6. Real-time (Intra-zonal) Congestion

6.1 Introduction/Background

Real-time congestion occurs when scheduled power flows overload the transfer capability of grid facilities. The CAISO's day-ahead and hour-ahead congestion management system has established congestion zones that it models in order to measure and manage congestion. Real-time congestion results from a combination of economic factors and the fact that the CAISO only manages zonal congestion in the day-ahead and hour-ahead markets.

Scheduling coordinators (SCs) submit day-ahead/hour-ahead generation 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 congestion management system measures and manages congestion only between zones, not within zones. This allows SCs, collectively, to submit day-ahead/hour-ahead schedules calling for transmission within a zone that is not physically feasible. This creates the need for CAISO operators to have to manage intra-zonal congestion in real-time.

A variety of factors have contributed to an increase in intra-zonal congestion in 2004, primarily within southern California (SP15). First, while no major new generation capacity has been added within southern California over the last two years, significant new efficient generation resources continue to be added outside of the CAISO system in the southwest and within the ISO system on the border with Mexico. Given daily spot market gas and electric prices in 2004, it was typically uneconomic to commit older generating units in southern California (with heat rates of 10,000 MMBtu/MWh or above), and economic to operate new generation units (with heat rates of 8,000 MMBtu/MWh or below). As a result, the amount of thermal capacity within southern California committed through the market in 2004 dropped significantly, while lower cost imports increased, thereby increasing intra-zonal congestion within SP15. As a result, the ISO relied heavily on the must-offer waiver denial process to commit additional thermal generation capacity within SP15.

There were a number of upgrades to the transmission infrastructure that took place in 2004 that required the transmission facility to be either de-rated or taken out of service for extended periods for the work to be completed. These facility outages, in turn, resulted in increased intra-zonal congestion. In these circumstances, the CAISO relied more heavily on must-offer units, compared with 2003, to relieve temporary intra-zonal congestion resulting from these outages.

Intra-zonal congestion most frequently occurs in load pockets, or areas where load is concentrated with insufficient transmission 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. Intra-zonal congestion can also occur due to generation pockets in which generation is clustered together, with insufficient transmission to allow the energy to flow out of the pocket area. 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. Typically, there is very 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 congestion is closely intertwined with the issue of locational market power. Methods to resolve intra-zonal congestion are designed to limit the ability of suppliers to exercise locational 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 long-start thermal units through the must-offer waiver (MOW) process in return for minimum load cost payments. This is the means 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. 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 call any 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);[1]
- 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. They do not set the real-time market-clearing price. Units decremented OOS to mitigate intra-zonal congestion are paid the lower of their bid reference level or the zonal market clearing price. They also do not set the real-time market-clearing price. Intertie bids taken OOS are paid-as-bid.

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. The provisions of Amendment 50 allow the CAISO to decrement generation for intra-zonal congestion using bid-reference levels supplied by an independent entity.

6.1.1 Major Points of Intra-zonal Congestion

The major points or categories of intra-zonal congestion in 2004 were located in the CAISO's southern congestion zone (SP15). They are described below:

- **Miguel.** Congestion on the Miguel substation close to San Diego is attributable largely to the addition of new generation within the CAISO system on the border with northern Mexico and in Arizona. In July 2003, three new generation units in northern Mexico began operation with a combined capacity of approximately 1,070 MW. They are connected to the

[1] 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.

CAISO system at the Imperial Valley substation. When combined with imported energy on the Palo Verde Intertie, also increased due to the addition of new generation units in Arizona, this additional generation frequently creates congestion at the Miguel substation close to San Diego. As we noted in the *2003 Annual Report on Market Issues and Performance*, the CAISO foresaw this congestion problem and, in response, filed Amendment 50 in late March 2003 to mitigate dec bids to relieve the congestion.[2] To mitigate congestion at Miguel, the CAISO must increment resources in the San Diego area, and must decrement generation in northern Mexico east of Miguel and/or decrement imports on the Palo Verde tie point with Arizona.

- **South of Lugo.** This constraint is coincident with the Lugo tie-point within SP15. It is one of the major points of intra-zonal congestion within the CAISO system. To mitigate intra-zonal congestion on the Lugo tie-point, the CAISO must increment generation from a limited number of units in southern California. Like congestion related to SCIT (see below), intra-zonal congestion on Lugo is a product of the lower price of energy from imports from California outside the load center and imports from Arizona.
- **Sylmar Substation.** Beginning in September 2003 to the end of 2004, upgrades on the Pacific DC Intertie (PDCI) required that Sylmar substation be frequently de-rated or out of service. In 2004, there was intermittent Sylmar bank congestion due to the equipment outages at the Sylmar substation. Most of the mitigation for this source of congestion consisted of incrementing units in the Ventura County area and the Los Angeles basin area.
- **Southern California Import Transmission (SCIT) Nomogram.** This operating nomogram places limits on imports into southern California based on a variety of conditions. They include power flows on five major paths into southern California, actual flow East of the River (EOR), and system inertia from generation within southern California.[3] When the SCIT nomogram becomes binding, the CAISO must increment additional generation from a limited number of units in southern California to mitigate flows. Intra-zonal congestion initiating the SCIT nomogram often is due to the large quantity of low cost energy from imports from Arizona or Mexico being used to serve southern California load.

6.1.2 Impacts of Intra-zonal Congestion

Intra-zonal congestion can have both reliability impacts and economic costs. Managing large amounts of intra-zonal congestion at different locations in real time can have detrimental reliability impacts. In addition, mitigation of intra-zonal congestion results in a number of different components of cost:

[2] See 2003 Annual Report on Market Issues and Performance, Chapter 1, Section 1.1.1.3 for a more detailed discussion of the filing.

[3] See Operating Procedure T-103, East of River (EOR)/ Southern California Import Transmission (SCIT), http://www.caiso.com/docs/2002/01/29/2002012909363927693.pdf

1. Minimum Load Cost Compensation (MLCC).[4] 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. Costs from RMR real-time dispatches that are the first response to intra-zonal congestion.
3. Costs of out-of-sequence dispatches.

In the following sections of this chapter, we examine these different cost components of intra-zonal congestion in terms of the "re-dispatch costs," or total net costs in excess of market clearing prices in the CAISO real-time imbalance markets. In addition, we quantify the portion of these re-dispatch costs that represent payments in excess of the actual operating cost of resources re-dispatched by the CAISO to resolve intra-zonal congestion.

6.1.2.1 Minimum Load Cost Compensation

When a generator plans not to run a long-start thermal unit for a certain period, it is required to offer its capacity to the CAISO under the terms of the must-offer obligation. If the CAISO determines that the unit is not needed, the generator is allowed to shut down through the must-offer waiver approval process. Should the CAISO believe that the unit would be needed for either system or local reliability, the unit is required to run and is compensated for the cost of running at minimum load. In addition to receiving full cost compensation for minimum load operating costs, generators operating under the must-offer process are also paid the real-time decremental energy price for their minimum load energy.[5] Generators operating due to must-offer waiver denials must bid all unloaded capacity into the CAISO real-time market. They keep all revenues they earn from any sales of instructed energy if dispatched in real time. In order to encourage units on must-offer waiver denials to bid into the ancillary service markets, the CAISO filed Amendment 60, which allows them to keep ancillary service revenues.

Table 6.1 tabulates the MLCC payments to units that were denied waivers for intra-zonal or other local reliability concerns during 2003-2004. As shown, overall capacity operating each day due to must-offer waiver denials increased by about 56 percent in 2004, from an average of 1,681 MW per day in 2003 to about 2,628 MW per day in 2004. However, due to increases in gas prices, the MLCC costs associated with this capacity increased by about 128 percent from $125 million to $285 million. Similarly, due to increases in real-time prices, the imbalance energy payments received by generators (in addition to MLCC payments) for the minimum load energy associated with this capacity increased by about 145 percent, from $48 million to $114 million. Figures 6.1 and 6.2 show the average daily capacity on must-offer waiver denial and total MLCC costs by month since June 2002 through 2004.

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

[5] Since generators are paid twice for minimum load energy – once through the MLCC and again through payments for uninstructed energy – the CAISO sought to net these uninstructed energy payments against MLCC as part of its Amendment 60 filing. However, FERC ruled that generators should continue to receive uninstructed energy payments for minimum load energy in order to provide a source of contribution to fixed costs.

Since generators receive the real-time energy price for uninstructed energy in addition to the MLCC when operating under the must-offer requirement, the MLCC is the net payment in excess of the market price of imbalance energy incurred by load serving entities for units constrained on through the must-offer requirement. Meanwhile, since the MLCC covers the generators' full operating costs, the uninstructed energy payment represents a net payment in excess of actual operating costs that is incurred by load serving entities for units constrained on through the must-offer requirement.

Table 6.1 Must-Offer Waiver Denial Capacity and Costs (Millions of Dollars)[6]

	2003			2004		
Month	Average MW *	MLCC (millionsl.)	Uninstructed Energy Payments (millions.)**	Average MW*	MLCC (millions.)	Uninstructed Energy Payments (millions)**
January	924	$5	$3	1,626	$13	$5
February	870	$4	$3	1,719	$13	$5
March	1,245	$9	$3	2,792	$21	$8
April	1,039	$5	$2	2,542	$18	$7
May	1,000	$4	$1	2,524	$23	$10
June	1,661	$10	$3	2,729	$25	$9
July	1,927	$14	$7	3,568	$33	$14
August	3,346	$21	$8	3,151	$30	$11
September	2,246	$14	$5	3,153	$25	$10
October	2,381	$15	$5	2,383	$23	$10
November	1,689	$11	$4	2,646	$30	$15
December	1,853	$14	$5	2,704	$33	$15
Annual Total	1,682	$125	$48	2,628	$287	$118

* 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.

[6] This table represents the total MLCC costs, whereas Table 6.7 only represents those costs associated with local reliability.

Figure 6.1 Average Daily Capacity on Must-Offer Waiver Denial (2002-2004)

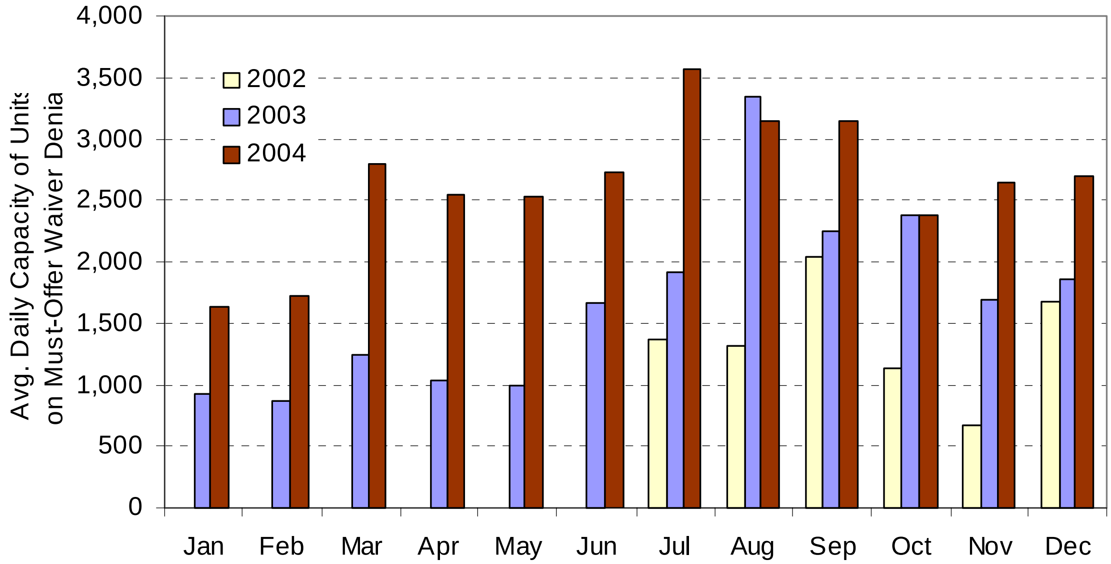
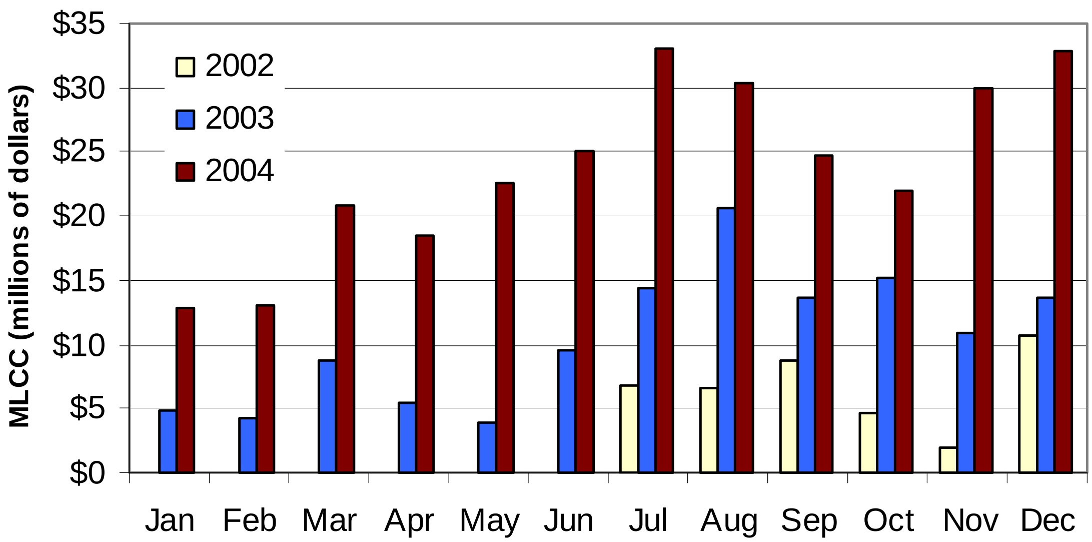


Figure 6.2 Total Monthly Minimum Load Compensation Costs (2002-2004)



The CAISO did not consistently or comprehensively track the specific reasons why units were required to operate under the must-offer requirement prior to June 2004. However, under Amendment 60, the CAISO now tracks and allocates must-offer costs based on three cost categories:

- **System.** Costs for units required to operate due to system-level reliability requirements (such as differences between load forecast and scheduled resources) are allocated based on a combination of a participant's share of negative uninstructed deviations and overall load up to a $/MWh threshold, with any remainder allocated to metered demand and in-state exports.[7]

- **Zonal.** This category includes various intra-zonal constraints and reliability requirements which are due to conditions within a single congestion zone, but which are affected by conditions across various local areas or transmission service territories. This category includes the major sources of congestion in SP15, such as Lugo, Sylmar and SCIT. MLCC costs for units required to operate due to these reasons are allocated based on a participant's share of metered demand within the applicable zone.
- **Local.** This category includes various local constraints and reliability requirements that are due to conditions within a very localized area within a single transmission service territory. MLCC costs for units required to operate due to these reasons are allocated to the local transmission owner.

Table 6.2 summarizes MLCC costs based on cost allocation categories and provides more detailed descriptions of the specific reasons why units were required to operate under the must-offer requirement. From June-December 2004, about 92 percent of total MLCC costs were attributable to intra-zonal congestion (i.e., the "Zonal" or "Local" cost allocation categories), with about 90 percent of MLCC costs involving constraints within SP15.

Table 6.2 Minimum Load Cost Compensation (MLCC) by Reason, June – December 2004 *

Reason*	Amendment 60 Cost Allocation Category*	MLCC	% of Total
South-of-Lugo	Zonal (SP15)	$59,587,968	31%
SCIT	Zonal (SP15)	$64,636,410	34%
Sylmar	Zonal (SP15)	$27,339,788	14%
Serrano (LA Basin)	Local (SP15)	$8,133,833	4%
System	System	$15,992,072	8%
Victorville-Lugo	Zonal (SP15)	$5,098,182	3%
Other Local/Zonal	SP15	$7,740,343	4%
Other Local/Zonal	NP15	$2,257,747	1%
		$190,786,344	100%

* See above description of cost categories in report.

There are several reasons for the increase in MLCC costs in 2004 compared to those incurred in 2003. Increase in fuel costs was one of the primary reasons for the increase in overall cost. Natural gas prices increased 12 percent on average from the prior year. They were notably higher during the months of November and December, where average prices were 40 and 65 percent higher, respectively, than in the same month in 2003.[8]

7 Please see CAISO filing of Amendment 60 (May 2004) for more information on the proposed allocation of MLCC.

8 In addition to the sharp increase in natural gas prices, the total MLCC for November and December was unseasonably high due to increased reliance on capacity from waiver denials resulting from the following conditions: Sylmar bank outage, Lugo substation outage, PDCI outage, and extended generation outages that contributed to inertia deficiencies at SCIT.

In addition, the need to commit additional generation in SP15 through must-offer waiver denials was increased due to a significant decrease in the amount of thermal generation within southern California scheduled to run in the bilateral markets on a day-ahead basis. As shown in Figure 6.3, during most months the amount of thermal capacity within southern California committed on a day-ahead basis through market schedules decreased by 1,000 to 3,000 MW relative to the same months of 2003.[9] On average, the amount of thermal generation capacity within southern California committed through day-ahead schedules during peak weekday hours dropped by about 1,300 MW during 2004 relative to 2003. Meanwhile, the amount of thermal capacity within southern California committed through the must-offer waiver denial process increased by an average of about 1,000 MW during these same peak weekday hours, while scheduled imports into SP15 increased about 20 percent, or an average of about 500 MW on the peak hour of each weekday.

The decrease in thermal generation within SP15 committed through the market can be primarily attributable to market conditions and prices. Spot market gas and electric prices in southern California during 2004 were such that the threshold heat rate necessary to at least "breakeven" on provision of electricity was below 9,000 MMBtu/MWh for most of the year. Figure 6.4 shows the daily threshold or breakeven heat rate for 2004. The points in Figure 6.4 represent the highest heat rate, given gas and day-ahead electricity prices for peak hour energy at major trading hubs, for which a unit would be economic to run (i.e., recover variable cost and O&M, not accounting for start-up costs). Most thermal generation within southern California (with heat rates of 9,000 to 10,000 MMBtu/MWh at high operating levels) are not efficient enough to economically operate at these prices.

[9] Data in Figure 6.3 is based on day-ahead schedules for the peak hour of each weekday during the month. RMR units were included only if committed as a result of a market transaction only, without having any requirement to run as a result of an RMR dispatch. Border generation units were excluded from the analysis since these units are outside of the major points in intra-zonal congestion within SP15.

Figure 6.3 Thermal Generation Capacity Committed Through Day-ahead Schedules

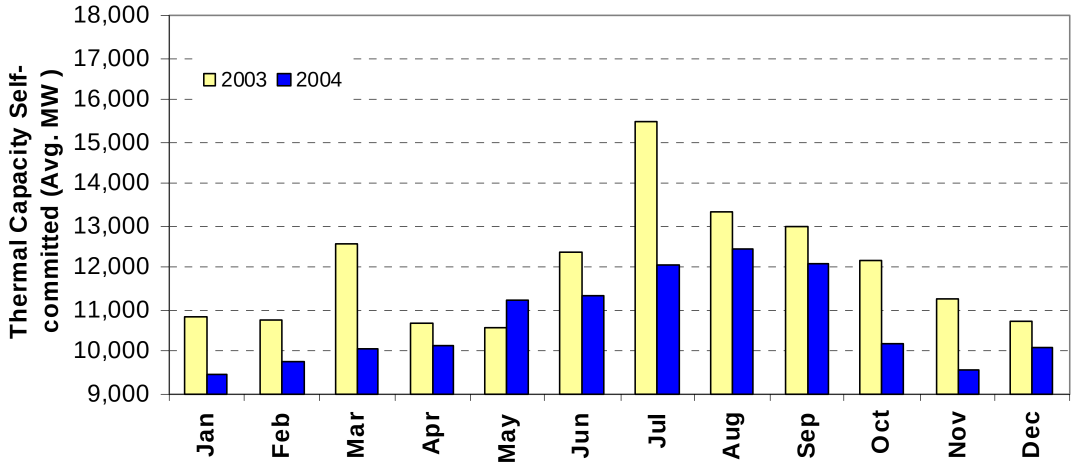
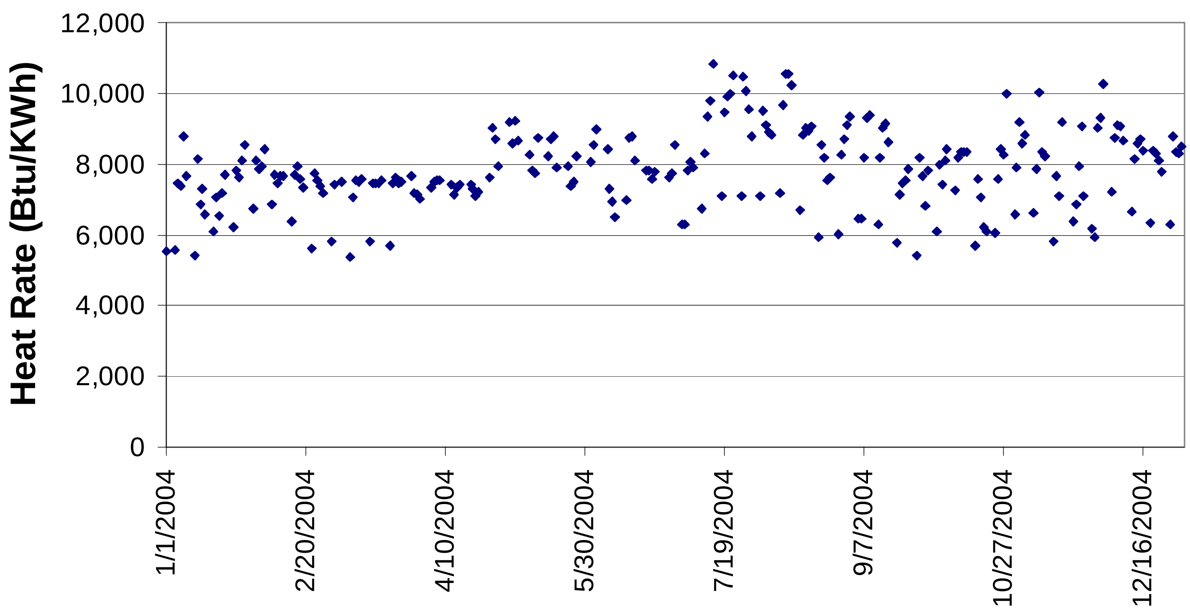


Figure 6.4 Breakeven Heat Rate for Gas Units in SP15 (based on hub prices for gas and electricity)[10]



[10] The breakeven heat rate was calculated using the southern California hub prices for both natural gas and peak hour electricity, an average 50¢/MMBtu transportation charge, and a $6/MWh O&M adder. Thus, the formula for the threshold heat rate is ((Hub Energy Price - 6)/(Hub Gas Price + 0.5)) * 1000. This may overestimate the actual breakeven heat since this simplified measure does not include costs and revenues during off-peak hours, when units may need to stay on-line at minimum load levels.

Finally, transmission outages and upgrades also contributed to the increase in MLCC costs during 2004. There were also a number of upgrades to the transmission infrastructure that were underway this year. Work on these upgrades often required the transmission facility to be either de-rated or taken out of service temporarily for the work to be completed. These facility outages changed the structure of the transmission grid in the respective region, which in turn resulted in increased intra-zonal congestion. To the extent no other generation was available (self-committed) to relieve these temporary conditions, the CAISO relied more heavily on must-offer units to provide relief for temporary intra-zonal congestion resulting from these facility outages. Below is a list of the transmission facility upgrades that were undertaken in 2004 (for more information on these upgrades refer to Chapter 1):

- South of Lugo
- Path 15 upgrade
- Serrano Transformer Bank,
- PDCI SRP
- Sylmar Transformer Bank

6.1.2.2 Reliability Must Run Costs

To mitigate local market power, California's current market design relies upon reliability must-run (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), a contribution to each unit's fixed costs, and (2) variable cost payments for energy provided under the RMR contract option, the difference (if any) between the unit's variable operating costs and market revenues received by the operators for energy provided in response to an RMR requirement.[11]

Table 6.3 shows total fixed and variable RMR costs by month in 2004, 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

[11] 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 re-imbursement for variable operating costs.

intra-zonal congestion.[12] Generators providing energy in response to a real-time RMR dispatch are paid based on their marginal 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 equals the difference between the RMR unit's marginal operating cost and the real-time price of energy.

Table 6.3 RMR Contract Energy and Costs (2004)

Month	Pre-dispatch Energy (GWh)	Real-time Energy (GWh)	Fixed Option Payments* (Millions)	Net Pre-dispatch Costs (Millions)	Net Real-time Costs (Millions)	Total RMR Costs (Millions)
Jan	1,075	109	$30	$19	$3	$52
Feb	1,299	160	$28	$18	$4	$50
Mar	1,593	139	$24	$25	$4	$53
April	1,317	117	$26	$25	$4	$55
May	1,095	80	$32	$28	$3	$63
June	1,000	66	$30	$25	$3	$57
July	1,364	479	$34	$18	$6	$58
Aug	1,233	242	$34	$20	$5	$59
Sept	1,254	167	$31	$17	$4	$52
Oct	1,245	421	$33	$13	$4	$49
Nov	1,179	470	$34	$11	$5	$51
Dec	1,078	225	$28	$17	$4	$50
Total	**14,730**	**2,673**	**$364**	**$235**	**$50**	**$649**
Change from 2003	+104%	+152%		+63%	+87%	

[12] 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 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.

Table 6.4 RMR Contract Energy and Costs for Major Transmission Owners (2004)

Owner	Pre-dispatch Energy (GWh)	Real-time Energy (GWh)	Fixed Option Payments* (Millions)	Net Pre-Dispatch Costs (Millions)	Net Real-time Costs (Millions)	Total RMR Costs (Millions)
PG&E	8,537	1,325	$264	$125	$29	$418
SDG&E	4,917	1,146	$23	$75	$18	$173
SCE	1,272	200	$72	$36	$2	$53

6.1.3 Out-Of-Sequence (OOS) Costs[13]

The CAISO tracks the net cost of re-dispatching resources to resolve intra-zonal congestion by dispatching real-time energy bids out-of-sequence based on the difference between the bid price for bids called OOS and the real-time price of energy. For incremental energy bids dispatched OOS, it calculates this re-dispatch cost based on the bid price paid for OOS energy less the market clearing price for incremental energy. For decremental energy bids dispatched OOS, it calculates the re-dispatch cost based on the market clearing price for incremental energy less the bid price received for decremental energy called OOS.

6.1.3.1 Incremental Out-Of-Sequence Dispatches

As shown in Table 6.5, gross payments for incremental OOS energy dispatches during 2004 totaled $92 million. The net cost to load serving entities of these dispatches, or cost over the market-clearing price for imbalance energy, was about $40 million. In all, the CAISO procured 1,378,070 MWh of energy at an average price of $67/MWh, with an average net re-dispatch cost of about $29/MWh.

The total volume of out-of-sequence dispatches of incremental energy rose by about 75 percent in 2004 from 2003, as shown in Figure 6.5. However, total net re-dispatch costs increased about 63 percent as the average net re-dispatch cost for OOS incremental energy dropped slightly from almost $32 to about $29/MWh.

Current local market power mitigation measures under the automated mitigation procedure (AMP) allows for the mitigation of incremental OOS dispatches at prices that exceed the real-time MCP by $50/MWh or 200 percent of the MCP. Bids dispatched OOS in excess of this threshold are mitigated to the higher of the MCP or the unit’s reference price. This local mitigation procedure has had a minimal impact on intra-zonal congestion costs in 2004. In 2004, re-dispatch costs were about $898,000 lower due to the local mitigation procedure. This was about 2.2 percent of the incremental re-dispatch costs and less than 1 percent of gross incremental costs.

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13 Intra-zonal congestion has traditionally been resolved by out-of-sequence calls. However, due to the absence of an obligation to insert decremental bids, as well as the workings of the Amendment 50 reference levels, some of these dispatches are tagged out-of-market (OOM). Whether the dispatches are OOS or OOM, the salient feature is that they are all for intra-zonal congestion. Within this document, any references to OOS calls will always include some OOM calls where those OOM calls are for intra-zonal congestion.

Virtually all OOS dispatches of incremental energy came from resources within the CAISO system, with about 96 percent of these from gas-fired generation. In addition, the bulk of OOS dispatches of incremental energy (96 percent) are for locational constraints within the CAISO's southern zone (SP15). About 68 percent of OOS incremental energy was dispatched from gas-fired units owned by a single operator in southern California.

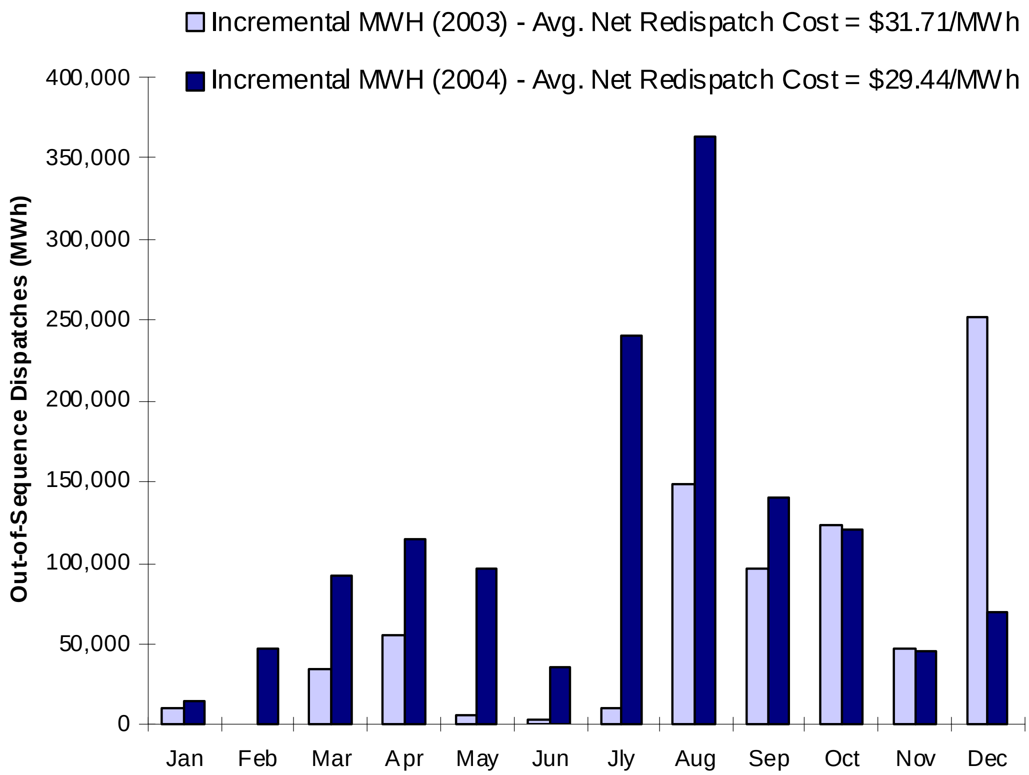
Because OOS dispatches must often be made from a relatively small pool of units to resolve a locational constraint, the ability of generation owners to exercise locational market power in such situations remains a concern to the CAISO. One way to measure the degree to which locational market power was exercised is to compare bid prices called OOS to the marginal costs of this generation and the market clearing price based on in-sequence dispatches.[14] Results of this analysis indicated that, during 2004, the dominant supplier of OOS incremental energy earned about 15 percent in excess of the market using the higher of (a) the generator's marginal cost, or (b) the market clearing price, or about $9.5 million of about $64 million of OOS energy sales. If the dominant generator's bids were mitigated using a 10 percent adder to the generator's marginal costs, the generators would have earned about $5.7 million, about 9 percent of $64 million of OOS energy sales.

Table 6.5 Incremental Congestion Costs 2004

	MWh	Gross Cost	Re-dispatch Premium	Mitigation Savings	Average Price	Average Net Cost
Jan	14,660	$1,038,411	$565,700	$2,180	$70.83	$38.59
Feb	45,960	$2,480,020	$1,081,461	$1,674	$53.96	$23.53
Mar	92,994	$5,356,275	$2,616,763	$63,959	$57.60	$28.14
Apr	114,008	$7,090,347	$3,460,794	$105,106	$62.19	$30.36
May	96,206	$6,613,296	$2,563,769	$41,485	$68.74	$26.65
Jun	35,620	$2,253,547	$903,893	$1,596	$63.27	$25.38
Jly	240,275	$16,635,977	$7,172,633	$94,422	$69.24	$29.85
Aug	362,985	$25,304,174	$13,079,562	$130,961	$69.71	$36.03
Sep	140,647	$8,905,386	$3,809,167	$204,868	$63.32	$27.08
Oct	120,324	$8,282,308	$2,725,069	$228,663	$68.83	$22.65
Nov	44,908	$3,658,487	$1,222,244	$11,492	$81.47	$27.22
Dec	69,483	$5,173,402	$1,373,973	$12,116	$74.46	$19.77
	1,378,070	$92,791,631	$40,575,029	$898,521	$67.33	$29.44
Change from 2003	+75%	+90%	+62%	-61%	+8%	-8%

[14] Specifically, we calculated the re-dispatch costs associated with locational market power based on the degree to which the bid price exceeded the higher of (a) the generator's marginal cost, or (b) the market clearing price. In order to assess the effect of allowing a 10 percent adder for contribution to fixed costs when the market clearing price did not exceed the unit's marginal costs, we performed a second calculation based on the degree to which the bid price exceeded the higher of (a) the generator's marginal cost + 10 percent, or (b) the market clearing price. We based marginal costs on heat rates filed with the CAISO, daily spot market gas costs and $6 for O&M.

Figure 6.5 Incremental Energy OOS Dispatches and Average Re-dispatch Costs, 2003-2004



6.1.3.2 Decremental Energy Dispatches

Gross payments to the CAISO for decremental energy dispatches in 2004 totaled $105 million. This was a net re-dispatch cost compared to the real-time MCP for incremental energy of about $56 million. As shown in Table 6.6, the average amount paid to the CAISO for decremental energy bids dispatched OOS was about $39/MWh, or about $23/MWh less than the value of this energy at the real-time MCP for incremental energy.

Table 6.6 Decremental OOS Congestion Costs 2004

	MWh	Gross Cost	Re-dispatch Premium	Average OOS Price	Average Net Cost
Jan	152,089	-$3,132,997	$3,549,225	$20.60	$23.34
Feb	307,684	-$6,550,744	$5,770,774	$21.29	$18.76
Mar	243,906	-$6,102,679	$4,947,832	$25.02	$20.29
Apr	123,114	-$3,023,655	$1,938,904	$24.56	$15.75
May	56,350	-$1,366,930	$1,251,746	$24.26	$22.21
Jun	39,932	-$1,278,820	$943,906	$32.02	$23.64
July	214,455	-$6,291,497	$3,957,249	$29.34	$18.45
Aug	179,910	-$4,944,844	$2,328,951	$27.49	$12.95
Sep	296,182	-$7,148,580	$8,244,472	$24.14	$27.84
Oct	404,377	-$26,007,907	$15,192,273	$64.32	$37.57
Nov	337,193	-$20,643,407	$7,940,046	$61.22	$23.55
Dec	322,095	-$18,454,838	$6,443,369	$57.30	$20.00
	2,677,287	-$104,946,903	$62,508,751	$39.20	$23.35
Change from 2003	+ 230%	+1017 %	+198 %	+23 %	-10 %

6.1.4 Total Intra-zonal Congestion Costs

As shown in Table 6.7 below, total costs incurred to relieve intra-zonal congestion within the control area increased by about $275 million or 180 percent compared to 2003. The largest component increase is seen in the incurrence of MLCC costs for congestion-related reasons, with an increase of over 200 percent. Preliminary figures for the first two months of 2005 show a significant decrease (45 percent) in MLCC costs compared to the same months for 2004.[15]

The ISO anticipates that a variety of actions and factors will decrease intra-zonal congestion costs in 2005 and the years beyond:

- As a result of a CPUC ruling in July 2004, the major LSEs in SP15 (SCE and SDG&E) have been directed to incorporate intra-zonal congestion costs and reliability impacts in their short-term dispatch and procurement decisions through 2005. The ISO continues to work with these entities in developing means for incorporating this directive into their short-term dispatch and procurement decisions.
- The ISO has also taken steps to provide better financial incentives for LSEs to incorporate intra-zonal congestion costs and reliability impacts in their short-term dispatch and procurement decisions. For example, as shown in Table 6.2, most must-offer waiver costs in 2004 were attributable to intra-zonal congestion in southern California. Under Amendment 60, these costs will now be allocated on a zonal or even sub-zonal level, rather than systemwide. This provides a greater incentive for LSEs in southern California to schedule and procure in a manner that reduces these costs.

[15] Preliminary MLCC figures for January and February of 2005 are $8 million and $4 million, respectively, indicating a significant decline in cost incidence compared with the same two months of 2004.

Table 6.7 Total Estimated Intra-zonal Congestion Costs for 2003 and 2004 (Millions of Dollars)[16] [17]

	MLCC		RMR		R-T Redispatch		Total	
	2003	2004	2003	2004	2003	2004	2003	2004
January	$6	$12	$0	$3	$1	$4	$7	$19
February	$6	$13	$1	$4	$0	$7	$7	$23
March	$6	$20	$0	$4	$1	$8	$7	$31
April	$4	$18	$1	$4	$2	$5	$7	$27
May	$1	$22	$3	$3	$0	$4	$3	$28
June	$2	$25	$2	$3	$0	$2	$4	$30
July	$3	$29	$2	$6	$0	$11	$5	$47
August	$13	$29	$4	$5	$9	$15	$25	$50
September	$10	$23	$3	$4	$6	$12	$19	$39
October	$11	$21	$6	$4	$8	$18	$25	$43
November	$9	$29	$2	$5	$2	$9	$13	$44
December	$9	$33	$3	$4	$17	$8	$29	$45
Totals	**$78**	**$274**	**$27**	**$49**	**$46**	**$103**	**$151**	**$426**

- As part of the Resource Adequacy process before the CPUC, the ISO is developing locational resource requirements and deliverability tests that will be incorporated into overall resource adequacy requirements for LSEs, which are scheduled for initial implementation in 2006. As these locational and deliverability requirements are factored into LSEs' capacity procurement practices, LSEs should have additional ability to schedule energy from resources in a manner that reduces intra-zonal congestion costs.
- Over the longer term, the MRTU market design, scheduled for implementation in February 2007, will manage intra-zonal congestion in both the day-ahead and hour-ahead time frames as well as in real-time. Having some forward management of intra-zonal congestion will reduce the need to manage such in real-time. This will positively impact reliability. Furthermore, by managing intra-zonal congestion through formal markets by imposing deliverability on schedules and dispatches, the costs associated with insuring this deliverability (intra-zonal congestion) will be allocated in a way that is more consistent with cost-causation, and thereby provides better incentives for participants to take steps to reduce these costs.

[16] Data indicating the specific reason for which a must-offer waiver was denied for the period prior to June 1, 2004, contains inaccuracies and omissions and cannot be relied upon to represent a wholly accurate portrayal of the MLCC costs associated with congestion. This data was used in the 2003 Annual Report on Market Issues and Performance and is reproduced in this report to provide some benchmark for year-to-year comparison.

[17] Note that the RMR figures presented in Table 6.7 for intra-zonal congestion are real-time dispatch costs for RMR units and do not include either the fixed-cost or pre-dispatch components of the total RMR costs reported in Table 6.3. It is important to note that some portion of the pre-dispatch energy from RMR units may have contributed to relieving intra-zonal constraints and therefore some portion of the pre-dispatch costs may be more appropriately attributed to the intra-zonal congestion cost. The pre-dispatch net cost for 2003 was $144 million and for 2004 was $235 million.