series of scenarios representing different load, hydro-electric and import conditions. Although these scenarios are based on historical data and are designed to cover a wide range of possible conditions, actual load and market conditions may vary from these scenarios.

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[83] For a detailed description of this methodology, see *Competitive Path Assessment for MRTU Final Results for MRTU Go-Live,* Department of Market Monitoring, February 2009, http://www.caiso.com/2365/23659ca314f0.pdf.

[84] The competitive path assessment is performed with relatively high penalty prices assigned to any overflow conditions on paths being tested for competitiveness. Major paths deemed to be competitive are assigned much higher penalty prices. This ensures that if a feasible solution does not exist, flows on paths being tested will exceed transmission limits before any overflow occurs on paths not being tested. With this approach, if flows on any paths being tested exceed limits, the path is deemed to be non-competitive.

[85] During 2009, constraints were designated as competitive and non-competitive based on a study performed in February 2009 prior to the start of the new market in April 2009. Results of this first study were applied for the first 12 months of the new market. See *Competitive Path Assessment for MRTU Final Results for MRTU Go-Live,* Department of Market Monitoring, February 2009, http://www.caiso.com/2365/23659ca314f0.pdf.

- DMM currently uses simulation software to perform the assessment, rather than the actual market software.

One of the drawbacks of the competitive path assessment is that the process is time-consuming given DMM's current modeling tools. The ISO has developed a new dynamic competitive path assessment that will be run in the market software and will more accurately account for current conditions that are influencing market dispatch and prices. The dynamic competitive path assessment will be implemented in the day-ahead market in April 2012 and in the real-time market in the fall of 2012.[86] The ISO will also implement a new method for triggering mitigation, based on the path competitiveness determined by the dynamic competitive path assessment, on a similar schedule.[87]

Residual supply index for counter-flow

The approach used for assessment of the competitiveness of constraints is referred to as the residual supply index for counter-flow on congested constraints. This specific approach was developed by DMM based on similar metrics used by several other ISOs to assess the competitiveness of transmission constraints. DMM has used this index to monitor the competitiveness of constraints and assess the accuracy of the competitive path assessment methodology under actual network and market conditions.[88]

The residual supply index measures how pivotal one or more suppliers are based on their ownership or control of the supply of effective counter-flow capable of relieving congestion of a specific transmission constraint. The index is the ratio of the demand for counter-flow divided by the total residual supply of potential effective counter-flow after removing the generation controlled by one or more of the largest suppliers. An index of less than 1 indicates that the residual supply of counter-flow controlled by all other suppliers is insufficient to meet the demand for counter-flow on a constraint. The index may be used to measure whether a single supplier is pivotal, or whether multiple suppliers are jointly pivotal.

One of the main strengths of the residual supply index is that it is calculated based on the actual supply and demand for counter-flow during hours when congestion occurs. Results therefore reflect changes in system conditions not captured in the competitive path assessment. For example, if a transmission line is de-rated, this increases the demand for counter-flow used in the test. If a unit effective at providing counter-flow is unavailable due to an outage, this decreases the supply of counter-flow used in the test.

Day-ahead market results

Figure 6.4 and Table 6.2 summarize results of the hourly residual supply index for non-competitive constraints on which day-ahead congestion occurred in 2011. Typically these constraints were deemed non-competitive because they did not meet the criteria used to determine candidate paths eligible to be analyzed and deemed competitive as part of the competitive path analysis studies. Under these criteria, constraints are only eligible to be studied for competitiveness if congestion on these constraints has been managed for at least 500 hours over the previous 12 months.

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[86] *Revised Draft Final Proposal – Dynamic Competitive Path Assessment,* Department of Market Monitoring, July 2011, http://www.caiso.com/Documents/RevisedDraftFinalProposal-DynamicCompetitivePathAssessment.pdf.

[87] *Draft Final Proposal – Local Market Power Mitigation Enhancements*, May 2012, http://www.caiso.com/Documents/DraftFinalProposal-LocalMarketPowerMitigationEnhancements.pdf.

[88] The methodology used to calculate these metrics is illustrated in Section A.5 of Appendix A of DMM's *2009 Annual Report on Market Issues & Performance*, April 2010, http://www.caiso.com/2777/27778a322d0f0.pdf.

As shown in Figure 6.4, the frequency of congestion on these constraints was relatively low in 2011. During hours when congestion occurred in the day-ahead market, the residual supply index indicates that these constraints were uncompetitive a relatively small portion of the time. These findings are similar to those from 2010.

Figure 6.5 and Table 6.3 summarize results of the hourly residual supply index for paths that met the 500 hour criteria used to determine candidate paths and were found to be competitive in the competitive path analysis. As shown in these results, most of these paths were competitive under the residual supply index. These findings are consistent with results of analysis of competitive constraints in 2010.

Figure 6.4 Residual supply index – Non-competitive paths in 2011 for day-ahead market

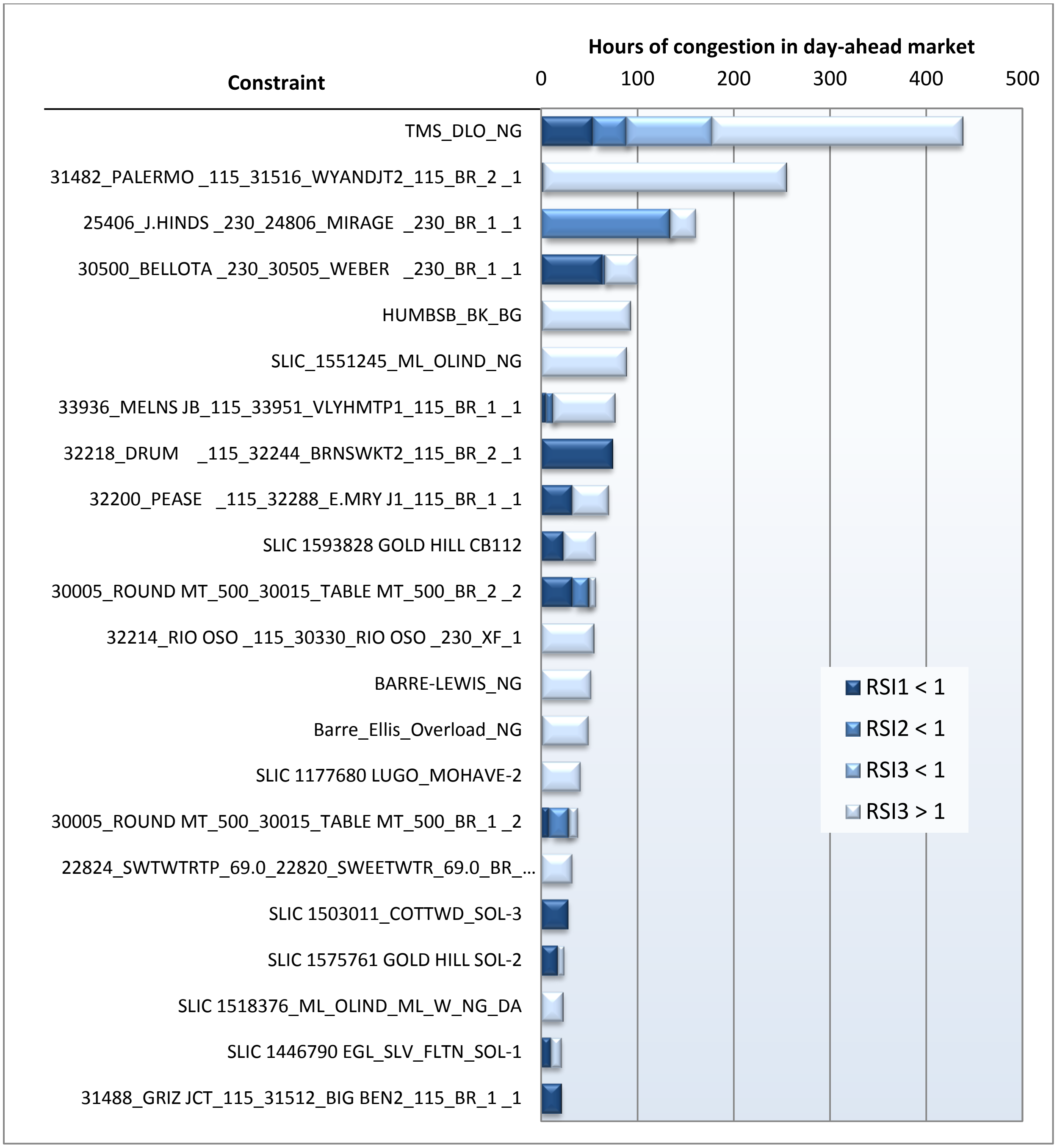


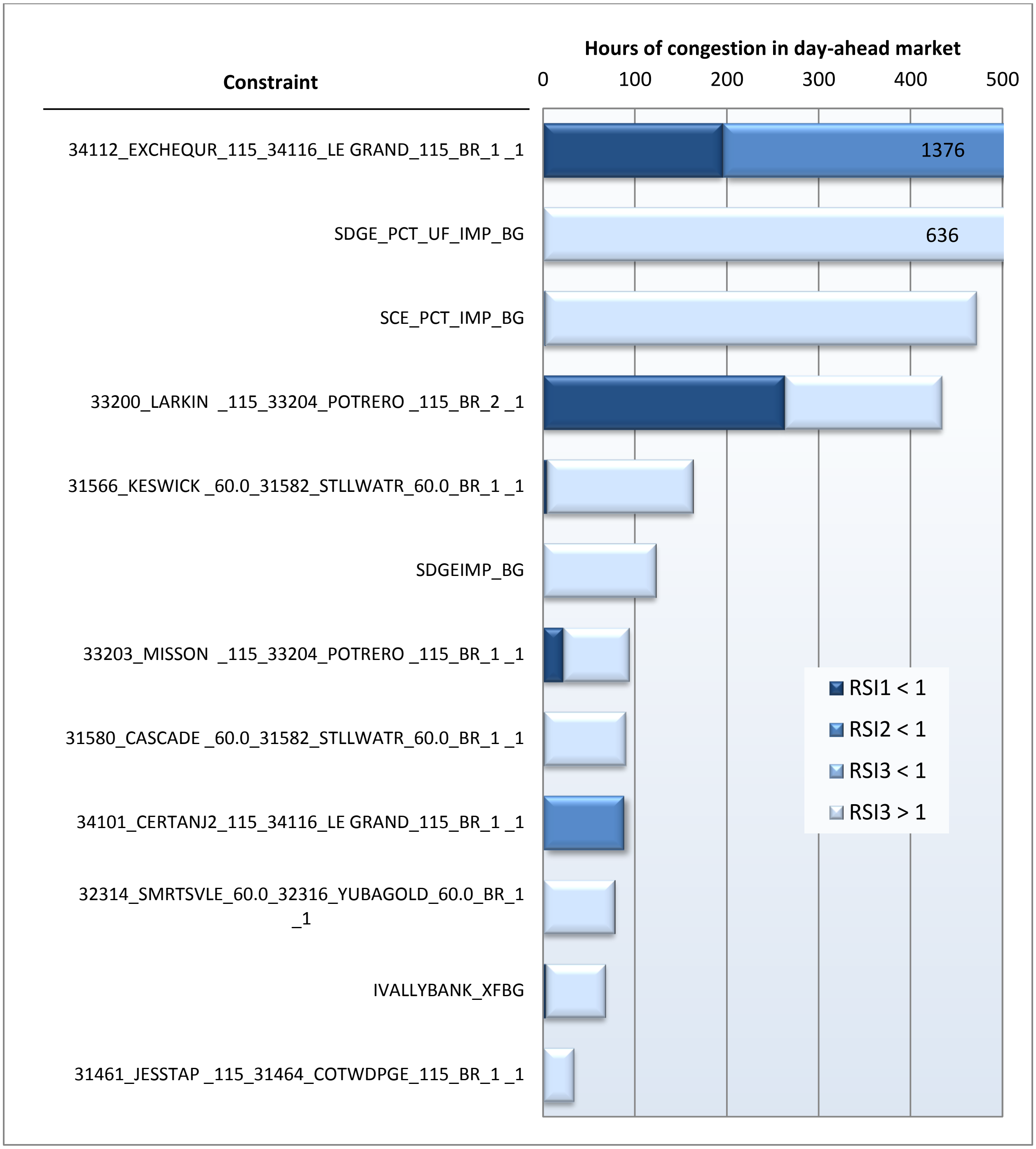
Table 6.2 Summary of RSI results – Non-competitive paths in 2011 for day-ahead market

	Congest.	$RSI_1 < 1$		$RSI_2 < 1$		$RSI_3 < 1$		$RSI_3 > 1$	
Constraint_Name	Hours	Hours	%	Hours	%	Hours	%	Hours	%
TMS_DLO_NG	438	53	12%	35	8%	89	20%	261	60%
31482_PALERMO _115_31516_WYANDJT2_115_BR_2_	255	1	0%	1	0%	0	0%	253	99%
25406_J.HINDS _230_24806_MIRAGE _230_BR_1 _1	161	0	0%	133	83%	1	1%	27	17%
30500_BELLOTA _230_30505_WEBER _230_BR_1 _1	100	63	63%	3	3%	0	0%	34	34%
HUMBSB_BK_BG	93	1	1%	0	0%	0	0%	92	99%
SLIC_1551245_ML_OLIND_NG	89	0	0%	0	0%	0	0%	89	100%
33936_MELNS JB_115_33951_VLYHMTP1_115_BR_1 _	77	5	6%	7	9%	0	0%	65	84%
32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1	74	74	100%	0	0%	0	0%	0	0%
32200_PEASE _115_32288_E.MRY J1_115_BR_1 _1	70	32	46%	0	0%	0	0%	38	54%
SLIC 1593828 GOLD HILL CB112	57	23	40%	0	0%	0	0%	34	60%
30005_ROUND MT_500_30015_TABLE MT_500_BR_2 _	57	32	56%	17	30%	1	2%	7	12%
32214_RIO OSO _115_30330_RIO OSO _230_XF_1	55	0	0%	0	0%	0	0%	55	100%
BARRE-LEWIS_NG	52	0	0%	0	0%	0	0%	52	100%
Barre_Ellis_Overload_NG	49	0	0%	0	0%	1	2%	48	98%
SLIC 1177680 LUGO_MOHAVE-2	41	0	0%	0	0%	0	0%	41	100%
30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _	38	8	21%	20	53%	1	3%	9	24%
22824_SWTWTRTP_69.0_22820_SWEETWTR_69.0_BR_	32	0	0%	0	0%	0	0%	32	100%
SLIC 1503011_COTTWD_SOL-3	28	28	100%	0	0%	0	0%	0	0%
SLIC 1575761 GOLD HILL SOL-2	24	17	71%	0	0%	0	0%	7	29%
SLIC 1518376_ML_OLIND_ML_W_NG_DA	23	0	0%	0	0%	0	0%	23	100%
SLIC 1446790 EGL_SLV_FLTN_SOL-1	21	10	48%	0	0%	0	0%	11	52%
31488_GRIZ JCT_115_31512_BIG BEN2_115_BR_1 _1	21	21	100%	0	0%	0	0%	0	0%
Totals	**1,855**	**368**	**20%**	**216**	**12%**	**93**	**5%**	**1,178**	**64%**

Table 6.3 Summary of RSI results – Competitive paths in 2011 for day-ahead market

	Congestion	$RSI_1 < 1$		$RSI_2 < 1$		$RSI_3 < 1$		$RSI_3 > 1$	
Constraint Name	Hours	Hours	%	Hours	%	Hours	%	Hours	%
34112_EXCHEQUR_115_34116_LE GRAND_115_BR_1 _1	1376	195	14%	1181	86%	0	0%	0	0%
SDGE_PCT_UF_IMP_BG	636	0	0%	0	0%	0	0%	636	100%
SCE_PCT_IMP_BG	472	0	0%	0	0%	2	0%	470	100%
33200_LARKIN _115_33204_POTRERO _115_BR_2 _1	434	262	60%	0	0%	0	0%	172	40%
31566_KESWICK _60.0_31582_STLLWATR_60.0_BR_1 _1	163	4	2%	0	0%	0	0%	159	98%
SDGEIMP_BG	123	0	0%	0	0%	0	0%	123	100%
33203_MISSON _115_33204_POTRERO _115_BR_1 _1	94	22	23%	0	0%	0	0%	72	77%
31580_CASCADE _60.0_31582_STLLWATR_60.0_BR_1 _1	90	1	1%	0	0%	0	0%	89	99%
34101_CERTANJ2_115_34116_LE GRAND_115_BR_1 _1	88	0	0%	88	100%	0	0%	0	0%
32314_SMRTSVLE_60.0_32316_YUBAGOLD_60.0_BR_1 _	78	0	0%	0	0%	0	0%	78	100%
IVALLYBANK_XFBG	68	3	4%	0	0%	0	0%	65	96%
31461_JESSTAP _115_31464_COTWDPGE_115_BR_1 _1	34	0	0%	0	0%	0	0%	34	100%
Totals	**3,656**	**487**	**13%**	**1,269**	**35%**	**2**	**0%**	**1,898**	**52%**

Figure 6.5 Residual supply index – Competitive paths in 2011 for day-ahead market



Real-time market results

Figure 6.6 and Table 6.4 summarize results of the residual supply index for non-competitive paths on which real-time congestion occurred in 2011.[89] As shown in Figure 6.6, during hours when congestion occurred in the real-time market, the residual supply index indicates that these constraints were uncompetitive a relatively high portion of the time. The summary totals in the bottom row of Table 6.4 show that during 49 percent of the hours when congestion occurred on these paths, the RSI_1 was less than 1, indicating a single supplier was pivotal.

Figure 6.7 and Table 6.5 summarize results of the hourly residual supply index for paths that met the 500 hour criteria used to determine candidate paths and were found to be competitive in the competitive path analysis. As shown in these results, a majority of time the constraints were competitive under the residual supply index.

Overall, these real-time analysis results indicate that although the current method of designating paths as competitive or non-competitive is not highly dynamic, this approach is reasonably accurate:

- Paths deemed non-competitive under the competitive path assessment methodology were structurally uncompetitive a much higher portion of the time in the real-time market than in the day-ahead market (compare Figure 6.4 and Figure 6.6). This reflects the fact that in real-time, the available supply of effective counter-flow is much more limited by resource ramping constraints and that long-start units that are not online cannot be used to relieve congestion.
- Paths deemed uncompetitive were structurally uncompetitive during about half of the time in the real-time market when congestion occurred on these paths based on the residual supply index (see Figure 6.6 and Table 6.4).
- Paths designated as competitive using the competitive path assessment methodology were structurally competitive in most hours under actual operating conditions based on residual supply index results in both the day-ahead and real-time markets (see Figure 6.5 and Figure 6.7).

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[89] The competitive path assessment is a procedure updated every few months. However, the ISO market model may vary daily. So there may be mismatches due to constant model evolutions. One of the issues is un-studied transmission constraints. Currently the implementation process marks any un-matched market transmission constraints as non-competitive, as these constraints are not in the competitive path list or grandfather path list. As shown in the real-time results, there are two paths PATH26_N-S and PATH15_S-N, which are not in the standard market model, have different ratings, are un-studied, and are thus set to be non-competitive. The corresponding grandfathered path names are PATH26_BG and PATH15_BG.

Figure 6.6 Residual supply index – Non-competitive paths in 2011 for real-time market

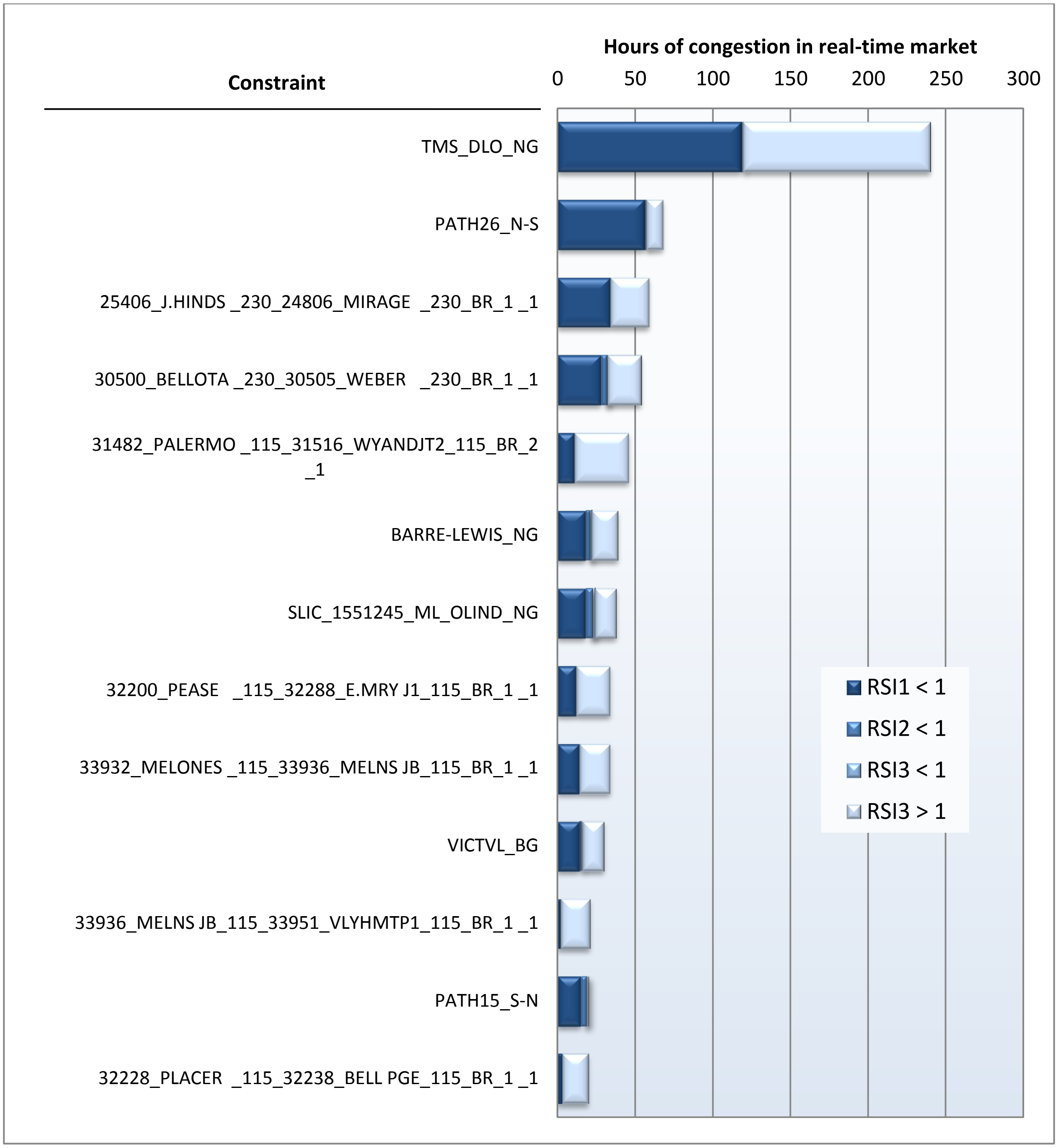


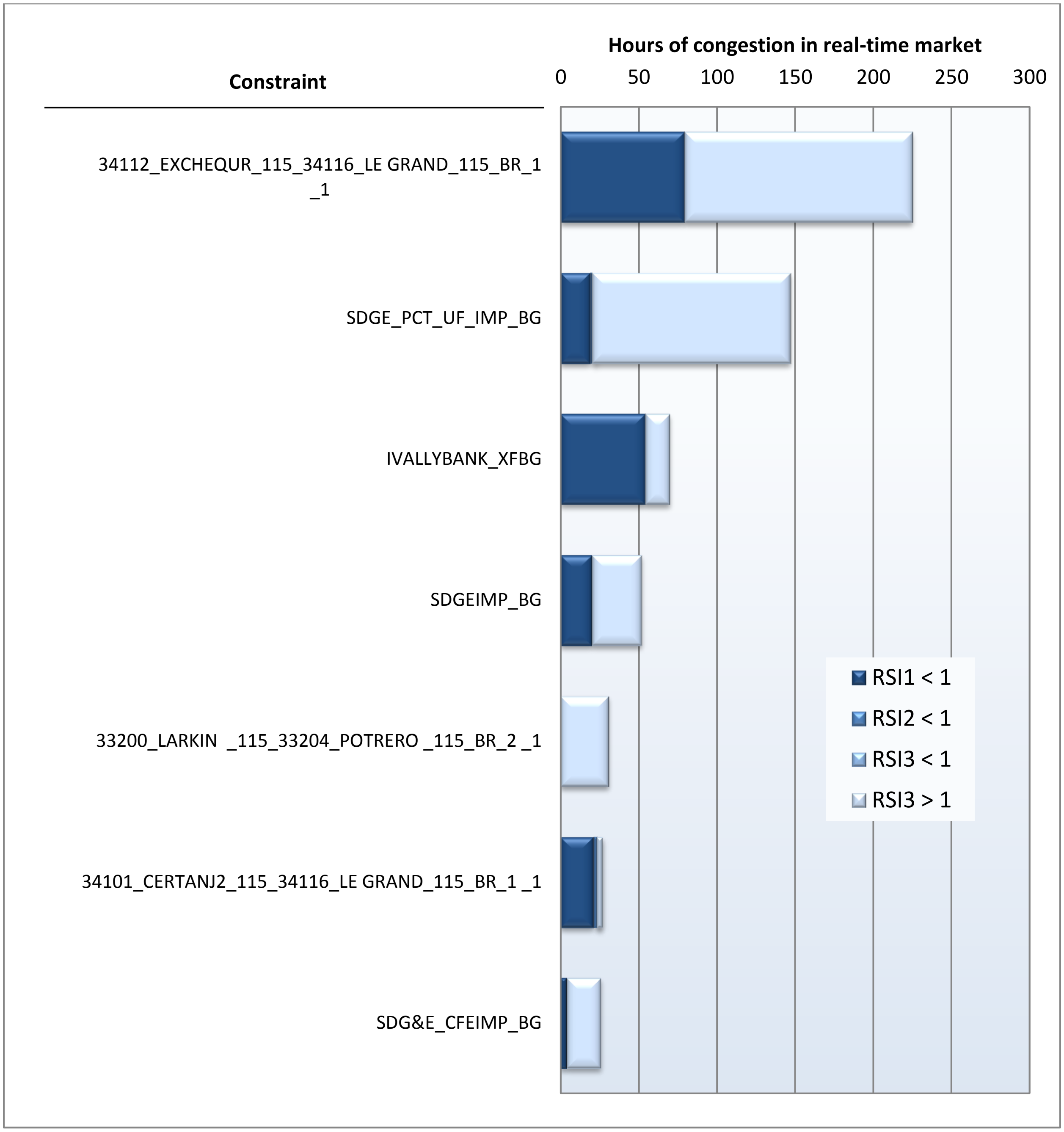
Table 6.4 Summary of RSI results – Non-competitive paths in 2011 for real-time market

	Congest.	$RSI_1 < 1$		$RSI_2 < 1$		$RSI_3 < 1$		$RSI_3 > 1$	
Constraint_Name	Hours	Hours	%	Hours	%	Hours	%	Hours	%
TMS_DLO_NG	240	118	49%	1	0%	0	0%	121	50%
PATH26_N-S	68	56	82%	1	1%	0	0%	11	16%
25406_J.HINDS _230_24806_MIRAGE _230_BR_1 _1	59	34	58%	0	0%	0	0%	25	42%
30500_BELLOTA _230_30505_WEBER _230_BR_1 _1	54	28	52%	4	7%	0	0%	22	41%
31482_PALERMO _115_31516_WYANDJT2_115_BR_2 _1	46	11	24%	0	0%	0	0%	35	76%
BARRE-LEWIS_NG	39	18	46%	3	8%	1	3%	17	44%
SLIC_1551245_ML_OLIND_NG	38	18	47%	5	13%	1	3%	14	37%
32200_PEASE _115_32288_E.MRY J1_115_BR_1 _1	34	12	35%	0	0%	0	0%	22	65%
33932_MELONES _115_33936_MELNS JB_115_BR_1 _1	34	14	41%	0	0%	0	0%	20	59%
VICTVL_BG	30	14	47%	1	3%	1	3%	14	47%
33936_MELNS JB_115_33951_VLYHMTP1_115_BR_1 _1	21	2	10%	0	0%	0	0%	19	90%
PATH15_S-N	20	15	75%	4	20%	0	0%	1	5%
32228_PLACER _115_32238_BELL PGE_115_BR_1 _1	20	3	15%	0	0%	0	0%	17	85%
Totals	**703**	**343**	**49%**	**19**	**3%**	**3**	**0%**	**338**	**48%**

Table 6.5 Summary of RSI results – Competitive paths in 2011 for real-time market

	Congestion	$RSI_1 < 1$		$RSI_2 < 1$		$RSI_3 < 1$		$RSI_3 > 1$	
Constraint Name	Hours	Hours	%	Hours	%	Hours	%	Hours	%
34112_EXCHEQUR_115_34116_LE GRAND_115_BR_1 _1	225	79	35%	0	0%	0	0%	146	65%
SDGE_PCT_UF_IMP_BG	147	19	13%	1	1%	0	0%	127	86%
IVALLYBANK_XFBG	70	54	77%	0	0%	0	0%	16	23%
SDGEIMP_BG	52	20	38%	0	0%	0	0%	32	62%
33200_LARKIN _115_33204_POTRERO _115_BR_2 _1	31	0	0%	0	0%	0	0%	31	100%
34101_CERTANJ2_115_34116_LE GRAND_115_BR_1 _1	27	21	78%	2	7%	0	0%	4	15%
SDG&E_CFEIMP_BG	26	4	15%	0	0%	0	0%	22	85%
Totals	**578**	**197**	**34%**	**3**	**1%**	**0**	**0%**	**378**	**65%**

Figure 6.7 Residual supply index – Competitive paths in 2011 for real-time market



6.4 Local market power mitigation

6.4.1 Frequency and impact of bid mitigation

The competitive baseline analysis presented in Section 6.1 is calculated by using default energy bids for all gas-fired units in place of their market bids. This analysis provides an indication of prices that would result if all gas-fired generators were always subject to bid mitigation. As discussed in Section 6.1, average monthly prices for this competitive baseline are nearly equal to actual market prices. This provides a clear indication that the competitiveness of market outcomes is primarily due to highly competitive bidding.

The impact of bids that are actually mitigated on market prices can only be assessed by re-running the market software without bid mitigation. Given the solution times for the market software, this is not a practical approach for assessing impacts that mitigating bids of individual units or suppliers may have on market prices. However, DMM has developed a variety of metrics to estimate the frequency with which bid mitigation provisions have been triggered and the impact of this mitigation on each unit's energy bids and dispatch levels.[90]

As shown in Figure 6.8 and Figure 6.9:

- The number of units eligible for mitigation in the day-ahead market increased slightly starting in the fourth quarter of 2010 through 2011. This slight increase in mitigation activity is in part related to the implementation of the multi-stage generating resources in December 2010.
- An average of 3.6 units were subject to mitigation each hour, with an average of 1.3 units having their bid actually lowered due to mitigation. In 2010, bids were lowered for an average of about 1.5 units per hour in the day-ahead market.
- The estimated increase in energy dispatched in the day-ahead market from these units averaged less than 6.6 MW per hour. This compares to an estimated impact from mitigation of about 4.6 MW in 2010.

Several factors contributed to the increase in day-ahead mitigation:

- Congestion on uncompetitive constraints within the ISO system was slightly higher in 2011.
- Spurious mitigation, mitigation that occurred when there was no congestion prevalent across the system, was more frequent in 2011 than in 2010.[91]

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[90] 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 & Performance*, April 2010, http://www.caiso.com/2777/27778a322d0f0.pdf.

[91] Further analysis of the frequency and scope of spurious mitigation is included as part of the FERC filling to amend the tariff for the new local market power mitigation procedure. For more information, see the following documentation:http://www.caiso.com/Documents/2011-11-16_ER12-423_LMPMAmend.pdf.

Figure 6.8 Average number of units mitigated in day-ahead market

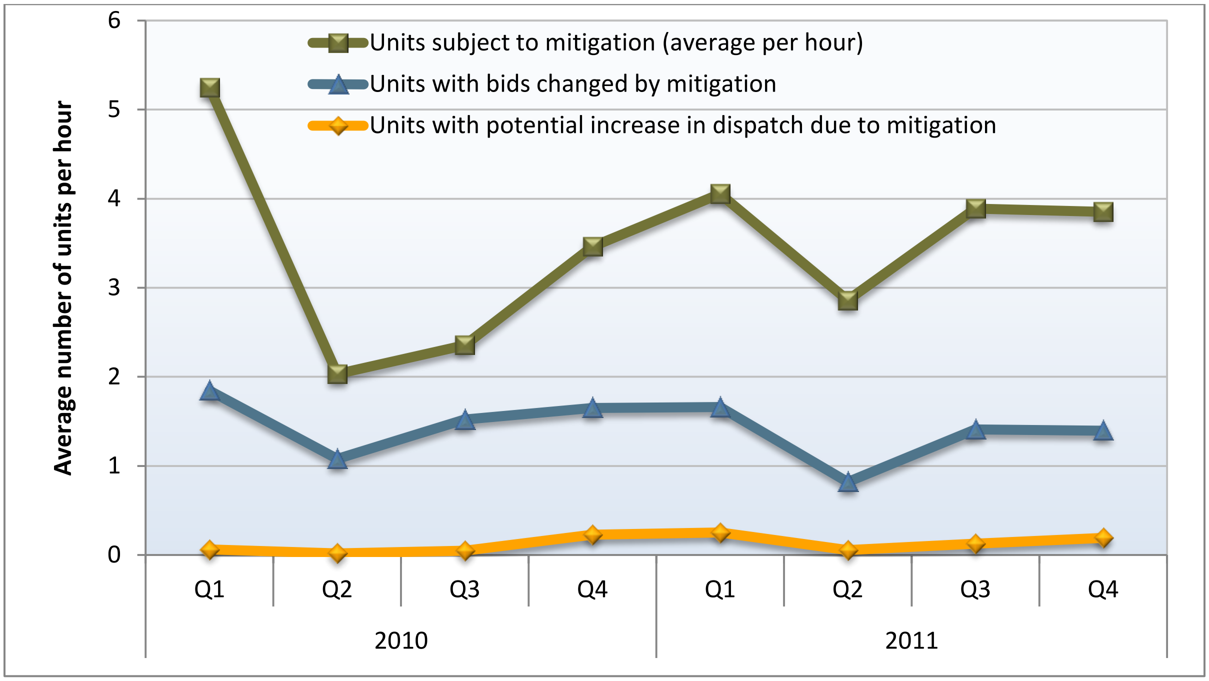


Figure 6.9 Potential increase in day-ahead energy dispatch due to mitigation: Hourly averages (2010 – 2011)

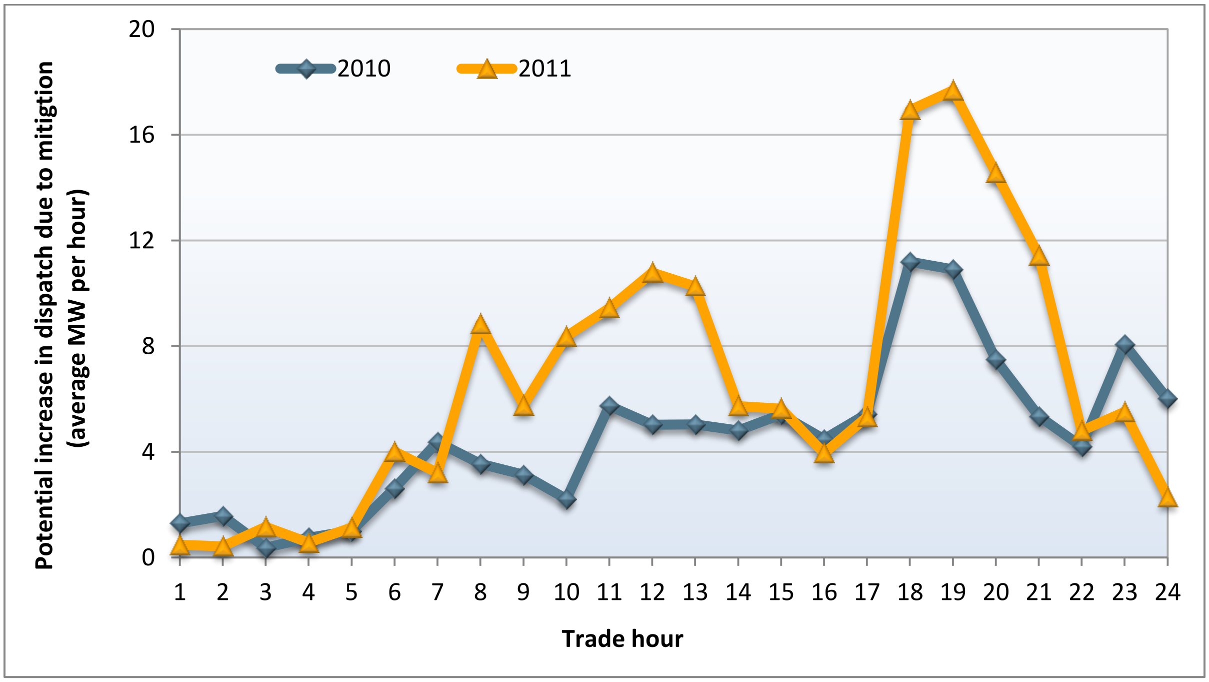


Figure 6.10 Average number of units mitigated in real-time market

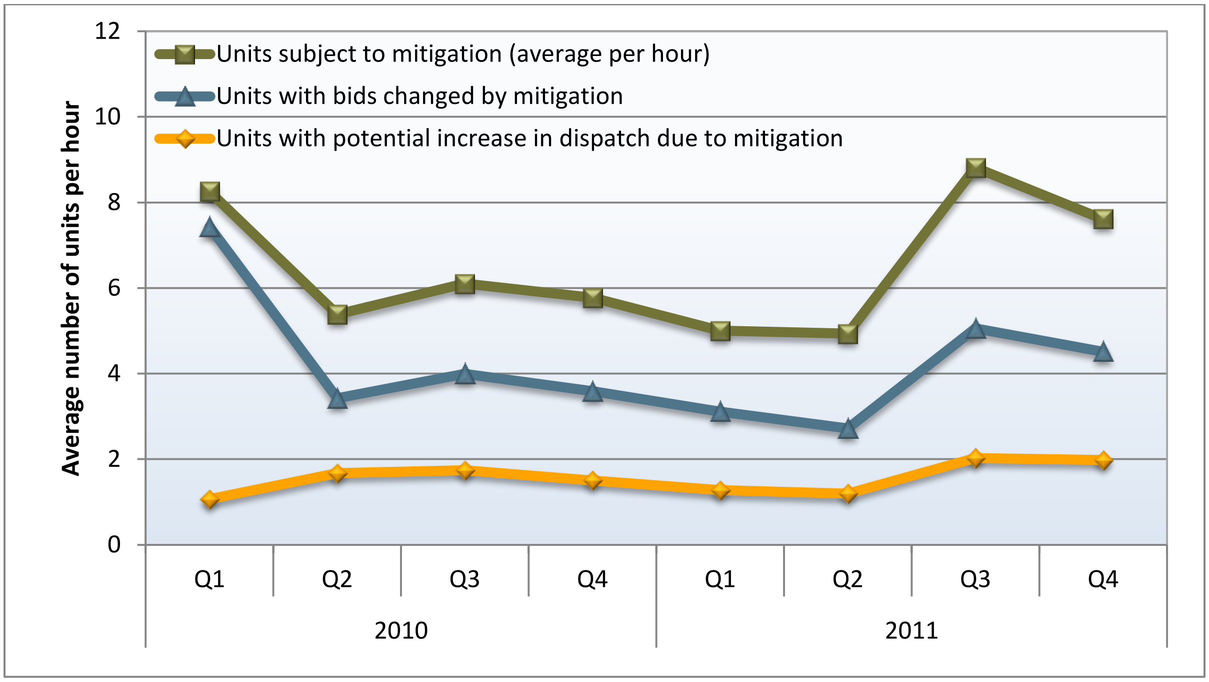
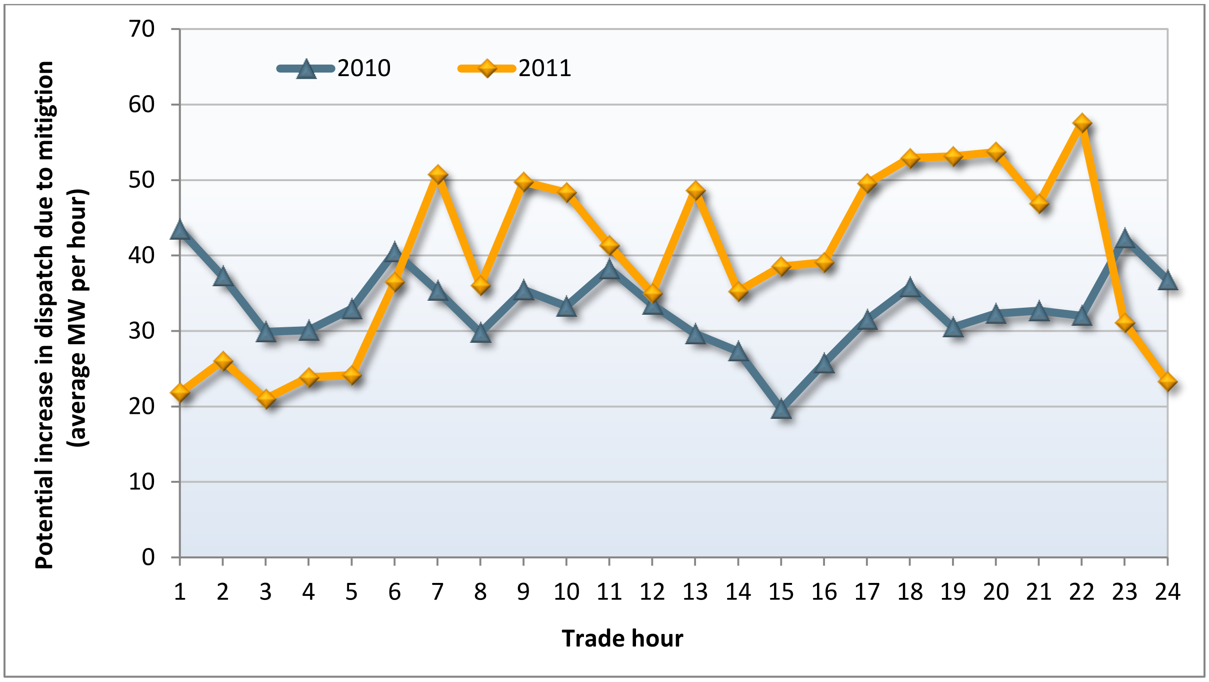


Figure 6.11 Potential increase in real-time energy dispatch due to mitigation: Hourly averages (2010 – 2011)



The frequency of bid mitigation in the real-time market in 2011 was comparable to that of 2010, as shown in Figure 6.10. However, as shown in Figure 6.11, the impact of bid mitigation increased slightly:

- In 2011, bids for an average of about 3.9 units were lowered as a result of the hour-ahead mitigation process. This compares to an average of about 4.6 units per hour in 2010.
- An average of about 1.6 units per hour was dispatched at a higher level in the real-time market as a result of bid mitigation in 2011, compared to about 1.5 units per hour in 2010.
- The estimated increase in real-time dispatches from these units because of bid mitigation averaged about 39 MW in 2011 compared to about 33 MW in 2010.

Thus, while the impact of mitigation on real-time dispatches increased in 2011, the overall impact of bid mitigation remains low in the real-time market.

6.4.2 Mitigation of exceptional dispatches

Exceptional dispatches are manual instructions issued when the automated market optimization is not able to address a particular reliability requirement or constraint. A more detailed discussion of exceptional dispatches is provided in Section 8.1.

Exceptional dispatches for energy above a unit’s minimum operating level are subject to mitigation if operator logs indicate the dispatch was issued to mitigate congestion on a designated non-competitive constraint. If an exceptional dispatch is mitigated, the generator is paid the greater of the unit’s nodal price or default energy bid. Otherwise, all exceptional dispatches are paid the greater of the nodal price or the unit’s unmitigated bid price.

As shown in Figure 6.12, the volume of total exceptional dispatch energy and the portion of this energy subject to mitigation decreased substantially in 2010, but rose again in the third quarter of 2011:[92]

- Over half of exceptional dispatch energy cleared the market in-sequence, meaning that bid prices were below the market clearing price for energy.
- An average of less than 8 MW of energy per hour was exceptionally dispatched out-of-sequence in 2010. In 2011, this number doubled to 16 MW.
- Only about 10 percent of this out-of-sequence exceptional dispatch energy in 2011 was logged as being related to a non-competitive constraint and therefore subject to mitigation. This is down from 19 percent in 2009 and only a small increase from 9 percent in 2010.

The total volume and portion of out-of-sequence energy logged as being for non-competitive constraints increased in 2011 without rising back to 2009 levels for several reasons:

- Exceptional dispatches for ramp rate issues comprised the bulk of out-of-sequence energy, particularly in the first and third quarters of 2011. Exceptional dispatches logged as being for unit ramp rate issues are not treated as being associated with non-competitive constraints and therefore are not subject to mitigation.
- Exceptional dispatches for mitigating congestion on Path 26 increased in the third and fourth quarters of 2011. Path 26 is one of the major constraints deemed to be a competitive constraint by default.

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[92] All exceptional dispatch numbers and figures in this report exclude April 2009 data due to lack of availability and reliability of that data.

Figure 6.12 Exceptional dispatches subject to bid mitigation

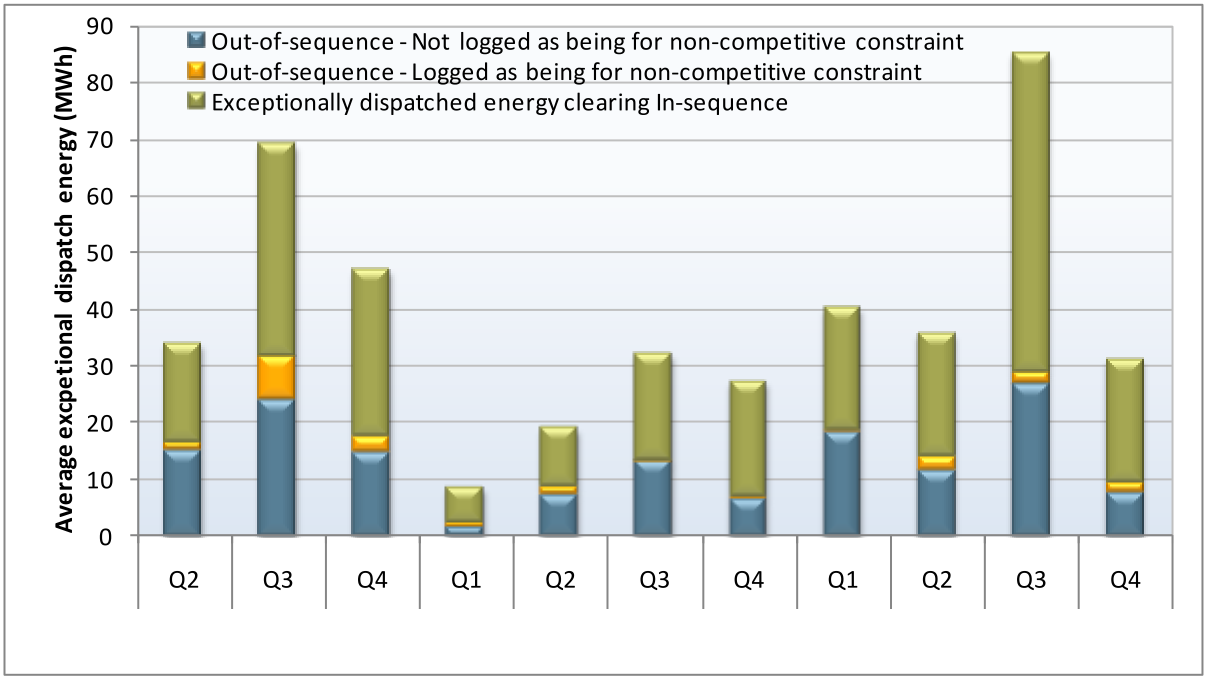

Figure 6.13 shows the average price of out-of-sequence exceptional dispatch energy with and without mitigation.

- The higher yellow line shows average prices if no exceptional dispatches were mitigated.
- The blue line shows the actual average prices paid for exceptional dispatch energy. The difference between this line and the higher yellow line shows the impact of mitigation on the overall price of exceptional dispatch energy.
- The lower green line shows average prices if all exceptional dispatches were mitigated to the higher of the market price or the unit's default energy bid. This line provides a benchmark for assessing actual exceptional dispatch prices. The difference in this line and the higher yellow line reflects the degree to which energy bids for exceptional dispatch energy exceed each unit's default energy bid and the market clearing price for energy.

The large increase in the average price of exceptional dispatch energy in the second quarter resulted from a relatively small volume of energy that was dispatched at a bid price of $1,000/MWh. In just five days, during a total of 24 hours, almost $5.3 million in exceptional dispatch payments were incurred for energy bids at prices approximately equal to the $1,000/MWh bid cap. This energy was not subject to mitigation since it was not logged as being a non-competitive constraint.[93]

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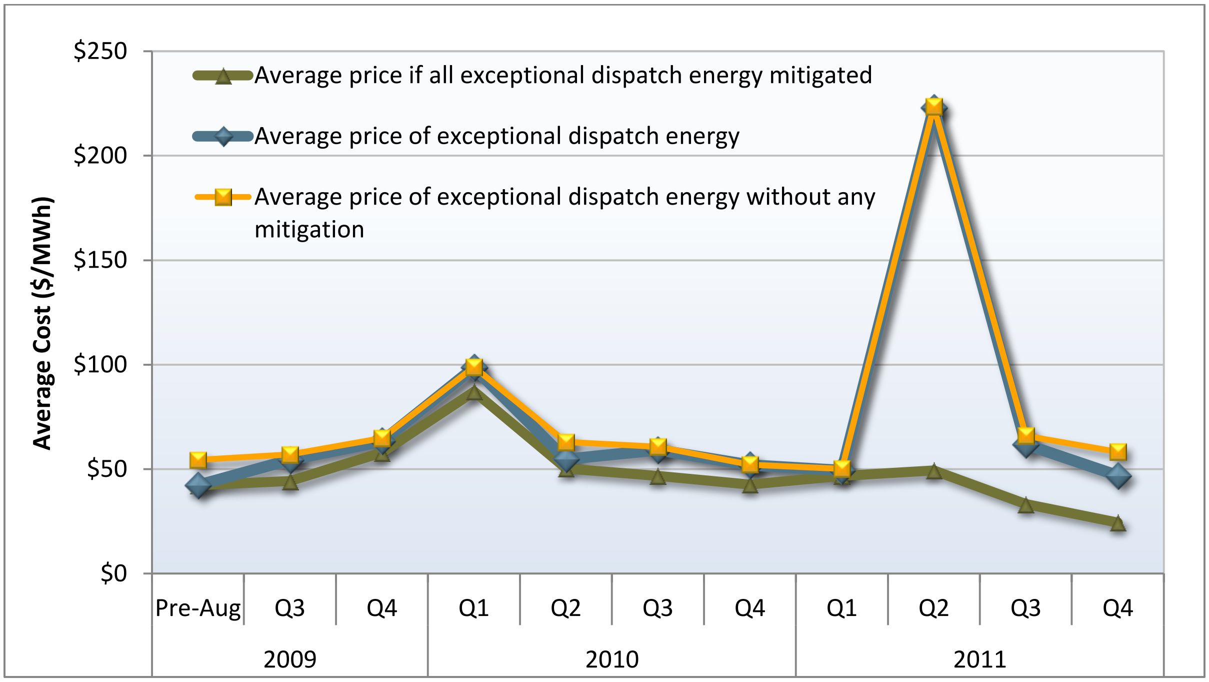
[93] This energy was logged as being needed to ramp a unit up to a level where it had a higher ramp rate and could provide more additional capacity or ancillary service if needed. See Section **Error! Reference source not found.** for further information on he implementation of dynamic ramp rates to address stranded ancillary services.

In the third and fourth quarter of 2011, the increase in the average prices of non-mitigated exceptional dispatches is predominately due to a small subset of units. The resources were exceptionally dispatched for reliability purposes, but were not the lowest cost units available. This caused the separation between what the in-sequence cost would have been and the out-of-sequence energy price actually paid in those intervals. This is indicated by the large gap between the yellow and blue lines compared to the green line.

Figure 6.13 Average prices for out-of-sequence exceptional dispatch energy



6.4.3 Start-up and minimum load bids

Owners of gas-fired generation can choose from two options for their start-up and minimum load bid costs: proxy costs and registered costs.[94] Prior to April 1, 2011, owners electing the registered cost option were required to submit costs for both minimum load and start-up. Starting on April 1, 2011, the options changed allowing participants to elect whichever combination of proxy or registered minimum load and start-up costs they prefer.[95]

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[94] Under the proxy cost option, each unit's start-up and minimum load costs are automatically calculated each day based on an index of daily spot market gas price and the unit's start-up and minimum load fuel consumption as reported in the master file. Unit owners selecting the registered cost option submit fixed monthly bids for start-up and minimum load costs, which are then used by the daily market software. Registered cost bids are capped at 200 percent of projected costs as calculated under the proxy cost option. One of the reasons for providing this bid-based 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 FERC filing September 29, 2009: http://www.caiso.com/23fc/23fcb61b29f50.pdf.

[95] See Start-Up Minimum Load Tariff Amendment in Docket Number ER11-2760-000, January 26, 2011: http://www.caiso.com/2b12/2b12b6a22ed60.pdf.

Capacity under registered cost option

At the start of the nodal market in April 2009, about 25 percent of gas-fired capacity was on the registered cost option for start-up and minimum load bids. This increased to approximately 48 percent by December 2010. As shown in Figure 6.14 and Figure 6.15, a noticeable upward shift in the amount of capacity under the registered cost option for both start-up and minimum load occurred after the April 2011 tariff modifications.

As shown in these figures:

- In December 2011, the portion of natural gas fueled capacity for start-up costs under the registered cost option increased approximately 48 percent from December 2010, while minimum load capacity increased over 16 percent.
- In December 2011, about 61 percent of all natural gas fueled capacity, or approximately 21,000 MW, was on the registered cost start-up option. About 42 percent, approximately 14,000 MW, was on the registered cost option for minimum load bids.
- By the end of 2011, no natural gas fueled capacity solely elected the registered cost minimum load option. Over 17 percent of natural gas fueled capacity chose the registered cost option for start-up costs only.
- The portion of capacity at or near the bid cap for start-up costs has remained large and stable in 2011, as shown in Figure 6.16. In the fourth quarter of 2011, over 76 percent of the registered start-up bids were greater than 180 percent of the calculated fuel costs.
- Registered cost bids for minimum load capacity tend to be lower and range more widely relative to actual minimum load fuel costs, as shown in Figure 6.17. In the fourth quarter, about 12 percent of minimum load bids were less than 120 percent of the bid cap, while 60 percent were greater than 180 percent of the cap.

Figure 6.14 Start-up gas-fired capacity under registered cost option

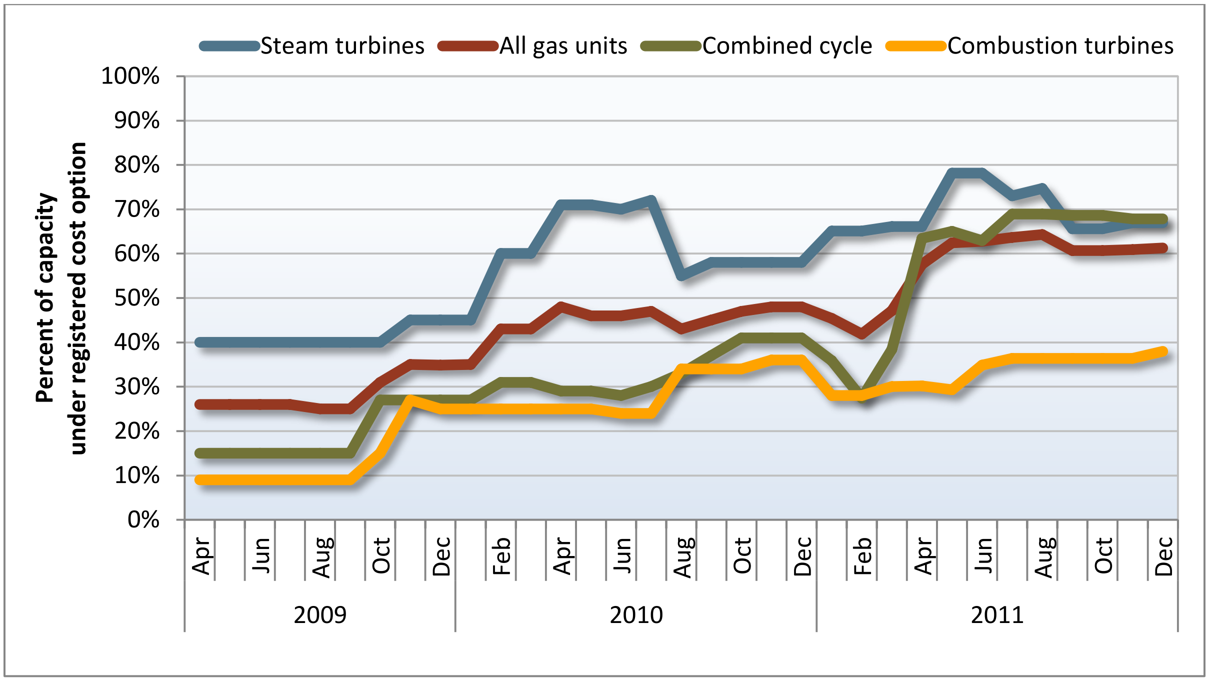


Figure 6.15 Minimum load gas-fired capacity under registered cost option

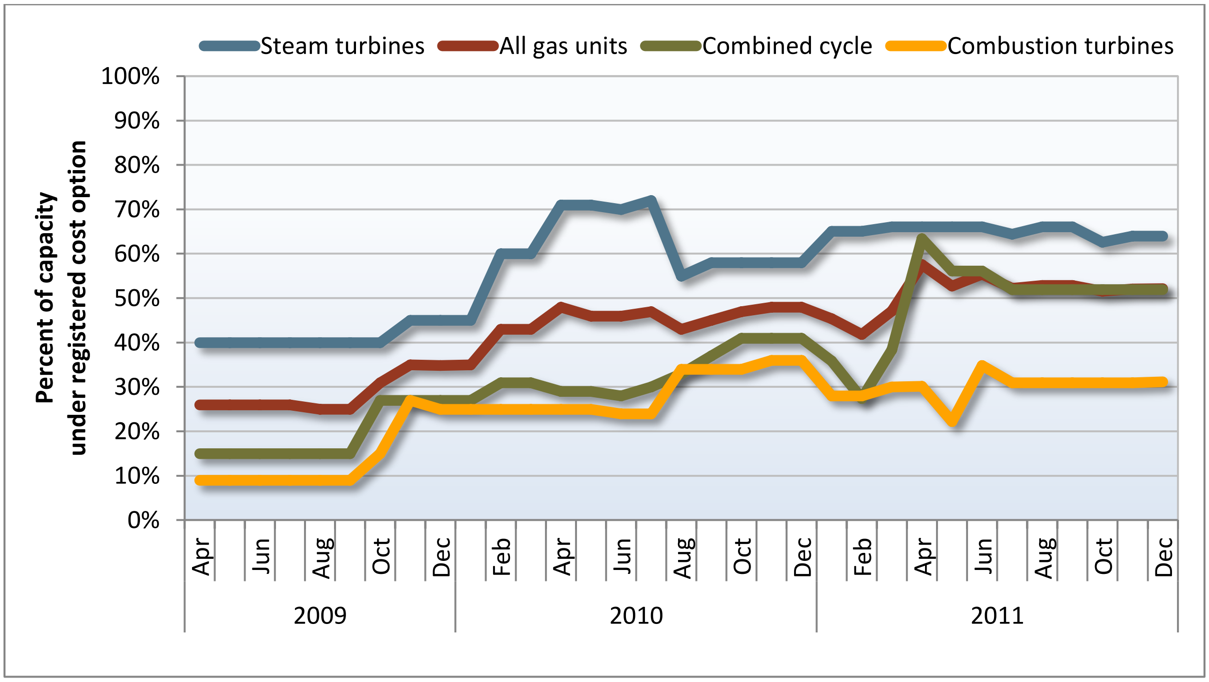


Figure 6.16 Registered cost start-up bids by quarter

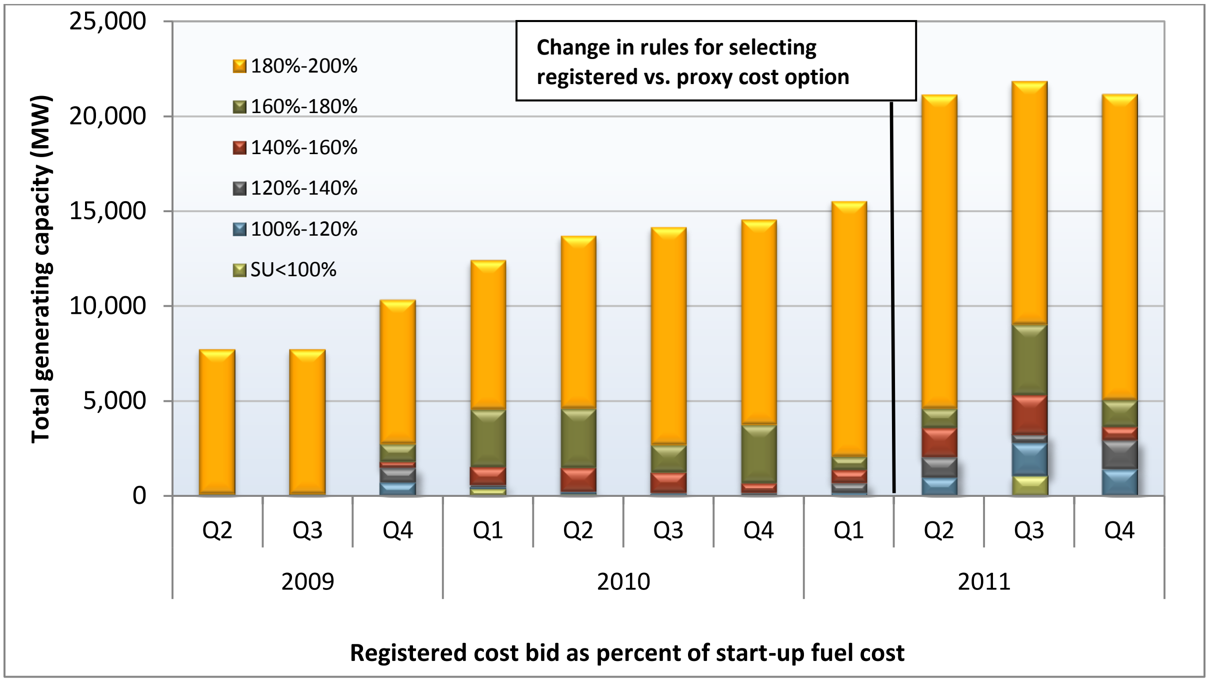
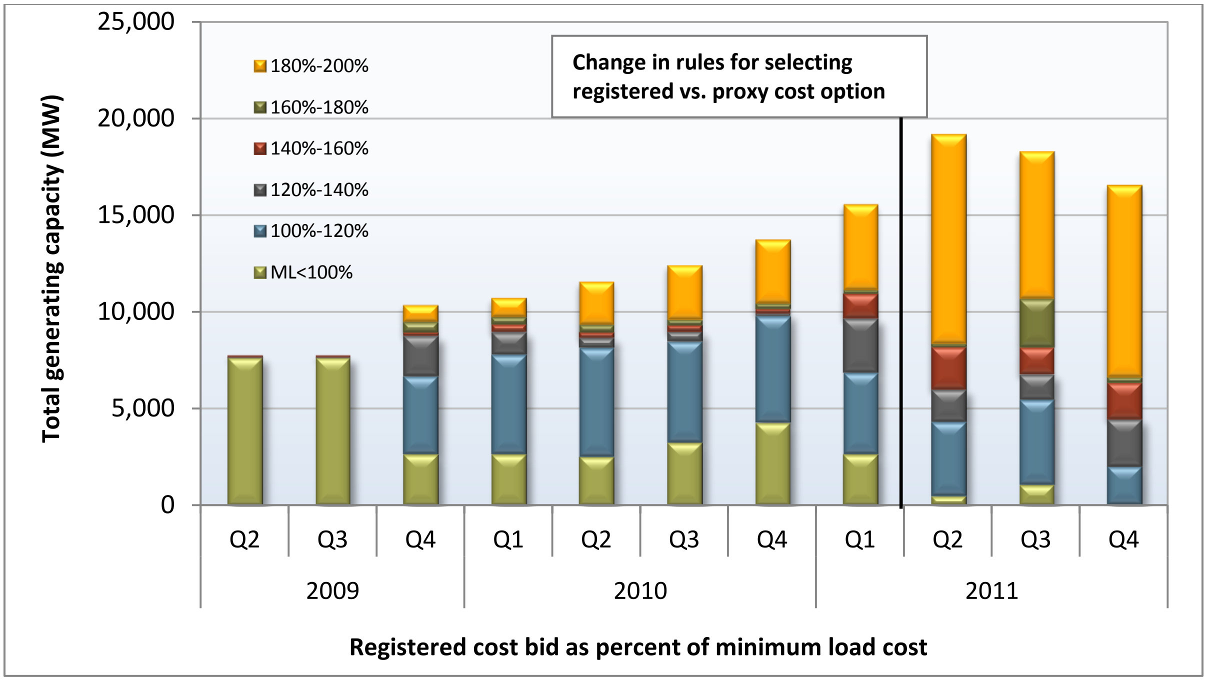


Figure 6.17 Registered cost minimum load bids by quarter



DMM also examined the amount of capacity under the registered cost option by technology.[96] As shown in Figure 6.18 and Figure 6.19:

- Of total natural gas capacity in December 2011, the registered start-up option was chosen by over 69 percent of combined cycles and 66 percent of steam turbines. Only 36 percent of gas turbines elected this option.
- Of total natural gas capacity in December 2011, the registered minimum load option was chosen by over 52 percent of combined cycles and 66 percent of steam turbines. Only 31 percent of gas turbines elected this option.
- Most capacity under the start-up registered cost bid option submitted bids at or near the bid cap. This trend began in December 2010. As shown in Figure 6.18, nearly 70 percent of capacity under the registered cost option submitted start-up bids greater than 180 percent of actual start-up fuel costs.
- Minimum load registered cost bid capacity has a wider range of bid costs than start-up costs. Nearly 30 percent of the bids are less than 140 percent of the actual minimum load proxy costs.
- Generally, steam turbines bid close to the bid cap for both start-up and minimum load costs. Bid costs for gas turbines and combined cycles had a wider range.
- Overall, results of this analysis suggest that the registered cost option for start-up and minimum load bids are heavily skewed toward the 200 percent cap.[97] This is especially true for steam turbine capacity.

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[96] Generation technology consists of steam turbines, gas turbines and combined cycles.

[97] DMM recommended in its third quarter report that the ISO reevaluate the composition of registered costs to determine the validity and effectiveness of the 200 percent cap: http://www.caiso.com/Documents/QuarterlyReport-MarketIssues_Performance-November2011.pdf. Furthermore, DMM continued to support consideration of the inclusion of a fixed component for non-fuel costs associated with start-up and minimum load costs, given that they can be reasonably quantified and verified. The ISO has begun a stakeholder process in 2012 to review commitment costs; more information can be found here: http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostsRefinement2012.aspx.

Figure 6.18 Registered cost start-up bids by generation type – December 2011

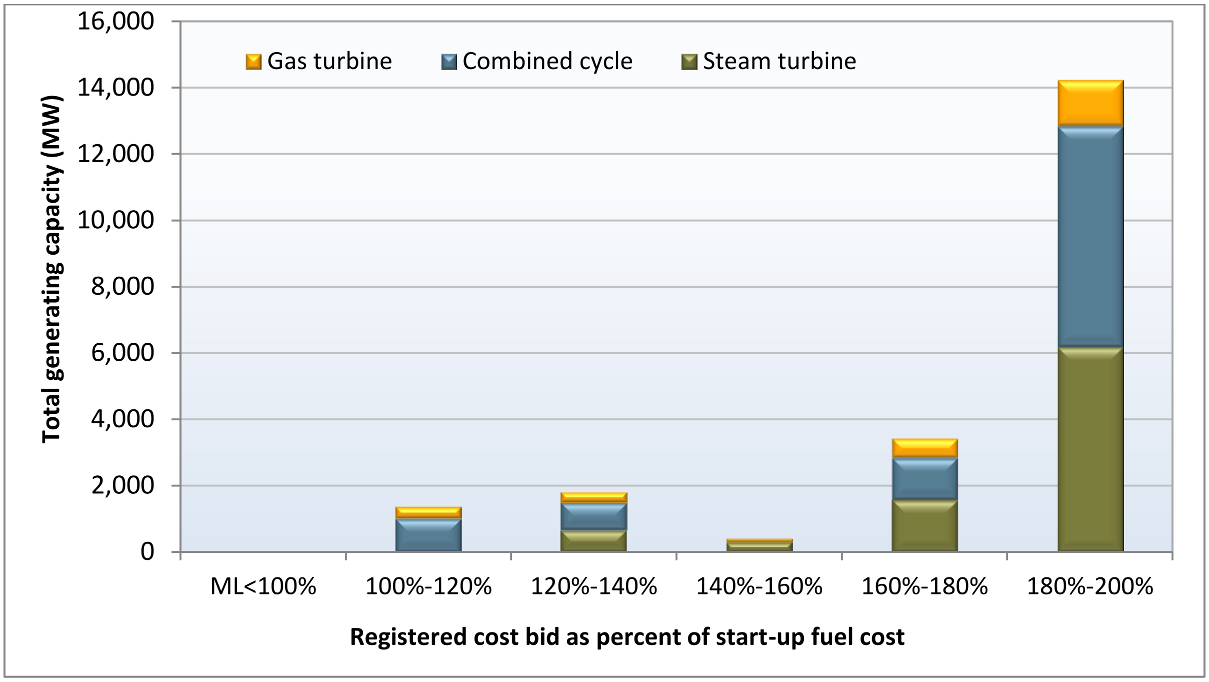
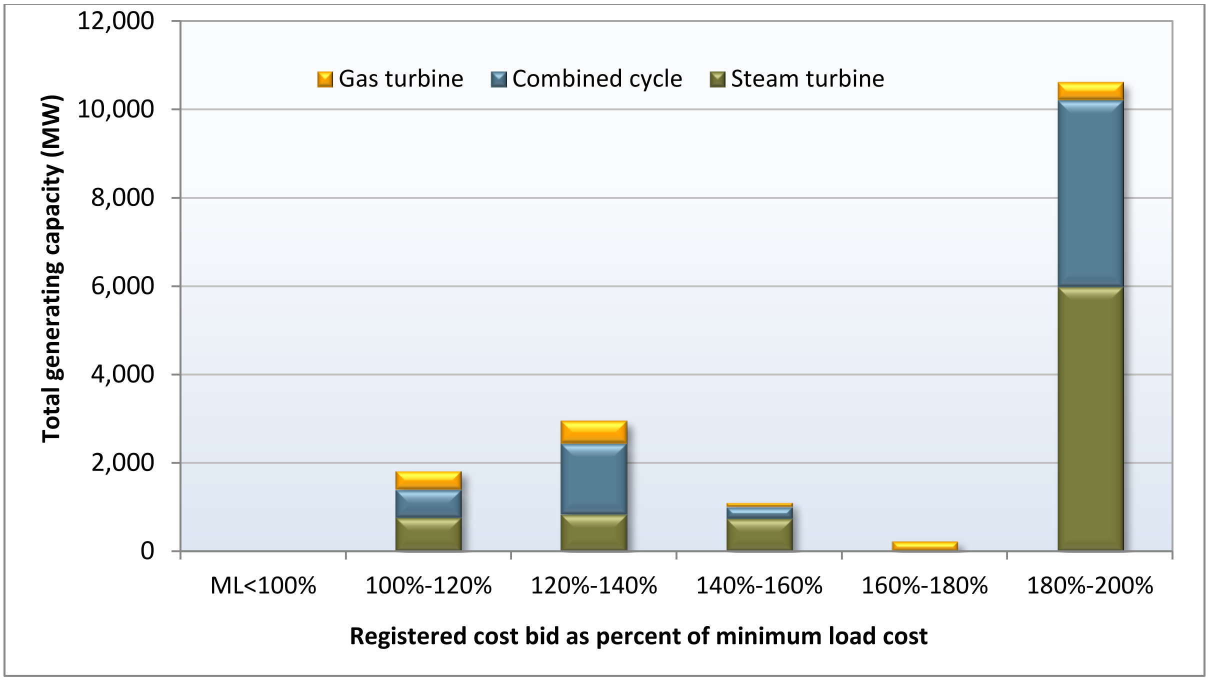


Figure 6.19 Registered cost minimum load bids by generation type – December 2011



7 Congestion

This chapter provides a review of congestion and the market for congestion revenue rights in 2011. Findings include:

- The frequency and charges for congestion on most major inter-ties connecting the ISO with other balancing authority areas was higher in 2011, particularly for inter-ties connecting the ISO to the Pacific Northwest. This appears primarily due to abundant supplies of relatively low-priced energy from hydro-electric and wind resources in the Northwest.

- Congestion on transmission constraints within the ISO continued to be relatively infrequent and had minimal impact on average overall prices in the different load areas.

- Prices in the San Diego area were impacted the most by internal congestion. However, congestion increased average prices in the San Diego area above the system average by just under $0.85/MWh or about 3 percent. Nearly all of this increase is due to congestion on import limits directly into the SDG&E area.

- Congestion drove prices in the SCE area above the system average prices by about $0.26/MWh or around 1 percent. About 50 percent of this increase was due to the limits on the percentage of load in the SCE area that can be met by total flows on all transmission paths into the SCE area.[98] About 35 percent of this increase was from smaller constraints throughout the time period and about 10 percent of this increase was due to congestion in the north-to-south direction on Path 26.

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

- Average profitability of all congestion revenue rights was close to $0.07/MW in 2011, compared to about $0/MW in 2010. This increase was driven largely by higher levels of congestion on inter-ties in 2011. The most consistently profitable congestion revenue rights continue to be those in the opposite direction of prevailing congestion patterns. Participants are paid for these congestion revenue rights in the auction, but then obligated to pay when congestion occurs.

7.1 Background

Locational marginal pricing enables the ISO to more economically and 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 congestion costs or benefits

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[98] This constraint is designed to ensure that enough generation is being supplied from units within SCE in the event of a contingency that significantly limit imports into SCE or decreases generation within the SCE area.

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 represents the cost savings that would occur if that constraint had one additional megawatt of transmission capacity available in the congested direction. This shadow price is not directly charged to participants; it only indicates an incremental cost on the objective function of the market software of the limited transmission on the binding constraint.

There are three major types of transmission constraints that are enforced in the market model and may impact prices when they become binding:

- Flowgates represent single transmission lines or paths with a single maximum limit.
- Branch groups represent multiple transmission lines with a limit on the total combined flow on these lines.
- Nomograms are more complex constraints that represent interdependencies and interactions between multiple transmission system limitations that must be met simultaneously.

Congestion on inter-ties between the ISO and other balancing areas decreases the price received for energy imports. This congestion also affects payments for congestion revenue rights. However, this congestion has generally had minimal impact on prices for loads and generation within the ISO. This is because when congestion has limited additional imports on one or more inter-ties, additional supply from other inter-ties or from within the ISO has been available at a relatively small increase in price.

7.2 Congestion on inter-ties

The frequency and financial impacts of congestion on most inter-ties connecting the ISO with other balancing authority areas was higher in 2011, particularly for inter-ties connecting the ISO to the Pacific Northwest.

Table 7.1 provides a detailed summary of the frequency of congestion on these inter-ties along with average and total congestion charges from the day-ahead market. The congestion price reported in Table 7.1 is the shadow price for the binding inter-tie constraint. For a supplier or load-serving entity trying to import power over a congested tie point, this congestion price represents the decrease in the price they receive for imports into the ISO. This congestion charge also represents the amount paid to owners of congestion revenue rights that are sourced outside of the ISO at points corresponding to these inter-ties.

Figure 7.1 compares the percentage of hours that major inter-ties were congested in the day-ahead market over the last three years. Figure 7.2 provides a graphical comparison of total congestion charges on major inter-ties in each of the last three years. As shown in these summaries:

- Congestion increased substantially on the two major inter-ties linking the ISO with the Pacific Northwest – the Nevada / Oregon Border (NOB) and the Pacific A/C Intertie (PACI). Total congestion on these two inter-ties increased from $32 million in 2010 to about $74 million in 2011. This reflects the increase in imports from the Northwest resulting from relatively abundant supplies of energy from hydro and wind resources.

- Congestion also increased significantly on the largest inter-tie linking the ISO with the Southwest – Palo Verde. Congestion charges on Palo Verde increased from $21 million in 2010 to about $26 million in 2011. Congestion on this inter-tie was driven up in 2011 when this path was de-rated on several occasions to accommodate transmission maintenance and upgrades.
- The frequency of congestion on the Mead inter-tie linking the ISO to the Southwest dropped from 21 percent to 13 percent, but overall congestion charges on this inter-tie remained about the same at $8.3 million.
- Virtually no congestion occurred on the Inter-mountain Power Project DC Adelanto branch group. Congestion charges for this constraint decreased from $7.9 million in 2010 to less than $190,000 in 2011.

Table 7.1 Summary of import congestion (2009 - 2011)

Import region	Inter-tie	Frequency of import congestion			Average congestion charge ($/MW)			Import congestion charges (thousands)		
		2009	2010	2011	2009	2010	2011	2009	2010	2011
Northwest	PACI	5%	11%	11%	$5.9	$9.2	$9.1	$6,370	$20,194	$48,903
	NOB	5%	7%	8%	$11.0	$12.7	$9.2	$7,078	$12,253	$25,471
	COTPISO	1%	1%	13%	$48.3	$10.9	$24.7	$43,483	$20,968	$629
	Summit	0%	0%	1%	$26.1	$10.0	$46.9	$29,027	$14,884	$317
	Cascade	0%	2%	32%	$15.5	$6.8	$12.0	$1	$78	$2,481
	New Melones	0%	0%	17%	$0.0	$0.0	$33.4	$0	$0	$6,788
	Tracy 230	0%	0%	1%	$0.0	$0.0	$669.4	$0	$0	$3,841
Southwest	Palo Verde	30%	14%	19%	$8.1	$7.0	$10.2	$49,586	$20,712	$25,885
	Mead	15%	21%	13%	$3.8	$5.1	$7.1	$3,728	$8,433	$8,287
	IPP DC Adlanto (BG)	15%	26%	0%	$4.9	$5.9	$11.7	$3,822	$7,859	$186
	IID - SCE	1%	1%	4%	$2.9	$34.0	$9.8	$85	$1,377	$1,579
	El Dorado	12%	1%	2%	$11.1	$11.4	$8.4	$10,126	$1,222	$2,183
	Mona IPP DC (MSL)	0%	0%	14%	$0.0	$0.0	$3.9	$0	$0	$631
	Adlanto SP	7%	1%	0%	$2.4	$5.0	$0.2	$1,312	$389	$0
	Other							$1,009	$312	$205
Total								***$155,628***	***$108,681***	***$127,386***

* The IPP DC Adlanto branch group and the Mona IPP DC market scheduling limit are not inter-ties, but are included here because of their function in limiting imports from the Adlanto / Mona regions and the frequency with which they were binding.

Figure 7.1 Percent of hours with congestion on major inter-ties (2009 – 2011)

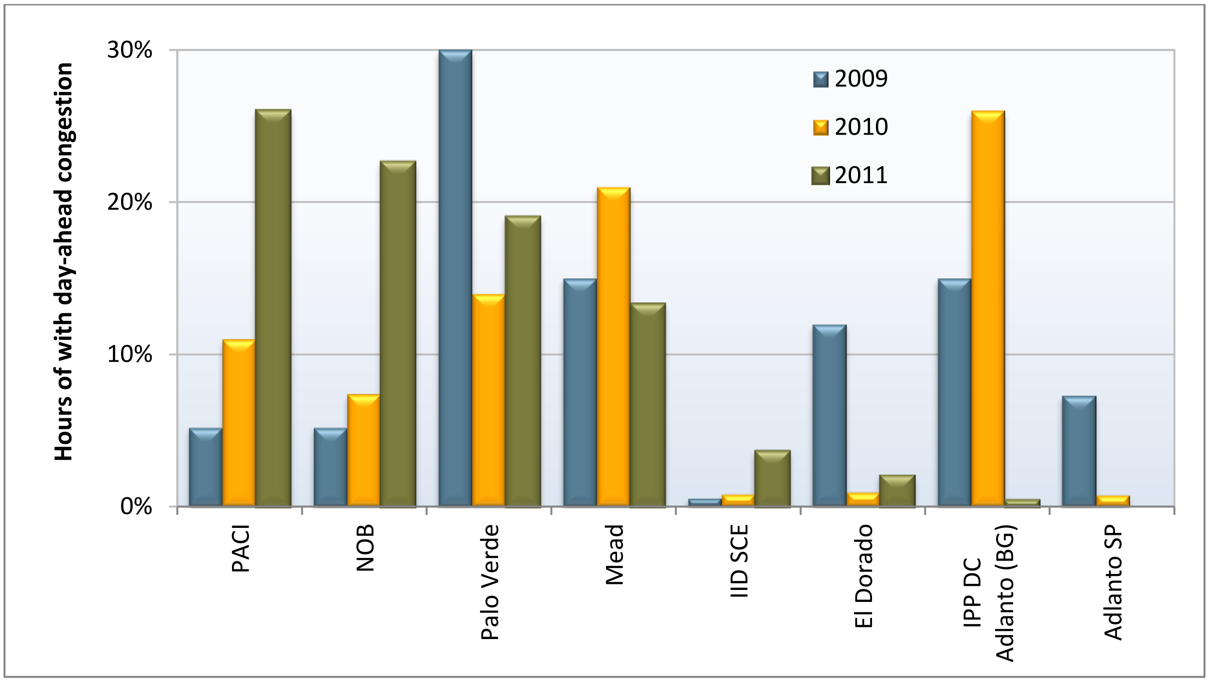
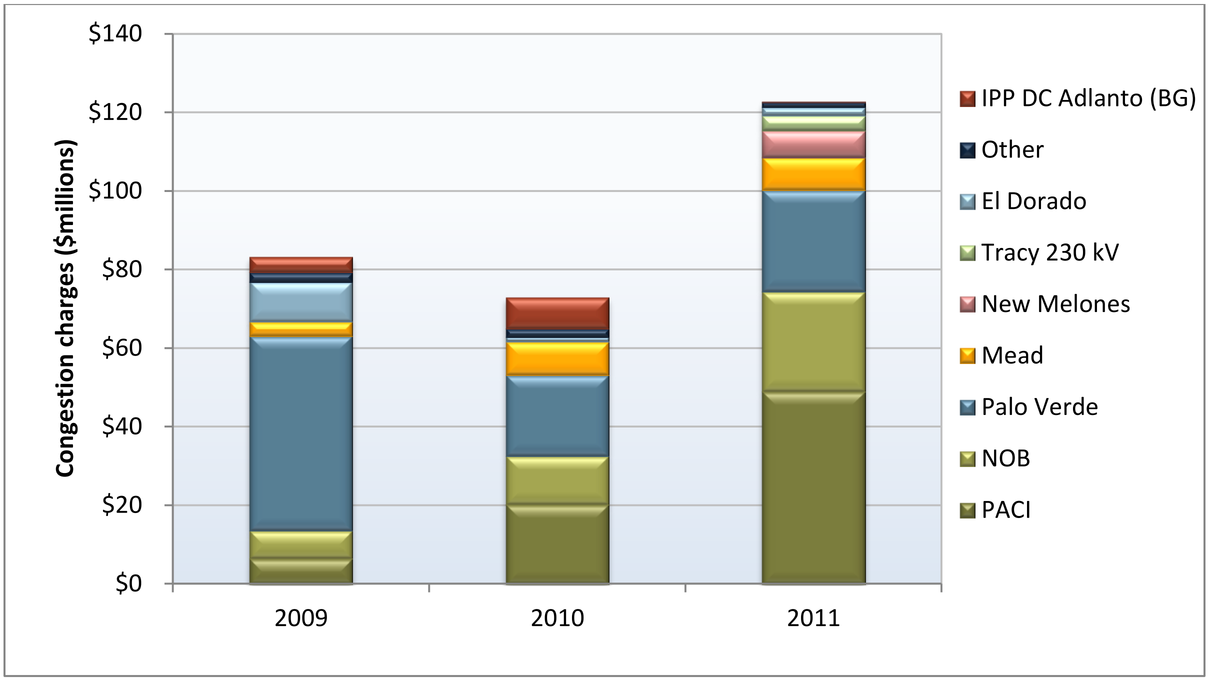


Figure 7.2 Import congestion charges on major inter-ties (2009 – 2011)



7.3 Day-ahead congestion on internal constraints

When a constraint within the ISO system is congested, resources on both sides of the constraint are re-dispatched to maintain flows under the constraint limit. In this case, congestion has a clear and direct impact on prices within the ISO system. In 2011, congestion on numerous internal constraints significantly affected prices during hours when congestion occurred. However, since this internal congestion occurred infrequently, it had a minimal impact on overall day-ahead energy prices.

Price impacts of individual constraints

The impact of congestion on any constraint on each pricing node in the ISO system can be calculated by summing the product of the shadow price of that constraint and the shift factor for that node relative to the congested constraint. This calculation can be done for individual nodes, as well as groups of nodes that represent different load aggregation points or local capacity areas.[99]

Figure 7.3 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. Often congestion on constraints within Northern California increases prices within the PG&E area, but decreases prices in the SCE and SDG&E areas, with the inverse being true of congestion within Southern California.

Table 7.2 provides a more detailed analysis by quarter and shows:

- Congestion occurred on SCE_PCT_IMP_BG primarily in the first three quarters of the year, with the highest number of hours occurring in the second quarter. This led to price increases of around $3.50/MWh in the second and third quarters for SCE and decreases for SDG&E and PG&E of just over $3.00/MWh.
- The SDGE_PCT_UF_IMP_BG was mainly congested in the first two quarters of the year, with most of this congestion occurring during periods of transmission outages. This increased prices in the SDG&E area by over $10/MWh and decreased prices in PG&E and SCE areas by about $1/MWh.
- Path 15 was congested in the south-to-north direction in the fourth quarter of 2011 due to scheduled maintenance. This increased prices in the PG&E area by about $3.32/MWh and decreased prices in the SCE and SDG&E areas by $2.73/MWh during congested hours.
- In the third quarter, congestion on the 30060_Midway_500_24156_Vinvent_500_BR_3_2 line within SCE occurred due to transmission outages. This constraint decreased PG&E prices by about $8/MWh and increased prices in SCE and SDG&E by $5.30/MWh during congested hours.
- Congestion in the north-to-south direction on Path 26 was associated with outages on the Midway – Vincent 500 kV line. Prices in the PG&E area decreased by over $6/MWh and prices in the SCE and SDG&E areas increased by almost $5/MWh during congested hours for the third quarter. Second quarter congestion decreased PG&E prices around -$2.50/MWh and increased SCE and SDG&E area prices by just over $5/MWh.
- The SDGE_IMP_BG constraint was mainly congested in the first two quarters of the year, which was associated with outages. This increased prices in the SDG&E area by about $3.40/MWh in the first

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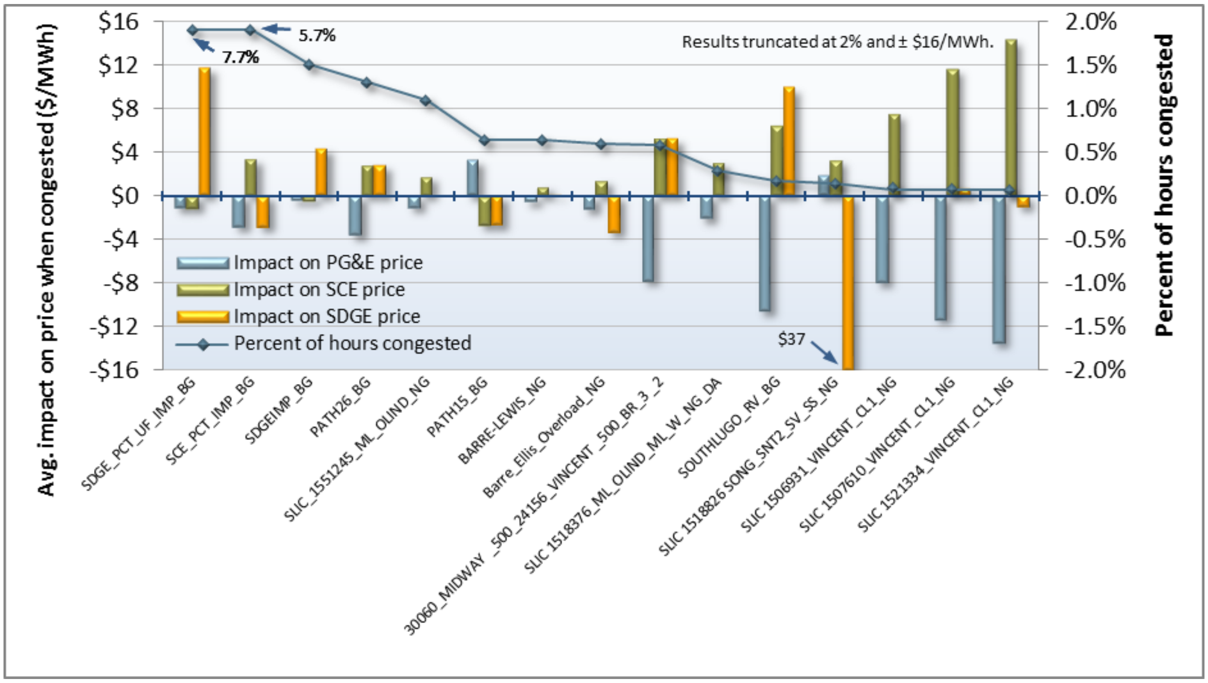
[99] Appendix A of DMM's 2009 annual report provides a detailed description of this calculation for both load aggregation points and prices within local capacity areas.

quarter and $7.50/MWh in the second, and decreased prices in PG&E and SCE areas by about -$0.37/MWh and -$0.78/MWh, respectively.

Figure 7.3 Frequency and impact of congestion on internal constraints (February – December)



As shown in these figures and tables, congestion on some constraints significantly affected prices during hours when congestion occurred. However, since this internal congestion occurred infrequently, it had a minimal impact on overall day-ahead energy prices. Additional analysis and discussion of the impact of congestion on average annual prices for different areas within the ISO is provided in the following section of this chapter.

Impact of average prices

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 that congestion has when it occurs.[100]

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[100] 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 7.2 Impact of congestion on day-ahead prices by load aggregation point (February – December)

		Congested hours				Q1			Q2			Q3			Q4		
Area	Constraint	Q1	Q2	Q3	Q4	PGAE	SCE	SDG&E	PGAE	SCE	SDG&E	PGAE	SCE	SDG&E	PGAE	SCE	SDG&E
PG&E	PATH15_BG				52										$3.32	-$2.73	-$2.73
	30630_NEWARK _230_30703_RAVENSWD_230_BR_1 _1		1						$41.82	-$41.82	-$41.82						
SCE	SCE_PCT_IMP_BG	115	238	114	3	-$2.29	$2.82	-$2.29	-$3.10	$3.64	-$3.10	-$3.16	$3.57	-$3.16	-$0.65	$0.75	-$0.65
	PATH26_BG		61	31	14				-$2.46	$2.02	$2.02	-$6.41	$4.91	$4.91	-$2.95	$1.86	$1.86
	SLIC_1551245_ML_OLIND_NG			89								-$1.13	$1.81	$0.00			
	BARRE-LEWIS_NG		4	6	42				-$0.32	$0.51	-$0.01	-$0.06	$0.50	-$1.47	-$0.66	$0.95	$0.39
	Barre_Ellis_Overload_NG			16	33							-$2.59	$2.71	-$6.76	-$0.66	$0.84	-$1.78
	30060_MIDWAY _500_24156_VINCENT _500_BR_3 _2			47								-$7.83	$5.30	$5.30			
	SLIC 1518376_ML_OLIND_ML_W_NG_DA		23						-$2.16	$3.04	$0.00						
	SOUTHLUGO_RV_BG			14								-$10.64	$6.43	$9.95			
	SLIC 1518826 SONG_SNT2_SV_SS_NG		11						$1.89	$3.31	-$37.66						
	SLIC 1506931_VINCENT_CL1_NG		8						-$8.02	$7.55	$0.00						
	SLIC 1507610_VINCENT_CL1_NG		6						-$11.37	$11.70	$0.72						
	SLIC 1521334_VINCENT_CL1_NG		5						-$13.58	$14.36	-$1.03	$0.00	$0.00	$0.00			
SDG&E	SDGE_PCT_UF_IMP_BG	285	242	95	10	-$1.07	-$1.07	$10.79	-$1.34	-$1.34	$13.66	-$1.01	-$1.01	$11.04	-$0.39	-$0.39	$4.06
	SDGEIMP_BG	85	16	22		-$0.37	-$0.37	$3.44	-$0.78	-$0.78	$7.50	-$0.56	-$0.56	$5.65			

Table 7.3 shows the overall impact of congestion on different constraints on average prices in each load aggregation area in 2011.[101] These results show that:

- Prices in the San Diego area were impacted the most by internal congestion. However, congestion increased average prices in the San Diego area above the system average by just under $0.85/MWh or about 3 percent. Nearly all of this increase is due to congestion on import limits directly into the SDG&E area.
- Congestion drove prices in the SCE area above the system average prices by about $0.26/MWh or around 1 percent. About 50 percent of this increase was due to limits on the percentage of load in the SCE area that can be met by total flows on all transmission paths into the SCE area.[102] About 35 percent of this increase was from a compilation of smaller constraints throughout the time period and about 10 percent of this increase was due to congestion in the north-to-south direction on Path 26.
- The overall impact of congestion on prices in the PG&E area was to reduce prices below the system average by about -$0.35/MWh or about -1 percent. This results from the fact that prices in the PG&E area are lowered when congestion occurs on the constraints that limit flows in the north-to-south direction on Path 26 and constraints limiting flows into the SCE and SDG&E areas.

Table 7.3 Impact of constraints on overall day-ahead prices (February – December)

	PG&E		SCE		SDGE	
Constraint	**$/MWh**	**Percent**	**$/MWh**	**Percent**	**$/MWh**	**Percent**
SDGE_PCT_UF_IMP_BG	-$0.09	-0.29%	-$0.09	-0.28%	$0.91	2.84%
SCE_PCT_IMP_BG	-$0.17	-0.54%	$0.19	0.62%	-$0.17	-0.52%
SDGEIMP_BG	-$0.01	-0.02%	-$0.01	-0.02%	$0.07	0.20%
SLIC 1518826 SONG_SNT2_SV_SS_NG	$0.00	0.01%	$0.00	0.01%	-$0.05	-0.16%
PATH26_BG	-$0.05	-0.15%	$0.04	0.12%	$0.04	0.11%
Barre_Ellis_Overload_NG	-$0.01	-0.02%	$0.01	0.03%	-$0.02	-0.06%
30060_MIDWAY _500_24156_VINCENT _500_BR_3 _2	-$0.04	-0.14%	$0.03	0.10%	$0.03	0.09%
PATH15_BG	$0.02	0.07%	-$0.02	-0.05%	-$0.02	-0.05%
30630_NEWARK _230_30703_RAVENSWD_230_BR_1 _1	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.02%
SOUTHLUGO_RV_BG	-$0.02	-0.06%	$0.01	0.03%	$0.02	0.05%
SLIC_1551245_ML_OLIND_NG	-$0.01	-0.04%	$0.02	0.06%	$0.00	0.00%
BARRE-LEWIS_NG	$0.00	-0.01%	$0.01	0.02%	$0.00	0.00%
SLIC 1518376_ML_OLIND_ML_W_NG_DA	-$0.01	-0.02%	$0.01	0.03%	$0.00	0.00%
SLIC 1507610_VINCENT_CL1_NG	-$0.01	-0.03%	$0.01	0.03%	$0.00	0.00%
SLIC 1506931_VINCENT_CL1_NG	-$0.01	-0.03%	$0.01	0.02%	$0.00	0.00%
SLIC 1521334_VINCENT_CL1_NG	-$0.01	-0.03%	$0.01	0.03%	$0.00	0.00%
Other	$0.05	0.16%	$0.03	0.09%	$0.03	0.10%
Total	-$0.35	-1.1%	$0.26	0.8%	$0.83	2.6%

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[101] Due to data limitations, this analysis only includes congestion for February through December 2012.

[102] This constraint is designed to ensure that enough generation is being supplied from units within SCE in the event of a contingency that significantly limit imports into SCE or decreases generation within the SCE area.

Table 7.4 shows the overall impact of congestion on day-ahead prices within each of the local capacity areas in 2010 and 2011.[103] The difference in the average congestion component for generation nodes within different local capacity areas was minimal. This analysis indicates that:

- Differences in day-ahead prices within the PG&E area are due to congestion and have remained relatively low in 2010 and 2011. For instance, congestion only raised prices in the Humboldt area about $0.50/MWh higher than prices in the Bay Area in 2011.
- In the SCE area, prices in the Big-Creek Ventura area were only about $0.09/MWh higher than prices in the LA Basin area due to congestion.

Table 7.4 Day-ahead congestion by local capacity area

		Average of Congestion LMP as Percent of System LMP			
LAP	LCA	2010 Avg. LMP (congestion)	2010 Avg.	2011 Avg. LMP (congestion)	2011 Avg.
PG&E	Bay Area	-$0.12	-0.3%	-$0.34	-1.1%
	Fresno	-$0.16	-0.4%	-$0.49	-1.6%
	Humboldt	$0.60	1.7%	$0.12	0.2%
	Kern	-$0.19	-0.5%	-$0.42	-1.4%
	North Coast North Bay	-$0.19	-0.5%	-$0.48	-1.6%
	Sierra	-$0.15	-0.4%	-$0.28	-1.2%
	Stockton	-$0.34	-0.9%	-$1.40	-4.7%
SCE	Big Creek-Ventura	$0.18	0.5%	$0.23	0.8%
	LA Basin	$0.18	0.5%	$0.14	0.5%
SDG&E	San Diego	-$0.11	-0.3%	$0.72	2.5%

7.4 Consistency of day-ahead and real-time congestion

Because most load and generation is scheduled in the day-ahead market, congestion in this market has the greatest overall market impact. Congestion revenue rights are also settled based on day-ahead prices. When real-time congestion occurs, it sometimes results in very high prices because the ability to re-dispatch resources in real-time to relieve congestion is much more limited. However, the overall cost impact of this real-time congestion was very low because of the high level of day-ahead scheduling.

Nevertheless, the consistency of day-ahead congestion with congestion in the hour-ahead and real-time energy markets provides a potential indicator of the degree to which the market and network model efficiently model and manage similar conditions and congestion. For example, if a constraint is frequently not binding in the day-ahead market but is in the real-time market, this may warrant further review of how the constraint is modeled in the day-ahead and real-time markets. Other factors such as loop flow and conforming of constraints may contribute to this trend.

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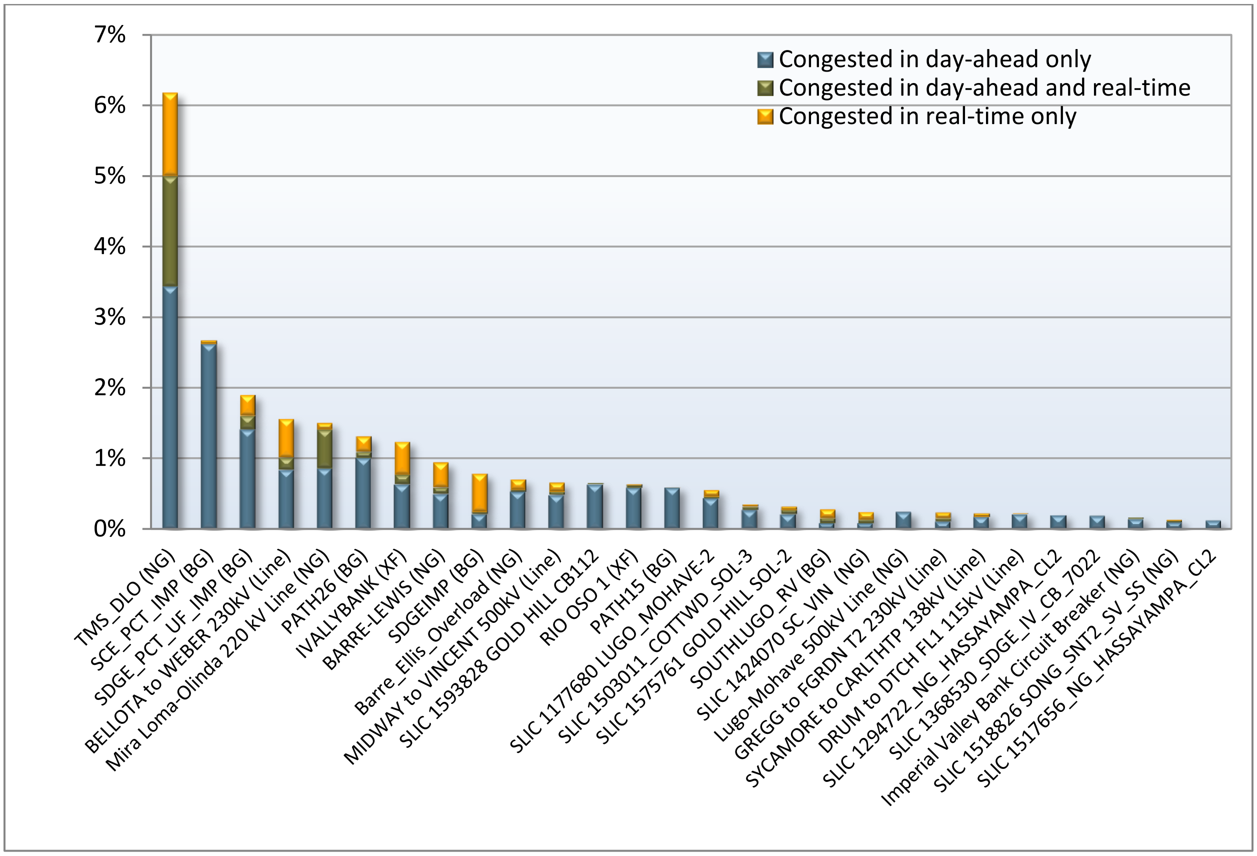
[103] Unlike the previous tables, this table includes congestion that occurred throughout all of 2011.

Figure 7.4 compares the frequency and consistency of congestion on binding constraints influencing prices at load aggregation points in 2011.[104] Table 7.5 provides a more detailed comparison of these data.

Figure 7.4 Consistency of congestion in day-ahead and real-time markets



As shown in Figure 7.4, congestion was extremely low in both the day-ahead and real-time markets on most internal constraints. On many constraints, the overall frequency of congestion in the day-ahead market tended to be slightly higher than in the real-time. This may reflect the fact that in real-time, operators can adjust constraint limits upwards to avoid congestion if actual real-time flows are observed to be lower than flows calculated by the market software. This is discussed in more detail in Section 7.5.

Table 7.6 provides a more detailed comparison of the frequency and consistency of congestion on inter-ties with neighboring control areas in the day-ahead and hour-ahead markets, including:

- The Cascade inter-tie was congested 32 percent of the time and the Pacific AC inter-tie about 26 percent in the day-ahead market, primarily because of planned outages and line maintenance.

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[104] SPRNG GJ to Mi-Wuk 115 kV (Line) and the EXCHECQUR to LE GRAND 115 kV (Line) are not included as the impact on the LMP is small. However, the SPRNG GJ to MI-Wuk 115 kV (Line) was 19.1 percent congested in the day-ahead market alone, 1.8 percent congested in the real-time market alone and 5.3 percent congested in both. EXCHECQUR to LE GRAND 115 kV (Line) was 1.6 percent congested in the day-ahead market alone, 0.9 percent congested in the real-time market alone and 2.3 percent congested in both markets.

- The Nevada / Oregon Border (NOB) inter-tie was congested about 23 percent of the time. This was also primarily because of planned outages and line maintenance.

Table 7.5 Summary of day-ahead and real-time congestion on internal constraints

Constraint Name	Average Binding Limit (MW)	Total Binding Frequency in IFM	Total Binding Frequency in RTD	Binding in IFM Only		Binding in RTD Only		Binding in Both IFM and RTD		
				Frequency of Congestion	Average Shadow Price	Frequency of Congestion	Average Shadow Price	Freq. of Cong.	Avg. SP IFM	Avg. SP RTD
SPRNG GJ to MI-WUK 115kV (Line)	96	29.0%	7.6%	23.5%	$11	2.1%	$44	5.5%	$14	$39
EXCHEQUR to LE GRAND 115kV (Line)	56	18.6%	3.3%	16.3%	$23	0.9%	$199	2.3%	$24	$74
SDGE_PCT_UF_IMP (BG)	1,540	7.4%	1.7%	6.2%	$12	0.5%	$158	1.2%	$18	$74
LARKIN to POTRERO 115kV (Line)	155	6.9%	0.7%	6.7%	$10	0.5%	$854	0.2%	$7	$913
IPPDCADLN (BG)	444	6.8%	2.7%	5.9%	$11	1.8%	$73	0.9%	$11	$70
SCE_PCT_IMP (BG)	6,589	5.9%	0.4%	5.8%	$6	0.3%	$208	0.1%	$3	$26
TMS_DLO (NG)	385	5.0%	2.7%	3.4%	$65	1.2%	$847	1.6%	$85	$758
DRUM to BRNSWKT2 115kV (Line)	77	3.2%	0.0%	3.2%	$38	0.0%	.	0.0%	.	.
PALERMO to WYANDJT2 115kV (Line)	61	2.9%	0.5%	2.6%	$20	0.2%	$86	0.3%	$19	$31
ULTRA JT to ULTR-RCK 115kV (Line)	31	2.2%	0.0%	2.2%	$10	0.0%	.	0.0%	.	.
KESWICK to STLLWATR 0.0kV (Line)	21	1.9%	0.1%	1.9%	$23	0.1%	$604	0.0%	$25	$1,000
J.HINDS to MIRAGE 230kV (Line)	306	1.8%	0.7%	1.5%	$17	0.4%	$387	0.3%	$60	$94
GRIZ JCT to BIG BEN2 115kV (Line)	65	1.8%	0.1%	1.7%	$13	0.1%	$77	0.1%	$11	$51
BELLOTA to WEBER 230kV (Line)	309	1.6%	1.0%	1.3%	$53	0.7%	$735	0.3%	$50	$1,000
SDGEIMP (BG)	2,188	1.6%	0.7%	1.5%	$5	0.6%	$376	0.1%	$4	$91
BRNSWKT1 to DTCH2TAP 115kV (Line)	75	1.6%	0.0%	1.6%	$54	0.0%	.	0.0%	.	.
Mira Loma-Olinda 220 kV Line (NG)	1,406	1.4%	0.6%	0.9%	$28	0.1%	$698	0.6%	$56	$181
MISSON to POTRERO 115kV (Line)	136	1.4%	0.1%	1.4%	$35	0.1%	$1,000	0.0%	.	.
ELECTRA to BELLOTA 230kV (Line)	174	1.4%	0.1%	1.4%	$170	0.0%	$51	0.0%	$64	$34
PATH26 (BG)	2,247	1.2%	0.6%	1.0%	$7	0.4%	$123	0.2%	$7	$66
ROUND MT to TABLE MT 500kV (Line)	1,890	1.1%	0.2%	1.0%	$19	0.2%	$56	0.1%	$24	$28
HUMBSB_BK (BG)	52	1.1%	0.1%	1.1%	$19	0.1%	$281	0.0%	$2	$502
T-133 METCALF (NG)	145	1.0%	0.2%	1.0%	$12	0.2%	$1,371	0.0%	$23	$1,000
CASCADE to STLLWATR 0.0kV (Line)	29	1.0%	0.1%	1.0%	$30	0.1%	$356	0.0%	.	.
CERTANJ2 to LE GRAND 115kV (Line)	68	1.0%	0.3%	1.0%	$16	0.3%	$300	0.0%	$22	$118
SMRTSVLE to YUBAGOLD 0.0kV (Line)	24	0.9%	0.1%	0.9%	$214	0.1%	$453	0.0%	$24	$333
MELNS JB to VLYHMTP1 115kV (Line)	55	0.9%	0.2%	0.8%	$33	0.2%	$386	0.1%	$34	$429
PEASE to E.MRY J1 115kV (Line)	95	0.9%	0.4%	0.6%	$24	0.2%	$22	0.3%	$23	$28
IVALLYBANK (XF)	1,000	0.8%	0.8%	0.6%	$10	0.7%	$63	0.1%	$3	$215
SLIC 1593828 GOLD HILL CB112	95	0.7%	0.0%	0.6%	$37	0.0%	.	0.0%	$700	$144
RIO OSO 1 (XF)	130	0.6%	0.1%	0.6%	$33	0.0%	$1,000	0.0%	$24	$1,109
BARRE-LEWIS (NG)	1,470	0.6%	0.5%	0.5%	$15	0.4%	$393	0.1%	$16	$136
PATH15 (BG)	2,522	0.6%	0.0%	0.6%	$7	0.0%	$1,000	0.0%	.	.
Barre_Ellis_Overload (NG)	1,320	0.6%	0.2%	0.5%	$41	0.2%	$366	0.0%	$5	$63
MIDWAY to VINCENT 500kV (Line)	1,492	0.5%	0.2%	0.5%	$32	0.1%	$516	0.1%	$50	$460

Table 7.6 Summary of day-ahead and hour-ahead congestion on inter-ties

Inter-Tie name	Full (Import) Rating (MW)	Total Binding Frequency in IFM	Total Binding Frequency in HASP	Binding in IFM Only		Binding in HASP Only		Binding in IFM and HASP		
				Binding Frequency	Avg. Shadow Price	Binding Frequency	Avg. Shadow Price	Binding Frequency	Avg. SP IFM	Avg. SP HASP
CASCADE_ITC	80	32.2%	18.2%	18.1%	$11	4.1%	$47	14.1%	$15	$53
PACI_ITC	3200	26.0%	23.0%	12.1%	$8	9.1%	$13	13.9%	$11	$16
NOB_ITC	1564	22.6%	21.0%	10.1%	$7	8.5%	$20	12.5%	$11	$19
PALOVRDE_ITC	3328	19.0%	8.3%	13.0%	$10	2.3%	$19	6.0%	$15	$18
MEAD_ITC	1460	13.3%	9.7%	7.3%	$6	3.7%	$13	6.0%	$8	$21
COTPISO_ITC	33	12.5%	5.8%	8.8%	$26	2.1%	$58	3.7%	$23	$55
IID-SCE_ITC	600	3.7%	0.0%	3.6%	$10	0.0%	$47	0.0%	$17	$62
ELDORADO_ITC	1655	2.1%	1.5%	1.5%	$8	0.9%	$25	0.6%	$13	$17
SUMMIT_ITC	120	1.3%	2.0%	0.9%	$75	1.5%	$62	0.4%	$289	$65
SILVERPK_ITC	17	0.0%	0.1%	0.0%	$2	0.1%	$29	0.0%	$1	$76

Day-ahead and real-time price differences by local capacity area

This section provides a more detailed analysis of locational price differences in the day-ahead and real-time markets because of congestion. Locations examined in this analysis represent the aggregation of all generation nodes within the local capacity areas and sub-areas used for determining local resource adequacy requirements (see Section 1.1.2). These areas have been identified as the major transmission constrained load pockets in the system.

As noted above, day-ahead and real-time prices in local capacity areas can diverge as a result of differences in congestion between these two markets. Table 7.7 and Table 7.8 show quarterly average peak hour and off-peak hour price differences by local capacity area, and also include the results for different sub-regions within the Bay Area[105] and Los Angeles local capacity areas. Various shades of red in the tables indicate areas where average monthly real-time prices were higher than day-ahead prices, while various shades of blue indicate areas where average monthly real-time prices were lower.

As shown in Table 7.7 and Table 7.8, differences in day-ahead and real-time prices between local capacity areas and sub-areas within each load aggregation point were very limited in 2011. This reflects that divergences in day-ahead and real-time prices have been primarily driven by specific grid and market conditions rather than congestion. However, there are specific examples of congestion related differences impacting the peak and off-peak hours:

- In the Bay Area, the San Francisco local capacity sub-area experienced price divergence in the third quarter. This was due to a forced outage on the A-H-W #2 115 kV (Bayshore to Potrero section) cable.
- The Sierra sub-area within NP26 experienced price divergence in the last two quarters of 2011. This was primarily due to forced outages on the Drum-Rio Oso #1 115 kV line and the Drum-Grass Valley-Weimar 70 kV line.
- In SP26, the San Diego sub-area experienced price divergence in the first and second quarters of 2011. This was primarily due to the South of SONGS branch group and the San Diego under-frequency import branch group.[106] These constraints were impacted by the outage of the Imperial Valley-North Gila 500 kV line and the Imperial Valley-San Miguel 500 kV line. Also, the San Diego/CFE import branch group was limited due to scheduled outages on the Miguel Sycamore Canyon-Otay Mesa 230 kV line. Additional outages impacting the sub-area included scheduled work on the North Gila-Hassayampa 500 kV line.
- The limit on the Humboldt branch group was conformed for grid reliability. This issue was outlined in a previous technical bulletin.[107]
- Price divergence occurred in the LA Basin (Western) sub-area in the first quarter. The divergence is associated with the SCE percent import branch group and the South of Lugo RV branch group. This congestion was primarily associated with outages on the Devers-Palo Verde 500 kV line, the Mira

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[105] The full network model database 55 was put into production on August 11, 2011. This incorporated the termination of generation within the San Francisco Bay Area, e.g. the Potrero Generating Station Units 3, 4, 5 and 6.

[106] See *Technical Bulletin 2010-09-03: Local San Diego Area 25% Minimum Generation Requirement*, http://www.caiso.com/2818/281883a449830.pdf.

[107] In September 2010, the ISO automated the enforcement of an under-frequency import limit in the market model to meet the 25 percent minimum generation requirement for the local San Diego area *Technical Bulletin 2010-11-01 Minimum Generation Online Commitment in Humboldt Area*, November 24, 2010, http://www.caiso.com/2858/2858789a3c1c0.pdf.

Loma 500 kV bank, the Midway-Vincent #3 500 kV line, the Santa Clara-Vincent 220 kV line, the Coachella Valley-Devers 220 kV line, the La Fresa-Hinson 230 kV line and the Lugo-Mira Loma #2 500 kV line.

Table 7.7 Average difference between real-time and day-ahead price by local capacity area – peak hours[108]

		2010				2011			
Region	**LCA (Sub-Area)**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
NP26	Humboldt	-1%	-3%	-5%	19%	17%	-11%	-14%	-9%
	Sierra	-1%	6%	-1%	17%	13%	-11%	-7%	0%
	North Coast North Bay	-1%	8%	-1%	17%	13%	-11%	-12%	-7%
	Bay Area (Pittsburg)	-1%	10%	-1%	17%	12%	-11%	-12%	-7%
	Bay Area (San Francisco)	0%	11%	6%	29%	11%	-12%	-24%	N/A
	Bay Area (San Jose)	-1%	12%	-1%	18%	13%	-10%	-12%	-7%
	Bay Area (Other)	-1%	12%	-1%	17%	13%	-11%	-11%	-7%
	Stockton	-1%	-13%	-13%	17%	13%	-9%	-9%	-4%
	Fresno	-1%	7%	-1%	17%	13%	-12%	-12%	-6%
SP26	Kern	-2%	7%	-1%	18%	12%	-11%	-13%	-8%
	Big Creek-Ventura	19%	8%	18%	22%	15%	1%	-10%	-4%
	LA Basin (Eastern)	16%	7%	23%	12%	10%	-6%	-9%	-6%
	LA Basin (Western)	17%	8%	21%	26%	20%	-1%	-10%	-2%
	LA Basin (Other)	17%	8%	21%	29%	12%	-5%	-10%	-5%
	San Diego	3%	10%	16%	46%	21%	-5%	-6%	-4%
	No LCA	2%	7%	3%	18%	13%	-10%	-14%	-8%

Table 7.8 Average difference between real-time and day-ahead price by local capacity area – off-peak hours[109]

		2010				2011			
Region	**LCA (Sub-Area)**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
NP26	Humboldt	-5%	36%	-7%	20%	25%	27%	-5%	-6%
	Sierra	-4%	55%	-5%	16%	21%	34%	6%	-3%
	North Coast North Bay	-4%	55%	-4%	17%	20%	33%	1%	-4%
	Bay Area (Pittsburg)	-4%	55%	-5%	16%	20%	34%	1%	-5%
	Bay Area (San Francisco)	-4%	55%	-4%	17%	21%	33%	0%	N/A
	Bay Area (San Jose)	-4%	55%	-4%	17%	21%	33%	2%	-4%
	Bay Area (Other)	-4%	56%	-5%	16%	21%	34%	3%	-5%
	Stockton	-4%	30%	-20%	16%	21%	30%	6%	-4%
	Fresno	-4%	55%	-4%	16%	21%	34%	2%	-4%
SP26	Kern	-4%	53%	-4%	17%	21%	34%	1%	-6%
	Big Creek-Ventura	0%	52%	-2%	18%	24%	28%	-1%	-5%
	LA Basin (Eastern)	0%	52%	-1%	18%	25%	29%	-2%	-5%
	LA Basin (Western)	0%	53%	-2%	19%	25%	29%	-2%	-5%
	LA Basin (Other)	1%	53%	-2%	19%	25%	29%	-1%	-5%
	San Diego	-4%	54%	-2%	23%	12%	21%	0%	-5%
	No LCA	-3%	55%	-4%	17%	22%	37%	0%	-5%

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[108] See footnote 105. This causes values in the fourth quarter in 2011 to be not applicable (N/A).

[109] See footnote 105. This causes values in the fourth quarter in 2011 to be not applicable (N/A).

7.5 Conforming constraint limits

Constraint limits in the market software are sometimes adjusted or conformed to account for differences in flows calculated by the market model and actual flows observed in real-time. The two most common reasons to adjust transmission limits are to:

- Achieve greater alignment between the energy flows calculated by the market software and those observed or predicted in real-time operation across various paths. For example, operators sometimes adjust operating limits upward to avoid *phantom congestion* in the day-ahead or real-time market. Phantom congestion refers to cases when congestion occurs in the market model when the actual physical flows are below the limit in the market model. In other cases, operators adjust constraints in the day-ahead market to mitigate the potential for congestion occurring in the real-time market.

- Set prudent operating margins, consistent with good utility practice, to ensure reliable operation under conditions of unpredictable and uncontrollable flow volatility.

Table 7.9 lists all constraints conformed in the real-time market. This table only presents the statistics calculated for intervals in which the conforming action moved the effective limit from the actual limit. As shown in Table 7.9:

- A total of 17 constraints were conformed greater than 3 percent of the time. Only nine of these constraints were conformed in real-time more than 20 percent of the time.

- There was strong consistency in conforming between the hour-ahead and real-time markets in both frequency and level of adjustment.

- A small portion of all constraints were conformed in the real-time market during a significant percentage of hours. Only 11 constraints were conformed over seven percent of the hours, with only nine being conformed between 20 and 97 percent of the time.

- Of the 17 constraints listed in Table 7.9 about 25 percent – or 4 constraints – were conformed only in the upward direction to avoid congestion that was not actually occurring based on observed flows.

- The TMS_DLO nomogram and the SDG&E import limit branch group were conformed mostly downward. Operators tend to conform down the operating limit of these major transmission lines to maintain an adequate reliability margin. The margin ensures the flows stay within the lines' operating limits, even when sudden unpredictable flow changes occur in real-time.

Figure 7.10 compares the consistency of conforming limits in real-time to hour-ahead for every interval. This analysis indicates conforming performed in the hour-ahead and real-time markets is consistently applied across both markets.

Congestion in the day-ahead market is reviewed on a regular basis to determine the need for conforming the constraints' operating limits. However, the market limit of constraints was rarely conformed in the day-ahead market. Table 7.11 lists all internal constraints conformed in the day-ahead market. The majority of the conformed hours were conformed upward to account for transmission outages and inconsistencies between the market software and actual values.

Table 7.9 Real-time congestion and conforming of limits by constraint

Flowgate name	Conformed intervals	Conformed upward				Conformed downward			
		Conformed interval	Average conformed limit	Congested intervals	Average shadow price	Conformed interval	Average conformed limit	Congested intervals	Average shadow price
LUGO_VINCENT (NG)	98.7%	98.6%	135			0.1%	74		
TRNBAY (MSL)	61.8%	61.8%	100						
T-163-Magunden-Pastoria (NG)	58.3%	58.3%	149			0.0%	95		
T-133 (NG)	49.2%	37.7%	111	0.00%	$40	11.5%	99	0.01%	$4,133
T-151 SOL-1 (NG)	46.7%	6.6%	121			40.1%	82	0.01%	$775
TMS_DLO (NG)	38.5%					38.5%	81	1.60%	$918
PATH26 (BG)	36.1%	34.8%	200			1.3%	85	0.05%	$23
IPPDCADLN (BG)	20.7%	20.7%	100						
T-167 SOL-2 (NG)	20.0%	20.0%	106						
SPRNG GJ to MI-WUK 115kV (Line)	18.8%	4.9%	106		$39	13.9%	92	0.79%	$36
EXCHEQUR to LE GRAND 115kV (Line)	14.1%	11.7%	107	0.13%	$47	2.4%	92	0.69%	$51
PATH26_N-S	6.5%	0.1%	165			6.4%	56	0.39%	$176
SDGE_PCT_UF_IMP (BG)	5.8%	4.4%	108			1.4%	93	0.13%	$106
GOLD HILL #2-115kV BUS (NG)	4.1%					4.1%	82	0.00%	$1,000
LARKIN to POTRERO 115kV (Line)	3.9%	3.9%	107	0.06%	$956	0.0%	95		
BELLOTA to WEBER 230kV (Line)	3.8%	2.6%	113	0.02%	$535	1.2%	93	0.24%	$1,070
PLACER to BELL PGE 115kV (Line)	3.0%	2.9%	120			0.1%	94		

Table 7.10 Conforming of constraint limits in hour-ahead and real-time markets

Flowgate name	Conforming in RTD	Conforming Level Match in RTD and HASP	Conforming Level Does not Match in RTD and HASP	Avg. Conforming Level Match in RTD and HASP (%)	Avg. Conforming Level Does not Match in RTD and HASP (%)
SPRNG GJ to MI-WUK 115kV (Line)	13.9%	11.5%	2.4%	95	92
EXCHEQUR to LE GRAND 115kV (Line)	10.5%	8.2%	2.3%	104	100
SDGE_PCT_UF_IMP (BG)	4.7%	4.3%	0.4%	104	102
PATH26 (BG)	4.3%	3.6%	0.7%	178	90
BELLOTA to WEBER 230kV (Line)	2.7%	2.4%	0.3%	105	96
TRNBAY (MSL)	2.6%	2.6%		100	100
LARKIN to POTRERO 115kV (Line)	2.3%	2.0%	0.2%	109	107
VICTVL (BG)	2.2%	1.4%	0.8%	89	88
KESWICK to STLLWATR 0.0kV (Line)	2.1%	2.0%	0.1%	187	129
SCE_PCT_IMP (BG)	2.0%	1.8%	0.2%	107	106
SUTTEROBANION (BG)	2.0%	2.0%	0.0%	100	100
IVALLYBANK (XF)	1.9%	1.7%	0.3%	86	85
MONAIPPDC (MSL)	1.6%	1.6%		100	0
MKTPCADLN (MSL)	1.6%	1.6%		100	0
ADLANTOSP (MSL)	1.6%	1.6%		100	0
IPP-IPPGEN (MSL)	1.6%	1.6%		100	0
PENSQTOS to MIRAMRTP 9.0kV (Line)	1.5%	1.4%	0.1%	114	102
CASCADE to STLLWATR 0.0kV (Line)	1.5%	1.4%	0.1%	122	119
PALERMO to WYANDJT2 115kV (Line)	1.2%	1.2%	0.1%	125	127
IPPDCADLN (BG)	1.2%	1.1%	0.2%	100	100
CERTANJ2 to LE GRAND 115kV (Line)	1.0%	1.0%		112	89
SDGE_CFEIMP (BG)	1.0%	0.8%	0.2%	102	94

Table 7.11 Conforming of internal constraints in day-ahead market

Constraint	Conformed hours	Average conformed limit	Congested intervals	Average shadow price
LARKIN to POTRERO 115kV (Line)	1.6%	113		
MISSON to POTRERO 115kV (Line)	0.9%	117		
EXCHEQUR to LE GRAND 115kV (Line)	0.5%	104		
BELLOTA to WEBER 230kV (Line)	0.5%	160		
PITSBRG to TBC 230kV (Line)	0.3%	120		
WEBER to TESLA E 230kV (Line)	0.3%	160		
ULTRA JT to ULTR-RCK 115kV (Line)	0.3%	110	0.02%	$1

7.6 Transmission infrastructure changes

In 2011, a variety of notable transmission infrastructure changes were made within and impacting the ISO balancing area.[110] The more significant upgrades or additions are described below:

- Hoodoo Wash New 500 kV Sub-loop and the North Gila-Hassayampa 500 kV line were added and form two new 500 kV lines (Hassayampa-HoodooWash and HoodooWash-NorthGila). These additions began operation in mid-December and connect the 290 MW Agua Caliente project.
- John Day-Grizzly #1 and #2 500 kV lines as part of the California-Oregon Intertie (COI) 4,800 MW and Pacific DC Intertie (PDCI) 3,100 Project were completed in the first quarter. Related work included the Malin 500 kV Sub-Replace Series Capacitors at Malin on Malin-Round Mountain #2 500 kV line.
- Phase one of a four-phase long-term program to facilitate the export of renewable energy from Imperial Valley, the Midway-Bannister 230 kV generation tie project was completed in mid-March. This consisted of building 8.5 miles of 230 kV single circuit transmission line (prepared for double circuit) from the Midway substation to the Salton Sea geothermal area. The project also includes the expansion and upgrade of the existing IID Midway Substation and the 3.5 mile generator tie to the planned Geothermal Generation Facility.
- The Gates-Gregg 230 kV substation upgrade project was completed in mid-March. This completed the Gates-Gregg 230 kV line and conductor upgrade and installation of new line relays at Gates, Gregg and Henrietta.
- In early August, the Hassayampa-Mesquite #2 new 500 kV transmission line was completed. This is the first phase of a project to bring in 150 MW of solar power. The project will eventually support up to 700 MW.

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[110] See information provided by the ISO Transmission Planning group: http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx.

7.7 Congestion revenue rights

Congestion revenue rights are financial instruments offered to allow participants to hedge against congestion costs in the day-ahead market. This section provides an overview of congestion revenue market results and trends. Our analyses show:

- The number and volume of congestion revenue rights awarded in 2011 decreased compared to 2010. This can be attributed to implementation of a new methodology for calculating the operating transfer capability of transmission paths.[111] The decrease in volumes was anticipated upon implementation of this new methodology.
- A $23 million revenue surplus at the end of 2011 will be allocated to measured demand. Revenue deficiencies occurred in four of the twelve months, but were offset by additional revenues collected during the rest of the year.
- Average profitability of all congestion revenue rights was close to $0.07/MW in 2011, compared to about $0/MW in 2010. This increase was driven largely by higher levels of congestion on inter-ties in 2011. The most consistently profitable congestion revenue rights continue to be those in the opposite direction of prevailing congestion patterns. Participants are paid for these congestion revenue rights in the auction, but then obligated to pay when congestion occurs. This was very similar to 2010, indicating that congestion revenue rights were an efficient financial hedge instrument.

Background

Locational marginal prices are composed of three components: energy, congestion, and transmission losses. The congestion component can vary widely depending on the location and severity of congestion, and it can be volatile. Market participants can acquire congestion revenue rights as a financial hedge against volatile congestion costs. As a market product, congestion revenue rights are defined by five elements:

- ***Life term —*** Each congestion revenue right has one of three categories of life term: one month, one calendar season, and one calendar season for 10 years. There are four calendar seasons corresponding to the four quarters of the calendar year.
- ***Time-of-use —*** Each congestion revenue right is defined as being for either the peak or off-peak hours as defined by Western Electricity Coordinating Council guidelines.[112]
- ***Megawatt quantity —*** This is the volume of congestion revenue rights allocated or purchased. For instance, one megawatt of congestion revenue rights with a January 2011 monthly life term and on-peak time-of-use represents one megawatt of congestion revenue rights during each of the 400 peak hours during this month.
- ***Sink —*** The sink of a congestion revenue right can be an individual node, load aggregation point, or a group of nodes.

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[111] The following document highlights the methodology for determining the operating transfer capacity values for the congestion revenue rights release process: http://www.caiso.com/27c4/27c4bc2f24b80.pdf.

[112] Peak hours are defined as hours ending 7 through 22 excluding Sundays and WECC holidays. All other hours are off-peak hours.

- ***Source* —** The source of a congestion revenue right can be an individual node, load aggregation point or a group of nodes.

The amount received or paid by the congestion revenue right holder each hour is the day-ahead congestion price of the sink minus the congestion price for the source. Prices used to settle congestion revenue rights involving load aggregation points or a group of nodes represent the weighted average of prices at individual nodes.

The congestion revenue rights market is organized into annual and monthly allocation and auction processes.

- In the annual program, rights are allocated and auctioned separately for each of the four calendar seasons. Long-term rights are valid for one calendar season for 10 years. A short-term right is valid for one calendar season of one specific year.
- The monthly program is an auction for rights that are valid for one calendar month of one specific year.

A more detailed explanation of the congestion revenue right processes is provided in the ISO's *2011 Annual Market Performance CRR Report.*[113]

Market results

Figure 7.5 and Figure 7.6 show the monthly average amount of the various types of congestion revenue rights awarded within a quarter since 2009 for peak and off-peak hours, respectively. As shown in these figures:

- The total volume of congestion revenue rights decreased in 2011, primarily because of a decrease in the rights purchased in the short-term auctions. The short term auction was conducted in November 2010.
- During 2011, rights purchased through the monthly auction remained relatively stable each quarter throughout the year. All other processes for acquiring congestion revenue rights for 2011 were completed in 2010. Therefore, market participants wanting to increase participation in the congestion revenue rights market for 2011 had to do so through the monthly processes.
- The overall amount of rights purchased through the monthly auction in 2011 decreased compared to 2010 levels. This reflects the fact that participants wanting to procure rights for 2011 relied less heavily on the short-term auction for seasonal congestion revenue rights conducted in November 2010.
- Congestion revenue rights awarded through the allocation process do not vary significantly from quarter to quarter. The small variation between calendar seasons reflects that the allocation process is based on historical load.

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[113] For further details, please see the following link: http://www.caiso.com/Documents/Market%20performance%20reports%7CCongestion%20revenue%20rights.

Figure 7.5 Allocated and awarded congestion revenue rights (peak hours)

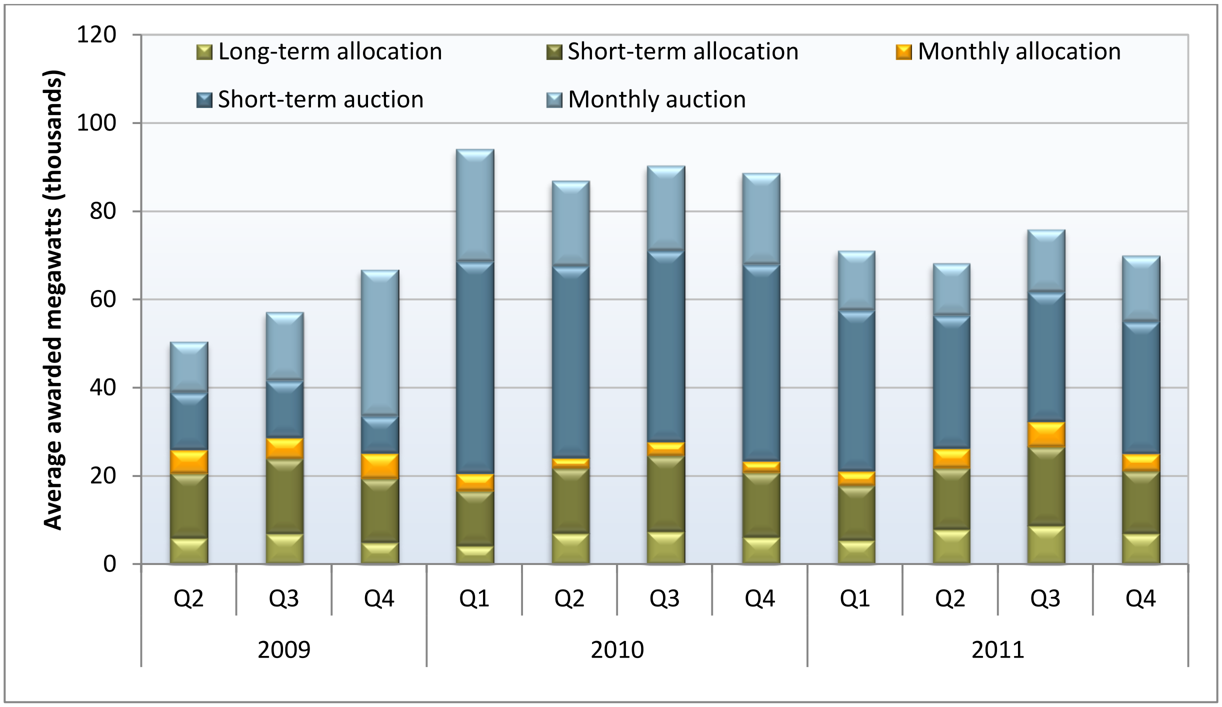


Figure 7.6 Allocated and awarded congestion revenue rights (off-peak hours)

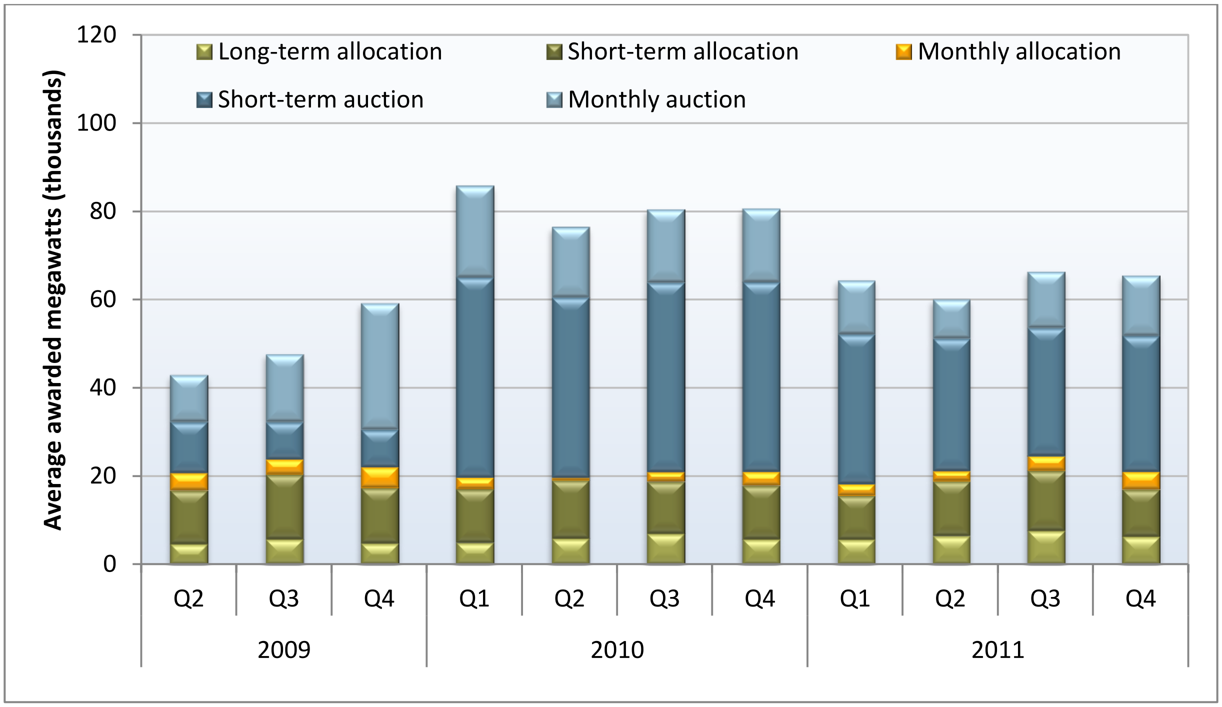


Figure 7.7 and Figure 7.8 provide a high level summary of the market clearing quantities and prices in the auctions for seasonal and monthly congestion revenue rights for each quarter over the last three years. Prices in these figures represent the price per megawatt-hour for each congestion revenue right. This is equal to the market clearing price divided by the total hours for which the right is valid. This allows the seasonal rights to be grouped and compared with monthly rights.

The same general trends occur for both peak and off-peak hours. On average, over half of 2011 awarded megawatts had a clearing price of between \$0/MWh and \$0.10/MWh. Figure 7.7 and Figure 7.8 show a decrease in the average number of awarded congestion revenue rights and average awarded megawatts from 2010 to 2011. The 2011 volumes were more consistent with 2009 volumes.

The average monthly megawatts awarded between \$0 and \$0.10/MWh fell by more than half from 2010 to 2011 for both on and off-peak congestion revenue rights. There were two main reasons for this decrease:

- A decrease in bids submitted for the short-term auction process resulted in less awarded congestion revenue rights and cleared megawatts, most notably priced between \$0/MWh and \$0.10/MWh.
- Less congestion revenue rights in the counter-flow direction cleared, thus allowing less congestion revenue rights in the positive prevailing direction to also clear.

Although the price of different congestion revenue rights varies widely, the price of most rights has been within ±\$0.10 MWh.

Figure 7.7 Auctioned congestion revenue rights by price bin (peak hours)

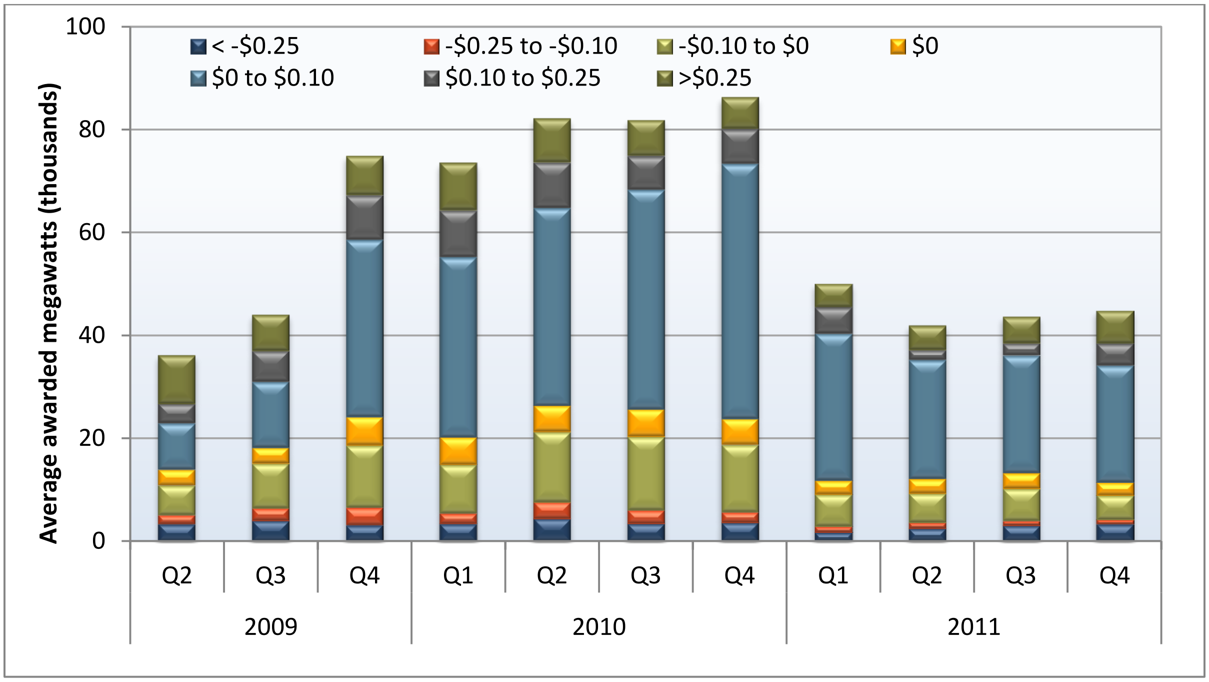
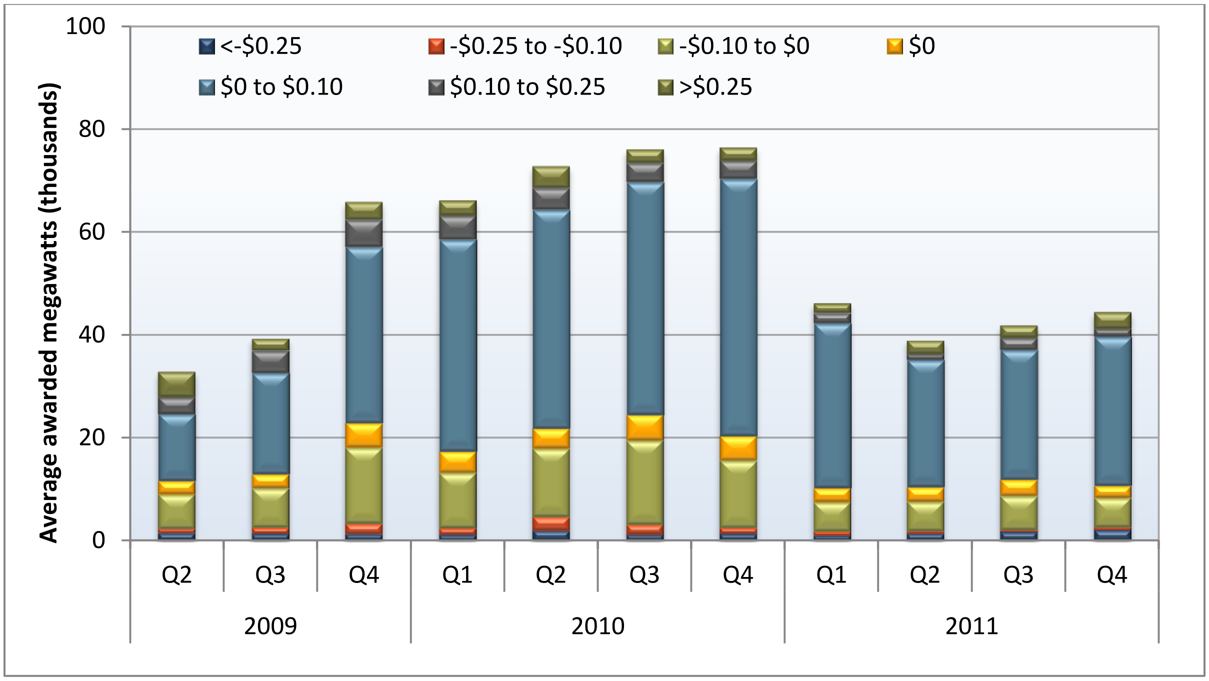


Figure 7.8 Auctioned congestion revenue rights by price bin (off-peak hours)



Congestion revenue right revenue adequacy

The market for congestion revenue rights is designed such that the amount of congestion rents collected from the day-ahead energy market is sufficient to cover all the payments to rights holders. This is referred to as revenue adequacy. The ISO limits the number of congestion revenue rights available in the allocation and auction processes between various sources and sinks to help maintain overall revenue adequacy.[114]

However, under actual market conditions, events such as transmission outages and derates can create revenue deficiencies and surpluses even when the congestion expectations in the auction and in the day-ahead market are identical. Therefore, all revenues from the annual and monthly auction processes are included in the account to help ensure revenue adequacy if needed. Any shortfall or surplus in the balancing account at the end of each month is allocated to measured demand.

Figure 7.9 shows the revenues, payments and overall revenue adequacy of the congestion revenue rights market by quarter for the last three years.

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

As seen in Figure 7.9, revenue deficiency occurred for the first quarter of 2011 before taking into account auction revenues. Revenue adequacy during the first and part of the second quarter of 2011 dropped for several reasons, including:[115]

- A modeling error allowed the volume of congestion revenue rights in the import direction on the COTPISO inter-tie to significantly exceed the capacity that could be scheduled in the ISO market on this inter-tie. This caused about $6.3 million in revenue inadequacy due to congestion on this inter-tie.
- About $4 million in revenue inadequacy resulted from congestion on the New Melones inter-tie. This is a *fully encumbered* inter-tie, meaning that all available capacity can only be scheduled by participants with rights to this transmission. Thus, no congestion revenue rights should have been

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[114] For a more detailed explanation of congestion revenue rights revenue adequacy and the simultaneous feasibility test, please see the ISO's 2011 reports on congestion revenue rights at: http://www.caiso.com/Documents/Market%20performance%20reports%7CCongestion%20revenue%20rights.

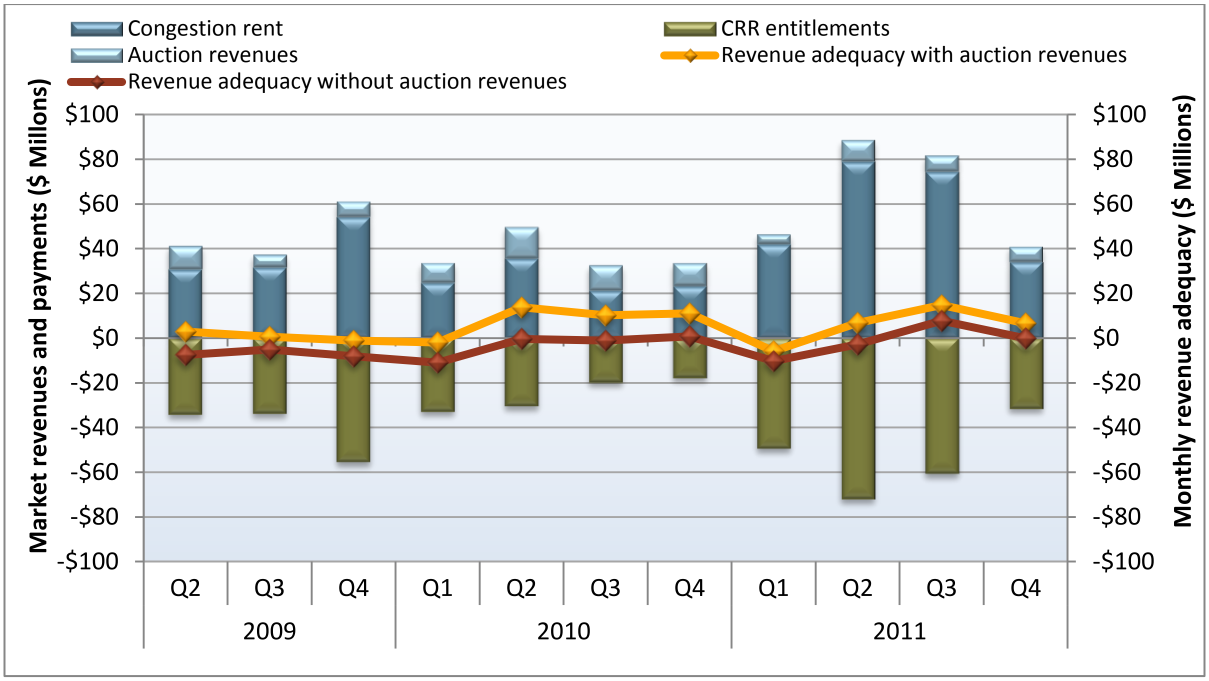
[115] *Quarterly Market Performance CRR Report (Q1 and Q2),* California ISO, July 28, 2011: http://www.caiso.com/Documents/QuarterlyMarketPerformanceCRRReport2011Q1-Q2.pdf.

awarded on this inter-tie. The ISO now does not allow congestion revenue rights to be allocated over fully encumbered inter-ties.

In total for the last three quarters of 2011, revenues for congestion revenue rights were approximately neutral before taking into account auction revenues. With auction revenues included, revenues were positive each of the last three quarters of 2011. The third quarter revenues were the highest since the market began in April 2009.

The total cumulative revenue adequacy of the congestion revenue rights balancing account for 2011 was about $23 million, a $10 million decrease from 2010. This represents about 80 percent of total net revenues from the annual and monthly auctions for 2011.

Figure 7.9 Quarterly revenue adequacy



Profitability of congestion revenue rights

Each entity participating in the congestion revenue rights auction reveals its expectation of congestion costs through bid prices. Participants with actual generation, load or contracts tied to nodal market prices may assign an additional value to congestion revenue rights as a hedge against extremely high congestion costs. These participants may be willing to pay a premium above the expected value of congestion to mitigate this risk.

- **Profitability of prevailing flow congestion revenue rights.** For prevailing flow congestion revenue rights, profitability depends on the initial purchase price, minus revenues received over the term of the right as the result of any congestion that occurs between the source and sink of the right. As previously noted, these rights are typically purchased by participants seeking a hedge against congestion costs associated with their expected energy deliveries, purchases or financial contracts. Therefore, these rights may tend to be slightly unprofitable on average.

- **Profitability of counter-flow congestion revenue rights.** For counter-flow congestion revenue rights, profitability is determined by the payment received from the auction, minus payments made over the term of the right as the result of any congestion between the source and sink of the right. These counter-flow rights are typically purchased by financial traders willing to take the risk associated with the obligation to pay unknown amounts based on actual congestion in return for the initial fixed payment they receive for these rights. Given the higher risk that may be associated with these rights, these rights may tend to be slightly profitable on average.

Figure 7.10 through Figure 7.13 show the profitability distribution of congestion revenue rights for peak and off-peak hours in 2011.[116] The figures only include congestion revenue rights acquired through the auction process since these rights were valued through a market process. Each chart distinguishes between prevailing flow and counter-flow congestion revenue rights.

Results of these figures show that:

- About 30 percent of the seasonal prevailing flow rights were profitable, while only 18 percent of monthly rights were profitable. Overall, profits for seasonal prevailing flow rights averaged about $0.13/MWh, whereas profits averaged about $0.01/MWh for monthly rights.
- About 77 percent of all seasonal counter-flow rights had positive profits, while about 81 percent of monthly rights had positive profits. Profits for seasonal counter-flow rights averaged $0.07/MWh, while profits averaged about $0.14/MWh for monthly rights.

In the monthly auction, the most profitable and unprofitable congestion revenue rights were those impacted by unforeseen outages, de-rates and modeling discrepancies. Congestion on major transmission constraints in June and August caused congestion in the day-ahead markets. This made some prevailing flow rights highly unprofitable and some counter-flow rights highly profitable.

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[116] The congestion revenue rights profit is defined as the total congestion revenue rights revenues minus auction cost, divided by the quantity megawatts and number of hours for which that right is valid. The same profit is represented for each awarded megawatt on the same path. For example, assume a 10 MW monthly on-peak congestion revenue right cost $100 in the auction (10 MW x $10/MW). If this right received $900 in day-ahead congestion revenues this would represent a net profit of $800 over the life of the right. Since the congestion revenue right is valid for 400 hours and was for 10 MW, the profit per megawatt hour would be $0.20/MWh ($800/400hrs/10MW = $0.20/MWh). This profit would be shown with a frequency of 10, representing each awarded megawatt.

Figure 7.10 Profitability of congestion revenue rights - seasonal CRRs, peak hours

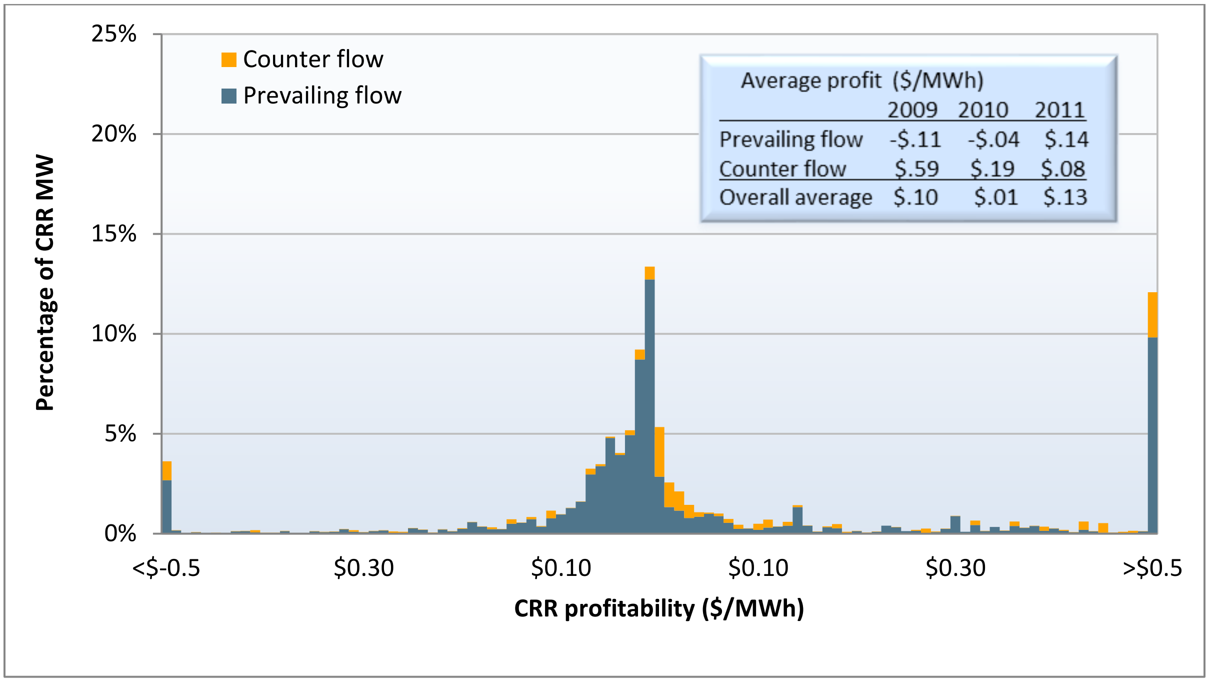


Figure 7.11 Profitability of congestion revenue rights - seasonal CRRs, off-peak hours

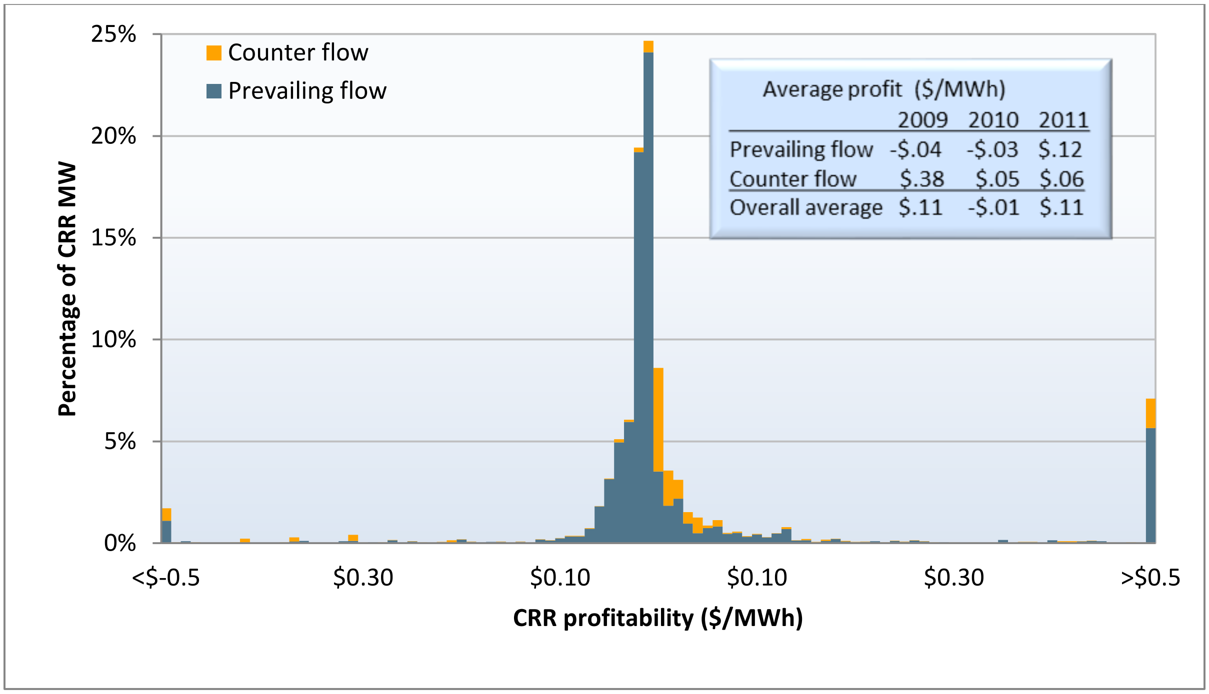
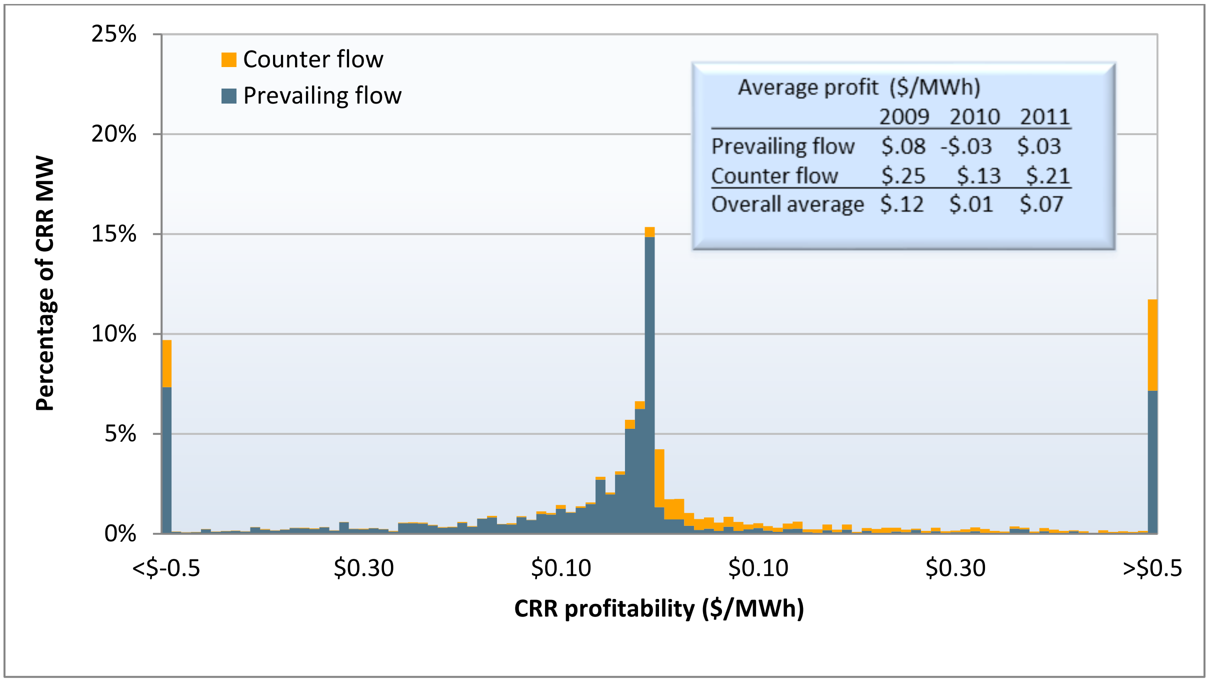


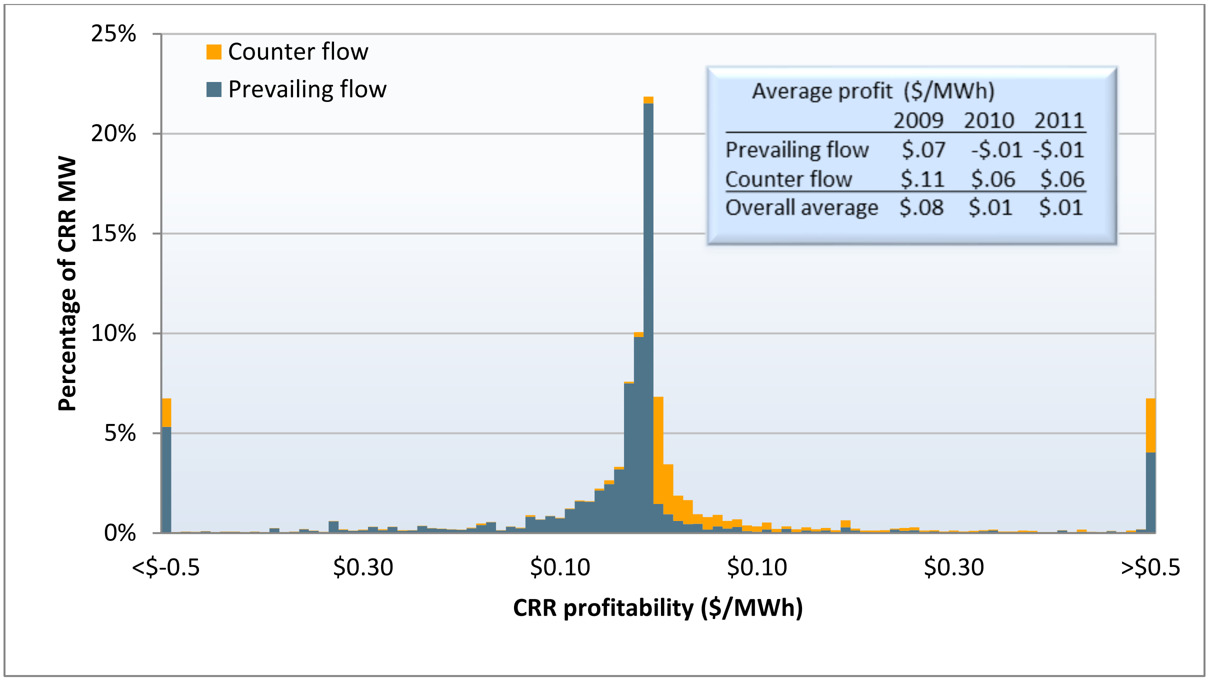
Figure 7.12 Profitability of congestion revenue rights - monthly CRRs, peak hours



Average profit ($/MWh)

	2009	2010	2011
Prevailing flow	$.08	-$.03	$.03
Counter flow	$.25	$.13	$.21
Overall average	$.12	$.01	$.07

Figure 7.13 Profitability of congestion revenue rights - monthly CRRs, off-peak hours



Average profit ($/MWh)

	2009	2010	2011
Prevailing flow	$.07	-$.01	-$.01
Counter flow	$.11	$.06	$.06
Overall average	$.08	$.01	$.01

8 Market adjustments

Given the complexity of ISO market models and systems, all ISOs must ultimately make some adjustments to the inputs and outputs of their standard market models and processes.[117] Market model inputs – such as transmission limits – may sometimes be modified to account for potential differences in modeled versus actual real-time power flows. Load forecasts may be adjusted to account for anticipated differences in modeled versus actual demand and supply conditions, including uninstructed deviations by generation resources. The ISO may need to modify market prices after the fact to correct for data and metering discrepancies or information system failures.[118]

In this chapter, DMM reviews the frequency of and reasons for a variety of key market adjustments, including:

- Exceptional dispatches
- Modeled load adjustments
- Transmission limit adjustments
- Compensating injections made at inter-ties to account for loop flows
- Blocked dispatch instructions
- Aborted and blocked pricing runs in the real-time market
- Price corrections

In 2011, reducing price corrections was incorporated in the ISO's internal business goals. In 2012, the ISO's internal corporate goals include reduction of several other categories of market adjustments – which are also sometimes referred to as *market interventions*. In order to meet these goals, the ISO has formed a team to reduce the need for such adjustments as well as address the underlying causes of these adjustments.

Numerous stakeholders and regulatory entities have also requested increased transparency on these types of adjustments.[119] DMM believes that additional analysis of these adjustments can provide feedback on the impact of modeling and process improvements implemented in 2011, as well as specific areas that may be targeted for further improvement.

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[117] 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.

[118] Price correction is a tariff-defined process that is not an operator adjustment, but rather is an after the fact process separate from operational conditions.

[119] The ISO already provides information on many of these processes both on its website and through public reporting. For instance, the ISO regularly publishes price correction, exceptional dispatch and market disruption reports, which are located here: http://www.caiso.com/market/Pages/ReportsBulletins/Default.aspx. Furthermore, the ISO publishes a market metric catalogue that contains several metrics, including metrics related to market adjustments. See the November report: http://www.caiso.com/Documents/MarketPerformanceMetricCatalogNovember2011.pdf.

In many instances, the specific underlying factors creating the need for individual adjustments are not well recorded. For instance, minimal information is currently recorded relating to the reasons for blocked dispatch instructions. This has limited the depth of some of the analysis. In other cases, such as with compensating injections, DMM had to develop its own categorization approach. In each case, DMM has done the best possible analysis with the available information. Going forward, DMM recommends that the ISO improve the ability to capture the reasons for adjustments so future analyses can more accurately highlight the specific areas for improvement.

8.1 Exceptional dispatch

Exceptional dispatches are special unit commitments or energy dispatches issued by operators when the result of the automated market optimization is not able to address a particular reliability requirement or constraint. Exceptional dispatches can displace or supplement generation that otherwise would have been selected by the competitive energy and residual unit commitment market optimization processes. While exceptional dispatches are necessary for reliability, the ISO has made an effort to minimize them by incorporating additional constraints into the day-ahead and real-time market models. These constraints reflect reliability requirements that would otherwise be met by exceptional dispatches.

Exceptional dispatches can be grouped into three distinct categories:

- **Unit commitments** — Exceptional dispatches can be used to instruct a generating unit to start-up or continue operating at their minimum levels of output. Almost all of these unit commitments are made after the day-ahead market to meet reliability issues not directly incorporated in the day-ahead market model. After operators review results of the day-ahead market, they then assess the location and quantity of additional capacity required to support system reliability. Minimum load energy from these unit commitments accounts for the bulk of energy resulting from exceptional dispatches.

- **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. These exceptional dispatches often result from hourly minimum generation level constraints that are entered into the software by operators several hours in advance. If the bid price of energy needed to meet this minimum generation level is lower than the market clearing price, this energy would clear the market in the absence of the exceptional dispatch. This report refers to this energy as *in-sequence* real-time energy. These exceptional dispatches have no impact on the real-time price.

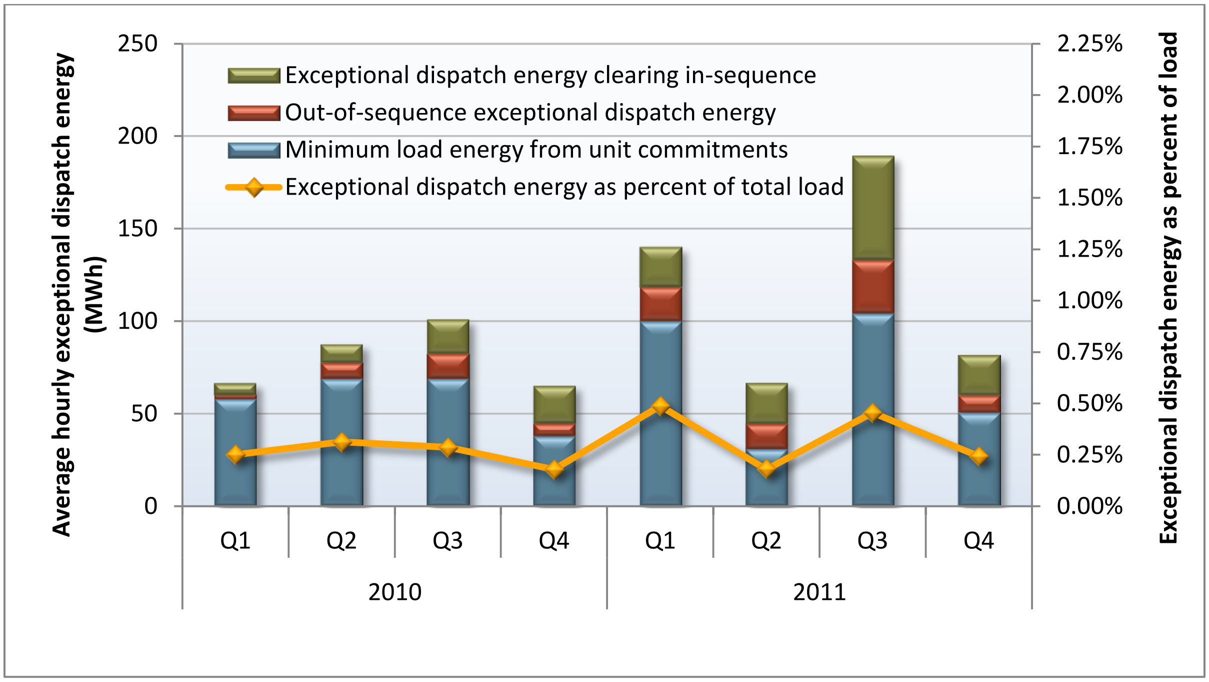
- **Out-of-sequence real-time energy** — Exceptional dispatches may also result in *out-of-sequence* real-time energy. This occurs when the bid price of energy needed to meet a minimum generation level (above a unit's minimum load level) established through an exceptional dispatch is higher than the market clearing price. These exceptional dispatches cannot set the market price since the dispatches are being issued due to a unit's minimum generation constraint. However, these exceptional dispatches may have the indirect effect of lowering market prices by reducing the amount of other energy that must be dispatched to meet demand.

As shown in Figure 8.1, total energy from all of these types of exceptional dispatches was somewhat higher and varied more in 2011 than 2010. Energy from these dispatches equaled 0.34 percent of system loads in 2011, compared to 0.26 percent in 2010. In 2009, exceptional dispatch energy was much higher, totaling 0.92 percent of system load.

DMM also assessed the costs associated with exceptional dispatches by calculating the degree to which the cost paid for these dispatches exceeds the cost of this energy at the market clearing price. The overall above-market costs of all exceptional dispatches in 2011 totaled around $43 million.

DMM considers 2010 and 2011 levels of energy and costs from exceptional dispatches to be relatively low and indicative of continued improvements in modeling and operational practices. Measures taken to reduce exceptional dispatches are described in multiple ISO whitepapers.[120] The slight increase in volumes in 2011 was due to an increase in the minimum load energy from units committed through exceptional dispatch and in-sequence exceptional dispatches in the first and third quarters. The following section of this chapter discusses the reasons for the increase in exceptional dispatches in these quarters.

Figure 8.1 Average hourly energy from exceptional dispatches



Exceptional dispatches for unit commitment

As discussed in DMM's 2010 annual report, unit commitments via exceptional dispatch were reduced significantly in 2010 largely as the result of the addition of new day-ahead market constraints – known as *minimum on-line constraints*.[121] These constraints require that a certain amount of capacity is committed in key areas to meet voltage requirements and other reliability criteria that cannot be directly incorporated in the power flow model used in the day-ahead market.

In 2011, unit commitments through exceptional dispatch increased slightly. This may be in large part attributable to lower loads and prices – which can reduce the amount of capacity committed in the day-

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[120] The December 2, 2009 *Exceptional Dispatch Whitepaper* is available at http://www.caiso.com/2478/2478ead066f50.pdf. The June 10, 2010 *Exceptional Dispatch Review and Assessment Whitepaper* is available at http://www.caiso.com/27b1/27b1ec8436300.pdf.

[121] *2010 Annual Report on Market Issues and Performance*, April 2011, p. 75-77.

ahead market and require additional capacity to then be committed through exceptional dispatch. As shown in Figure 8.1, minimum load energy from units committed through exceptional dispatch accounted for about 60 percent of all energy from exceptional dispatches in 2011.

Figure 8.2 provides a summary of minimum load energy from exceptional dispatches by the reason these units were committed as recorded in operating logs. The major reasons for these unit commitments include:

- **Overall system reliability** — Operators continue to issue commitment exceptional dispatches for overall system reliability in the event of generation, transmission and load contingencies and uncertainties not incorporated in the day-ahead model. These exceptional dispatches protect the system from voltage collapse should worst-case contingencies occur. They also protect crucial inter-ties from potential thermal overload in the event of worst-case contingencies. This category accounted for 40 percent of minimum load energy from exceptional dispatches in 2011.
- **Path 26** — The market model does not include the loss of the Pacific DC inter-tie into Southern California – also known as the Nevada-Oregon Border (NOB) transmission path. In the event of a contingency on this line, sufficient capacity within Southern California must be ramped up within 30 minutes to avoid overloading Path 26 due to increased flows from Northern to Southern California. Therefore, under some conditions operators have to continue to issue unit commitment exceptional dispatches to ensure adequate online capacity for protecting Path 26 from the loss of the Pacific DC inter-tie. This category accounted for 15 percent of minimum load energy from exceptional dispatches in 2011.
- **Southern California import transmission nomogram** — The market model cannot account for unit commitment requirements for maintaining system inertia. The Southern California import transmission (SCIT) nomogram defines the maximum allowed flows on key transmission corridors as a function of inertia in Southern California. Difficulties remain in incorporating forecasts for required inertia into the model. Therefore, under some conditions commitment of units via exceptional dispatch are needed to protect against violations of this nomogram in real-time. This category accounted for 11 percent of minimum load energy from exceptional dispatches in 2011.
- **Temporary transmission outages** — In some cases, operators must commit additional capacity to mitigate special temporary transmission outages that cannot be incorporated in the market model. This category accounted for 11 percent of minimum load energy from exceptional dispatches in 2011.

The increase in exceptional dispatch minimum load energy under the “Not Specified” category in the fourth quarter of 2011 was due to special generation requirements associated with a scheduled outage of the Southern California Gas pipeline into the San Diego area. The outage began in October 2011 and continued during the weekends until mid-November.

Figure 8.3 shows net above-market costs of minimum load energy from exceptional dispatch unit commitments.[122] These costs were higher in 2011 than 2010 due to exceptional dispatches to increase

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[122] Net above-market cost for each generating unit’s minimum load energy is calculated by taking the unit’s hourly minimum load bid cost minus the real-time energy market revenue for that minimum load energy.

both system and south of Path 26 capacity in the third quarter.[123] Costs in the third quarter accounted for about 74 percent of total net minimum load costs in 2011.

Figure 8.2 Average minimum load energy from exceptional dispatch unit commitments

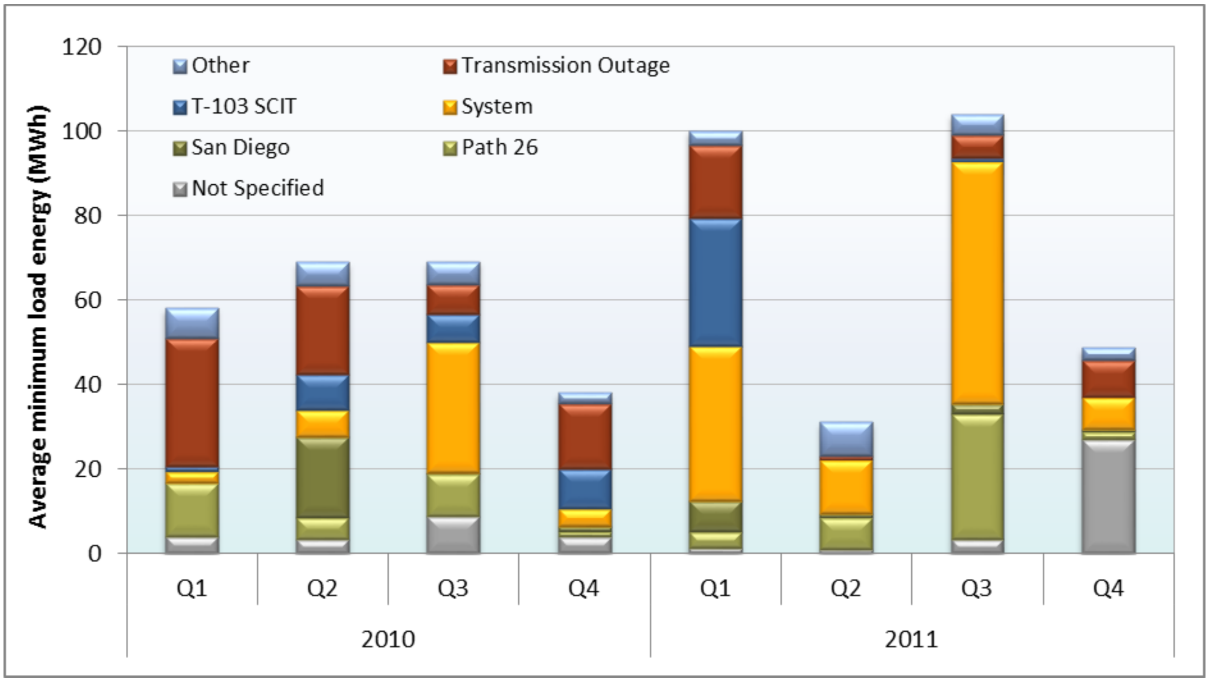
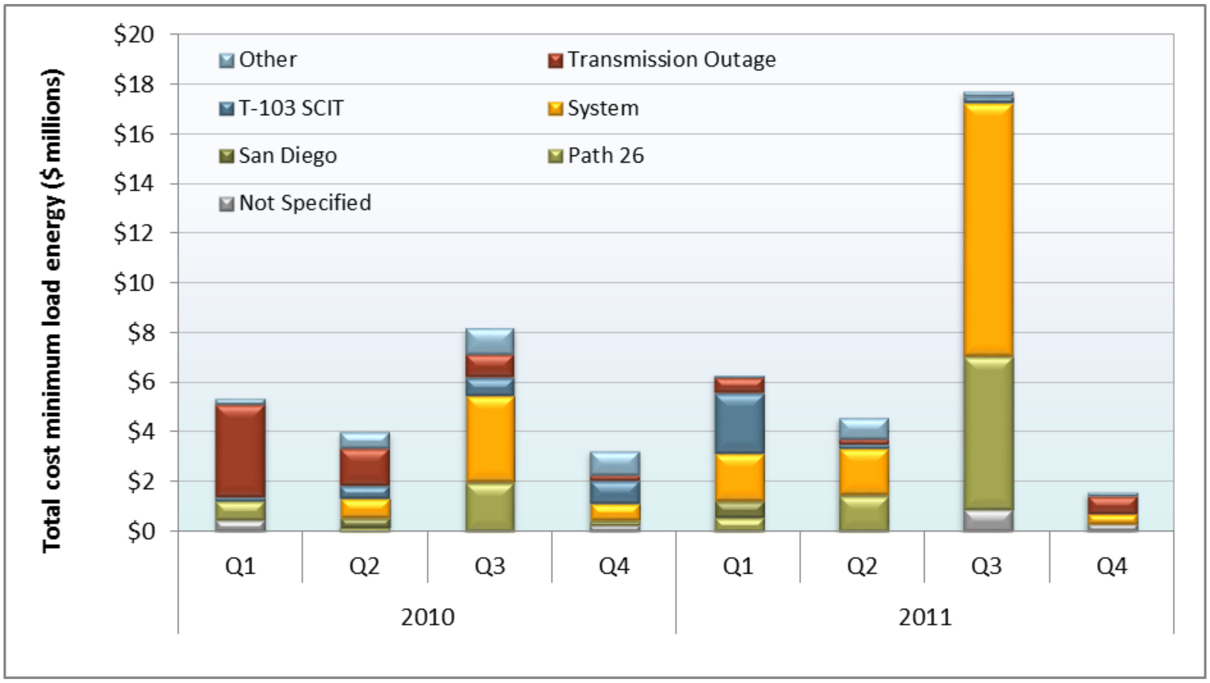


Figure 8.3 Total cost of minimum load energy from exceptional dispatch unit commitments



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[123] In July and August, most unit commitments for these two reasons coincided with peak load days. In September, much of these commitments were associated with the outage of the 500 kV line connecting Arizona with the ISO and peak load days.

Exceptional dispatches for real-time energy

Exceptional dispatches for additional real-time energy also increased in 2011 after dropping in 2010. Average hourly out-of-sequence energy from exceptional dispatch dropped from 22 MW in 2009 to 8 MW in 2010 as the ISO improved its modeling of constraints and market flows. However, in 2011 average out-of-sequence energy from exceptional dispatches increased to 18 MW.

As shown in Figure 8.4, this increase was almost entirely due to exceptional dispatches logged as being associated with ramp rates. These dispatches accounted for 64 percent of exceptional dispatches for additional real-time energy in 2011. These exceptional dispatches are issued to move units to output levels where the units have optimal ramping capabilities. This category of exceptional dispatches results from two different situations arising from limitations of the day-ahead and real-time market models:

- **30 minute ramping capacity.** As noted above, the ISO market model does not incorporate some system level contingencies and uncertainties that may require additional capacity to be available during peak hours that can be ramped up within 30 minutes. Within Southern California, sufficient capacity must be online that can be ramped up within 30 minutes in the event of an outage of the Pacific DC inter-tie.[124] In some cases, units must be ramped up to operating levels at which they have a higher ramp rate to ensure sufficient 30 minute ramping capability to protect against these potential contingencies.

- **Ancillary services.** Prior to August 2011, the ISO procured ancillary services using a fixed ramp rate representing the maximum ramp rate established for each unit as part of the ancillary service certification process. However, participants can submit lower ramp rates with each unit's actual market energy schedule. This caused some units with day-ahead ancillary service awards to be unable to provide their scheduled day-ahead reserves in real-time (see Section **Error! Reference source not found.** for further detail). To make the ancillary service schedules feasible in this situation, the operators sometimes exceptionally dispatched the units to a level with a faster ramp rate. In early August, the day-ahead market software was enhanced so that day-ahead ancillary services were procured based on the bid-in ramp rates of each unit.

ISO logs do not provide more specific information on the extent to which exceptional dispatches logged as being due to ramp rates were due to these two different situations. However, since the day-ahead software was enhanced in August to eliminate the need for exceptional dispatches to ensure the feasibility of ancillary services, the relatively high level of exceptional dispatches for ramp rates in the third quarter can be attributed to the need for 30 minute ramping capacity to protect against potential contingencies on a system level or involving Path 26.

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[124] In many cases, it appears that operators log exceptional dispatches that may be made to meet 30 minute ramping needs for South of Path 26 using the more general "Ramp Rate" code. As shown in Figure 8.4, very few exceptional dispatches were logged as being specifically for Path 26.

Figure 8.4 Average out-of-sequence energy from exceptional dispatches by reason

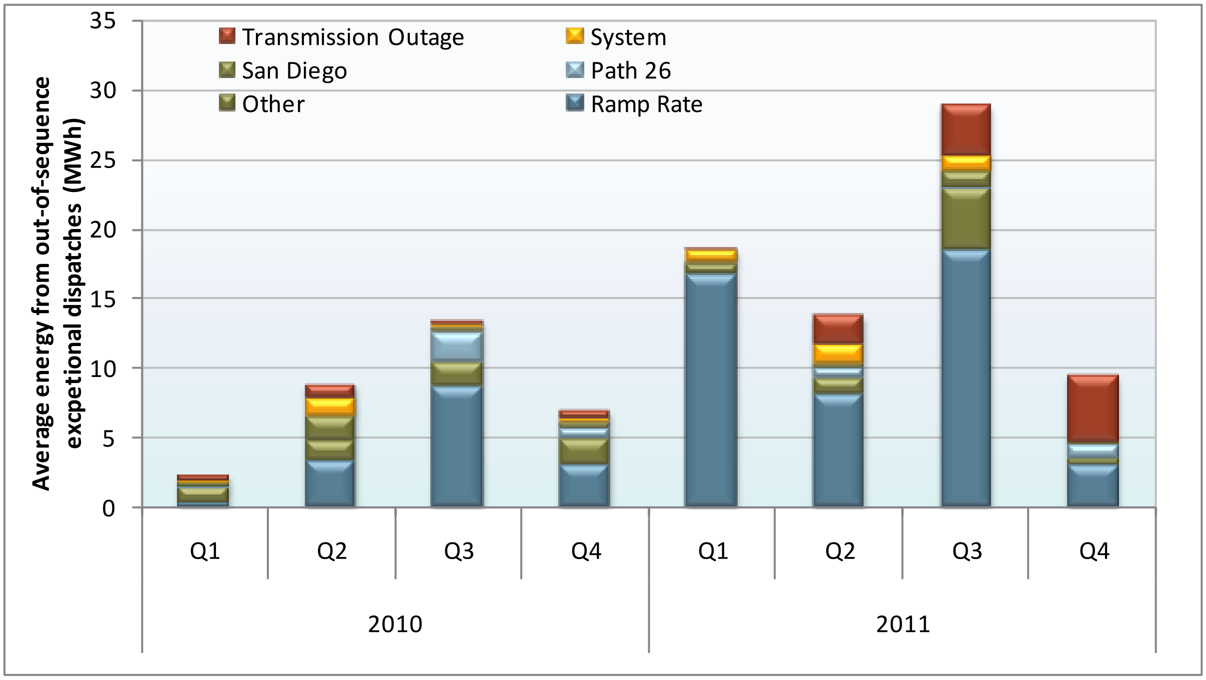

Figure 8.5 Out-of-sequence energy costs from exceptional dispatches by reason

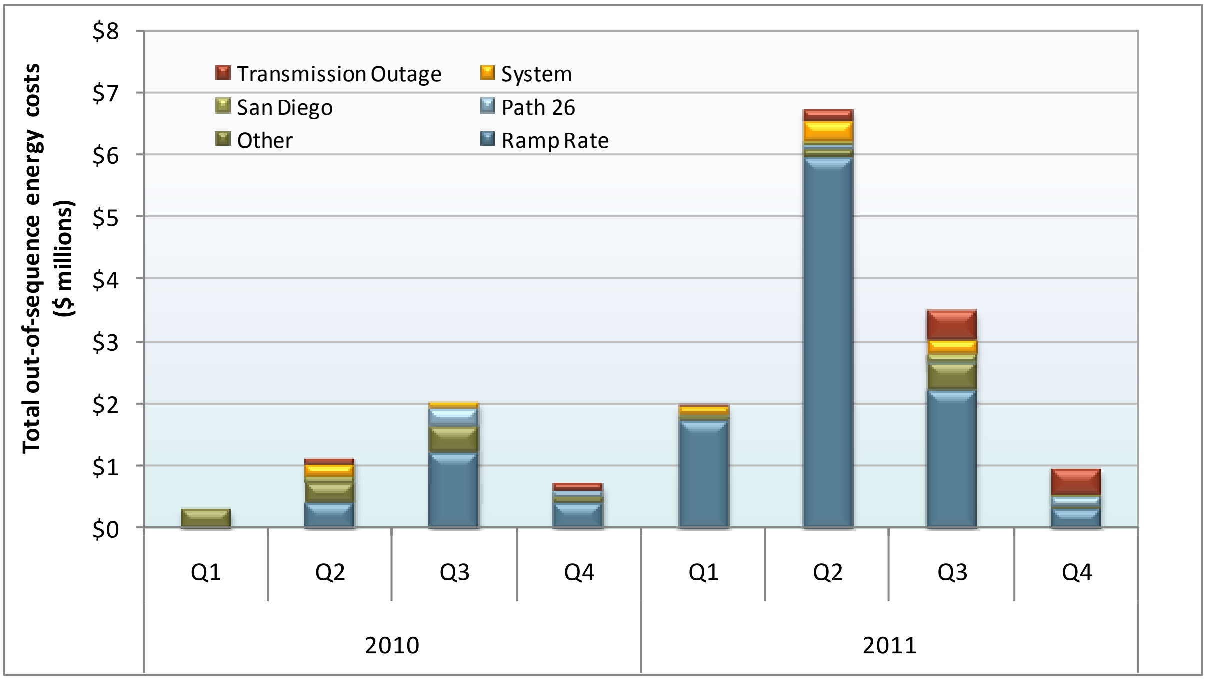

Figure 8.5 shows the above-market costs of out-of-sequence energy from exceptional dispatches.[125] The ramp rate category also constitutes the highest portion of the out-of-sequence exceptional dispatch costs. These costs were the highest in the past two years in the second quarter of 2011. This increase in exceptional dispatch payments was related to a manipulative strategy designed to increase bid cost recovery payments. In just five days, almost $5.3 million in exceptional dispatch payments were incurred for energy bids at prices approximately equal to the $1,000/MWh bid cap.[126] After this bidding strategy was addressed, overall exceptional dispatch energy costs declined significantly in the second half of 2011.

8.2 Load adjustments

In the hour-ahead and real-time markets, the ISO frequently adjusts real-time loads to account for potential modeling inconsistencies or inaccuracies. Some of these inconsistencies are due to changing system and market conditions, such as changes in load and supply, between the execution of the hour-ahead market and the real-time market. Other inconsistencies result from the fact that the hour-ahead market is based on a model that solves for 15-minute time intervals, while the real-time market actually dispatches units for each 5-minute interval. Furthermore, some adjustments were made to address transition issues associated with the transition to the new load forecasting model. These occurred primarily in the summer and declined as the forecasting models improved.

Operators can manually adjust load forecasts used in the software through a *load adjustment*. These adjustments are sometimes made manually based entirely on the judgment of the operator informed by actual operating conditions. Other times these adjustments are made in a more automated manner using special tools developed to aid ISO personnel in determining what adjustments should be made and making these adjustments into the necessary software systems.

In spring 2011, the ISO began to develop and deploy more systematic procedures, tools, and training that gave operators additional guidance to determine whether a load adjustment should be removed or continued and at what magnitude. The guidance was based on metrics of observed differences between forecast and actual load between hour-ahead and real-time conditions for different time periods. DMM attributes the changes in procedures, automation and modeling as helping improve price convergence beginning in April.

In May, the ISO also incorporated an interim automated real-time load adjustment mechanism to account for additional generation from units shutting down.[127] When a generating unit is scheduled to shut down, the market software does not account for the energy generated while the unit is ramping down from its minimum load level to zero. On a system-wide basis, this can create several hundred megawatts of unscheduled energy during the evening hours when the load starts decreasing. This new

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[125] Out-of-sequence exceptional dispatch cost for a unit is the area between the unit's bid curve and its default energy bid curve above the real-time market price. This area's boundary is between the minimum load energy and exceptionally dispatched energy. Out-of-sequence exceptional dispatch energy costs represent the net energy bid costs from an exceptional dispatch.

[126] For details on the related FERC filing, see Tariff Revision and Request for Waiver of Sixty Day Notice Requirements**,** June 22, 2011, pp. 17-18 of transmittal letter, http://www.caiso.com/Documents/2011-06-22_Amendment_ModBCRrules_EDEnergySettRules_ER11-3856-000.pdf.

[127] The ISO is developing more systematic software enhancements to model the unscheduled energy for both start-up and shut-down profiles outside of the load adjustment process. The ISO anticipates implementation of the new start-up and shut-down feature in 2012.

mechanism automatically adjusts the load downward to account for the additional generation, offsetting the need for operator intervention through manual load adjustments.

The impact to procedural and modeling improvements implemented in 2011 is reflected in the increased consistency of the load adjustments made after these improvements were made.

Figure 8.6 shows the average hourly load adjustment profile for the hour-ahead, 15-minute pre-dispatch and 5-minute real-time markets during the first quarter of 2011 (January through March). Figure 8.7 shows the average load adjustments for each operating hour in these markets during the second half of the year (July through December).[128] As shown in these figures:

- In Figure 8.6, during the first quarter, significant adjustments were made in the hour-ahead market, but minimal load adjustments were made when the 15-minute and 5-minute markets were run. Also, load adjustments made in the hour-ahead market peaked sharply in a few morning and evening hours.
- In Figure 8.7, during the second half of the year, load adjustments in the hour-ahead market increased overall, but changed much more gradually from hour-to-hour and were usually less extreme during individual hours. In addition, adjustments in the 15-minute real-time pre-dispatch process became more pronounced and followed the same pattern of adjustments made in the hour-ahead market. During this period, the 5-minute real-time load adjustments reflect how load adjustments were adjusted on a 5-minute basis throughout the day depending on system conditions. Some values were negative during the morning ramping hours 7 through 12.

Figure 8.8 highlights how load adjustments during peak hour ending 17 changed from month-to-month over the course of 2011. As shown in Figure 8.8:

- The use of load adjustments in all markets increased beginning in the summer months.
- The hour-ahead market and 15-minute real-time pre-dispatch load adjustments were highest in November. This reflects an effort to use load adjustments to account for modeling inconsistencies during the steeper evening ramping period created by higher lighting loads during fall and winter months.
- Real-time load adjustments were negative in the month of May and well below the 15-minute real-time pre-dispatch levels in the months of September through December.

As discussed in DMM's third quarter report, extreme load adjustment levels can lead to extreme market outcomes.[129] During a period of three days in early July, ISO operators adjusted the hour-ahead market load by over 3,000 MW, which resulted in prices that exceeded $1,000/MWh in several intervals. DMM discussed the lessons learned from these price spikes with operators and no further instances of extreme hour-ahead load adjustments have occurred since early July.

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[128] The ISO initially had two ways to adjust load in the 5-minute real-time market. One method is readily quantifiable based on data stored by the ISO. Data needed to easily reconstruct adjustments made using the second methods are not readily available. Data in Figure 8.6 reflect adjustments made with this first method. Starting in April, the 5-minute real-time load adjustments were consolidated into a single approach that can be quantified based on data stored in the ISO systems.

[129] *Quarterly Report on Market Issues and Performance*, Department of Market Monitoring, November 8, 2011, pp. 37-39: http://www.caiso.com/Documents/QuarterlyReport-MarketIssues_Performance-November2011.pdf.

Figure 8.6 Average hourly load adjustments (January through March)

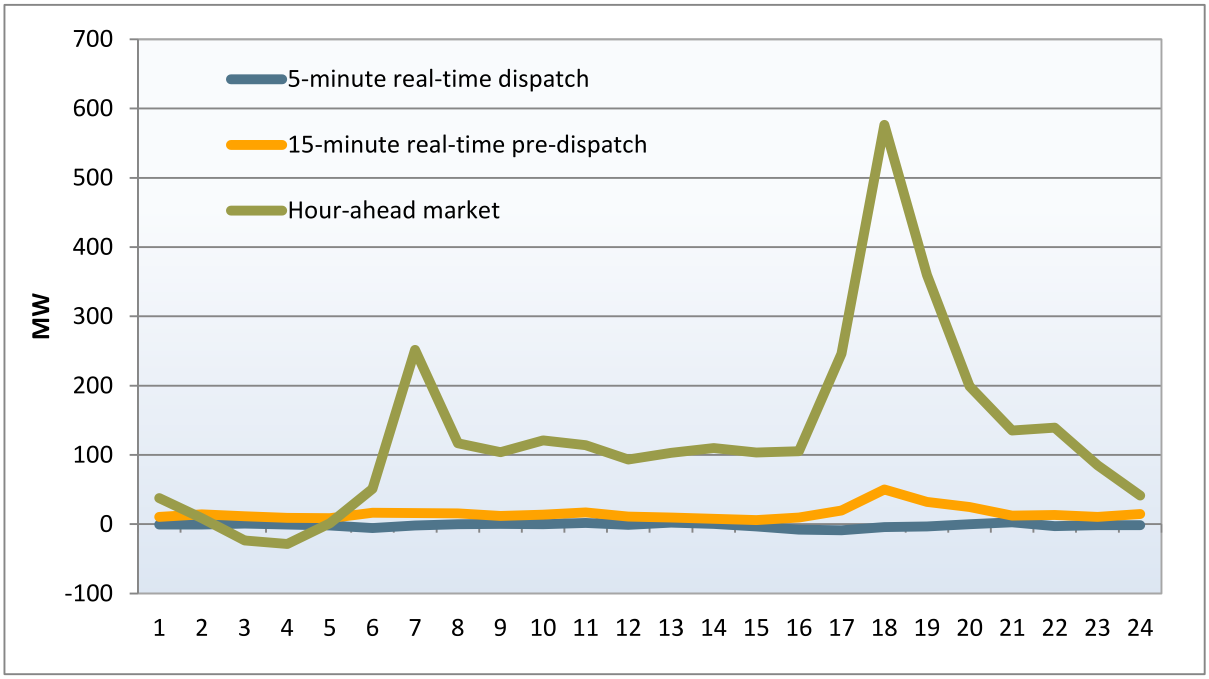


Figure 8.7 Average hourly load adjustments (July through December)

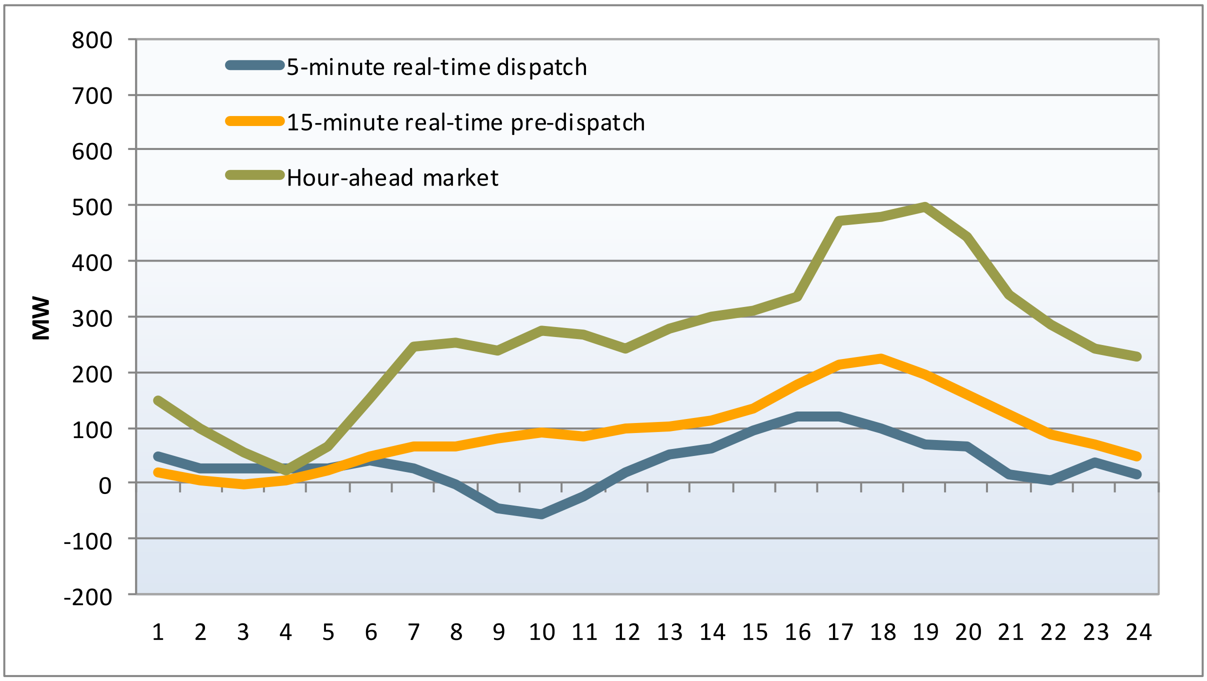
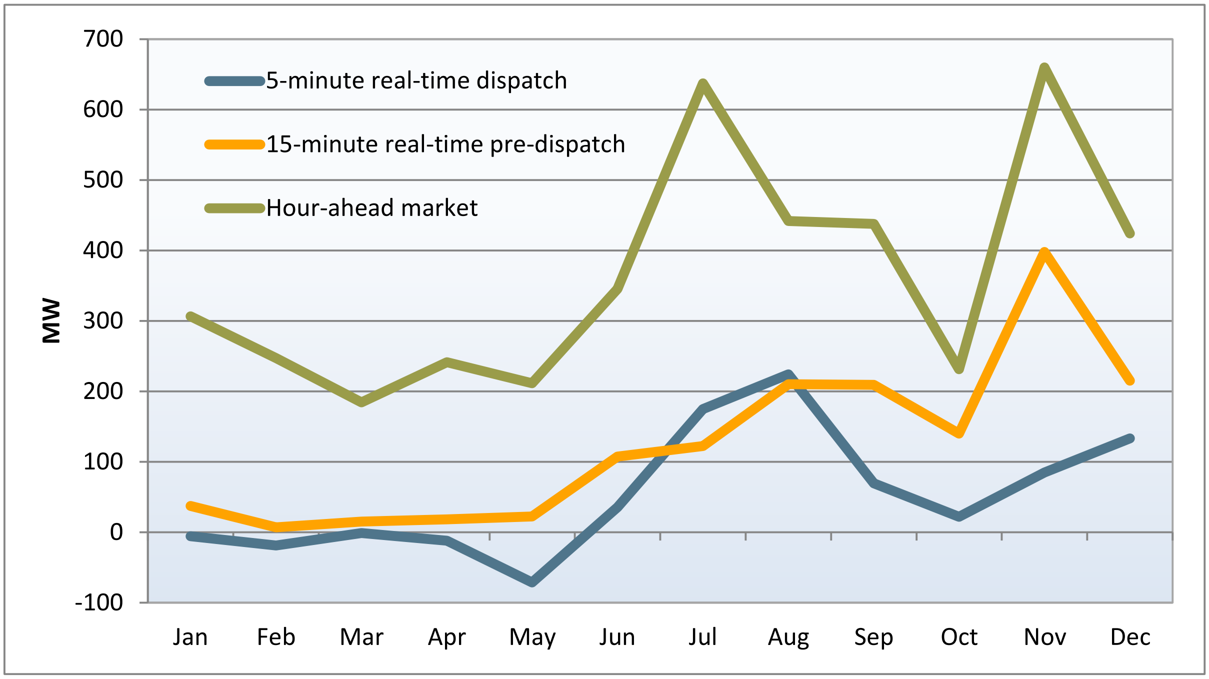


Figure 8.8 Average monthly load adjustments (hour ending 17)



8.3 Transmission limit adjustments

Actual flows on transmission lines can sometimes vary significantly from flows predicted by the network model. In the real-time market, operators track actual transmission line flows and may determine that the market model is not accurately reflecting the actual flows. There are a variety of causes for these modeling inaccuracies. Unscheduled flows on major transmission paths – also known as *loop flows* – can originate due to differences in scheduled and actual power flows outside the ISO system.[130] Within the ISO system, differences in line flows can result from demand forecast errors and generating units deviating from their schedules, known as uninstructed deviations.[131]

In the real-time market, operators track actual transmission line flows and may determine that the market model is not accurately reflecting the actual flows. The ISO network model may overestimate or underestimate transmission line flows. The operators will adjust the transmission limit incorporated in the market model depending on the nature of the inconsistency.

- There are times when the estimated power flow on a transmission line reaches the constraint limit incorporated in the market model. As a result, price congestion occurs on the line. After reviewing actual metered line flows, the operators may determine that the price congestion is not reflective of

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[130] The ISO attempts to model these flows at the inter-ties through a feature known as *compensating injections.* However, analysis by DMM indicates that the effectiveness of this tool is often likely to be quite limited (see Section 8.4).

[131] Differences also occur as a result of units generating below their minimum operating level due to start-up or shut-down profiles being left out of the market optimization. The ISO is developing more systematic software enhancements to model the unscheduled energy for both start-up and shut-down profiles. The ISO anticipates implementation of the new start-up and shut-down feature in 2012.

actual system conditions, and will therefore increase the line limit incorporated in the market model upwards to eliminate the inaccurate market congestion.

- Alternatively, there are times when the estimated flow on a transmission line is below the constraint limit, but the operators may determine that the actual metered loads are indeed approaching or at the transmission limit. In this situation, operators will decrease the line limit in the market model downwards to force the model to account for the actual congestion. This triggers price congestion and causes the market model to manage the congestion by re-dispatching resources based on their bid prices and effectiveness at reducing congestion.

The ISO refers to such adjustments as *conforming* of transmission limits since the goal is to conform the limits in the market model to the actual level of flow being observed. Figure 8.9 shows the frequency operators have conformed transmission in either an upward or downward direction, along with the average volume of these transmission adjustments.[132] As Figure 8.9 shows:

- The frequency of transmission adjustments decreased by over 60 percent in 2011 compared to 2010. The ISO attributes this improvement primarily to improvements and corrections to modeling and forecasting. In addition, the ISO instituted the use of summer and winter ratings on some paths, which improved line ratings.

- The magnitude of the adjustments has increased by 20 percent in 2011 compared to 2010. However, this increase was driven largely by upward adjustments to the Path 26 branch group during the third quarter to prevent false congestion in real-time. The ISO operators manage the Path 26 flows in real-time through use of nomograms. Because the Path 26 branch group has a line rating of up to 4,000 MW, an adjustment of 100 percent in the upward direction would result in a potential change of up to an additional 4,000 MW. Over a day, this can create large volumes of adjustments.[133]

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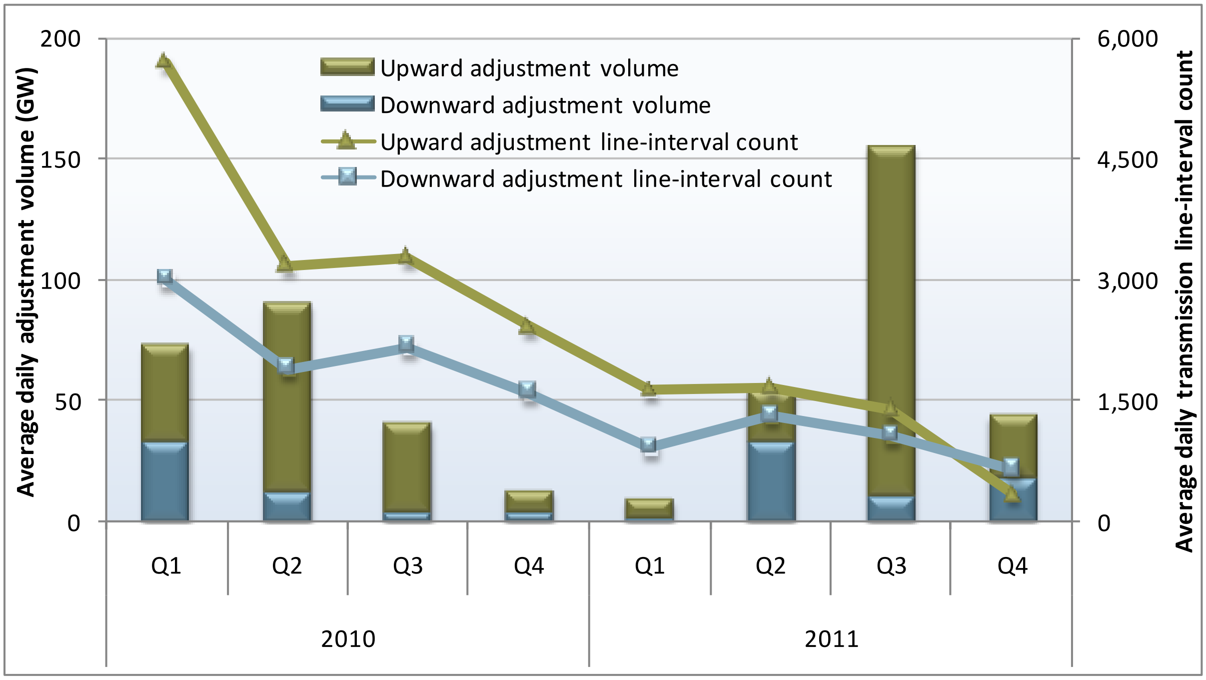
[132] The frequency of transmission adjustments is measured by counting the number of intervals that each different line is adjusted. The ISO reports on transmission conforming in its monthly performance metric catalogue. Transmission conforming information can be found in Figures 114 and 115 on pp. 107-108 of the November 2011 report: http://www.caiso.com/Documents/MarketPerformanceMetricCatalogNovember2011.pdf.

[133] When adjusting transmission in the upward direction, the goal is to alleviate false congestion. Therefore, the size of the upward adjustment is less important than a downward adjustment, as it is designed to eliminate congestion; the higher the number for an upward adjustment the more likely congestion will be eliminated. The size of a downward adjustment is important because the larger the adjustment, the bigger the potential market effect.

Figure 8.9 Average daily frequency and volume of internal transmission adjustments by quarter



8.4 Compensating injections

In July 2010, the ISO re-implemented an automated feature in the hour-ahead and real-time software to account for unscheduled flows along the inter-ties. This feature accounts for observed unscheduled flows by incorporating *compensating injections* into the market model. These are additional injections and withdrawals that are added to the market model at various locations external to the ISO system. The quantity and location of these compensating injections are calculated to minimize the difference between actual observed flows on inter-ties and the scheduled flows calculated by the market software. The software re-calculates the level and location of these injections in the real-time pre-dispatch run performed every 15 minutes. The injections are then included in both the hour-ahead and 5-minute market runs.

Before implementing this feature, the ISO identified that if the net quantity of compensating injections – the difference between the injections and withdrawals added to the market model – is significantly positive or negative, this can create operational challenges due to the impact this has on the area control error (ACE). The ACE is a measure of the instantaneous difference in matching supply and demand on a system-wide basis. It is a critical tool for managing system reliability.

To avoid creating problems managing the ACE, a constraint was added to the software that limits the net impact of compensating injections to an absolute difference of no more than 100 MW. This limitation is imposed by applying a discount factor to the compensating injections calculated by the software as this absolute difference increases beyond this 100 MW threshold. This reduces the compensating injections at each location if the overall net system-level compensating injections exceed this 100 MW threshold. This discount factor is set to 0.3 for absolute net compensating injections between 100 MW and 335 MW. Compensating injections are cancelled when absolute net injections increase above 335 MW.

As a result of this constraint, there can be three distinct modes or statuses of compensating injections.

- **Full compensating injections.** This is when compensating injections are fully enabled and are not limited by the discount factor.
- **Partial compensating injections.** This is when the compensating injections are limited by the discount factor.
- **Compensating injections turned off.** This is when the compensating injections are turned off because the net compensating injections value would have been too high relative to the area control error to resolve the flows.

Prior analysis by DMM indicates the accuracy of the modeled transmission flows relative to the actual flows is only improved when this software is consistently operating with full compensating injections in effect.[134] Moreover, DMM has expressed concern that if partial injections are frequently switched from these different modes this may create sudden and frequent changes in modeled flows that could in some cases decrease the efficiency of congestion management. The following section provides additional analysis of this issue.

Analysis

Compensating injections varied frequently between the full, partial and off statuses most of the year. Figure 8.10 shows how often the compensating injection status varied over consecutive 15-minute intervals during 2011.

- About 56 percent of the time, compensating injections remained in a single status for less than an hour. Frequent status-switching adds an additional level of variability to the real-time model as flows vary on the impacted lines.
- In about 43 percent of intervals, compensating injections were in a single status for an hour or more. In 64 percent of these intervals, the compensating injection status was either limited by the discount factor or completely off. Thus, the compensating injection feature remained completely on for an hour or more for only about 27 percent of the time.
- Since the third quarter of 2010, compensating injection has been in full operational mode in only about 36 percent of the total intervals. In the rest of the intervals during this time frame, the compensating injection was either off (18 percent of total intervals) or only partially active (46 percent of total intervals).

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[134] *Quarterly Report on Market Issues and Performance*, Department of Market Monitoring, November 8, 2010, pp. 39-42: http://www.caiso.com/Documents/QuarterlyReportonMarketIssuesandPerformance-November2010.pdf.

Figure 8.10 Frequency of compensating injection status change

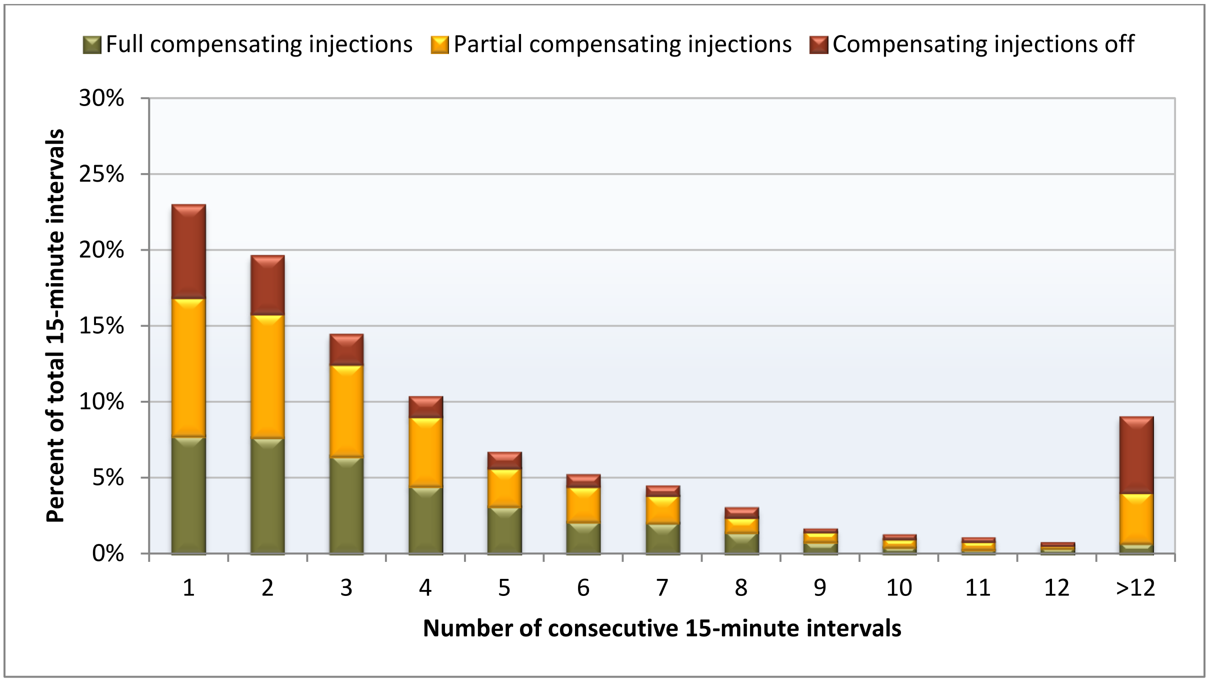

Table 8.1 displays the percentage of 15-minute intervals in 2011 during which compensating injections changed from one status of operation to another. Table 8.1 shows that:

- The operating status of compensating injections changed from one 15-minute interval to the next during about 47 percent of all intervals.
- The compensating injection remained in full operational mode during only about 21 percent of the intervals.
- During the remaining 79 percent of consecutive intervals, compensating injection status was either partially active or completely off, or had just switched to full status. As will be highlighted below, market flows were not close to actual flows during these intervals.

Table 8.1 Compensating injection consecutive 15-minute interval status

	Current interval status		
Previous interval status	**Off**	**Partial**	**Full**
Off	12%	5%	4%
Partial	6%	23%	12%
Full	4%	13%	21%

During the first nine months of 2011, DMM periodically compared the actual line flows with the market flows during the different compensating injection statuses. DMM found that the gap between the flows was smallest when compensating injections were operating in full mode continuously. However, when the compensating injection status kept changing, the gap between the market and actual flows increased. The gap between the flows was even higher during the intervals when the compensating injection was off or partially limited due to the discount factor.

Figure 8.11 and Figure 8.12 display data for a sample day that illustrate these trends.

- Figure 8.11 displays the 15-minute status of compensating injections for the sample day to highlight how the operating status of compensating injections changed over the course of a day.
- Figure 8.12 displays the difference between the market flows and the actual flows on the three selected inter-ties during this same day.

As shown by a comparison of these figures, when the compensating injection was off (hour ending 15), the gap between the inter-tie actual flows and the market flows was substantial. When the compensating injection was in full status for a continuous duration (hour ending 19), the market flows were fairly close to the actual flows on the selected inter-ties.

DMM recommends that the ISO review the effectiveness of the compensating injections feature and consider modifying the limiting parameters to improve the accuracy of the modeled flows. Furthermore, the analysis of compensating injections continues to be hampered by data limitations outlined in previous reports.[135] DMM continues to stress the importance of capturing this data to further understand the impacts of compensating injections on internal congestion and to understand the relationship of the market flows both with and without compensating injections.

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[135] *Quarterly Report on Market Issues and Performance*, November 8, 2010, p. 42 and *Quarterly Report on Market Issues and Performance*, February 8, 2011, p. 32.

Figure 8.11 Compensating injection levels (October 5, 2011)

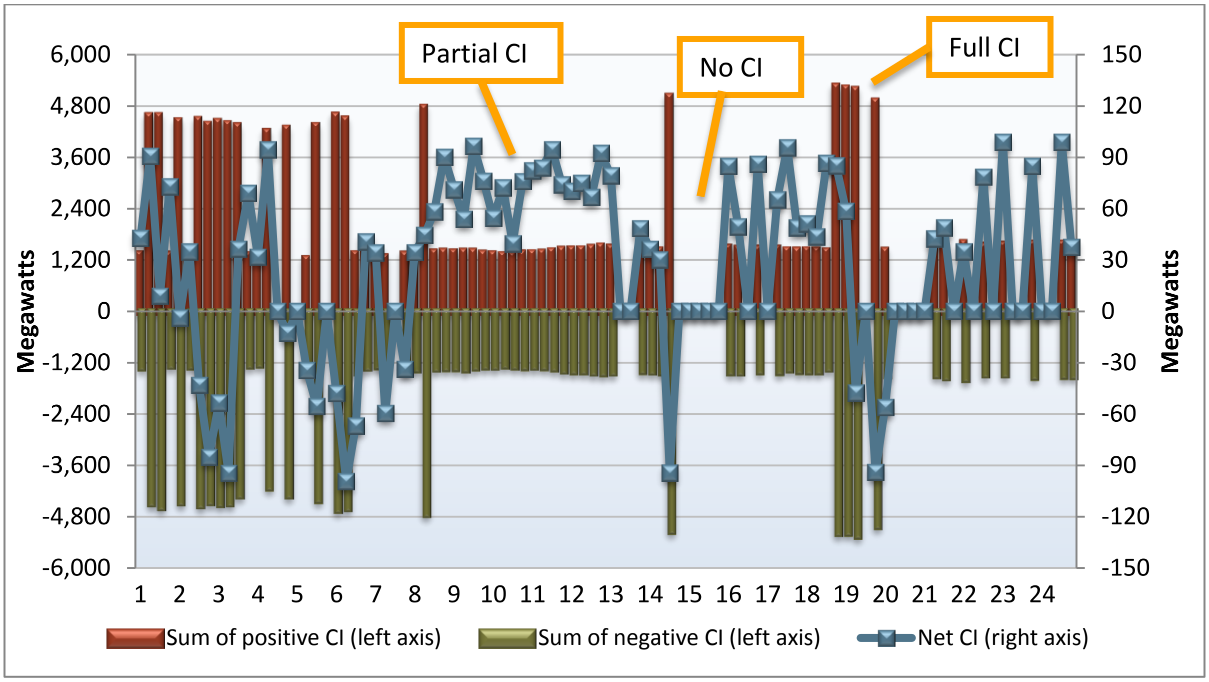
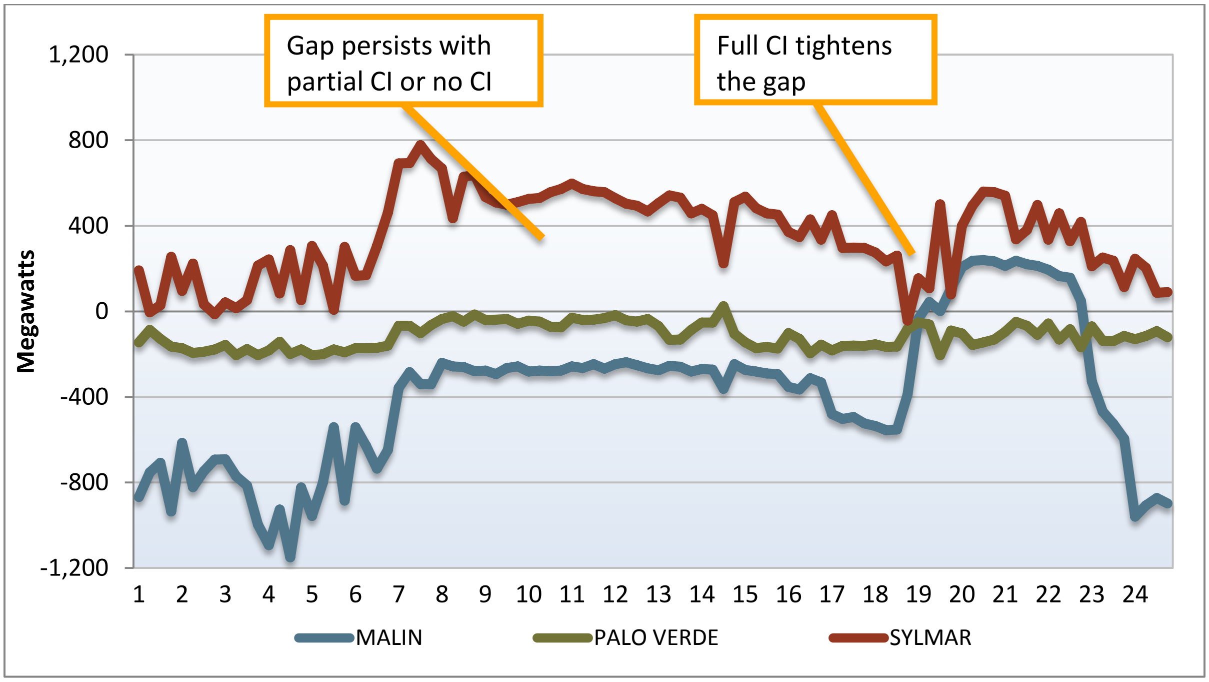


Figure 8.12 Difference between market flows and actual flows on selected inter-ties (October 5, 2011)



8.5 Blocked instructions

The ISO's real-time market includes a series of processes. Imports and exports are dispatched through the hour-ahead scheduling process. The 15-minute pre-dispatch process is used to commit or de-commit short-start peaking units within the ISO and to transition multi-stage generating units from one configuration to another. Finally, the 5-minute dispatch process is used to increase or decrease the dispatch level of online resources within the ISO.

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. This can occur for a variety of reasons, including:

- **Data inaccuracies.** Results of the market model may be inconsistent with actual system or market conditions as the result of a data systems problem. For example, the ISO takes telemetry data and feeds the telemetry into the real-time system. If the telemetry is incorrect, the market model may try to commit or de-commit units based on the bad telemetry data. The operators will act accordingly to stop the instruction from being incorrectly sent to market participants.

- **Software limitations of unit operating characteristics.** Software limitations can also cause inappropriate commitment or dispatch decisions. For example, the ISO software has had difficulty modeling pump generator characteristics.[136] Also, some unit operating characteristics of thermal units are also not completely incorporated in the real-time market models. For instance, some thermal generating units are physically configured such that one of the units requires another unit to generate. The model may attempt to commit the dependent unit without committing the first unit. As a result, operators will either have to exceptionally dispatch the first unit or block the commitment of the second unit to make the outcome feasible.

- **Information systems and processes.** In some cases, problems occur in the complex combination of information systems and processes needed to perform the various processes required 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.

Blocked instructions increased in 2011 compared to 2010. Figure 8.13 shows the frequency and volume of blocked dispatches on inter-ties. Figure 8.14 shows the frequency of blocked real-time commitment start-up and shut-down and multi-stage generator transition instructions for internal generation.[137]

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[136] A pump generator may require at least an hour of transition between pumping and generating. Prior to the ISO fall software release, the model did not recognize this limitation and required corrective action by the operator.

[137] The ISO reports on blocked instructions in its monthly performance metric catalogue. Blocked instruction information can be found in Figures 110 through 113 and Table 16 on pp. 102-105 of the November 2011 report: http://www.caiso.com/Documents/MarketPerformanceMetricCatalogNovember2011.pdf.

Figure 8.13 Frequency and volume of blocked real-time inter-tie instructions

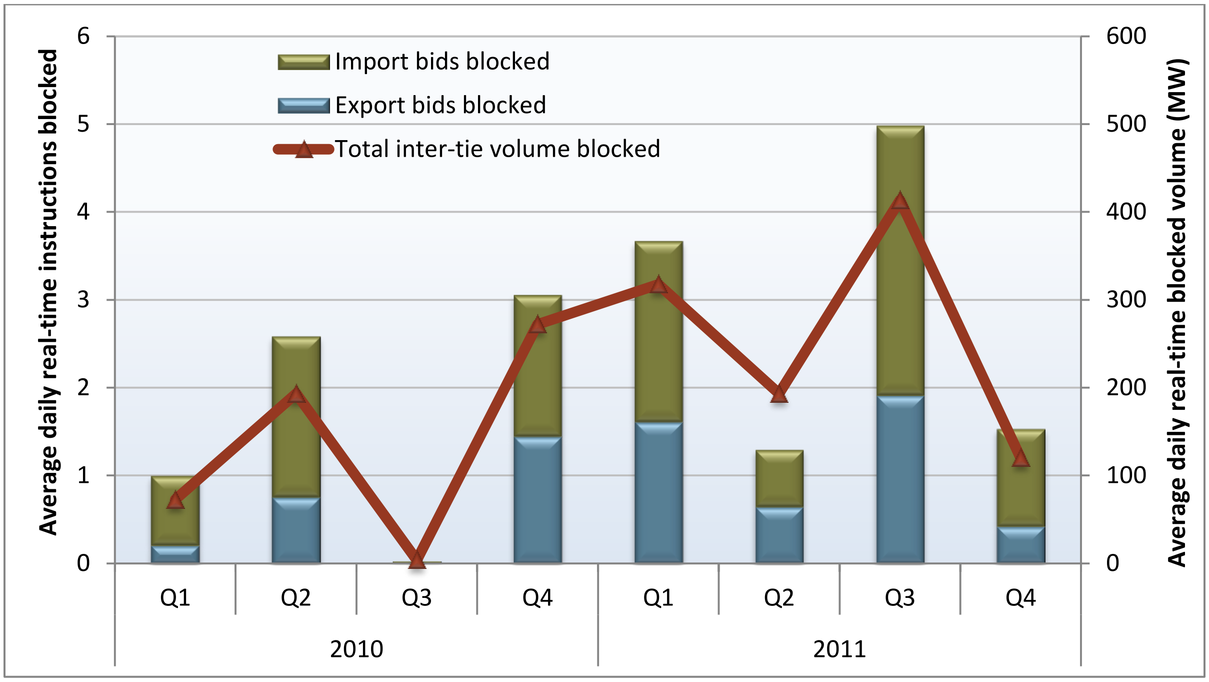
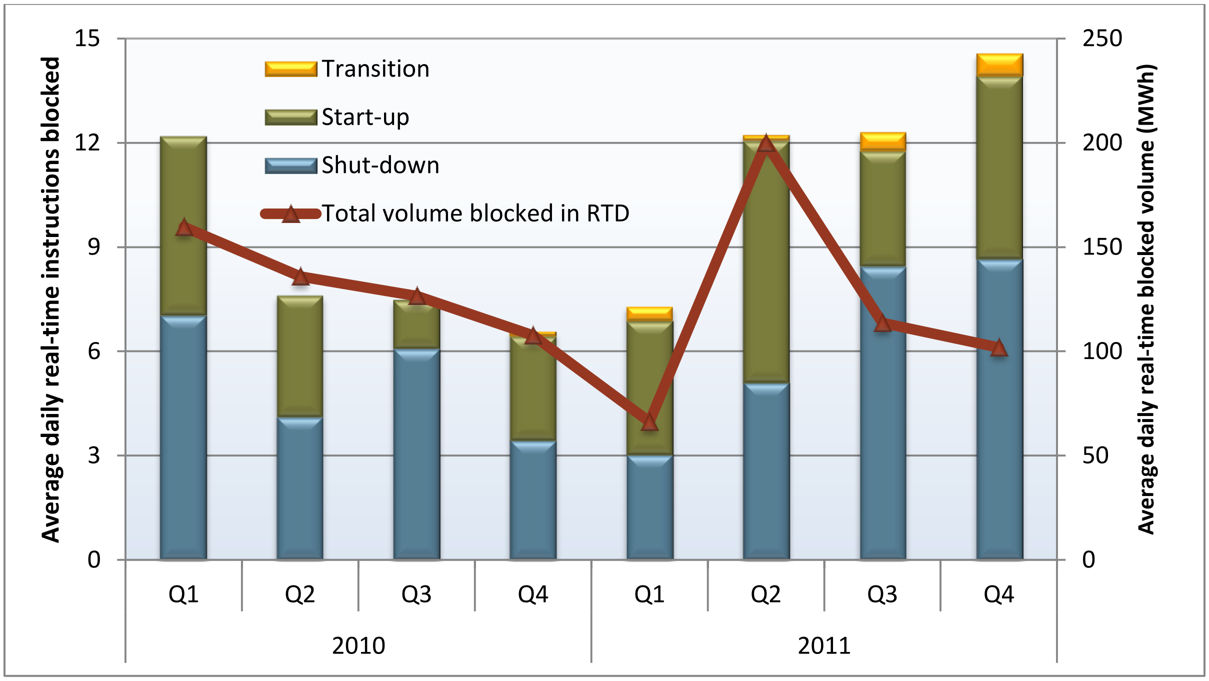


Figure 8.14 Frequency and volume of blocked real-time internal instructions



The number of blocked inter-tie instructions was up over 70 percent in 2011 compared to 2010. Blocked instructions for internal resources increased by over 35 percent in 2011 compared to 2010.[138] The increase in blocked instructions for resources within the ISO is mainly driven by an almost 50 percent increase in blocked start-up instructions in 2011 compared to 2010. Even though the volume of blocked start-up instructions increased, blocked shut-down instructions were the most common reason for blocked instructions at 54 percent. Blocked start-up instructions accounted for 42 percent of blocked instructions within the ISO in 2011, with blocked transition instructions to multi-stage generating units accounting for only 4 percent.

8.6 Aborted and blocked dispatches

Operators review dispatches issued in the 5-minute real-time market before these dispatch and price signals are sent to the market. If the operators determine that the 5-minute dispatch results are inappropriate, they are able to *abort* or *block* entire real-time dispatch instructions and prices from reaching the market. Operators can choose to abort and block 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.

The ISO increased the use of aborting or blocking price results in 2011 because 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. This would often cause participants to act inappropriately when considering actual and not modeled system conditions. Quite frequently, many of the aborted or blocked intervals eliminated the need for a subsequent price correction.

Originally, the ISO did not have a tool that allowed operators to block these dispatch and price signals, even if they knew that these were inaccurate. Instead, operators could only *abort* or cancel the entire 5-minute real-time dispatch signal. This eliminated all data associated with the interval, so that the market results could not be reviewed after the fact. Alternatively, operators could block the dispatch, but the associated prices for the blocked dispatch would be published, sending inaccurate price signals. The benefit of blocking compared to aborting was that blocking preserves the data.

As a result, the ISO developed software functionality to block the dispatch and price signal and replace these with the previous 5-minute market solution.[139] This new tool for blocking 5-minute interval results was implemented in late July.

Figure 8.15 shows the frequency that operators aborted and blocked price results from the real-time dispatch process in 2011. From May through December, real-time market results were aborted or blocked an average of 25 intervals per month in 2011. As shown in Figure 8.15, the practice of aborting market results was initiated in May, but declined dramatically in July and was not used after August. Starting in July, unreliable market results were blocked instead of being aborted. Using the previous

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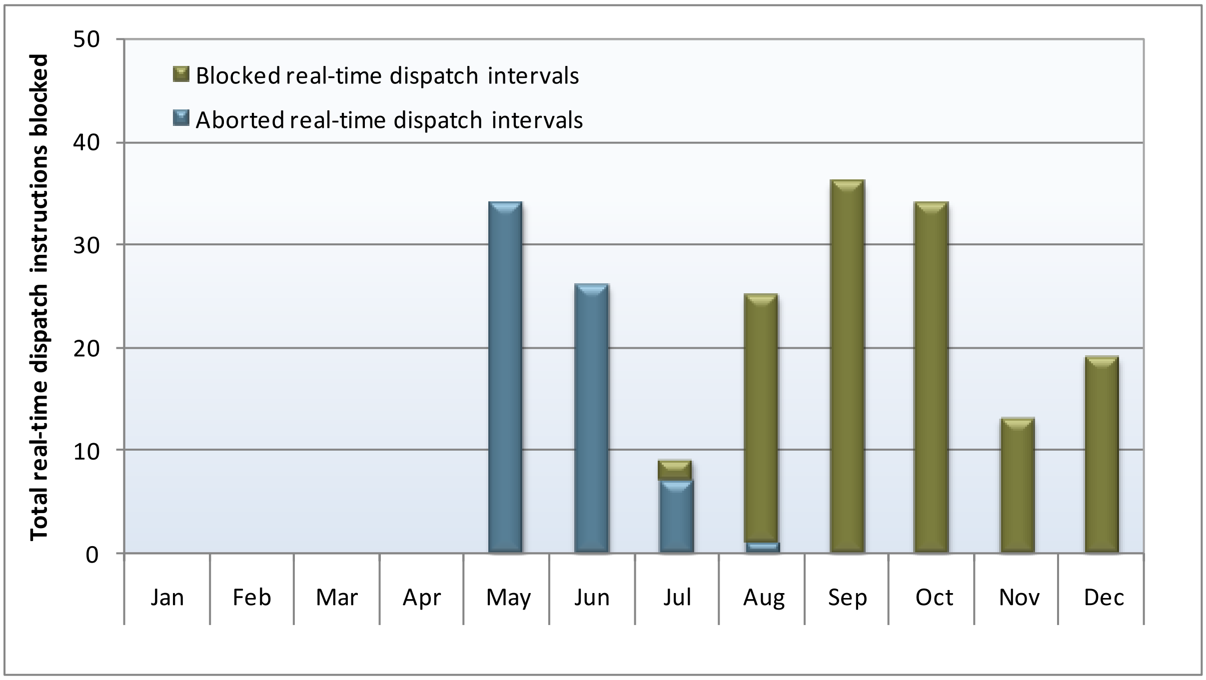
[138] The maximum number of start-up instructions blocked in a single day was 72 on October 10 and 14, 2011. The start-up instructions were blocked as a result of software glitches related to CAISO interchange transaction software (CAS) issues and the promotion of a new network model, known as DB 56, respectively. There were 115 shut-down instructions blocked on July 30, 2010 and 50 on December 8, 2011. The shut-down instructions were blocked as a result of reliability concerns caused by wildfires and as a result of a natural gas pipeline problem, respectively. Maximum transition blocks were 10 on February 4, 2011 as a result of limitations of natural gas supply into California.

[139] DMM raised concerns with the ISO that the aborted results could not be reviewed for accuracy or were not sufficiently logged or tracked, and that the procedures around the abort process were not well defined. The block interval feature that was deployed in late July, as well as an enhanced procedure, addressed DMM's concerns.

solution, the majority of the replaced prices decreased as a result. However, sometimes prices increased or remain unchanged. As noted above, the capability to block rather than abort market pricing results was implemented in July and allowed these results to be reviewed.

Figure 8.15 Frequency of aborted and blocked real-time dispatch intervals



8.7 Price corrections

Numerous participants expressed concern with the ISO's price correction process in 2011. DMM recognizes that price corrections are inevitable given the nature of computer systems and the need for prices to reflect just and reasonable rates. DMM also recognizes the importance of price accuracy for the market. DMM has reviewed all price corrections made in 2011 and finds that the reasons for price corrections appear consistent with the tariff. However, DMM's review indicates that the price correction process should provide better feedback within the ISO when issues are identified. For example, transmission related corrections, such as constraint enforcement errors, can often persist. By alerting the appropriate transmission modeling staff about persistent problems early, the ISO could potentially reduce the number of price corrections going forward by directly addressing the problem and developing safeguards to ensure the proper constraints are included in the model.

The ISO corrects prices pursuant to tariff section 35.[140] In 2011, the ISO corrected almost 1.8 million price nodes (0.2 percent) affecting over 1,700 intervals (0.9 percent) in its markets.[141] Corrections to 5-

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[140] In 2010, the ISO implemented a 5-day correction process and further clarified the process in the tariff for making any corrections after the 5-day period. Administrative prices are governed under ISO tariff section 7.7 and are not included in this analysis.

minute real-time prices represented 67 percent of corrected intervals, whereas hour-ahead market corrections represented 20 percent of corrected intervals. Price corrections in the day-ahead market represented 11 percent of intervals and the 15-minute pre-dispatch market represented only 2 percent of corrected intervals.[142]

The volume of price corrections increased throughout much of the year before falling off in November and December. Figure 8.16 shows the frequency of price corrections by interval. Figure 8.17 shows the frequency of price corrections by price node. The figures also show the categorization of price correction type.

- The most frequent price correction category by both interval and node is transmission modeling. This represents 62 percent of the corrected intervals and 42 percent of the corrected nodes. Transmission modeling includes issues related to line ratings, switch and circuit breaker statuses, constraint enforcement, outage application, and compensating injection modeling. While there was no consistent pattern as to type or location of the transmission modeling issue, there appears to be room for improvement with how the ISO models transmission.

- The second most frequent category is hardware/software issues, representing 12 percent of the corrected intervals and 34 percent of the corrected nodes. Sub-categories include network upgrades and CAISO interchange transaction software (CAS) issues. The largest volume of nodal corrections in 2011 was caused by problems related to the implementation of the new network model in October, known as DB 56. This implementation required almost 450,000 nodal price corrections, representing 25 percent of all nodal corrections and 8 percent of the intervals corrected in 2011.

The other price corrections categories include:

- Generation modeling, which includes corrections made as a result of multi-stage generating unit modeling problems and telemetry inaccuracies;
- Load modeling, which includes corrections related to the new load forecasting system, known as ALFS3, and improper load distribution factors;
- Tariff consistency corrections, which primarily correct for open tie problems; and
- Other causes, which primarily include corrections related to the improper inclusion of the Sutter pseudo tie in the NP-15 trading hub definition.

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[141] There are 288 intervals in the 5-minute market, 96 intervals in the hour-ahead and 15-minute real-time pre-dispatch markets, and 24 intervals in the integrated forward market and the residual unit commitment. There are roughly 4,400 price nodes in the ISO system. This analysis did not count corrections to aggregate pricing nodes or trading hubs.

[142] Results are similar for the percentages of all nodal prices corrected in these markets.

Figure 8.16 Frequency of price corrections by category and interval in 2011

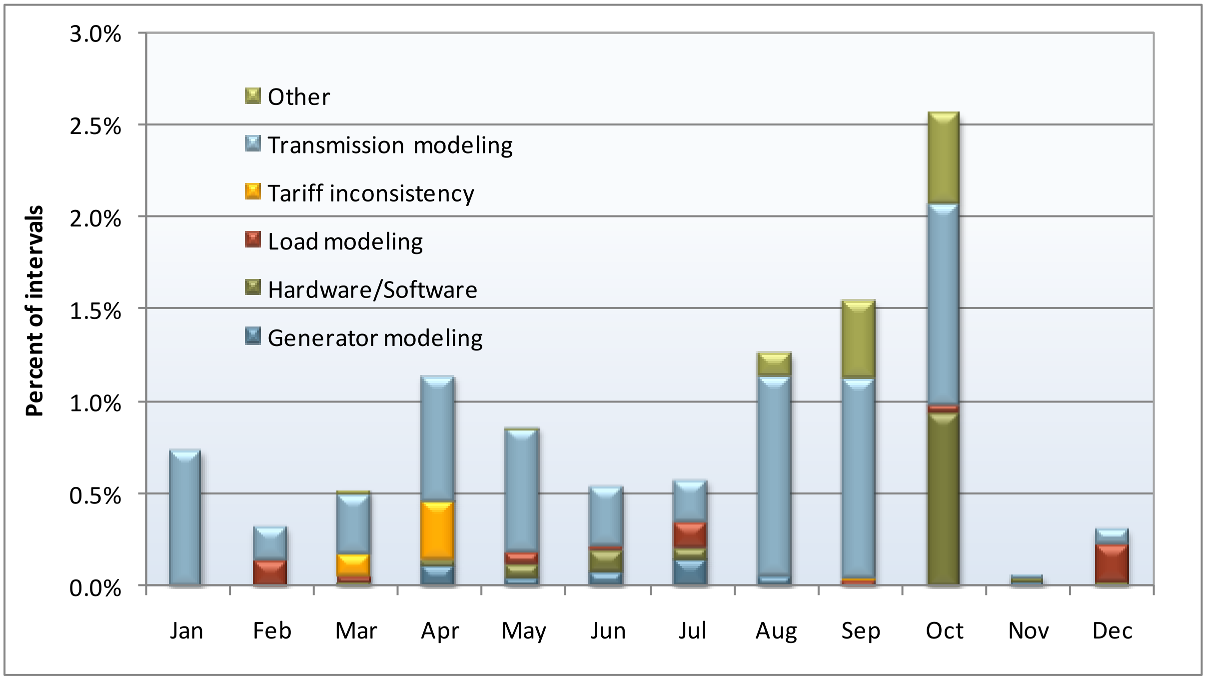
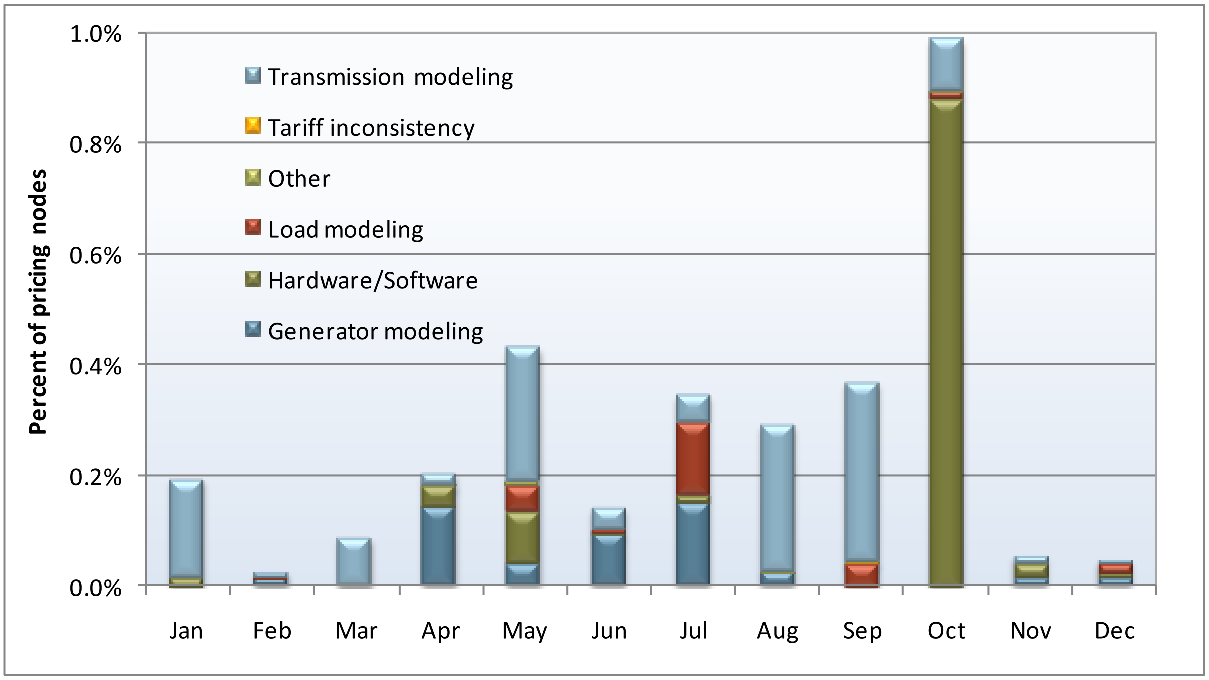


Figure 8.17 Frequency of price corrections by category and by nodal prices corrected in 2011



After reviewing the ISO price correction process, DMM has identified that some causes of price corrections continued to occur well after the original problem was identified. For example, congestion on the Sutter pseudo tie was incorrectly included in the NP-15 trading hub definition. The issue was first identified in late August, but price corrections continued to be made until mid-October. While this represented less than 0.001 percent of the nodal prices corrected in 2011, this was the most frequently corrected item by interval, affecting over 10 percent of all intervals corrected in 2011. Having the appropriate feedback and priority assigned to this item would have likely reduced the incidence of this correction.

In late 2011, the ISO emphasized the importance of the price validation and correction process. The ISO centralized the function of validating prices and the quality of the market solution into a new group. The main objective of the new group is to continue to perform timely price validation using consistent and enhanced procedures, and to also provide feedback to other groups to help reduce the incidence of recurring price corrections.

9 Resource adequacy

California's wholesale market relies on a resource adequacy program and long term procurement planning process adopted by the CPUC to provide sufficient capacity to ensure reliability. The resource adequacy program includes ISO tariff requirements that work in conjunction with state regulatory requirements and processes adopted by the CPUC.

This chapter analyzes the short-term effectiveness of the resource adequacy program based on availability of resource adequacy capacity in the ISO market in 2011.

- During the 210 hours with the highest loads, about 91 percent of resource adequacy capacity was available to the day-ahead energy market and the residual unit commitment process. This is approximately equal to the target level of availability incorporated in the resource adequacy program design and similar to the availability in 2010.

- At the 70th percentile, wind and solar output were generally lower than their resource adequacy capacities. Wind output at the 70th percentile was higher than the resource adequacy capacity only in August while solar output at the 70th percentile remained below the resource adequacy capacity in all the three months. Also, wind generation dropped substantially in September, whereas solar generation stayed relatively high and stable.

- Capacity made available under the resource adequacy program in 2011 was sufficient to meet virtually all system-wide and local area reliability requirements. As a result, the ISO placed very limited reliance on the capacity procurement mechanisms provisions of the ISO tariff.

To date, the resource adequacy program has not been designed to serve as a mechanism for longer-term investments and contracting needed to ensure future supplies. However:

- In late 2011, Calpine Corporation informed the ISO that it intends to retire a 550 MW combined cycle unit (Sutter Energy Center) in 2012 unless it either received a resource adequacy contract or was contracted by the ISO through the capacity procurement mechanism. While the ISO determined that this capacity was not needed in 2012, the ISO indicated the unit is likely to be needed in 2017 due to the retirement of other existing gas-fired capacity and the need to retain sufficient capacity with the operational flexibility to integrate the large volume of intermittent renewable resources coming online in the next few years.

- This case has highlighted several key limitations of the current resource adequacy program and capacity procurement mechanism. Both of these mechanisms are based on procurement of capacity only one year in advance, and neither mechanism incorporates any specific capacity or operational requirements for the type of flexible capacity characteristics that will be needed from a large portion of gas-fired resources to integrate the large volume of intermittent renewable resources coming online in the next few years.

9.1 Background

The resource adequacy provisions of the ISO tariff require load-serving entities to procure generation capacity to meet 115 percent of their forecast peak demand in each month.[143] The 115 percent requirement is designed to include the additional operating reserve needed above peak load (about 7 percent), plus an allowance for outages and other resource limitations (about 8 percent). This capacity must then be bid into the market through a must-offer requirement. Load-serving entities provide these resource adequacy showings to the ISO on a year-ahead basis.

About half of the generating capacity counted toward resource adequacy requirements must be bid into the market for each hour of the month except when this capacity is reported to the ISO as being unavailable because of outages. This includes most gas-fired generation – 93 percent of gas-fired capacity and all but one small gas-fired unit was contracted to provide resource adequacy – with a total capacity of over 23,000 MW. If the market participant does not submit bids or report capacity as being on outage, the ISO automatically creates bids for these resources.

The other half of generation resources that are counted toward the resource adequacy requirement do not have to offer their full resource adequacy capacity in all hours of the month. These resources are required to be made available to the market consistent with their operating limitations. These include:

- Hydro resources, which represent 13 percent of resource adequacy capacity.
- Use-limited thermal resources, such as combustion turbines subject to use limitations under air emission permits, which represent 6 percent of resource adequacy capacity.[144]
- Non-dispatchable generators, which include nuclear, qualifying facilities, wind, solar and other miscellaneous resources. These resources account for about 20 percent of capacity.
- Imports, which represent 8 percent of resource adequacy capacity.

After January 1, 2012, the ISO began to automatically create bids for imports when market participants fail to either report this capacity as being unavailable or submit bids for this capacity.

All available resource adequacy capacity must be offered in the ISO market through economic bids or self-schedules as follows:

- **Day-ahead energy and ancillary services market** — All available resource adequacy capacity must be either self-scheduled or bid into the day-ahead energy market. Resources certified for ancillary services must offer this capacity in the ancillary services market.
- **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.

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[143] As noted in Section 1.1.2 , the ISO tariff also requires load-serving entities to procure generation capacity to meet capacity requirements for local capacity areas.

[144] Use-limited thermal resources generally have environmental or regulatory restrictions on the hours they can operate, such as a maximum number of operating hours in a month or year. Most of these resources are peaking units within more populated and transmission constrained areas that are only allowed to operate 360 hours per year under air permitting regulations. Market participants submit to the ISO use plans for these resources. These plans describe their restrictions and outline their planned operation.

- **Real-time market** — All resource adequacy resources committed in the day-ahead market or residual unit commitment process must also be made available to the real-time market.

Short-start units providing resource adequacy capacity must also be offered in the real-time energy and ancillary services markets even when they are not committed in the day-ahead market or residual unit commitment process. Long-start units and imports providing resource adequacy capacity that are not scheduled in the day-ahead market or residual unit commitment process do not need to be offered in the real-time market.

9.2 Overall resource adequacy availability

Generation capacity is especially important to meet the peak loads of the summer months. However, it is also important that sufficient resource adequacy capacity be made available to the market throughout the year. For example, significant amounts of generation can be out for maintenance during the non-summer months, making resource adequacy capacity instrumental in meeting even moderate loads.

Figure 9.1 summarizes the average amount of resource adequacy capacity made available to the day-ahead, residual unit commitment and real-time markets in each quarter of 2011.

- The red line shows the total amount of this capacity used to meet resource adequacy requirements.[145]
- The bars show the amount of this resource adequacy capacity that was made available during critical hours in the day-ahead, residual unit commitment, and real-time markets.[146]

Figure 9.1 shows that a high portion of resource adequacy capacity was available to the market throughout the year.

- The highest availability was during the third quarter, which includes the summer months of July through September. During these months, out of the 49,400 MW of resource adequacy capacity included in this analysis, an average of around 44,300 MW or about 90 percent was available in the day-ahead market.
- The lowest level of availability was during the first quarter, during which about 85 percent of resource adequacy capacity was available to the day-ahead market.
- Over all the twelve months, virtually all capacity offered in the day-ahead energy market was also available in the residual unit commitment process.

Figure 9.1 also shows that a smaller portion of resource adequacy capacity was available to the real-time market. This reflects that long-start 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.

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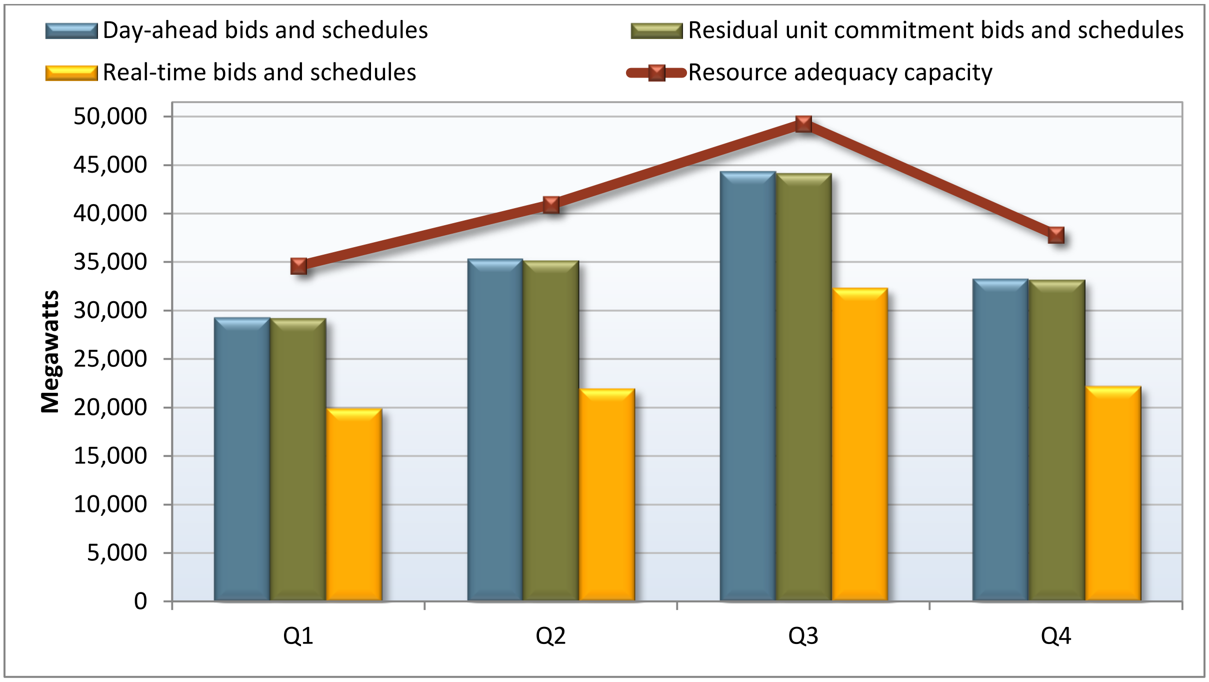
[145] The resource adequacy capacity included in this analysis excludes as much as 5,000 MW of resource adequacy capacity for which this analysis cannot be performed or is not highly meaningful. This includes: resource adequacy resources representing some imports and firm import liquidated damages contracts, resource adequacy capacity from reliability must-run resources, resource adequacy requirements met by demand response programs, and load-following metered subsystem resources.

[146] 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 14-18 during April through October and operating hours 17-21 during the remainder of the year.

Figure 9.1 Quarterly resource adequacy capacity scheduled or bid into ISO markets (2011)



9.3 Summer peak hours

California's resource adequacy program recognizes that a portion of the state's generation is only available during limited hours. To accommodate this, load-serving entities are allowed to meet a portion of their resource adequacy requirements with generation that is available only a portion of the time. This element of the resource adequacy program reflects the assumption that this generation will generally be available and used during hours of the highest peak loads.

Resource adequacy program rules are designed to ensure that the highest peak loads are met by requiring that all resource adequacy capacity be available at least 210 hours over the summer months of May through September.[147] The rules do not specify that these hours must include the hours of the highest load or most critical system conditions. Since participants do not have perfect foresight when the highest loads will actually occur, the program assumes that they will manage these use-limited generators so that they are available during the peak load hours.

DMM believes that the availability of resource adequacy capacity during the 210 peak hours is an important indication of how well the program meets actual peak loads. Accordingly, each of the last three years DMM has evaluated the availability of resource adequacy generation during the 210 hours of the months of May through September with the highest peak loads. In 2011, this includes all hours with peak load over 39,479 MW.

Figure 9.2 provides an overview of monthly resource adequacy capacity, monthly peak load, and the number of hours with loads over 39,479 MW that occurred during the period. 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.

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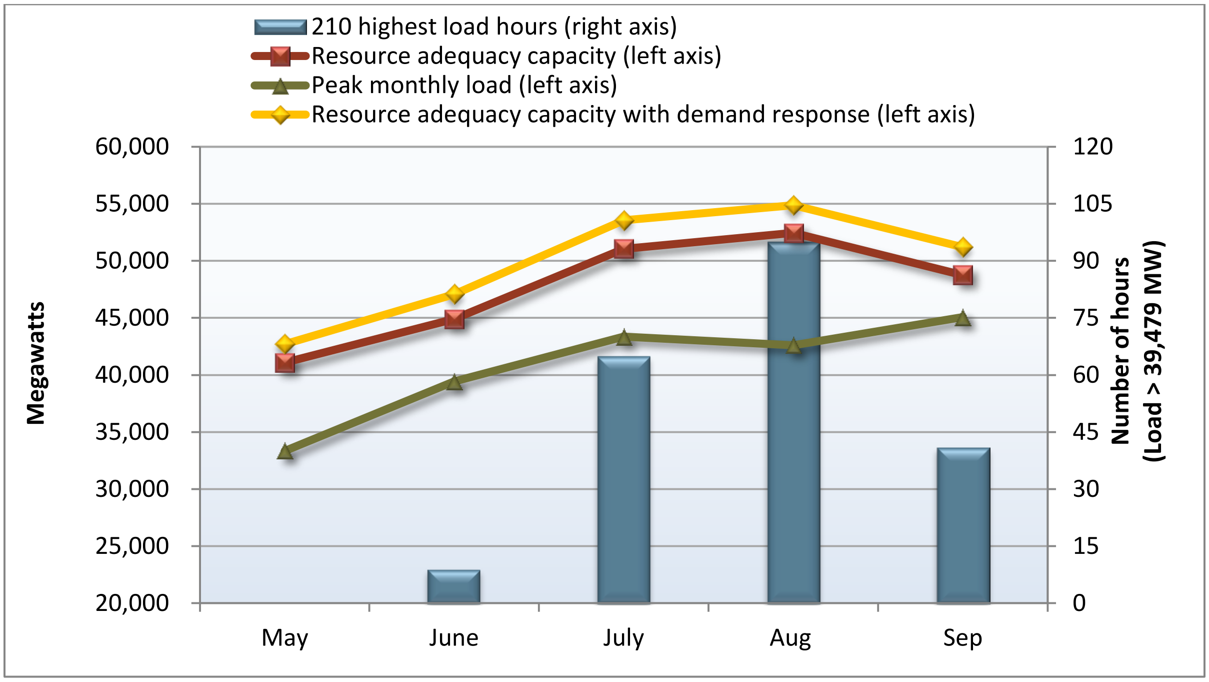
[147] The CPUC requires the resources be available 30, 40, 40, 60, and 40 hours during each of these months, respectively.

Figure 9.3 shows the amount of capacity scheduled or bid in the day-ahead and real-time market during these 210 peak hours. These results are ranked in descending order of total resource adequacy megawatts bid or scheduled in each of the three markets listed below.[148] Figure 9.3 indicates the following:

- ***Day-ahead market*** **—** Bids and self-schedules for resource adequacy capacity in this market averaged about 91 percent of overall resource adequacy capacity, varying in individual hours from about 80 to 96 percent of resource adequacy capacity.
- ***Residual unit commitment*** **—** Resource adequacy capacity available to this process was 88 percent of overall resource adequacy capacity, just slightly less than the amount available to the day-ahead market.
- ***Real-time market*** **—** Bids and self-schedules for resource adequacy capacity in the real-time market averaged about 71 percent of overall resource adequacy capacity, varying in individual hours from about 61 to 80 percent. As previously noted, the lower amount of resource adequacy capacity available to the real-time market results was because not all resource adequacy capacity was committed in the day-ahead market or residual unit commitment process.

Figure 9.2 Summer monthly resource adequacy capacity, peak load, and peak load hours May-September 2011



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[148] Real-time bid amounts shown include energy bids and self-schedules for energy from resource adequacy capacity submitted to the real-time market and included in a day-ahead energy schedule.

Figure 9.3 Resource adequacy bids and self-schedules during 210 highest peak load hours

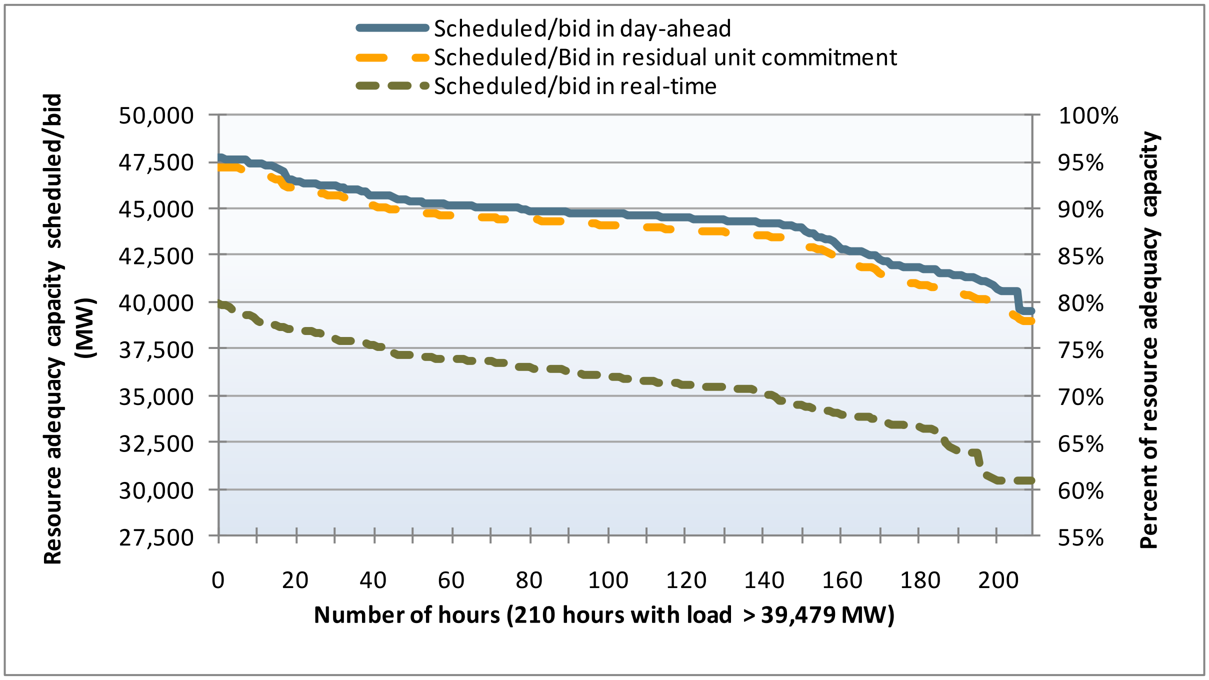


Table 9.1 provides a detailed summary of the availability of resource adequacy capacity over the 210 summer peak load hours for each type of generation. Separate sub-totals are provided for resources for which the ISO creates bids if market participants do not submit a bid or self-schedule, and resources for which the ISO does not create bids. As shown in Table 9.1:

- ***Resource adequacy capacity after reported outages and derates —*** Average resource adequacy capacity was around 49,400 MW during the 210 highest load hours in 2011. After adjusting for outages and derates, the remaining capacity equals about 94 percent of the overall resource adequacy capacity. This represents an outage rate of about 6 percent during these hours.

- ***Day-ahead market availability —*** For the 23,820 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 only 90 percent of the available capacity of these resources after accounting for reported derates and outages. This compares to the 92 percent of the available capacity from the resources for which the ISO creates bids. Outages that may have affected the availability of import resources are not reflected in Table 9.1 because market participants cannot report outages affecting imports in the ISO outage reporting system.

- ***Residual unit commitment availability —*** The overall percentage of resource adequacy capacity made available in the residual unit commitment process was just slightly less, 1 percent, than that available to the day-ahead market.

- ***Real-time market availability —*** The last three columns of Table 9.1 compare the total resource adequacy capacity potentially available in the real-time market timeframe with the actual amount of capacity that was scheduled or bid in the real-time market. An average of about 87 percent of the resource adequacy capacity that was potentially available to the real-time market was scheduled or bid in the real-time market.

As shown in Figure 9.3 and Table 9.1, the overall aggregate availability of resource adequacy capacity is relatively high during high load hours. More detailed findings shown in Table 9.1 include:

- ***Use-limited gas units* —** Almost 3,000 MW of use-limited gas resources are used to meet resource adequacy requirements. Most of these resources are peaking units within more populated and transmission constrained areas that are only allowed to operate 360 hours per year under air permitting regulations. Market participants submit to the ISO use plans for these resources, but are not actually required to make them available during peak hours. Only about 81 percent of this capacity was available in the day-ahead market during the highest 210 load hours. In real-time, only about 1,000 MW of this 3,000 MW of capacity was scheduled or bid into the real-time market.

- ***Imports* —** Almost 4,000 MW of imports are used to meet resource adequacy requirements. About 93 percent of this capacity was scheduled or bid in the day-ahead market during the 210 highest load hours. Most of this capacity was self-scheduled or bid at competitive prices in the day-ahead market. As a result, about 91 percent of this capacity was also scheduled or bid into the real-time market. The availability of imports is discussed in more detail in Section 9.4.

The availability of wind, solar, qualifying facilities, and other non-dispatchable resources is discussed in more detail in Section 9.5.

Table 9.1 Average resource adequacy capacity and availability during 210 highest load hours

Resource type	Total resource adequacy capacity (MW)	Net outage adjusted resource adequacy capacity		Day-ahead bids and self-schedules		Residual unit commitment bids		Total real-time market resource adequacy capacity (MW)	Real-time market bids and self-schedules	
		MW	% of total RA Cap.	MW	% of total RA Cap.	MW	% of Total RA Cap.		MW	% of real-time RA Cap.
ISO Creates Bids:										
Gas-Fired Generators	23,209	21,385	92%	21,280	92%	21,280	92%	15,318	13,897	91%
Other Generators	2,401	2,280	95%	2,269	95%	2,269	95%	2,359	2,123	90%
Subtotal	**25,609**	**23,665**	**92%**	**23,549**	**92%**	**23,549**	**92%**	**17,677**	**16,020**	**91%**
ISO Does Not Create Bids:										
Use-Limited Gas Units	2,982	2,418	81%	2,320	78%	2,291	77%	1,189	1,052	89%
Hydro Generators	6,617	6,375	96%	5,989	91%	5,833	88%	6,617	5,605	85%
Nuclear Generators	4,966	4,911	99%	4,896	99%	4,896	99%	4,966	4,606	93%
Wind/Solar Generators	686	682	99%	420	61%	420	61%	686	686*	100%
Qualifying Facilities	3,624	3,544	98%	3,298	91%	3,298	91%	3,621	3,048	84%
Other Non-Dispachable	864	850	98%	675	78%	672	78%	814	596	73%
Imports	4,081	4,081	100%	3,809	93%	3,809	93%	4,012	3,657	91%
Subtotal	**23,820**	**22,861**	**96%**	**21,408**	**90%**	**21,219**	**89%**	**21,905**	**18,564**	**85%**
Total	**49,430**	**46,526**	**94%**	**44,956**	**91%**	**44,768**	**91%**	**39,582**	**34,584**	**87%**

* Actual wind/solar generation is used as a proxy for real-time bids.

9.4 Imports

Load-serving entities are allowed to utilize imports to meet a substantial amount of their resource adequacy requirement. There are roughly 11,000 MW of total import capability into the ISO system and net imports averaged about 9,000 MW during the peak summer months. In 2011, imports were used to meet over 4,000 MW or about 8 percent of resource adequacy requirements and less than 40 percent of the total import capability.

Imports used to meet resource adequacy requirements are not required to be resource specific or backed by specific portfolios of resources. In addition, resource adequacy imports are only required to bid into the day-ahead market. These resources can be bid at any price and do not have any further obligation if not scheduled in the day-ahead energy or residual unit commitment process. DMM has expressed concern that these rules could in theory allow a significant portion of resource adequacy requirements to be met by imports that may have limited availability and value during critical system and market conditions.

In practice, however, analysis by DMM continues to indicate that a very large portion of resource adequacy imports are self-scheduled in the day-ahead market and most of the remainder is bid at relatively low prices. This suggests that resource adequacy imports are supported by a relatively high degree of commitments for energy and transmission.

Figure 9.4 summarizes the bid prices and volume of self-schedules and economic bids for resource adequacy import resources in the day-ahead market during peak hours throughout the year.

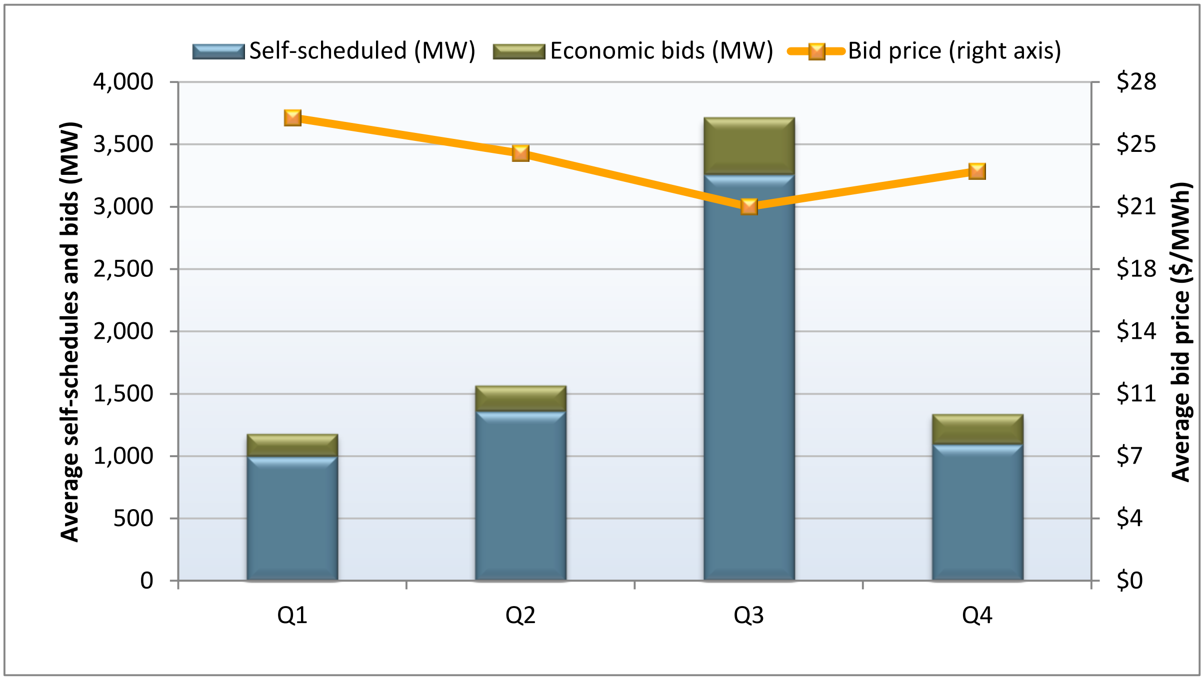
- The blue and green bars (plotted against the left axis) show the respective average amounts of resource adequacy import capacity that market participants either self-scheduled or economically bid in the day-ahead market.

- The gold line (plotted against the right axis) shows the average maximum bid prices for resource adequacy import resources for which market participants submitted economic bids to the day-ahead market.

As shown in Figure 9.4, market participants self-scheduled a large proportion of resource adequacy imports in the day-ahead market. For example, during the peak summer months (third quarter), they self-scheduled an average of about 3,250 MW of resource adequacy imports in the day-ahead market while they submitted additional energy bids for an average of 460 MW. An even larger proportion of resource adequacy imports were self-scheduled during the rest of the year.

Figure 9.4 also shows that market participants submitted relatively low-priced energy bids for the portion of resource adequacy imports not self-scheduled. During the peak summer months (third quarter), the average maximum economic bid was only about $21/MWh. Bid prices averaged around $24/MWh during the other quarters, but the volume of resource adequacy capacity economically bid averaged around 210 MW per hour in the non-summer periods.

Figure 9.4 Resource adequacy import self-schedules and bids (peak hours)



9.5 Intermittent resources

Intermittent resources include wind, solar, qualifying facilities and other miscellaneous non-dispatchable resources. Unlike conventional generation, the output of these resources is variable and cannot be dispatched. Consequently, the amount of resource adequacy capacity that these resources can provide is based on past output rather than nameplate capacity. The amount of resource adequacy capacity that each individual resource can provide is known as its *net qualifying capacity.*

The net qualifying capacity of wind and solar resources is based on the output that they exceed in 70 percent of peak hours (1:00 p.m. to 6:00 p.m.) during each month over the previous three years.[149] These amounts are adjusted upward by a factor that reflects the system-wide benefit that is assumed to result from a low covariance between the outputs of many individual intermittent generators.

This analysis compares the following three measures of different types of intermittent resource capacity:

- The amount of capacity from these resources used to meet 2011 resource adequacy requirements or the net qualifying capacity.

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[149] This methodology assumes that the wind or solar generation data in the peak hours have a univariate distribution where the probability function is a flat line and therefore each observation has the same probability of occurrence. The methodology simply sorts the generation from a specified period in a descending order and calculates the 70th percentile of the observations for each month. The calculated value at 70th percentile means that the generation is expected to be above the calculated value 70 percent of the time.

- The 70th percentile of the output of these resources during hours used to calculate the net qualifying capacity (weekdays from 1 p.m. to 6 p.m.).
- The 70th percentile of the output of these resources during the 210 highest load hours in 2011.

Figure 9.5 and Figure 9.6 show this comparison for wind and solar resources.

As shown in Figure 9.5, in July and September, wind resources' output (at the 70th percentile) in both the hours used to calculate net qualifying capacity and the 210 highest load hours was less than their resource adequacy capacity.[150] In contrast, output from wind resources in August exceeded their resource adequacy capacity. Also, in August, wind output is lower in the highest peak load hours than in the hours used to determine the net qualifying capacity. Resource adequacy capacity and wind generation are significantly less in September than the previous two months.

Figure 9.6 shows a comparison of the same data for solar resources in July through September. Solar output in hours used to calculate net qualifying capacity was greater than the output in the 210 highest summer peak load hours in July and August. In all the three months, solar resources' output in both the hours used to calculate net qualifying capacity and the 210 highest load hours were less than their resource adequacy capacity. Actual solar output in the 210 highest summer peak load hours equaled about 85 percent of solar resource adequacy capacity during these months.

Figure 9.7 provides a similar analysis for qualifying facilities and other miscellaneous non-dispatchable resources. The net qualifying capacity of qualifying facilities and other non-dispatchable resources is based on their average output during peak hours over the previous three years and it is calculated for each month. An annual net qualifying capacity value is calculated based on their output during the summer months. This analysis shows the average actual output of these resources during these hours.

As shown in Figure 9.7, the actual output of these resources in July through September 2011 during hours used to calculate net qualifying capacity was less than their output in the 210 highest load hours. In July and August, resource adequacy capacity was higher than both net qualifying capacity output and actual output in the 210 highest load hours.

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[150] Note that the calculated 70th percentile refers to a minimum generation value. That is, generation is expected to be above this calculated value 70 percent of the time.

Figure 9.5 Resource adequacy capacity available from wind resources

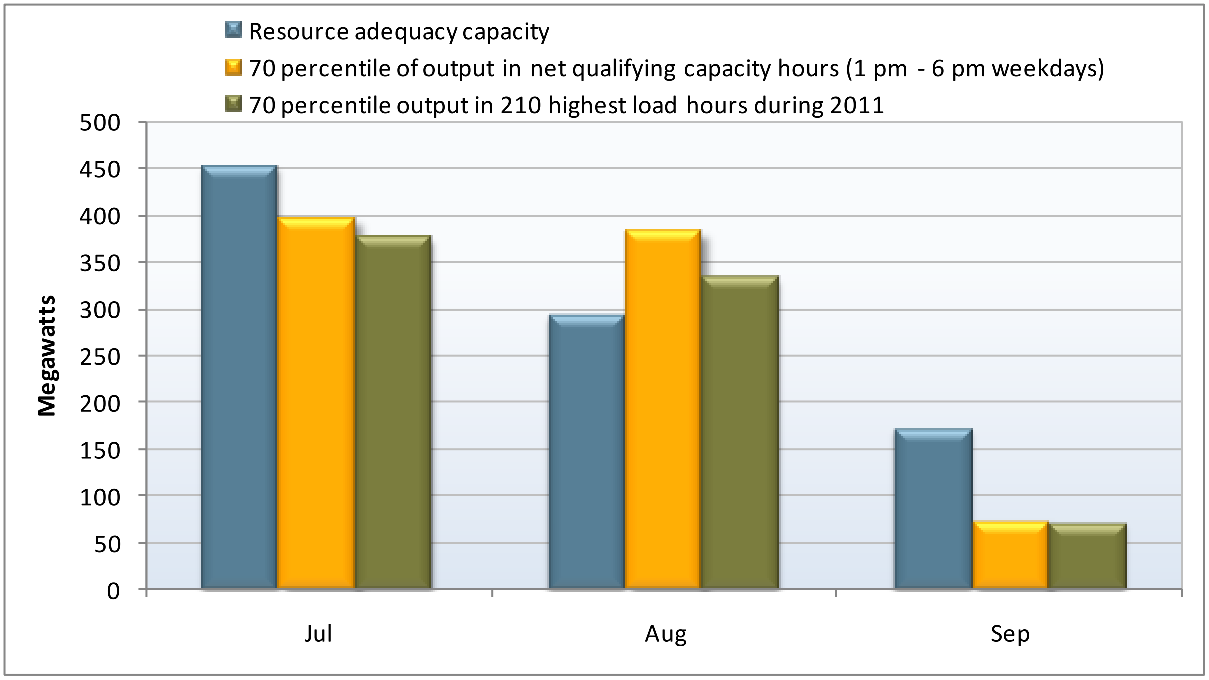


Figure 9.6 Resource adequacy capacity available from solar resources

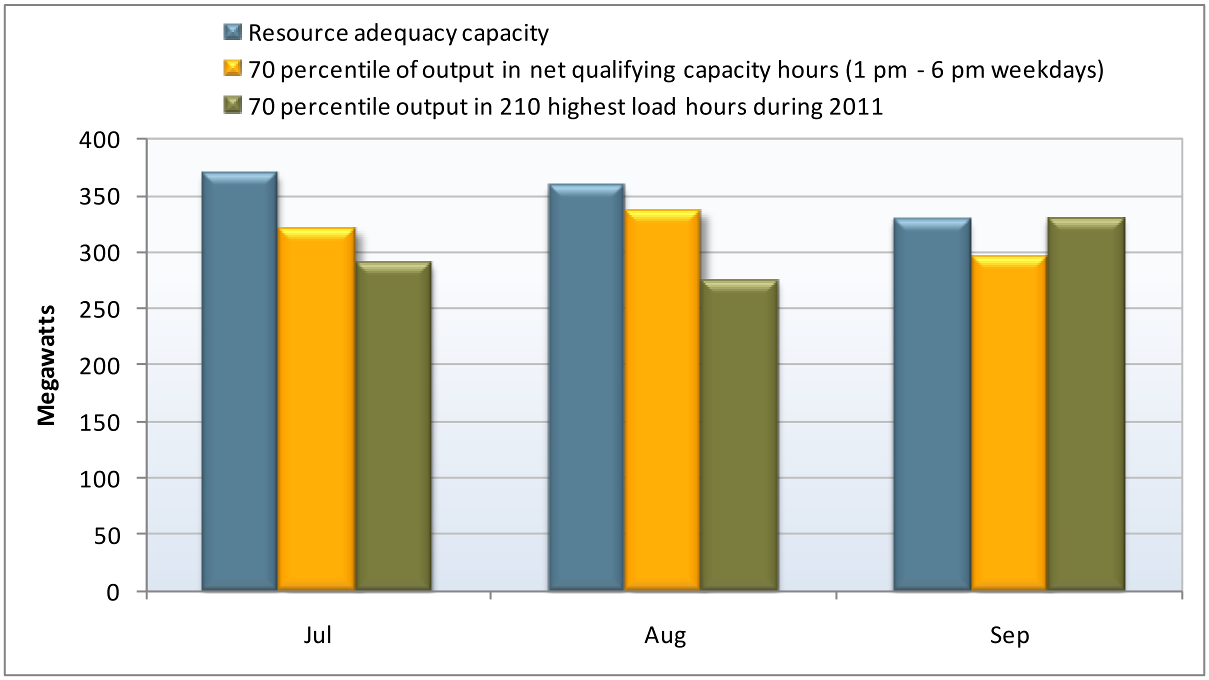
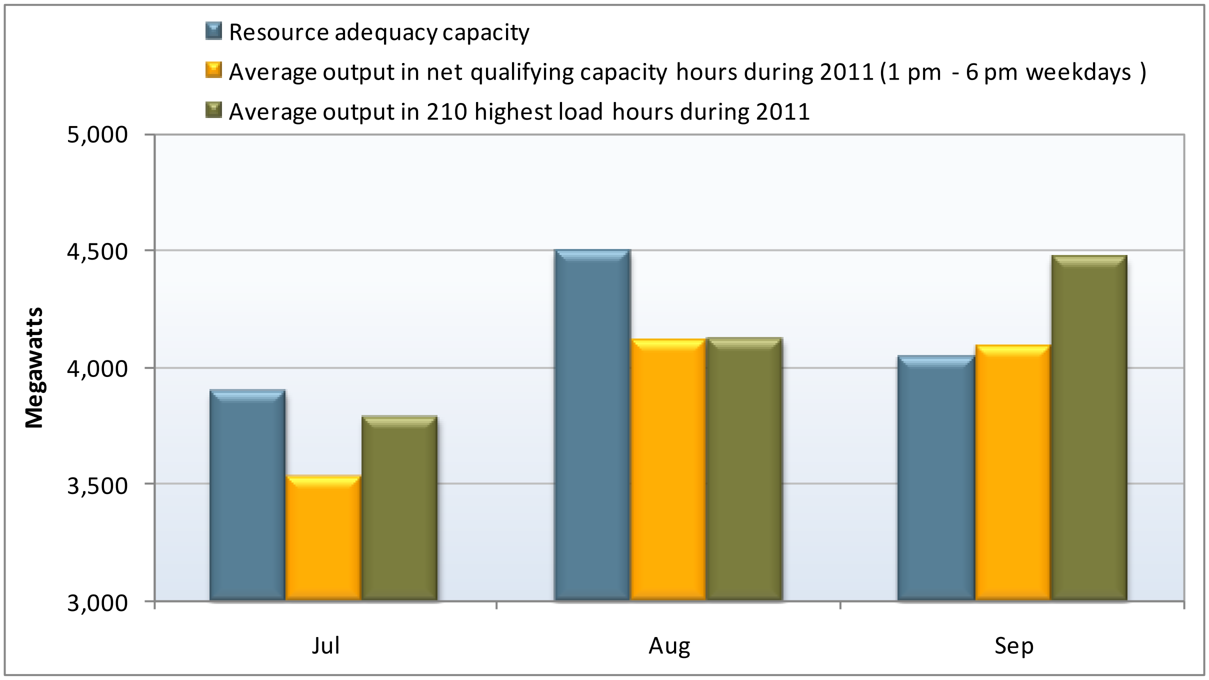


Figure 9.7 Resource adequacy capacity available from qualifying facility resources



9.6 Backup capacity procurement

The ISO tariff includes provisions allowing the ISO to procure any resources needed if capacity procured by load-serving entities under the resource adequacy program is not sufficient to meet system-wide and local reliability requirements. These provisions are called the *capacity procurement mechanism*.

In 2011, procurement of capacity in 2011 under the resource adequacy program was sufficient to meet virtually all of the ISO system-wide and local area reliability requirements, and the cost of additional capacity procurement by the ISO was minimal. As shown in Table 9.2, only 120 MW of capacity was procured under this mechanism with a procurement period of about one month. This capacity was procured to improve the system reliability and the total cost of this capacity was $350,000.

Table 9.2 Capacity procurement mechanism costs (2011)

Resource	Local capacity area	CPM designation (MW)	Estimated cost	CPM designation dates
Moss Landing Power Block 2[1]		75		9/9 - 9/30
Moss Landing Power Block 2[1]		45		10/1 - 10/7
		120	**$354,988**	

[1] Dispatched for system capacity.

In late 2011, however, Calpine Corporation informed the ISO that it intends to retire a 550 MW combined cycle unit (Sutter Energy Center) in 2012 unless it either received a resource adequacy contract or was contracted by the ISO through the capacity procurement mechanism. While the ISO determined that this capacity was not needed in 2012, the ISO indicated the unit is likely to be needed in 2017 due to the retirement of other existing gas-fired capacity as a result of the state's once-through cooling regulations. The Sutter unit was specifically needed since it can provide flexible ramping capabilities that will be needed to integrate the large volume of intermittent renewable resources coming online in the next few years.[151]

This case has highlighted several key limitations of the state's current long-term procurement planning and resource adequacy programs.

- Neither of these processes incorporates any specific capacity or operational requirements for the flexible capacity characteristics that will be needed from a large portion of gas-fired resources to integrate the large volume of intermittent renewable resources coming online in the next few years.
- The resource adequacy program and the capacity procurement mechanism in the ISO tariff are based on procurement of capacity only one year in advance. This creates a gap between these procurement mechanisms and the multi-year timeframe over which some units at risk of retirement may need to be kept online to meet future system flexibility or local reliability requirements.

In response to these issues, the ISO has taken several specific steps:

- The ISO is working with the CPUC and stakeholders to integrate requirements for new categories of flexible resource characteristics into the current resource adequacy program.[152]
- The ISO is also proposing that the CPUC establish a multi-year resource adequacy requirement, including flexibility requirements, in the next resource adequacy proceeding that would establish resource adequacy requirements starting in 2014.
- Finally, the ISO has initiated a stakeholder process to develop a mechanism in the ISO tariff to ensure the ISO has sufficient backstop procurement authority to procure any capacity at risk of retirement not contracted under the resource adequacy program that the ISO identifies as needed up to five years in the future to maintain system flexibility or local reliability.[153]

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[151] For a detailed discussion see California Independent System Operator Corporation Petition for Waiver of Tariff Revisions and Request for Confidential Treatment, January 25, 2012: http://www.caiso.com/Documents/2012-01-26_ER12-897_Sutter_Pet_TariffWaiver.pdf.

[152] For further details see the Flexible Capacity Procurement stakeholder process site: http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleCapacityProcurement.aspx.

[153] For further details see *Flexible Capacity Procurement Market and Infrastructure Policy Straw Proposal*, March 7, 2012: http://www.caiso.com/Documents/StrawProposal-FlexibleCapacityProcurement.pdf.

10 Recommendations

In our prior annual and quarterly reports, DMM has provided a variety of specific recommendations for short-term market improvements. DMM also works closely with ISO staff and stakeholders to provide recommendations on new market design initiatives on an ongoing basis. While the ISO has already taken steps responsive to many of these recommendations, continued emphasis on these issues is warranted in 2012. This chapter summarizes DMM recommendations on selected key issues, along with steps that have been taken or are being taken to address these issues.

Improve price convergence

Recommendation: In many of its reports for the last couple of years, DMM highlighted the lack of price convergence in the ISO markets. In particular, DMM stressed the difference between the hour-ahead and real-time markets as problematic. In our 2010 annual report, DMM warned that continued divergence in prices would pose an increasing problem after the implementation of convergence bidding.[154] Price divergence and the resulting real-time imbalance costs remained a significant issue for much of 2011.

Resolution: Starting in the summer of 2011, price convergence began to improve as the frequency of 5-minute real-time price spikes fell. Consequently, the price convergence between the hour-ahead and real-time markets improved significantly. The ISO has taken a number of steps as part of an effort to improve system reliability and price convergence:

- *Development of detailed load adjustment procedures and systematic training for operators.* The ISO improved the procedures, training and tools relating to how adjustments are made to the load forecasts used in the hour-ahead, 15-minute and 5-minute real-time markets. DMM had identified sudden load adjustments as one of the causes of price divergence.[155] The improved procedures and training helped to address the consistency and magnitude of the load adjustments.

- *Accounting for generator shut-down profiles.* The ISO has temporarily incorporated an automated real-time load adjustment mechanism to account for additional generation from units shutting down.[156] When a generating unit is scheduled to shut down, the market software does not account for the energy generated while the unit is ramping down from its minimum load level to zero. On a system-wide basis, this can create several hundred megawatts of unscheduled energy during the evening hours when the load starts decreasing. The new mechanism automatically adjusts the load to account for the additional generation, offsetting the need for operator intervention through manual load adjustments.

- *Implementation of the flexible ramping constraint.* This was designed to account for variations between load and supply in the real-time market processes. This constraint has improved operational performance during ramping periods, reducing the frequency of ramp-related 5-minute

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[154] *2010 Annual Report on Market Issues and Performance*, April 2011, p. 12: http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf.

[155] Quarterly *Report on Market Issues and Performance*, May 24, 2011, pp. 14-16: http://www.caiso.com/Documents/QuarterlyReport-MarketIssuesandPerformanceMay2011.pdf.

[156] The ISO is developing more systematic software enhancements to model the unscheduled energy for both start-up and shut-down profiles. The ISO anticipates implementation of the new start-up and shut-down feature in 2012.

real-time price spikes and improving price convergence between the hour-ahead and real-time markets.

While the ISO has taken numerous actions that have ultimately improved price convergence, DMM recommends that the ISO remain committed to addressing the underlying causes of price divergence between the hour-ahead and 5-minute real-time markets. This includes addressing factors that may cause real-time prices to be systematically higher or *lower* than day-ahead or hour-ahead prices for sustained periods.

Convergence bidding on inter-ties

Issue: Within the first few months after virtual bidding was implemented, DMM noted that large volumes of virtual supply at inter-ties were offsetting virtual demand bids clearing at internal locations. These offsetting virtual supply and demand bids allowed some participants to profit from price divergence between the hour-ahead and 5-minute real-time markets. However, these offsetting bids provided little or no increase in efficiency or reliability by improving day-ahead unit commitment. In many cases, these virtual import bids completely offset the impact that internal virtual bidding could otherwise have on helping to converge day-ahead and real-time prices. In addition, these offsetting bids created significant revenue imbalances that are imposed on other participants. Based on these findings, DMM supported the suspension of inter-tie convergence bidding while modifications to settlement provisions for virtual inter-tie bids are assessed.

Resolution: In September, the ISO filed with FERC to suspend convergence bidding at the inter-ties. In late November, FERC temporarily suspended convergence bidding at the inter-ties, pending further comments from interested parties and consideration by the Commission. In 2012, the ISO continued its stakeholder process to assess modifications to the hour-ahead and real-time markets that might facilitate re-implementation of virtual bidding on inter-ties.

Re-implementing convergence bidding on interties

Recommendation: DMM has been actively involved in working with ISO staff and stakeholders to identify various market design changes that would facilitate re-implementation of virtual bidding on inter-ties. However, DMM believes that virtual bidding on inter-ties should only be re-implemented in conjunction with market design changes that will ensure virtual bidding on inter-ties will be beneficial to overall market efficiency and will not impose significant costs on other participants.

Many participants agree that virtual bidding on inter-ties should not be reinstated until fundamental market design and inter-control area seams issues underlying problems with the hour-ahead and real-time markets are addressed. DMM believes developing and implementing such changes will take time. Extreme care must be taken to avoid introducing inefficiencies or other unintended consequences into the ISO's physical markets that are more critical to system reliability and overall market performance.

The ISO is also facing a wide array of other market design enhancements to improve market efficiency, facilitate renewable integration and respond to other stakeholder priorities. There is inevitably a trade-off between the amount of resources the ISO can allocate to these other important initiatives and the effort to make design changes necessary to implement virtual bidding on inter-ties. Thus, the potential benefits of re-instating virtual bidding on inter-ties – particularly on an accelerated timeframe – must be carefully weighed against the cost and risks of any approach that is implemented.

Resolution: In 2012, the ISO is continuing its stakeholder process to assess modifications to the hour-ahead and real-time markets that might facilitate re-implementation of virtual bidding on inter-ties. Options being proposed by the ISO appear to provide reasonable assurance that the problems previously observed with convergence bidding on inter-ties will not reoccur. However, DMM continues to recommend that the details of various options be thoroughly reviewed and that proper safeguards be incorporated into any market design changes made in conjunction with re-implementation of virtual bidding on inter-ties.

Modify local market power mitigation procedures

Recommendation: The local market power mitigation provisions of the new energy market design have proven to be effective without imposing an excessive level of mitigation. However, prior to implementation of virtual bidding in 2011, DMM recommended that current local market power mitigation procedures be modified to ensure that virtual bids do not undermine the effectiveness of these procedures. DMM also recommended that the ISO implement a more dynamic process for assessing the competiveness of transmission constraints using the actual market software based on actual system and market conditions.

Resolution: In 2011, the ISO and DMM worked with stakeholders to develop a package of modifications to local market power mitigation procedures to achieve these goals. These modifications will be phased in during 2012 and will make the mitigation process more dynamic in two ways:

- The competitiveness of binding constraints is determined by the market software based on actual system conditions, rather than based on studies performed up to four months in advance.
- Bid mitigation for the real-time dispatch could be determined in the real-time pre-dispatch process run every 15-minutes, rather than in the hour-ahead scheduling process.

In addition, modifications will be made to ensure that bid mitigation is targeted at individual units that can relieve congestion on uncompetitive constraints. DMM believes these modifications will help ensure that mitigation is applied when appropriate, while avoiding bid mitigation in cases when local market power does not exist.

Flexible generation characteristics

The ISO has proposed spot market and forward procurement products that will provide additional generation dispatch flexibility to improve reliability as more variable energy resources are integrated. The flexible ramping product may provide significant revenue opportunities for more flexible generating resources on the margin. The ISO has also proposed incorporating specific requirements for flexible unit operating characteristics in the state’s resource year-ahead adequacy requirements and eventually into a five year forward capacity procurement process. As the requirements for such characteristics increase over time it will be increasingly important that forward capacity procurement also include flexible ramping characteristics. The ISO has deferred pursuing forward procurement of flexible ramping capacity; however, it does intend to develop a mechanism to evaluate the risk of unit retirement in the context of future ramping requirements and have in place a compensation mechanism to bridge the time between potential retirement and when the resource will provide needed ramping capacity.

Recommendation: For the spot product, DMM has recommended that the ISO provide further clarification on how the requirements will be set. We have also recommended that the ISO pursue cost allocation during this initiative and do so in a way that most closely adheres to cost causation principles.

For the forward procurement, DMM has recommended a clear linkage between the target requirement for forward procurement and anticipated needs.

Resolution: The ISO is currently in the process of more clearly defining the requirements for the spot product, but has not yet indicated a final form or expected magnitude during different circumstances. It is difficult to anticipate potential scarcity or market power issues without this information; however, DMM is optimistic that more development and empirical work will be done this year. For the forward procurement, the ISO has elected not to pursue incorporating flexible ramping characteristics into the existing forward capacity procurement process. We note that while there may appear to be sufficient flexible ramping capacity over the next few years, including this characteristic and requirement in the long-term procurement process is the most likely means to providing a price signal that will ensure adequate flexible ramping capacity further out in time.

Cost allocation

Recommendation: In DMM's 2009 and 2010 annual reports, we recommended that the costs of any additional products needed to integrate different resources should also be allocated in a way that reflects the reliability and operational characteristics of different resources. This will help ensure proper price signals for investment in different types of new resources. For example, if new ancillary services or other products are specifically procured to mitigate the impacts of intermittent renewable resources, the cost of these additional products should be allocated to these intermittent resources. Currently, the cost of all ancillary services is allocated to load.

Resolution: The ISO is conducting a process to define principles that will be applied in determining cost allocation for specific market and non-market items going forward. The proposed principles include cost causation, along with providing proper incentives, rationality (e.g., the cost of implementation relative to the cost to be allocated), and alignment with public policy. DMM has recommended that cost causation should be the driving principle of cost allocations.[157] Allocating costs to those participants whose actions directly cause the cost provides a direct incentive to modify actions when this is cost-effective and reduces the associated cost. DMM believes this will ultimately be the most efficient and effective way to manage the costs associated with renewable integration and thereby help achieve the state's public policy goals for increased reliance on renewable energy.

The first product to which the ISO will be applying these principles is allocation of costs for procuring the new flexible ramping product in the spot market. The ISO's initial proposal for allocation of costs for this product would have allocated these costs entirely to load. However, the ISO has developed a revised proposal that would allocate these costs in a manner that reflects the contribution of each individual resource to the real-time variability that ultimately influences the quantity and cost of procurement. This revised approach should provide an incentive for resources to reduce variability which will, over time, reduce the procurement requirement and cost associated with this product.

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[157] See DMM comments at: http://www.caiso.com/Documents/DMM_Comments-CostAllocationGuidingPrinciplesStrawProposal.pdf.

Lowering bid floor

Recommendation: DMM has consistently recommended that the ISO reduce the bid floor no lower than may be needed to incent sufficient additional downward flexibility.[158] DMM has also recommended an incremental approach to reducing the bid floor. Before lowering the floor further, DMM recommends that an assessment should be performed to determine if additional decremental flexibility is needed in the real-time market and if further reductions in the bid floor are likely to provide significant additional decremental flexibility.

Resolution: After initially proposing a bid floor of -$1,000/MWh, the ISO ultimately adopted this general approach. The ISO plans to lower the bid floor to -$150/MWh during the second half of 2013.[159] The ISO also plans to consider lowering the negative bid floor to -$300/MWh a year later, but has committed to performing some analysis prior to making any further reductions in the bid floor.

Reduce impact of manual load adjustments on real-time prices and track manual load adjustments

Recommendation: In early 2011, DMM identified that only a portion of manual load adjustments made were saved in the ISO data systems since adjustments made directly to the load forecasts were not recorded.[160] DMM recommended that the ISO keep a database of these manual adjustments and utilize these data to perform more systematic monitoring and analysis that could help make improvements in manual load adjustment practices and the load forecasting tool.

Resolution: In the second half of 2011, the ISO discontinued use of the methods for manual load adjustments that were not being captured in the ISO data systems so that all manual load adjustments are now captured. The ISO also developed more detailed load adjustment procedures for operators.

Extreme San Diego congestion prices

Recommendation: In DMM's 2010 annual report we recommended that the ISO address extreme congestion results that occur periodically in the San Diego area.[161] The conditions that cause such high prices have been very infrequent – 41 intervals in 2010 and 26 intervals in 2011. However, DMM believes that modeling enhancements to address these extreme prices would produce prices that are more reflective of actual underlying system conditions and congestion relief being provided.[162]

Resolution: This item was not addressed by the ISO in 2011. DMM reiterates its recommendation to address this issue going forward. This issue could be increasingly important in 2012 if congestion in the San Diego area increases as a result of a prolonged outage of the San Onofre nuclear plant.

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[158] Memorandum to ISO Board of Governors, Eric Hildebrandt, Director, Market Monitoring, December 8, 2011, re: Market Monitoring Report: http://www.caiso.com/Documents/Department_MarketMonitoringUpdateDec2011.pdf.

[159] More details are provided under the Renewable Integration Market Product Review stakeholder initiative at: http://www.caiso.com/informed/Pages/StakeholderProcesses/RenewableIntegrationMarketProductReviewPhase1.aspx.

[160] *Quarterly Report on Market Issues and Performance*, February 8, 2011, pp. 15-17: http://www.caiso.com/Documents/QuarterlyReportonMarketIssuesandPerformance-February2011.pdf.

[161] *2010 Annual Report on Market Issues and Performance*, April 2011, p. 12: http://www.caiso.com/2777/27778a322d0f0.pdf.

[162] *Quarterly Report on Market Issues and Performance*, February 8, 2011, pp. 7-8.

Monitor and limit impact of capacity exceptional dispatches on bid cost recovery payments

Recommendation: In the third quarter of 2011, real-time bid cost recovery payments increased to the highest levels since the start of the nodal market in 2009. DMM recommended that the ISO monitor and limit the effects on bid cost recovery payments of exceptional dispatches related to needs for online capacity and ramping capability to meet overall system and south of Path 26 needs.[163] While total bid cost recovery payments declined in the fourth quarter, DMM recommended that the ISO continue to monitor and limit the economic impact of these exceptional dispatches. DMM also suggested incorporating additional modeling enhancements in the day-ahead market to the extent possible to avoid these exceptional dispatches. DMM is supportive of tariff changes to facilitate these results if necessary.

Resolution: The ISO intends to review the factors that cause exceptional dispatch and reduce their incidence if possible. DMM reiterates its recommendation to address this issue going forward, especially before the summer peak load conditions occur.

Review effectiveness of the 200 percent cap for registered costs

Recommendation: In 2011, DMM observed that the majority of bids for both start-up and minimum load costs for units under the registered cost option have approached the current cap of 200 percent of fuel costs.[164] DMM recommended that the ISO re-evaluate the appropriateness and effectiveness of the current cap. If this cap is lowered, DMM also continues to support consideration of the inclusion of a fixed component for non-fuel costs associated with any verifiable start-up and minimum load costs.

Resolution: The ISO has included this item to be considered as part of its commitment cost refinement stakeholder process.[165] DMM also continues to recommend that the ISO revise the caps for transition cost bids for multi-stage generating units as part of this initiative.

Analyze compensating injections

Recommendation: In 2011, DMM recommended that the ISO capture additional data elements needed to more effectively determine the impacts of compensating injections.[166] Analysis of the difference between modeled versus actual flows over longer time periods could provide insights into systematic patterns in unscheduled flows that might be incorporated into the day-ahead modeling process, rather than only the hour-ahead and real-time markets.

Deeper analysis using the current ISO data has been infeasible for several reasons. Data on metered flows requires extensive manual processing, which makes it impractical for DMM or other ISO staff to perform monitoring or analysis over any substantial time period. In addition, the ISO has captured data for total market flows with compensating injections, but has not captured data on the contributions of compensating injections to these total market flows. Without this information, DMM has not been able to determine if false congestion caused by market flow divergence occurred because of over-compensating the market flows on internal paths. DMM has also not been able to determine the

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[163] *Quarterly Report on Market Issues and Performance*, Department of Market Monitoring, November 8, 2011, pp. 16-17: http://www.caiso.com/Documents/QuarterlyReport-MarketIssues_Performance-November2011.pdf.

[164] Quarterly Report on Market Issues and Performance, November 8, 2011, pp. 41-44.

[165] See http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostsRefinement2012.aspx.

[166] Quarterly *Report on Market Issues and Performance*, Department of Market Monitoring, February 8, 2011, p. 32: http://www.caiso.com/Documents/QuarterlyReportonMarketIssuesandPerformance-February2011.pdf.

degree to which compensating injections may be creating false congestion on inter-ties by over-correcting for loop flows along the inter-ties.

Resolution: While the ISO indicated that it would look into capturing the missing data elements, the ISO did not capture any additional compensating injection information into its data systems. DMM reiterates is recommendation that more data is required to allow more detailed analysis of compensating injections.

Review and refine tariff provisions related to administrative prices

Recommendation: After the San Diego power outage in September 2011, DMM recommended that the ISO review and refine its tariff provisions related to administrative pricing.[167] During the September power outage, the ISO suspended real-time markets and initially set administrative prices to $250/MWh and later dropped them to $100/MWh. DMM recommended that the ISO further review and potentially refine the process for setting administrative prices in the tariff to better prescribe in advance how prices should be settled during a market suspension. The September events highlighted that the current tariff provisions for administrative prices were not effective in achieving the desired operational outcomes.

Resolution: As part of the ISO's request for tariff waiver filing, the ISO indicated that it would review its tariff provisions relating to administrative pricing.[168] The ISO plans to form a stakeholder process to address this item and is awaiting resolution of the pending filing from FERC before proceeding.

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[167] *Quarterly Report on Market Issues and Performance***,** November 8, 2011, pp. 39-40.

[168] See ISO waiver filing on October 26, 2011 under FERC docket ER12-205-000, p. 21: http://www.caiso.com/Documents/2011-10-26_ER12-205_pet_waiver_tariffprov_adminpricing.pdf.