6 Intra-Zonal Congestion

6.1 Introduction/Background

Scheduling Coordinators (SCs) submit day-ahead/hour-ahead generation and load schedules to the CAISO. Due to differences in the price and availability of power in different locations, these schedules vary daily and, collectively, may exceed the transfer capability of grid facilities within the congestion zones. However, the CAISO's Day Ahead and Hour Ahead Congestion Management Markets only manage congestion between zones, not within zones. This allows SCs to submit day-ahead/hour-ahead schedules that require transmission within a zone that is not physically feasible, and, as a consequence, creates the need for CAISO operators to have to manage intra-zonal congestion in real-time. Managing large amounts of intra-zonal congestion in real-time creates operational and reliability challenges and can result in significant costs.

Intra-zonal congestion costs are comprised of three components:

1) Minimum Load Cost Compensation (MLCC).[1] These costs result from generating units that are committed to operate on a day-ahead basis under the provisions of the Must-Offer Obligation in order to mitigate anticipated intra-zonal congestion.[2]

2) Costs from Reliability Must Run (RMR) real-time dispatches that are the first response to intra-zonal congestion.

3) Costs of Out-of-Sequence (OOS) dispatches.

Intra-zonal congestion most frequently occurs in load pockets, or areas where load is concentrated, where transmission within the zone is not sufficient to allow access to competitively-priced energy. In some cases, the CAISO must also decrement generation outside the load pocket to balance the incremental generation dispatched within it. Intra-zonal congestion can also occur due to pockets in which generation is clustered together, without the transmission necessary for the energy to flow out of that pocket to load. In both cases, the absence of sufficient transmission access to an area means that the CAISO has to resolve the problem locally, either by incrementing generation within a load pocket or by decrementing it in a generation pocket. Such congestion is inefficient if, over the course of congestion in that area, the market costs due to the transmission congestion (i.e., the cost imposed by the fact that load cannot be served by the lowest-cost supplier(s), and instead must be served by higher-cost suppliers) exceed the cost of a transmission upgrade that could alleviate the congestion.

Typically, there is limited competition within load or generation pockets, since the bulk of generation within such pockets is owned by just one or two suppliers. As a result, intra-zonal

[1] MLCC payments are cost-based and are calculated as variable cost for providing the minimum load energy plus a $6/MWh O&M adder.

[2] Pursuant to Amendment 60, MLCC costs are categorized into three categories (system, zonal and local), which reflect the primary reason the unit was denied a must-offer waiver. Both zonal and local MLCC costs are included as the MLCC component of intra-zonal costs.

congestion often coexists with locational market power. Methods to resolve intra-zonal congestion are designed to limit the ability of suppliers to exercise local market power.

The CAISO's current method for dealing with incremental intra-zonal congestion involves a combination of steps and operating procedures. On a day-ahead basis, the CAISO often constrains-on or commits long-start thermal units through the must-offer waiver (MOW) process in return for minimum load cost payments and/or Resource Adequacy (RA) capacity payments. This forward unit commitment process helps to mitigate intra-zonal congestion that may be anticipated based upon day-ahead schedules submitted by market participants. Units required to operate under the MOW process are typically dispatched at minimum load levels. They are then required to bid all unloaded capacity into the CAISO real-time market.[3] In real-time, the CAISO dispatches real-time energy bids in merit order (based on bid price) in order to balance overall system or zonal loads and generation. If dispatch of in-sequence bids does not resolve intra-zonal congestion in real-time, the CAISO can mitigate intra-zonal congestion in three ways:

- First, the CAISO may dispatch available RMR capacity to mitigate congestion;
- Second, should energy from RMR units be insufficient, the CAISO may dispatch other units by calling real-time energy bids Out-of -Sequence (OOS);[4]
- Finally, if insufficient market bids exist to mitigate intra-zonal congestion, the CAISO may call units Out-of-Market (OOM).

Units incremented OOS to mitigate intra-zonal congestion are paid the higher of their bid price or the zonal market clearing price (MCP). They do not set the real-time market clearing price. Units decremented OOS to mitigate intra-zonal congestion are charged the lower of their decremental reference price or the zonal market-clearing price. They also do not set the real-time market clearing price. Inter-tie bids taken OOS are settled on an as-bid basis.

In addition, OOS bids are subject to local market power mitigation. Specifically, incremental OOS dispatches are subject to a conduct test where accepted OOS bids priced greater than the minimum of $50 or 200 percent above the interval MCP are mitigated to their reference price for that OOS dispatch and are settled at the greater of the mitigated bid price or the interval MCP. To the extent decremental bids are dispatched OOS for intra-zonal congestion, such dispatches will be based on decremental reference levels rather than market bids and will be settled based on the lower of the unit's decremental reference price and the real-time interval MCP.

6.2 Points of Intra-Zonal Congestion

Both NP15 and SP15 experienced intra-zonal congestion in 2006. As in 2005, the largest congestion point within NP15 was the Geysers-Cortina area in the northern San Francisco Bay Area. There was also congestion in the Sacramento River Delta region, a large generation pocket where the Pittsburg, Contra Costa, Delta, and Los Mendanos power plants are located.

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[3] Available thermal units within the CAISO Control Area are subject to the Must-Offer Obligation (MOO) whereby incremental energy bids are automatically inserted for them if they fail to do so themselves. There is no MOO for decremental energy bids.

[4] The term "out-of-sequence" refers to the fact that such dispatches require the CAISO, when incrementing (or decrementing) generation, to bypass lower (or higher) priced, in-sequence, real-time bids to find a unit whose grid location enables it to mitigate a particular intra-zonal congestion problem.

Intra-zonal congestion within SP15 was predominately at locations where intra-zonal congestion has been an issue in recent years. These include the following:

- The Southern California Import Transmission (SCIT) nomogram, a technical limit on the instantaneous import of power into the SP26 region from Northern California and other neighboring areas. This congestion can be mitigated using either intra-zonal (real-time out-of-sequence dispatch) or inter-zonal (day-ahead dispatch) congestion management procedures.

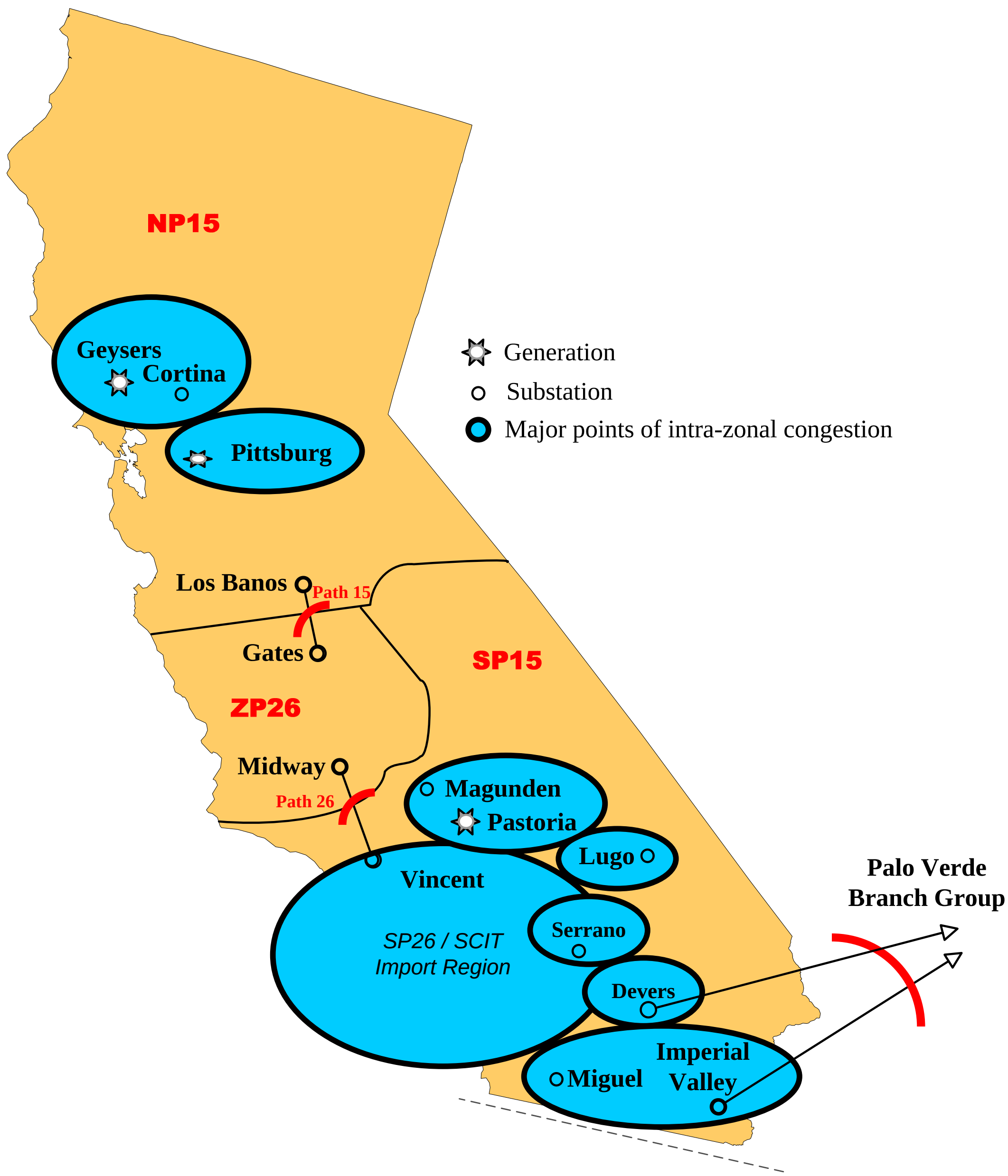
- The Miguel and Imperial Valley substations, resulting from the transmission of power to Southern California load from generation facilities located in Mexicali, Baja California, Mexico, and imports on the Southwest Power Link (i.e., North Gila to Imperial Valley).

- The Magunden/Pastoria region, near Bakersfield. The large generation facilities of the Big Creek Project, the largest hydroelectric project in Southern California, and the Pastoria generating facility, located in Lebec, interconnect with the Southern California grid at the same location, and often result in intra-zonal congestion.

- South of the Lugo substation, near Hesperia. Power from the Hoover Dam in Nevada and new combined-cycle facilities in California interconnect to the Southern California grid at this point, often resulting in congestion.

Figure 6.1 provides a representation of the CAISO Control Area's key intra-zonal congestion locations in 2006.

Figure 6.1 Key Points of Intra-Zonal Congestion



6.3 Intra-Zonal Congestion Management Costs

Overall, intra-zonal congestion has declined substantially in recent years, due largely to transmission upgrades and the installation of new generation. Estimated intra-zonal congestion management costs totaled $207 million in 2006, compared to $222 million in 2005, and $426 million in 2004. Of the costs incurred in 2006, 58 percent were incurred between January and

April, during the completion of several key transmission upgrade projects. Once these projects were completed, congestion costs declined substantially.

Measurable intra-zonal congestion management costs include three components: Minimum-Load Cost Compensation (MLCC) for intra-zonal (non-system) reasons, reliability must-run variable costs associated with real-time congestion management, and out-of-sequence redispatch costs. Table 6.1 shows total estimated intra-zonal congestion management costs for 2004 through 2006 by the three components discussed above. While MLCC costs and Real-time Redispatch costs declined in 2006 by approximately $5 million and $12 million, respectively, these savings were offset to some extent by an increase in real-time RMR dispatch costs of $8 million.

Table 6.1 Total Estimated Intra-Zonal Congestion Costs for 2004-2006 ($MM)[5]

	MLCC Costs			RT RMR Costs			RT Redispatch Costs			Total		
Month	**2004**	**2005**	**2006**	**2004**	**2005**	**2006**	**2004**	**2005**	**2006**	**2004**	**2005**	**2006**
Jan	$ 12	$ 8	$ 10	$ 3	$ 3	$ 13	$ 4	$ 6	$ 4	$ 19	$ 17	$ 27
Feb	$ 13	$ 4	$ 8	$ 4	$ 3	$ 15	$ 7	$ 3	$ 2	$ 24	$ 10	$ 25
Mar	$ 20	$ 3	$ 11	$ 4	$ 5	$ 13	$ 8	$ 3	$ 3	$ 32	$ 11	$ 27
Apr	$ 18	$ 6	$ 27	$ 4	$ 5	$ 8	$ 5	$ 3	$ 6	$ 27	$ 14	$ 41
May	$ 22	$ 14	$ 12	$ 3	$ 5	$ 3	$ 4	$ 2	$ 1	$ 29	$ 21	$ 16
Jun	$ 25	$ 7	$ 15	$ 3	$ 2	$ 4	$ 2	$ 0	$ 0	$ 30	$ 9	$ 19
Jul	$ 29	$ 13	$ 14	$ 6	$ 5	$ 2	$ 11	$ 1	$ 0	$ 46	$ 19	$ 17
Aug	$ 29	$ 14	$ 5	$ 5	$ 9	$ 3	$ 15	$ 1	$ 0	$ 49	$ 24	$ 8
Sep	$ 23	$ 8	$ 3	$ 4	$ 6	$ 2	$ 12	$ 3	$ 0	$ 39	$ 17	$ 5
Oct	$ 21	$ 13	$ 1	$ 4	$ 8	$ 3	$ 18	$ 4	$ 1	$ 43	$ 25	$ 5
Nov	$ 29	$ 12	$ 1	$ 5	$ 5	$ 6	$ 9	$ 6	$ 0	$ 43	$ 23	$ 7
Dec	$ 33	$ 11	$ 2	$ 4	$ 16	$ 7	$ 8	$ 5	$ 0	$ 45	$ 32	$ 9
Total	**$ 274**	**$ 114**	**$ 109**	**$ 49**	**$ 72**	**$ 80**	**$ 103**	**$ 36**	**$ 17**	**$ 426**	**$ 222**	**$ 207**

Each of the three cost components shown in Table 6.1 are discussed in greater detail below.

6.3.1 Minimum Load Cost Compensation

Pursuant to a FERC Order issued May 25, 2001,[6] and subsequent Orders, the CAISO provides minimum load cost compensation to generators that apply for waivers to the Must-Offer Obligation but are denied, and thus are required to be on-line at minimum load for the following operating day. In such cases, the CAISO compensates the generators for their minimum load costs, based upon unit operating costs and natural gas prices, where applicable. In addition, generators that are neither an RA or RCST resource[7] and whose waiver requests are denied are also entitled to receive the real-time price for energy supplied while operating at minimum load. Units subject to the Must-Offer Obligation are required to bid all unloaded capacity into the CAISO Real Time Market. In order to encourage units subject to must-offer to bid into the Ancillary Services Market, the CAISO filed Amendment 60, which enables them to keep ancillary services revenues without having to forfeit MLCC.

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[5] The figures representing real-time out-of-sequence redispatch costs in this chapter include some real-time dispatches that were not clearly identified as a direct consequence of real-time intra-zonal congestion management, but appear to have been related to the mitigation of intra-zonal congestion.

[6] 95 FERC 61,275; 95 FERC 61,418, etc. (2001).

[7] See Chapter 1 for a discussion of Resource Adequacy (RA) and Reliability Capacity Services Tariff (RCST).

Table 6.2 shows average must-offer and RA waiver denial capacity and total monthly costs in 2005 and 2006, as well as the imbalance energy payments that these generators received for their minimum-load energy based on real-time market prices. The costs shown in Table 6.2 also include MLCC costs for "system" reliability reasons in addition to intra-zonal reasons, which accounts for why these numbers are higher than the numbers shown in Table 6.1. The most notable trend in Table 6.2 is that the vast majority of the waiver denials and MLCC costs occurred during the first seven months of 2006. Of particular note are the high MLCC costs incurred in April 2006, which are attributed to the replacement of a key transmission line between the Lugo and Serrano substations. The decline in MLCC costs in the August-December 2006 time period can be attributed to the completion of the Lugo-Serrano upgrade, the Southwest Transmission Expansion Plan (which included upgrades to the Palo Verde-Devers and Hassayampa-North Gila-Imperial Valley 500kv series capacitors), and the installation of the Mountain View units, all of which have improved import capability from the Southwest. In addition, the end of the peak summer season reduced the need for zonal and system commitments.

Table 6.2 Must-Offer Waiver Denial Capacity and Costs ($MM)

	2005			2006		
Month	**Average MW***	**MLCC ($MM)**	**Imbalance ML Energy Payments ($MM)****	**Average MW***	**MLCC ($MM)**	**Imbalance ML Energy Payments ($MM)****
Jan	910	$ 8.3	$ 4.5	1065	$ 10.9	$ 4.0
Feb	823	$ 4.1	$ 1.5	965	$ 8.6	$ 2.8
Mar	770	$ 3.8	$ 1.5	1323	$ 11.6	$ 4.7
Apr	629	$ 5.9	$ 2.8	2444	$ 27.3	$ 13.7
May	1816	$ 14.3	$ 5.7	1331	$ 12.7	$ 6.8
Jun	1385	$ 7.5	$ 3.7	2478	$ 18.3	$ 2.9
Jul	1844	$ 21.8	$ 10.9	2150	$ 19.6	$ 7.1
Aug	1469	$ 18.0	$ 8.1	879	$ 4.9	$ 0.5
Sep	854	$ 8.6	$ 4.0	796	$ 2.8	$ 0.2
Oct	1236	$ 13.9	$ 6.0	309	$ 0.8	$ 0.0
Nov	1220	$ 12.2	$ 6.1	391	$ 1.1	$ 0.1
Dec	839	$ 11.5	$ 4.1	445	$ 2.1	$ 0.1
Annual Total	**1150**	**$ 130.1**	**$ 58.9**	**1215**	**$ 120.7**	**$ 42.8**

* Average maximum daily capacity of units on must-offer waiver. Includes minimum operating level plus unloaded capacity.

** Uninstructed energy payment for minimum load energy received by generator. Since MLCC covers full operating costs, this represents net operating revenue for the generator, or contribution to fixed costs.

Figure 6.2 compares MLCC payments to units that were denied waivers for intra-zonal or other local, zonal, and system reliability concerns, by reason, during 2005 and 2006. Figure 6.3 provides a breakdown of the 2006 figures by month.

The CAISO commits resources for system needs to protect against the risk of exhausting total power supply on the grid, particularly in summer months and days of unexpectedly high loads. As can be seen in Figure 6.2, system commitments decreased 36 percent to $11.5 million in 2006, from $18 million in 2005, due largely to higher levels of forward scheduling and self-commitment. MLCC costs for system needs in 2006 were mainly limited to the peak demand days in June and July.

SP26 zonal commitments increased to $25.9 million in 2006, a 32 percent increase from $17.7 million in 2005. These are commitments of Southern California resources to hedge against shortfalls within the SP26 zone. During peak summer periods, additional capacity is also committed within SP26 for contingencies. During the summer of 2005, there were large commitments across the control area and within SP15 in particular, for both system and South-of-Lugo reasons. Those unit commitments diminished the need to commit additional units for zonal reasons in 2005, as committed units can provide support for multiple constraints. Fewer commitments were made for local and system reasons during the peak summer months of June and July 2006, which reduced the amount of energy and unloaded capacity that contributed to maintaining reliability in SP15. As a result, the CAISO committed additional units in SP15 during this period to ensure reliability.

Other commitments are more local in nature and tend to be in response to local outages or for maintenance or transmission upgrades. MLCC costs associated with South-of-Lugo congestion declined 18.6 percent to $35 million in 2006 from $43 million in 2005. The decrease was due primarily to two factors: (1) the installation of the Mountain View generation facility in August 2005, which provides voltage support in the Los Angeles basin and increases the Lugo capacity rating, and (2) the replacement of the Lugo-Serrano 500kv line in April 2006 with lines connecting Lugo to Mira Loma, and Mira Loma to Serrano. This replacement resulted in congestion during the line work that caused the spike in Serrano-area MLCC costs in April, as seen prominently in Figure 6.3, but also resulted in significantly lower South-of-Lugo costs after it was completed. Other work in the area of the Serrano substation in northern Orange County occurred in late 2006.

Figure 6.2 MLCC Costs by Reason, 2005-2006

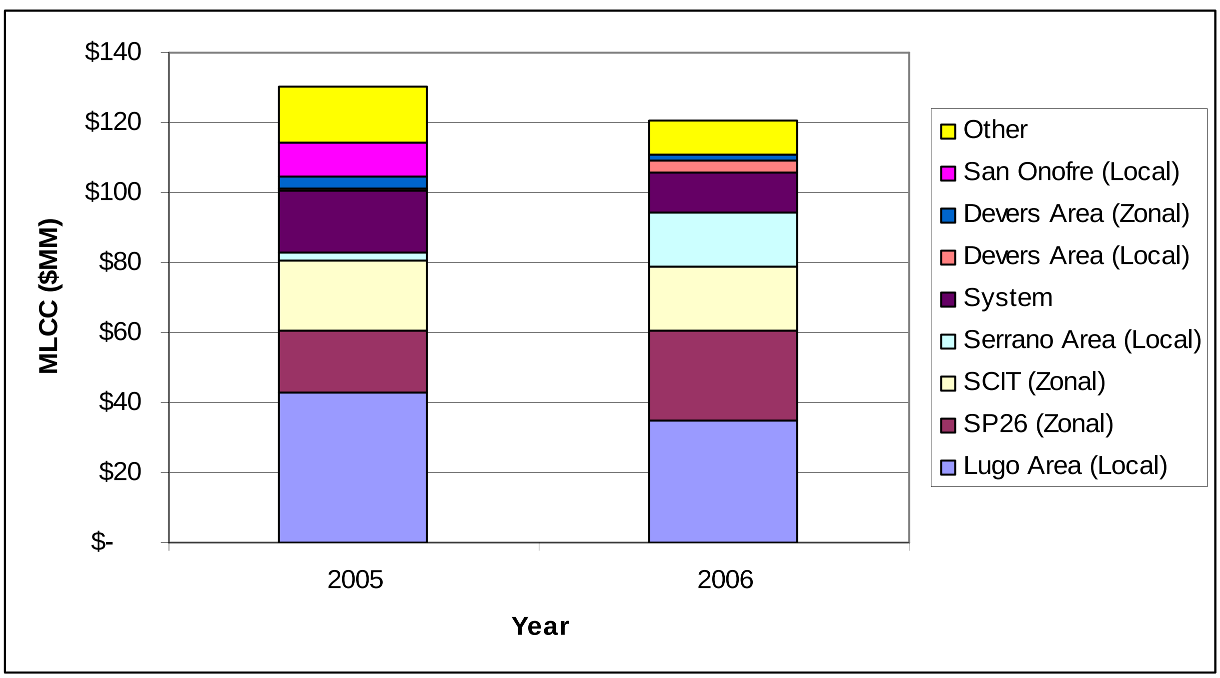


Figure 6.3 Monthly MLCC Costs by Reason, 2006

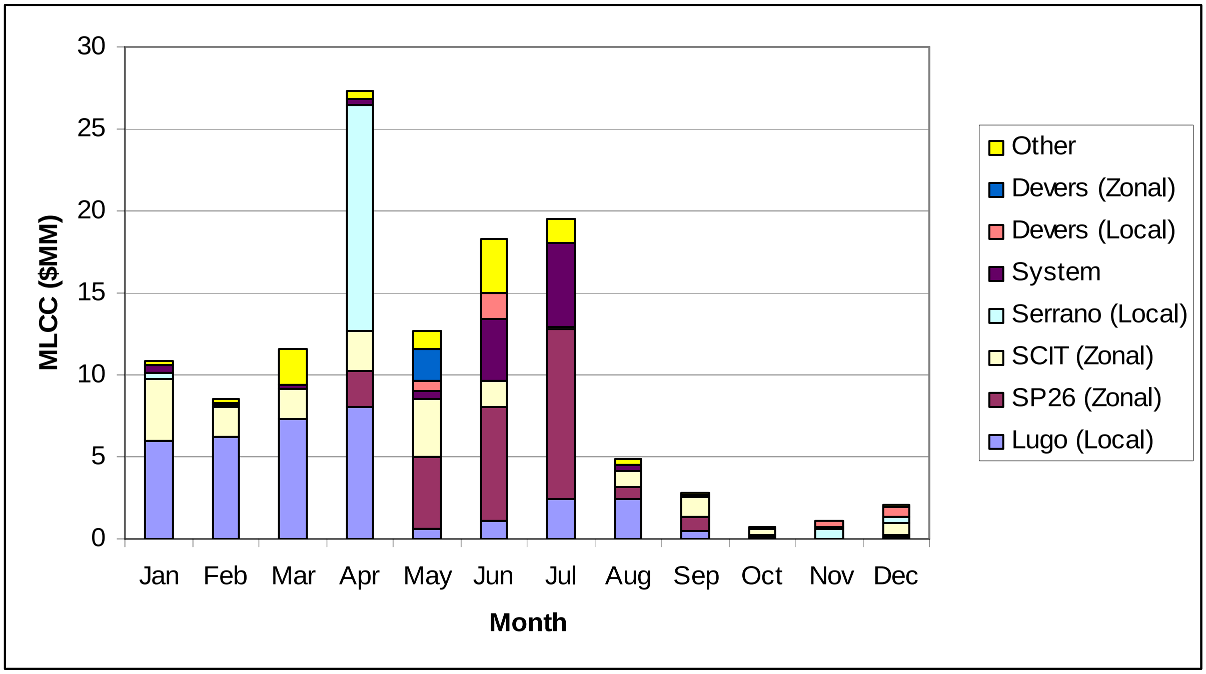


Figure 6.4 and Figure 6.5 show the average daily capacity commitments and average daily MLCC cost of waiver denials, respectively, by reason types (Local, Zonal, and System). The totals for all three reason type categories are the same as the values shown in Table 6.2. However, these figures provide additional detail on how the total average daily volume and costs break out across the three categories. Most notable in these figures is the significant increase in zonal (SP26) waiver denials and costs for the months of May through July, relative to 2005. The transmission upgrades and the installation of the Mountain View units reduced the need for local commitments within SP26, as previously noted, but resources were still needed to ensure zonal and system reliability. Additionally, the significant increase in local waiver denials and costs in April, as noted above, is due to the Serrano upgrade.

Figure 6.4 Average Daily Capacity on Must-Offer Waiver Denial for All Reasons (Local, Zonal, and System), 2005-2006

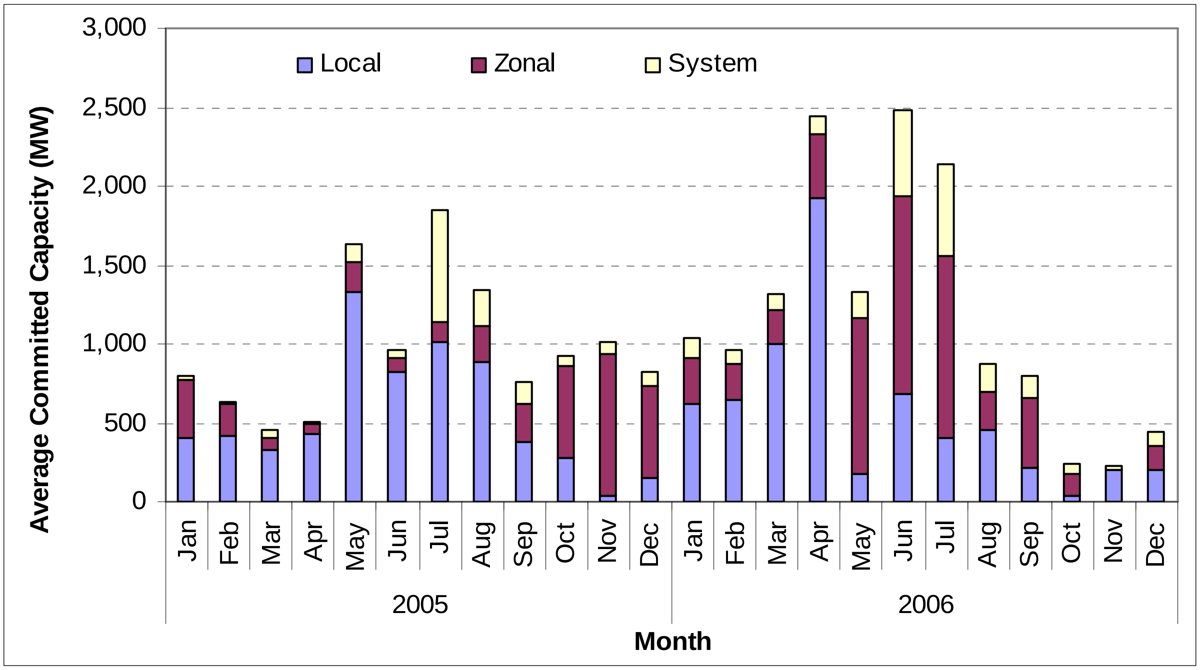
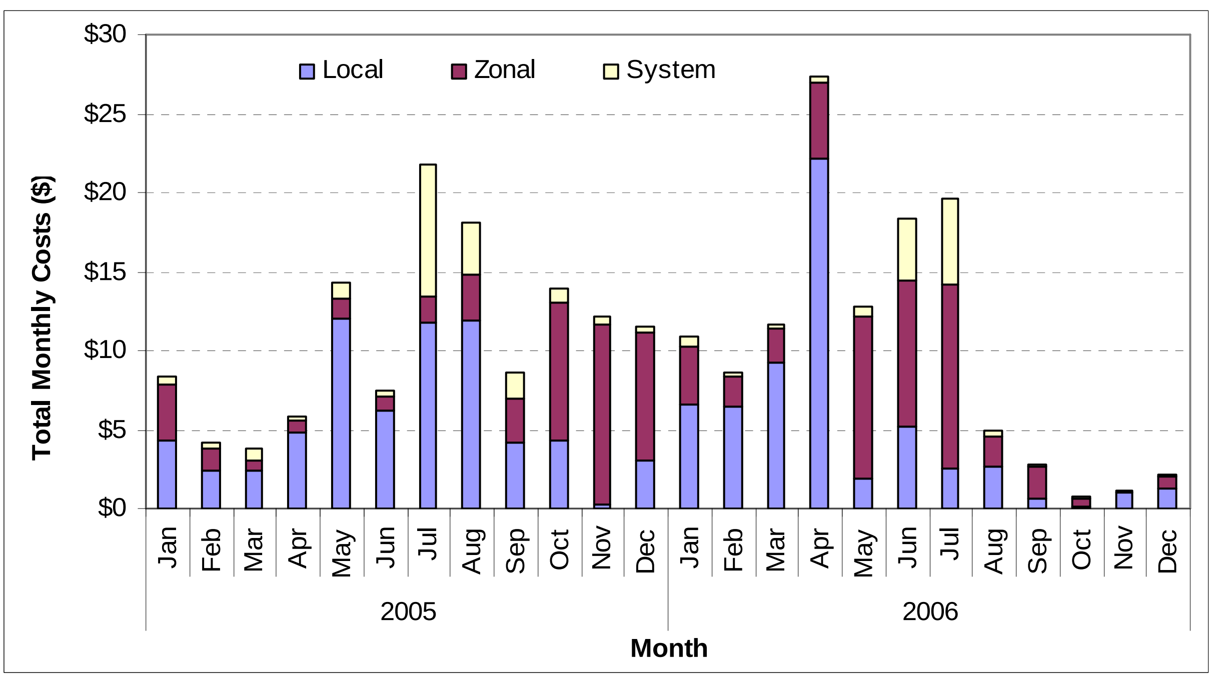


Figure 6.5 Total Monthly MLCC Payments for All Reasons (Local, Zonal, and System), 2005-2006

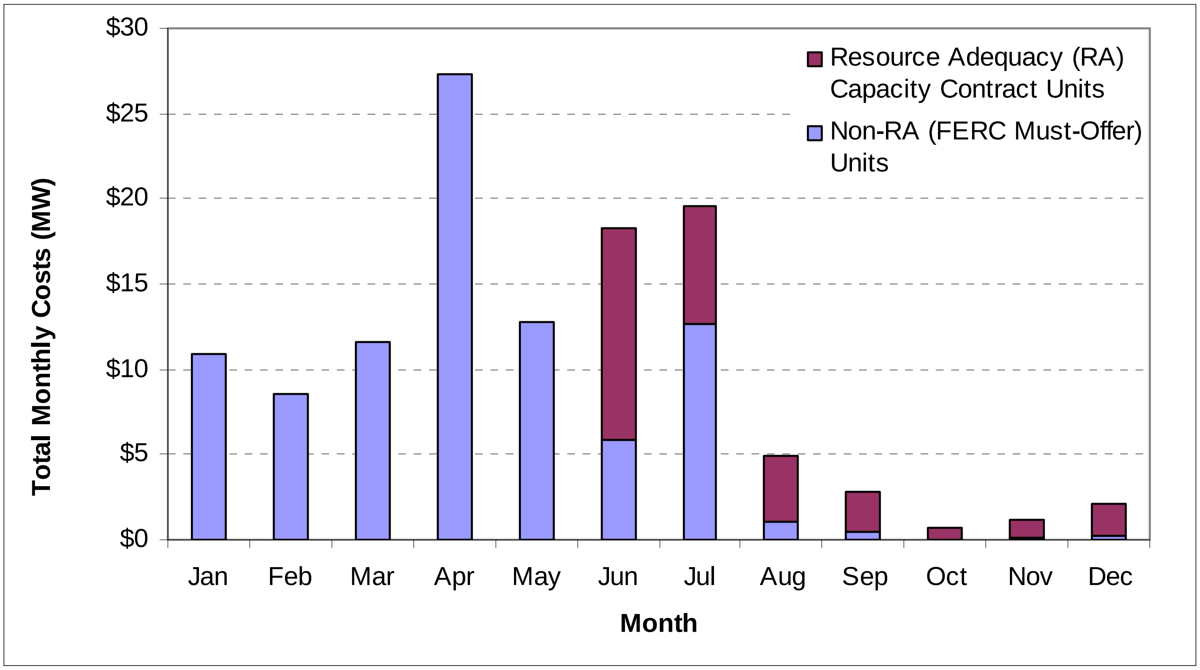


In 2006, resource adequacy (RA) programs developed by the CPUC and other Local Regulatory Authorities (LRAs) became effective. These programs require that load-serving entities (LSEs) procure sufficient resources to meet their peak load along with appropriate reserves. RA programs support system and local grid reliability by creating a framework intended to promote new generation investment in California by providing generation resources a revenue source to contribute towards fixed cost recovery. The CAISO facilitates implementation of these RA programs through its Interim Reliability Requirements Program (IRRP), which defines how RA resources are made available to the CAISO prior to the implementation of MRTU.

Beginning in June 2006, the CPUC directed its jurisdictional LSEs to procure sufficient resources to cover 100 percent of their forecasted load for each month, plus a 15 percent margin for operating and planning reserves. The California Energy Commission determined for each CPUC-jurisdictional LSE load forecast based on an allocation of each LSE's coincident share of the forecasted CAISO system peak for each month. Before applying the 15 percent reserve margin, each LSE's forecast load was adjusted downward based on its administratively determined share of demand response resources (i.e., load that can be curtailed) available in the utility service territory in which their load is located. LSEs not under CPUC jurisdiction, mainly local publicly-owned utilities, meet roughly similar requirements determined by their respective LRAs.

The implementation of the RA program in June 2006 has significantly reduced reliance on the FERC-directed Must-Offer Obligation. Since August 2006, the CAISO has been able to commit resources covered predominantly under RA contracts. However, in the months of June and July, a significant amount of non-RA capacity was denied waivers due to local and zonal needs in June and early July and system needs during the July heat wave. With the introduction of local resource adequacy requirements in 2007, the need for non-RA resources during the peak summer months should be further diminished. Figure 6.6 provides a monthly breakdown of minimum-load commitment costs by commitment type (RA or FERC Must-Offer).

Figure 6.6 Total Monthly MLCC Payments to Must-Offer vs. RA-Contracted Units in 2006



6.3.2 Reliability Must Run Costs

To mitigate local market power and to ensure that local reliability requirements are met, California's current market design relies upon RMR contracts with units located at known congested locations on the transmission grid. Through an annual planning process, the CAISO designates specific generating units as RMR units, based on the potential need for these units to be on-line and/or generate at sufficient levels to provide voltage support, adequate local generation in the event of system contingencies, and meet other system requirements related to local reliability. RMR contracts provide a mechanism for compensating unit owners for the costs of operating when units are needed for local reliability but may not be economical to operate based on overall energy and ancillary service market prices. RMR units are either pre-dispatched for local reliability needs (prior to real-time), or incremented in real-time either for local reliability or for intra-zonal congestion. RMR units cannot be pre-dispatched for intra-zonal congestion.

All RMR units receive two basic forms of compensation: (1) a Fixed Option Payment (FOP) that provides a contribution to each unit's fixed costs, and (2) a variable cost payment for energy provided under the RMR contract option, which is paid as the difference (if any) between the unit's variable operating costs and market revenues received for energy provided in response to an RMR requirement.[8]

Table 6.3 shows total fixed and variable RMR costs by month in 2006, and further divides variable cost payments into costs associated with pre-dispatched RMR energy for local reliability and additional real-time RMR energy dispatches for any remaining intra-zonal congestion.[9] Generators providing energy in response to a real-time RMR dispatch are paid based on their variable operating costs, with the responsible Transmission Owner (TO) receiving a credit back for the value of this energy at the real-time price. Thus, the net cost of real-time RMR dispatches for intra-zonal congestion or other local reliability requirements is equal to the difference between the RMR unit's variable operating cost and the real-time price of energy.

Table 6.3 Monthly RMR Contract Energy and Costs in 2006*

Month	Pre-Dispatched Energy (GWh)	Real-Time Energy (GWh)	Fixed Option Payments ($MM)	Net Pre-Dispatch Costs ($MM)	Net Real-Time Costs ($MM)	Total RMR Costs ($MM)
Jan	248	238	$ 25	$ 11	$ 13	$ 49
Feb	222	323	$ 19	$ 9	$ 15	$ 43
Mar	216	370	$ 21	$ 7	$ 13	$ 42
Apr	264	197	$ 21	$ 7	$ 8	$ 37
May	315	58	$ 22	$ 7	$ 3	$ 32
Jun	418	90	$ 25	$ 8	$ 4	$ 37
Jul	327	110	$ 26	$ 5	$ 2	$ 34
Aug	230	61	$ 23	$ 10	$ 3	$ 37
Sep	196	52	$ 22	$ 6	$ 2	$ 30
Oct	142	89	$ 20	$ 6	$ 3	$ 30
Nov	105	134	$ 17	$ 5	$ 6	$ 27
Dec	146	139	$ 18	$ 7	$ 7	$ 31
2006 Total	**2,830**	**1,861**	**$ 259**	**$ 88**	**$ 80**	**$ 428**
% ∆ from 2005	-47.8%	21.8%	2.7%	-51.7%	10.9%	-15.7%

* Dispatch quantities and costs reported in Table 6.3 only include dispatches under the "Contract Option."

Total RMR costs continued to decrease in 2006 to approximately $428 million, from approximately $505 million in 2005.[10] This continued the trend between 2004 and 2005. The decrease in costs may be due to a combination of factors; namely:

- The portion of RMR unit capacity selecting Condition 2 (non-market) of the pro forma RMR contract continued to decrease, resulting in lower variable cost payments. RMR-providing generation owners may select either Condition 1 or 2. Condition 1 entitles the

8 Units under Condition 1 of the RMR contract are free to select the "Market Option" when receiving an RMR dispatch on a day-ahead or hour-ahead basis, in which case they keep all revenues from sales of this energy and do not receive any reimbursement for variable operating costs.

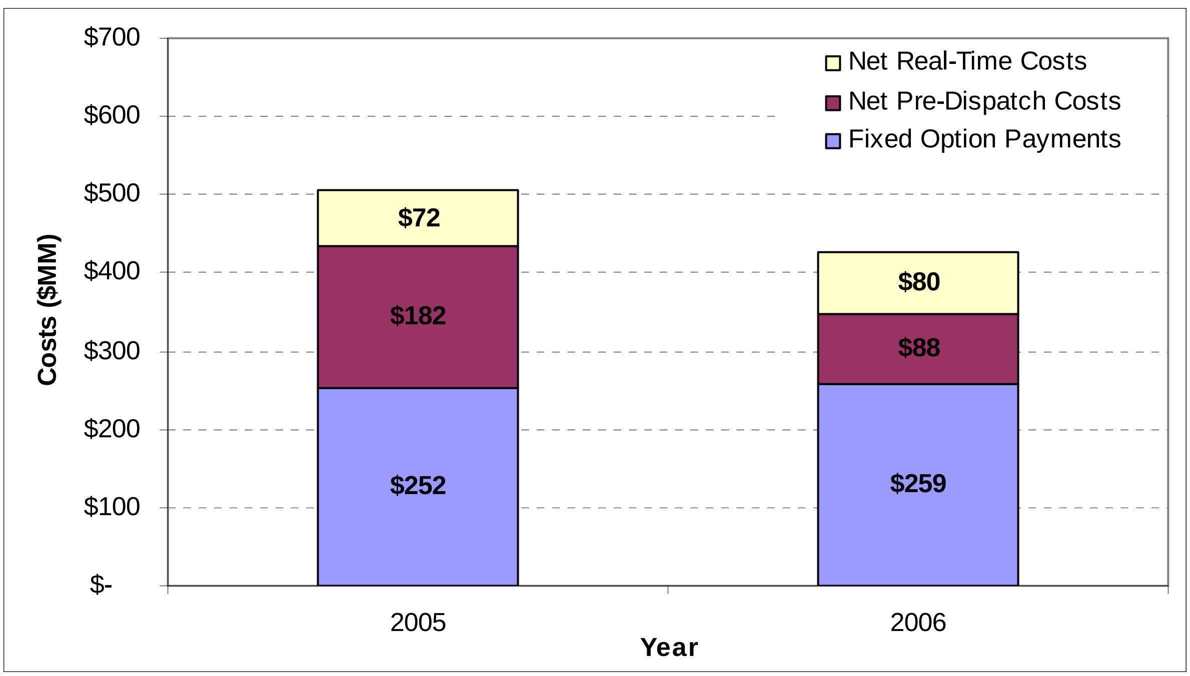
9 Since selection of RMR units and pre-dispatch of RMR units is based on local reliability requirements, these costs are not specifically associated with intra-zonal congestion. While annual designation of RMR units and pre-dispatch of RMR units to meet local area reliability requirements may reduce intra-zonal congestion in real-time, these costs would be incurred even if intra-zonal congestion did not occur in real-time. Thus, it is more appropriate to exclude costs associated with the FOP and pre-dispatch of RMR units from intra-zonal congestion costs.

10 In last year's report, total RMR costs of $460 million were reported in 2005. However, this estimate was based on preliminary settlement information for November and December 2005. The $505 million estimate for 2005 reflects final settlement data for those months as well as other settlement corrections, which in total, amount to an increase of $45 million over last year's reported estimate. A similar issue may occur next year with regard to the reported RMR costs for 2006.

generation owner to participate in the market, and, if dispatched for RMR, to select on a daily basis whether to collect variable contract-based rates (Contract Path) or market revenues (Market Path). Because Condition 1 units have market opportunities, they receive a lower monthly FOP.[11] Condition 2 effectively is a tolling agreement between the CAISO and the generation owner, where the owner receives a higher FOP, but receives cost-based payments for its energy and cannot participate in the market unless given an RMR dispatch. The higher proportion of owners electing Condition 1 is indicative of improved market conditions for energy sales in bilateral and real-time markets. Several RMR-contracted resources have also been sold by traditional merchant energy companies to investor, private equity, and investment bank-backed organizations. Condition 2 unit capacity accounted for approximately 11.8 percent of total RMR-contracted unit capacity by the end of 2006, compared to 19.6 percent at the end of 2005.

- Due to greater installed generation and transmission, RMR dispatch requirements decreased. Total RMR dispatch volumes, including both contract and market path dispatches, decreased to 6,349 GWh in 2006, compared to 9,454 GWh in 2005, and approximately 15,000 GWh in 2004. Variable contract-path costs totaled $168 million in 2006, compared to approximately $254 million in 2005.

Figure 6.7 Total RMR Costs, 2005-2006



[11] RMR Condition 1 revenues from dispatch under the Market Path are not included in the calculation of reliability costs, but are included as real-time market costs in the calculation of total wholesale market costs in Chapter 2.

Figure 6.8 RMR Capacity by Resource and Contract Type, 2004-2006

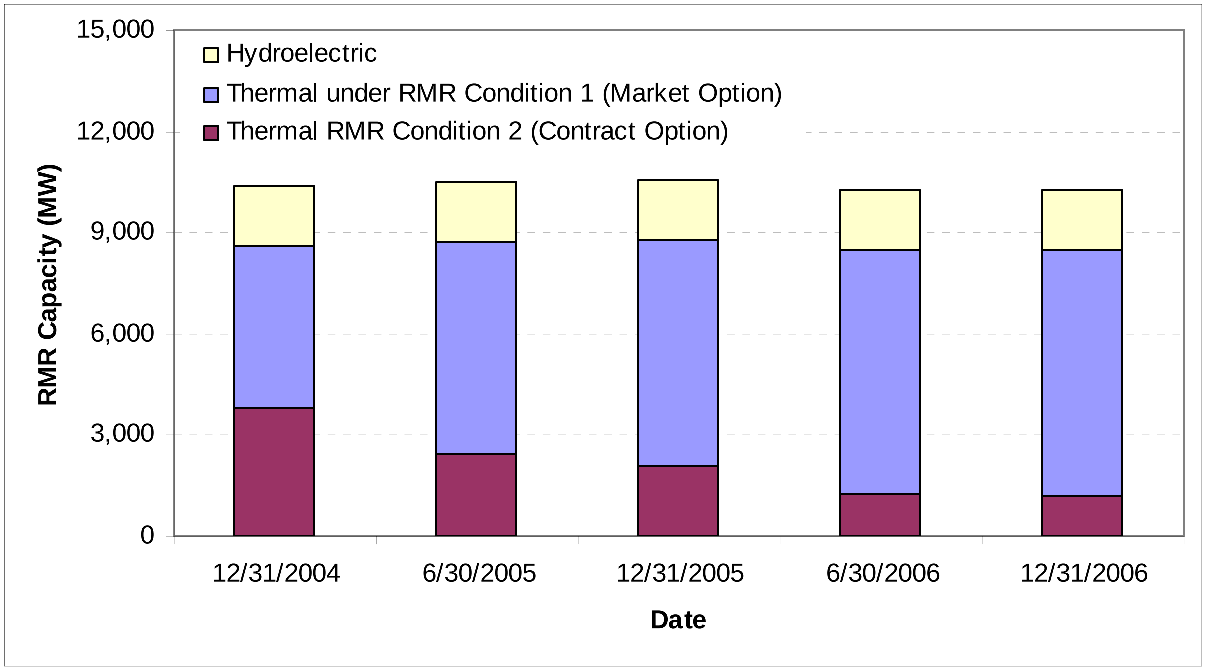
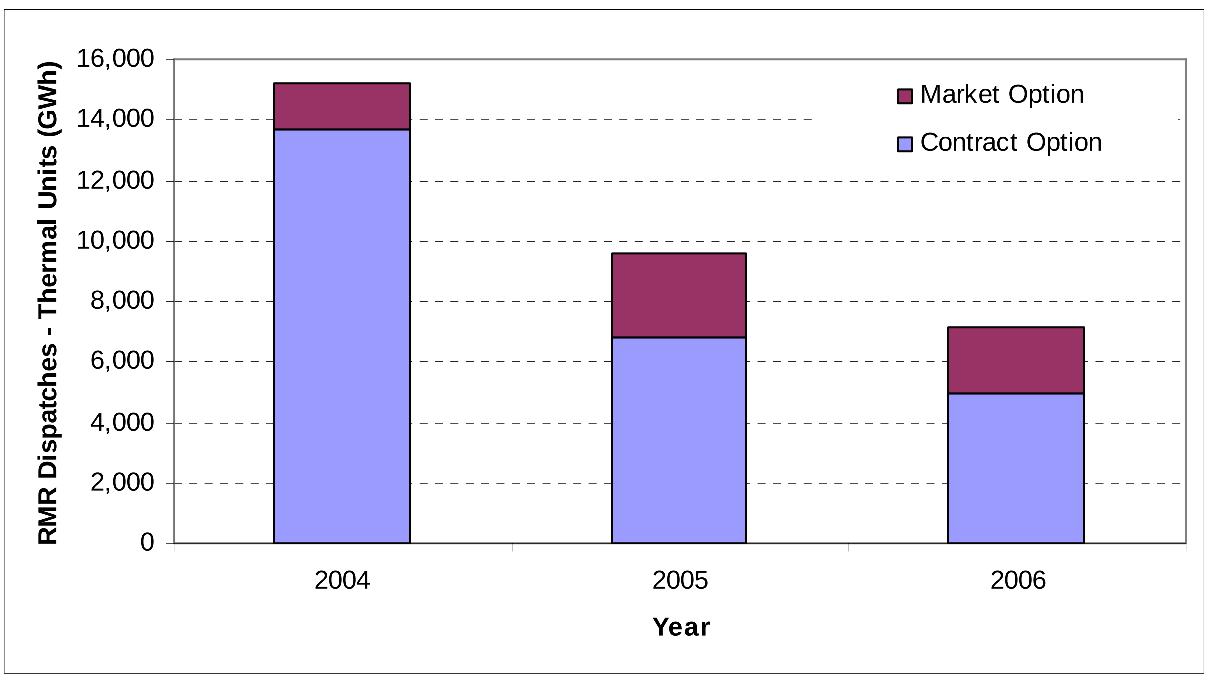


Figure 6.9 RMR Dispatch Volumes – Thermal Units (2004-2006)



6.3.3 Out-of-Sequence (OOS) Costs

The costs of Out-Of-Sequence (OOS) dispatches for mitigating real-time intra-zonal congestion is measured in terms of the redispatch cost, which is the incremental cost incurred from having to dispatch some resources up and other resources down to alleviate the congestion. For incremental energy bids dispatched OOS, the redispatch cost is the difference between the price paid to the resource for OOS energy (generally, their bid price) less the market clearing price (the cost of balancing the OOS energy). For decremental energy bids dispatched OOS, the redispatch cost is based on the market clearing price for incremental energy less the reference price for decremental OOS energy.[12]

As shown in Table 6.4, net redispatch costs of incremental dispatches to load-serving entities, or the costs in excess of real-time market prices, was approximately $4.3 million in 2006, compared to $3.3 million in 2005. In all, the CAISO procured 127 GWh of incremental OOS energy at an average price of $68.89/MWh, or $33.70/MWh above market.

Table 6.5 shows decremental OOS statistics. Decremental redispatch costs, or the amount of money below the market price that resources save when the CAISO reduces their output in order to avoid intra-zonal congestion, totaled $13.2 million in 2006, compared to $31.3 million in 2005. In all, the CAISO decremented 783.8 GWh of OOS energy in 2006 at an average price of $36.11/MWh, or $16.83/MWh below market.

The decline in total costs was largely attributable to upgrades at the Miguel and Pastoria/Magunden areas. These congestion points were very problematic in 2005, and transmission work has resulted in significantly lower costs.

Table 6.4 Incremental OOS Congestion Costs in 2006

	GWh	Gross Cost ($MM)	Redispatch Premium ($ MM)	Mitigation Savings ($)	Average Price	Average Net Cost ($/MWh)
Jan	4.0	$ 0.3	$ 0.2	$ 16,197	$ 78.93	$ 49.04
Feb	2.8	$ 0.2	$ 0.1	$ 2,204	$ 73.40	$ 32.53
Mar	5.6	$ 0.5	$ 0.3	$ 48,145	$ 81.14	$ 55.03
Apr	49.1	$ 3.5	$ 2.1	$ 33,035	$ 71.55	$ 41.98
May	16.9	$ 1.1	$ 0.5	$ -	$ 66.42	$ 30.29
Jun	12.4	$ 0.8	$ 0.3	$ 313	$ 66.13	$ 26.90
Jul	18.6	$ 1.3	$ 0.4	$ 18,727	$ 69.07	$ 20.16
Aug	1.3	$ 0.1	$ 0.0	$ -	$ 74.72	$ 16.53
Sep	2.5	$ 0.2	$ 0.2	$ -	$ 95.21	$ 62.72
Oct	0.3	$ 0.0	$ 0.0	$ -	$ 40.40	$ 11.75
Nov	5.2	$ 0.3	$ 0.1	$ 1	$ 52.29	$ 15.18
Dec	8.3	$ 0.4	$ 0.1	$ 5,572	$ 50.00	$ 17.16
2006 Total	**127.0**	**$ 8.7**	**$ 4.3**	**$ 124,193**	**$ 68.89**	**$ 33.70**

[12] This discussion excludes OOS and OOM dispatches for system conditions, which totaled approximately $6.5 million in redispatch costs in 2006. These dispatches were largely incremental dispatches to RMR Condition 2 units during the summer heat wave, which under the RMR contract are not required to bid, and decremental dispatches to pump storage units to offset over-generation during the spring months.

Table 6.5 Decremental OOS Congestion Costs in 2006

	GWh	Gross Cost ($MM)	Redispatch Premium ($ MM)	Average Price	Average Net Cost ($/MWh)
Jan	(154.1)	$ (5.3)	$ 3.5	$ 34.51	$ 22.46
Feb	(105.0)	$ (2.7)	$ 1.7	$ 25.54	$ 16.40
Mar	(150.5)	$ (4.9)	$ 2.3	$ 32.32	$ 15.61
Apr	(142.5)	$ (4.6)	$ 3.7	$ 32.06	$ 26.06
May	(4.8)	$ (0.1)	$ 0.1	$ 27.76	$ 20.45
Jun	(6.0)	$ (0.2)	$ 0.2	$ 27.82	$ 25.60
Jul	(2.1)	$ (0.1)	$ 0.1	$ 41.87	$ 32.08
Aug	(10.1)	$ (0.4)	$ 0.3	$ 35.71	$ 34.57
Sep	(24.5)	$ (1.0)	$ 0.1	$ 38.76	$ 4.75
Oct	(88.8)	$ (4.1)	$ 0.6	$ 46.30	$ 6.80
Nov	(35.0)	$ (1.9)	$ 0.3	$ 55.20	$ 7.39
Dec	(60.4)	$ (3.1)	$ 0.3	$ 51.80	$ 5.01
2006 Total	**(783.8)**	**$ (28.3)**	**$ 13.2**	**$ 36.11**	**$ (16.83)**

Figure 6.10 shows annual redispatch costs by reason in 2006. Figure 6.11 provides a similar breakdown on a monthly basis. As evident in Figure 6.11, intra-zonal congestion costs were most significant during the first part of the year (January-April) and declined significantly for the rest of the year. Congestion at the Pastoria/Magunden substations and the South-of-Lugo area were particularly costly between January and April, totaling approximately $8.5 million in redispatch costs in those months. The Big Creek Project and the Pastoria generation facility respectively are key sources of generation connected to the Southern California grid. Together, they represent approximately 1,770 MW of generation capability, and provide important flexibility to the import-constrained SP26 region. With the completion in mid-2006 of upgrades to the Pastoria-Pardee, Pastoria-Baily-Pardee, and Pastoria-Warner-Pardee 230kv lines, and the installation of two new 230kv Magunden-Antelope lines, congestion costs at the Magunden/Pastoria transmission facilities were nearly eliminated. Beginning in May 2006 through the end of the year, South of Pastoria/Magunden congestion costs were limited to $547,000. South-of-Lugo congestion is primarily due to power from Hoover Dam and other generation facilities in the Southwest, as well as from the High Desert and Cool Water combined-cycle facilities, which pass through the Lugo Substation. South-of-Lugo congestion costs were particularly significant in April 2006, totaling $2 million in that month alone. This increase was again due to the rerouting of the Lugo-Serrano line through the Mira Loma substation. As a consequence of this upgrade, South-of-Lugo congestion was minimal after April.

Figure 6.10 Intra-Zonal OOS/OOM Redispatch Costs by Reason in 2006

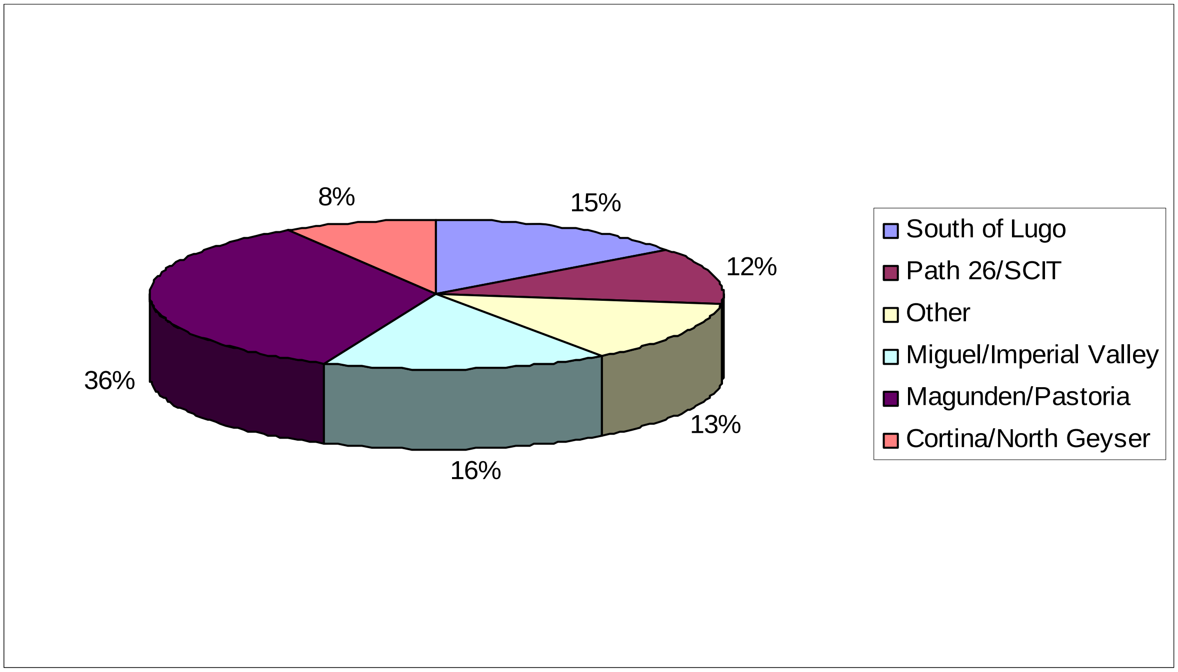
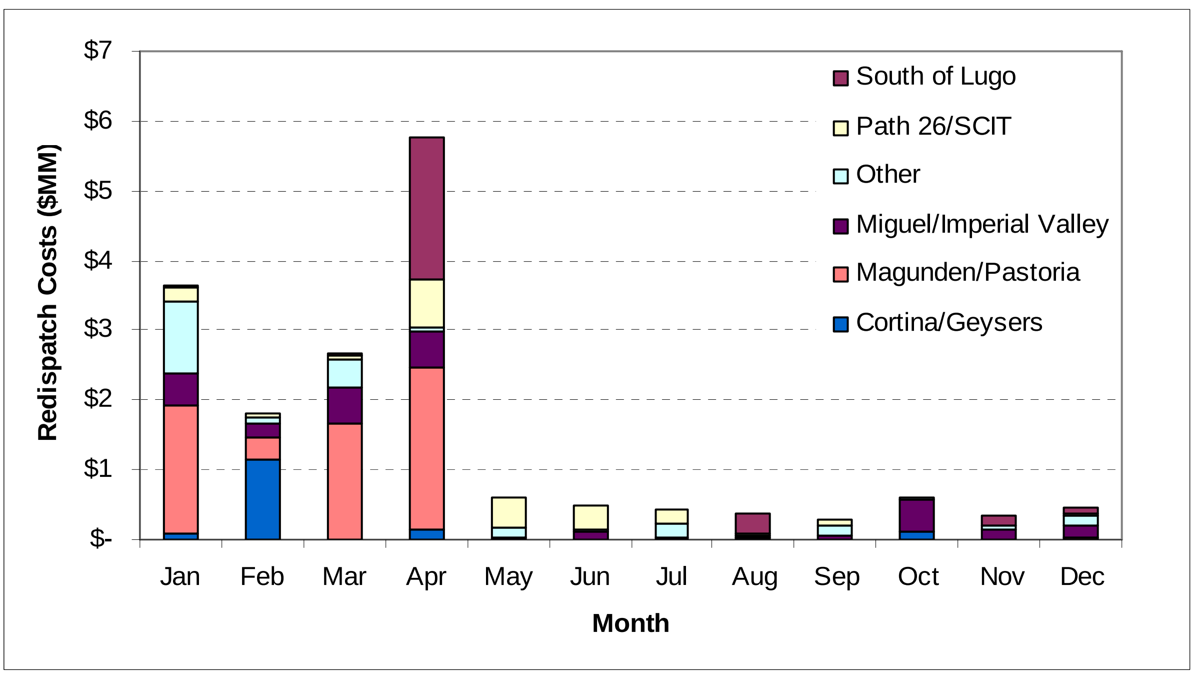


Figure 6.11 Monthly Contribution to Intra-Zonal Congestion OOS Redispatch Costs by Reason in 2006



Intra-zonal congestion at the Miguel substation, which had been a major bottleneck in prior years, was largely eliminated in 2006 due to transmission upgrades in that region in mid-2005.

Congestion in the Miguel-Imperial Valley area decreased to $2.8 million in 2006 from $10.1 million in 2005. Most of this congestion occurred between January and April, due to outages for the short-term STEP upgrades. One Bay Area location in particular incurred substantial intra-zonal congestion costs in 2006. The bulk of these costs were due to transmission upgrades for the Cortina substation and the Geysers generation facilities, particularly in February. The derates of the Cortina substation for the upgrade necessitated out-of-sequence decremental dispatches of the Geysers area facilities.

The Southern California Import Transmission (SCIT) Nomogram, a constraint on the quantity of energy that can be imported into Southern California at any moment, was binding less frequently in 2006 than in the past. Pursuant to Operating Procedure T-103,[13] SCIT can be mitigated either by intra-zonal congestion management through out-of-sequence redispatch or by splitting the NP15 and SP26 markets, as deemed necessary by operators given conditions on the grid. SCIT and SP26 import intra-zonal congestion costs were approximately $2.1 million in 2006, compared to $1.1 million in 2005.[14]

[13] http://www.caiso.com/docs/2002/01/29/2002012909363927693.pdf

[14] The costs of the various reasons for SP26 intra-zonal congestion are not explicitly separable.