1 Market Structure and Design Changes

1.1 Introduction/Background

This chapter reviews some of the major market design and infrastructure changes that impacted market performance in 2006. New market design elements in 2006 include an increase in the bid cap for energy and ancillary services from $250/MWh to $400/MWh. Additionally, in June 2006, the CPUC Resource Adequacy (RA) program went into effect along with similar type reliability showings for non-CPUC jurisdictional load-serving entities. The CAISO implemented these resource adequacy 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. In a related matter, in spring 2006, the CAISO filed a proposed Offer of Settlement with in a proceeding stemming from a 2005 complaint by the Independent Energy Producers (IEP) which alleged that the must-offer waiver process is unjust and unreasonable. The Offer of Settlement proposed tariff changes to establish a Reliability Capacity Services Tariff (RCST) under which any non-RA unit committed by the CAISO through the must-offer waiver process would be compensated. Although FERC approval of RCST provisions was not reached until February 2007, key provisions regarding the compensation of non-RA units committed by the CAISO through the must-offer process and allocation of these costs were ultimately approved with an effective date of June 1, 2006. All of these changes are discussed in greater detail below.

The infrastructure changes discussed below include changes in generation retirements and additions, various transmission upgrades implemented in 2006 and future projects. The chapter concludes with an overview of the implementation of market enforcement provisions relating to the CAISO Enforcement Protocols.

1.2 Market Design Changes

1.2.1 Increase in Bid Cap for Energy and Ancillary Services

On January 14, 2006, the bid cap governing transactions in the CAISO real-time balancing energy market was raised from $250/MWh to $400/MWh. The bid cap remained a “soft-cap,” meaning that participants could submit bids above $400/MWh but such bids are not eligible to set the market clearing price, and, if dispatched, would be paid as-bid and would be subject to cost justification with FERC. The Department of Market Monitoring (DMM) and the Market Surveillance Committee (MSC) spearheaded the effort to raise the bid cap due to concerns about rising natural gas prices stemming from the gulf coast hurricanes in the fall of 2005. DMM and the MSC expressed concern that if natural gas prices continued to escalate during the peak winter heating season, the marginal costs of some generation units could increase above the then current bid cap of $250/MWh. Though the energy bid cap is a “soft-cap,” both the DMM and MSC were concerned that suppliers, particularly importers, might elect not to offer into the CAISO Real Time Market rather than run the regulatory risk and burden of having their bids cost justified. DMM also pointed out a number of advantages a higher bid cap could produce, such as providing increased incentives for forward contracting and greater incentives for generator availability during peak demand periods.

The proposal to raise the bid cap was overwhelmingly supported by industry participants, and was approved by FERC on January 13, 2006 (January 13 Order) to be effective the following day. FERC maintained the bid cap as a "soft" cap.[1] The January 13 Order also instituted an investigation into the price cap in the WECC (outside the CAISO) and the bid cap for the CAISO Ancillary Services Market. After receiving comments, FERC issued an order on February 13, 2006 establishing a $400/MWh "soft" price cap in the WECC (outside the CAISO) and establishing a $400 "soft" bid cap for ancillary services bids in the CAISO market. The changes became effective upon issuance of the February 13 Order.

Though natural gas prices declined shortly after raising the bid cap, due to an unusually mild winter in the Eastern U.S. that reduced demand for gas, the $400/MWh "soft" bid cap for energy and ancillary services has remained in place. As a result of this increase, prices in both the CAISO Real Time Market and Ancillary Services Market have periodically approached or hit the new $400 cap. A more detailed discussion of the impact from the higher cap is provided throughout Chapters 2 through 4.

1.2.2 2006 Resource Adequacy Requirements

In 2006, Resource Adequacy (RA) programs developed by the CPUC and other Local Regulatory Authorities (LRAs) became effective. These programs, developed pursuant to Assembly Bill 380, 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 forecast load for each month, plus a 15 percent margin for operating and planning reserves. The California Energy Commission determined a load forecast for each CPUC-jurisdictional LSE 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 load forecast 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 CPUC and LRAs established various "counting rules" that established the types and quantities of resources that can be used to provide RA capacity in 2006. These included criteria for determining the amounts of capacity that could be provided by various types of resources. For CPUC-jurisdictional entities, the high-level criteria were as follows:

[1] Federal Energy Regulatory Commission, "Order Accepting and Modifying Tariff Filing and Instituting a Section 206 Proceeding," issued January 13, 2006, 114 FERC ¶ 61,026.

- Generating units in the CAISO Control Area were counted based on their net qualifying capacity. This value was based on a generating unit's capacity reduced, as applicable, by testing results and deliverability restrictions. Although generating unit net qualifying capacity was not adjusted for outage rates, it is anticipated that performance criteria to adjust for outages will be developed by the CAISO in the future. The counting rules also specified criteria for determining the eligible capacity of wind and solar generation. In addition, the capacity provided by generating units under RMR Condition 2 contracts was allocated to those LSEs that paid the costs for these units.

- Imports were counted up to each LSE's allocation of import capacity on each inter-tie. These allocations were determined based on each LSE's existing resource commitments outside the CAISO Control Area as well as its proportional share of the forecasted peak load.

- Liquidated damages (LD) contracts, which are contracts to deliver energy that do not specify a generating unit as the source of the energy or inter-tie where an import will be delivered, were counted up to specified criteria. As the goal of the RA program is to make physical resources available to the system, the CPUC guidelines reduce the amount of LD contracts that can count as resource adequacy capacity over the next two years. For 2006, existing LD contracts could count towards as much as 75 percent of an LSE's capacity requirement. This value decreases 25 percent per year until LD contracts are precluded in 2009. The CPUC has adopted an exception to the LD contract prohibition for contracts executed by the California Department of Water Resources during the energy crisis – the total capacity under these contracts may be counted until they expire, which is generally over the next several years.

- Demand response resources were counted as a reduction to each LSE's forecasted load. As demand response programs are paid for through state-wide charges to end-use customers, demand response resources were allocated to LSEs in proportion to their share of the forecasted load.

In addition to the above, the CPUC counting rules included criteria to accommodate standard energy contracts. As standard energy contracts provide for capacity to be available for only specified hours (e.g., 5x8, 6x16), rather than for all hours of the month, the counting rules specified maximum capacity amounts in various categories defined by the hours available per month that could count as fulfilling an LSE's RA obligations.

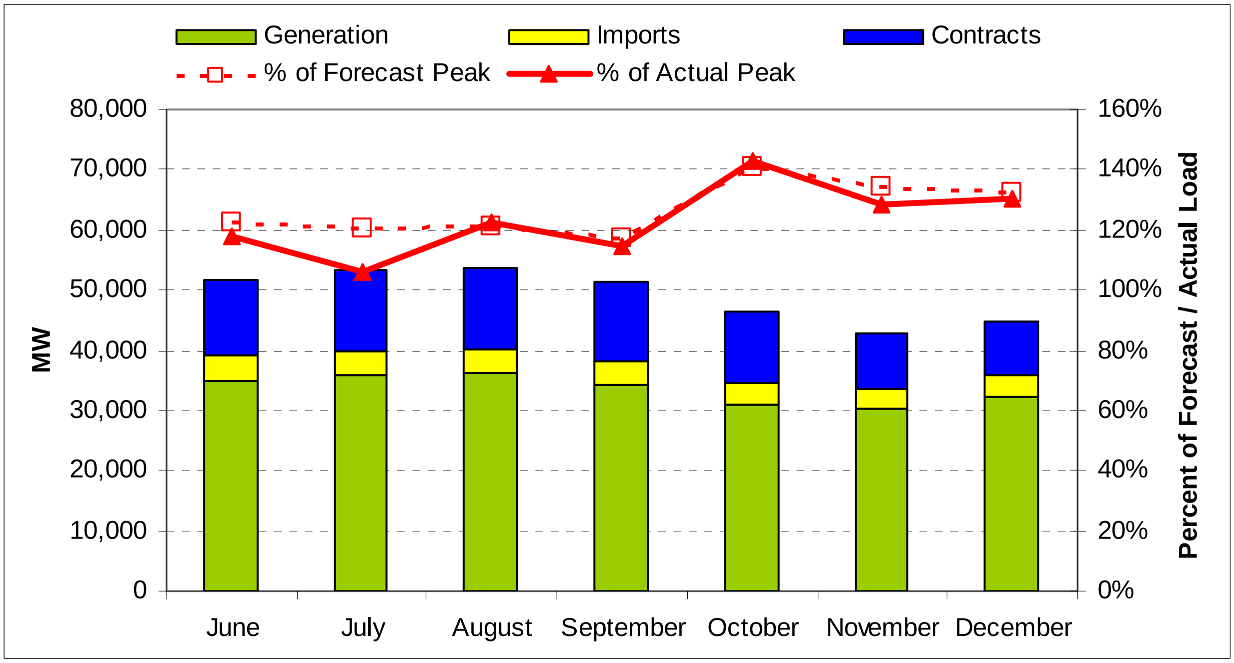
Figure 1.1 compares the RA resources available system-wide to the forecasted and actual system peak load for the months the RA program was in effect during 2006 – June through December. [2] Figure 1.1 also summarizes the mix of resources that were available system-wide, including generation, imports, and LD contracts. As shown in Figure 1.1, LSEs procured resources system-wide for each month in quantities that ranged from about 118 percent to 140 percent of the respective system monthly peak load forecast.[3] For July, the month in which the system peak load of 50,270 MW occurred, which was also a record peak, LSEs procured resources that amounted to about 121 percent of the forecast system peak and about 106

[2] Based on "1-in-2" load forecasts developed by the CEC and CAISO in April 2006, minus demand response resources. Resource quantities shown exclude demand response resources.

[3] The percentages shown in Figure 1.1 ("% of Forecast Peak" and "% of Actual Peak") are calculated by dividing the total capacity showing for each month by the forecasted or actual peak load for each month.

percent of the actual system peak. The quantities of resources procured for the other months ranged from about 115 to 143 percent of the respective actual monthly system peak load.

Figure 1.1 System-Wide RA Resources



The procurement requirements for 2006 were entirely on a system-wide basis. There was no requirement to procure resources based on capacity needs determined on a local load pocket or zonal basis. For 2007, LSEs under CPUC jurisdiction are required to obtain resources located within defined load pockets based on their share of the forecasted load within each CAISO Transmission Access Charge Area, which equate to the old service territories of the investor owned utilities. Both the system and local requirements are important to reliability, short-term revenue adequacy, and to provide a framework for investment in infrastructure. However, when viewing existing reliability issues in the CAISO Control Area, generation capacity at the local or regional level is of primary concern, and this is especially true in SP26. SP26 has higher loads than NP26, but less available generation. In addition, transfer capability between NP26 and SP26 is limited by the 4,000 MW north-to-south capacity of Path 26.[4]

Figure 1.2 compares the RA resources for NP26 and SP26 that were procured for the peak load month of July 2006, to the respective NP26 and SP26 forecasted and actual peak loads. For the purpose of this analysis, generation resources were allocated to NP26 or SP26 based on their geographic location. LD contracts and imports were allocated based on their point of delivery.[5] As shown in Figure 1.2, LSEs procured RA resources with a total capacity of 23,757 MW in NP26 for July 2006, which provided a 20 percent margin over the July NP26 peak load forecast and a 4 percent margin over the NP26 actual peak load. As shown, the RA resources procured

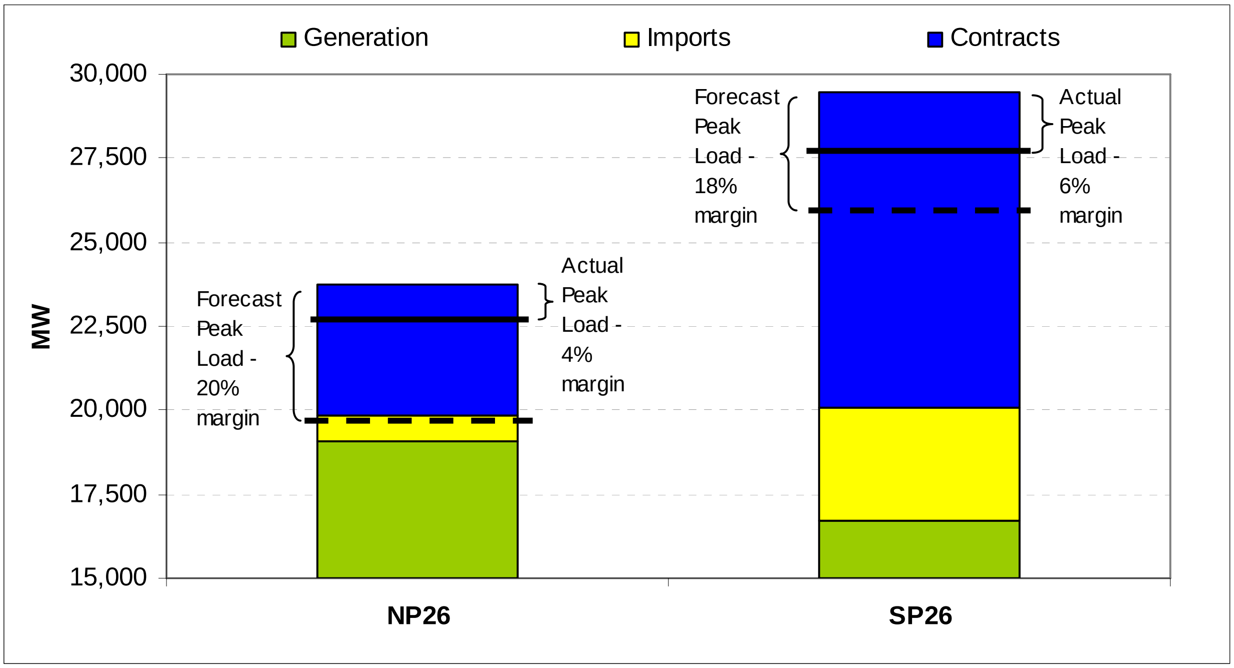
[4] NP26 is defined as the NP15 and the ZP26 congestion zones, which are both north of Path 26. SP26 is defined as the SP15 congestion zone, which is south of Path 26.

[5] Approximately 1,000 MW of RA resources that were not designated as specific to NP26 or SP26 were pro-rated between NP26 and SP26.

in NP26 for July included 19,078 MW of generation, 758 MW of imports, and 3,884 MW of LD contracts.

For SP26, Figure 1.2 shows that LSEs procured RA resources with a total capacity of 29,473 MW for July 2006, which provided an 18 percent margin over the July SP26 peak load forecast and a 6 percent margin over the SP26 actual peak load. As Figure 1.2 shows, the mix of RA resources procured in SP26 consisted of significantly less generation and significantly more contracts and imports than that procured in NP26. In SP26, LSEs procured 16,712 MW of generation, 3,359 MW of imports, and 9,401 MW of LD contracts.

Figure 1.2 NP26 and SP26 RA Resources - July 2006



1.2.3 Changes to the Must-Offer Requirement

Under the terms of the IRRP taking effect in June 2006, all RA capacity that is available must be scheduled or made available to the CAISO for commitment through the CAISO's must-offer waiver denial process. Since RA units are eligible for capacity payments under bilateral contracts, IRRP tariff changes taking effect in June 2006 also specified that RA resources committed through the CAISO's must-offer process would be eligible to recover only minimum load operating costs from the CAISO and would no longer receive an additional payment for minimum load energy at the real-time energy price.

In recognition of the fact that RA and RMR resources may not be sufficient to meet all system reliability needs, CAISO continues to have the authority to commit other resources with Participating Generator Agreements with the CAISO through the must-offer waiver denial process. However, the IRRP specified that the CAISO could commit non-RA resources through the must-offer waiver process only if there are insufficient RA or RMR resources available to meet any local, zonal, or system reliability needs. Any non-RA resources committed through the must-offer process continue to receive payments for minimum load operating costs along with an additional payment for minimum load energy at the real-time energy price. These non-RA units are sometimes referred to as "FERC-MOO" units, due to the fact that their offer obligation stems from the Must-Offer Obligation (MOO) of the CAISO tariff approved by FERC, rather than through a bilateral RA contract or RMR contract with the CAISO.

In addition, starting in June 2006, any non-RA resources committed through the must-offer process also became eligible to receive additional payments under the terms of proposed tariff changes filed by the CAISO and other settling parties under an offer of settlement with various participants stemming from a 2005 complaint by generators that compensation under the must-offer waiver process is unjust and unreasonable. The dispatch on non-RA units under the must-offer process and these potential tariff changes are discussed below.

1.2.4 Reliability Capacity Services Tariff

In spring 2006, the CAISO, along with other settling parties, filed a proposed Offer of Settlement in a proceeding stemming from a 2005 complaint by the Independent Energy Producers (IEP), which alleged that the must-offer waiver process is unjust and unreasonable.[6] The Offer of Settlement proposed tariff changes to establish a Reliability Capacity Services Tariff (RCST) under which any non-RA unit committed by the CAISO through the must-offer waiver process for reliability needs would be compensated with a daily capacity payment. The RCST settlement also provided the CAISO with the authority to designate non-RA units to provide services under the RCST tariff as a "backstop" in the event that the CAISO determined that RA resources procured by LSEs did not meet projected reliability needs.

The proposed effective date for RCST was designed to be concurrent with terms of the IRRP, which was to take effect on June 1, 2006. All provisions of the RCST settlement were subject to FERC approval. Although FERC final approval of all RCST provisions was not granted until January 2007, key provisions regarding the compensation of non-RA units committed by the CAISO through the must-offer process and allocation of these costs were ultimately approved with an effective date of June 1, 2006.[7]

In approving the RCST settlement, FERC found that RCST provisions meet the reliability needs of the CAISO and ensure that generators providing reliability services will be appropriately compensated, thereby reducing the likelihood that units critical for reliability will be mothballed or shut down. Key provisions of the RCST include the following:

- **RCST Capacity Payments.** In addition to receiving minimum load costs, non-RA units designated as RCST are eligible to receive an RCST capacity payment. The capacity payments are equal to $73/kW-year, less a variable Peak Energy Rent (PER) amount that is calculated each month based on the potential net energy and ancillary services revenues that could be earned by a new peaking unit given actual CAISO market prices. The net payment was designed to reflect a reasonable price for "backstop" capacity and encourage LSEs and generators to engage in longer term contracting and not rely on the must-offer mechanism. This net RCST capacity payment is calculated on a monthly

[6] In addition to IEP and the CAISO, other settling parties were the California Public Utilities Commission and the state's three major utilities: SCE, PG&E and SDG&E. The proposed settlement can be found on the CAISO website at http://www.caiso.com/17ca/17cad5ec10650.pdf.

[7] See FERC's January 22, 2007 Order on Rehearing, Clarification and Compliance Filing, ER06-723-001, et al . http://www.caiso.com/1b70/1b70e88c20010.pdf.

basis by allocating these annual fixed costs to each month using monthly percentages, which allocate a higher portion of annual fixed costs to summer months relative to other months of the year.

- **RCST Designations.** Any non-RA units designated as RCST units by the CAISO for one or more months are eligible for the monthly capacity payment described above. The RCST settlement also provides that if any non-RA unit is committed under the must-offer waiver process for four separate days in any year, the CAISO would evaluate whether a significant change in grid operations had occurred that warrants making additional RCST designations.

- **Daily RCST Capacity Payments**. Any non-RA units committed through the CAISO's must-offer process are eligible for a daily RCST capacity payment equal to 1/17th of the monthly capacity payment described above. However, daily RCST capacity payments for any month may not exceed the total monthly capacity payment described above. As discussed below, about $10.6 million in daily RCST capacity payments under this provision occurred in 2006 due to non-RA units being committed through the must-offer waiver process, with over three-quarters of these costs occurring during periods of extremely high system loads in June through August.

- **Real Time Energy Mitigation Adder.** The RCST tariff provisions also include a potential $40/MWh payment adder for certain units that are mitigated under the CAISO's current local market power mitigation (LMPM) measures more than four 10-minute intervals in one day.[8]

Figure 1.3 shows the total amount of non-RA capacity committed by the CAISO through the must-offer waiver process on a daily basis since the effective date of new RA and RCST provisions in June 2006. Committed capacity is summarized for the following three categories:

- **System.** This category includes units committed to ensure that on a system-wide level sufficient capacity is available to meet all interruptible and firm load based on day-ahead forecasts and expected imports.[9]

- **Zonal**. This includes capacity committed to ensure that sufficient resources are online or available in Southern California (south of Path 26) to meet the East-of-River/Southern California Import Transmission (SCIT) nomogram and/or to meet the WECC MORC requirements for managing pre- and post-contingency loading criteria on transmission serving the region south of Path 26.

[8] Under current LMPM measures, bids dispatched out-of-sequence for intra-zonal congestion or local reliability needs which are in excess of $50 or 200 percent of the interval MCP are mitigated to their reference price and settled on the greater of the mitigated bid or the interval MCP. Under the RCST tariff provisions, bids mitigated under these LMP provisions may have up to $40/MWh added to their mitigated price if the unit is subject to LMPM more than four 10-minute intervals in one day. However, the $40/MWh adder is reduced if necessary so that the total price paid under LMPM does not exceed the original bid price.

[9] See Procedure M-432. http://www.caiso.com/docs/2004/09/03/2004090313342914798.pdf.

- **Local.** This includes capacity committed to local environmental and reliability constraints. Environmental constraints include restrictions established by state or federal agencies that limit or require generation to be operated in a particular way for environmental quality reasons. Local reliability requirements include capacity needed to meet temporary operational requirements to support planned transmission maintenance work.

As shown in Figure 1.3, since the IRRP took effect in June 2006, virtually all of the non-RA capacity committed under the must-offer waiver process was due to system and zonal requirements. More specifically:

- Over half (54 percent) of the total non-RA capacity committed under the must-offer waiver process was committed due to system level requirements. Virtually all of these commitments occurred during late June and late July, when total system loads significantly exceeded the 1-in-2 year load forecast upon which RA requirements are based.

- About one-third (35 percent) of the non-RA capacity committed under the must-offer waiver process were due to zonal reliability requirements in Southern California. Again, virtually all of these commitments occurred during late June and late July, when total system loads significantly exceeded the 1-in-2 year load forecast upon which RA requirements are based.

- Only about 11 percent of the non-RA requirements were for local reasons. About half of these commitments were due to environmental regulations in the Bay Area.

Table 1.1 provides a summary of day-ahead waiver denial activity for non-RA resources in 2006, which is based on preliminary reports published by the CAISO on a monthly basis pursuant to the RCST Settlement, combined with updated estimates of daily RCST capacity payments developed as part of the settlement process.[10] Figure 1.4 summarizes estimated total minimum load costs and daily RCST capacity payments for non-RA units since the effective date of new RA and RCST provisions in June 2006.

As shown in Table 1.1 and Figure 1.4, minimum load costs associated with must-offer waiver denials for non-RA units from June through December totaled just over $20 million, while potential daily RCST capacity payments totaled about $10.6 million. Zonal requirements involving zonal reliability needs in Southern California accounted for about 50 percent of these minimum load costs and about 75 percent of daily RCST capacity payments. About 37 percent of these minimum load costs and 10 percent of daily RCST capacity payments are associated with system level requirements. Local environmental and reliability needs accounted for about 13 percent of these minimum load costs and 15 percent of daily RCST capacity payments.

The relatively low portion of daily RCST capacity payments associated with must-offer waiver denials for system needs reflects the fact that during the months of June and July – when

[10] Non-RA units may also receive a payment adder of up to $40/MWh for out-of-sequence dispatches mitigated under LMPM provisions. However, initial analysis indicates that these additional payments would total only about $23,000 for 2006.

virtually all of these commitments occurred – the daily RCST capacity payments were very low due to the fact that high market prices caused the Peak Energy Rent (PER) calculation to offset all or most of the potential capacity payment. As shown in Figure 1.5 , the PER in Northern California exceeded the monthly cost of installed capacity during June and July, resulting in a zero net RCST payment for this area. Similarly, the PER for Southern California offset about 87 percent of the monthly installed capacity cost during June and July (Figure 1.6). The daily RCST payment for non-RA units committed for system reliability are based on the region in which the resource is located.

Figure 1.3 Non-RA Capacity Committed Under Must-Offer Waiver Process Eligible for RCST

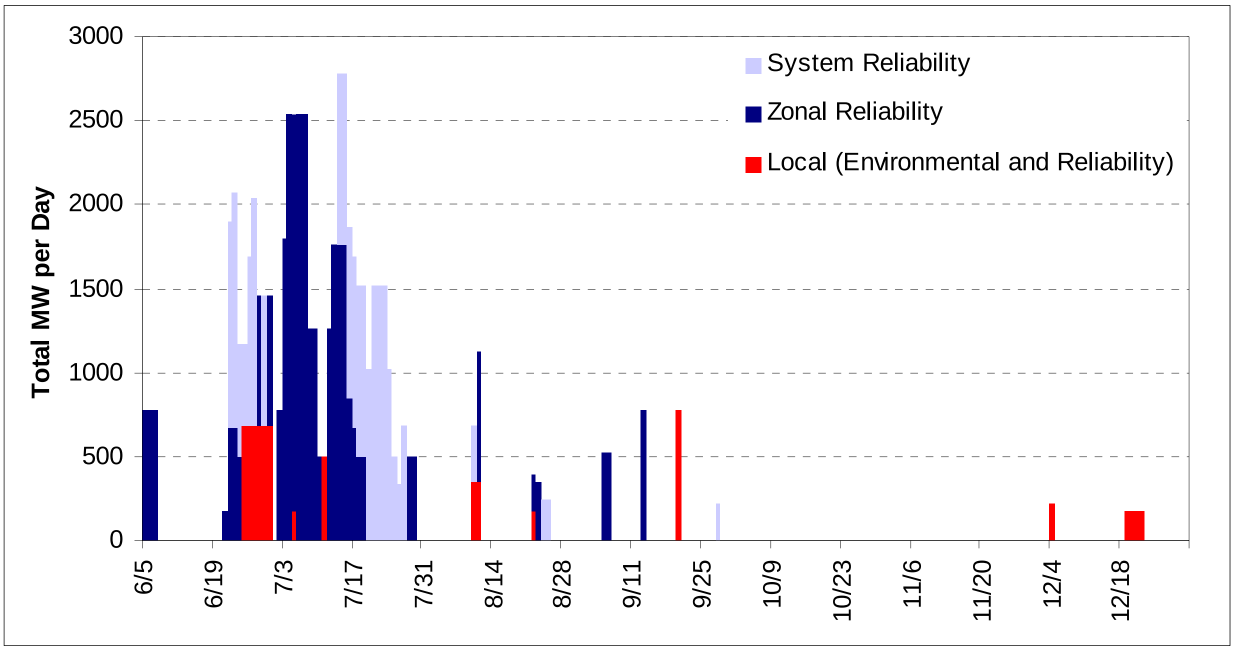
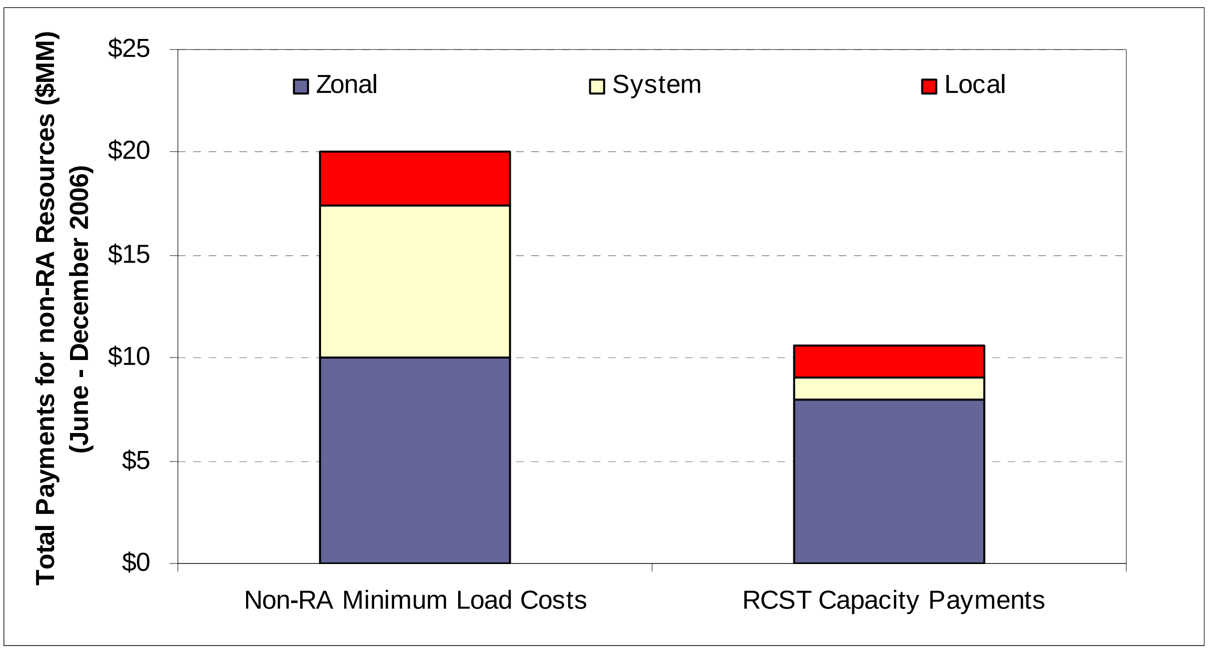


Table 1.1 Non-RA Waver Denials (June – December 2006)[11]

TAC/Service Area	Description	Local	Zonal	System	Total
Northern (PG&E)	FERC-MOO Waiver Denials (Unit-Days)	6	0	32	38
	Estimated Minimum Load Costs	$2,024,621	$0	$5,020,298	$7,044,919
	Estimated FERC-MOO Capacity Costs[12]	$0	$229,711	$0	$229,711
East Central (SCE)	FERC-MOO Waiver Denials (Unit-Days)	13	81	26	120
	Estimated Minimum Load Costs	$659,825	$10,051,071	$2,324,530	$13,035,427
	Estimated FERC-MOO Capacity Costs[12]	$1,600,070	$830,198	$7,941,019	$10,371,286
Southern (SDG&E)	FERC-MOO Waiver Denials (Unit-Days)	0	0	0	0
	Estimated Minimum Load Costs	$0	$0	$0	$0
	Estimated FERC-MOO Capacity Costs[12]	$0	$0	$0	$0
Total	FERC-MOO Waiver Denials (Unit-Days)	19	81	58	158
	Estimated Minimum Load Costs	$2,684,446	$10,051,071	$7,344,828	$20,080,345
	Estimated FERC-MOO Capacity Costs[12]	$1,600,070	$1,059,915	$7,941,019	$10,600,997

Figure 1.4 Total Payments for Non-RA Resources (June – December, 2006)



[11] Source: Total of preliminary monthly reports posted on CAISO website (see http://www.caiso.com/17c6/17c6a16019910.html). Estimated costs for FERC-MOO Capacity Costs based on updated calculations developed as part of settlement process.

[12] Based on 1/17th of the annual capacity payment ($73/kw-yr) and applying a monthly shaping factor specified in the RCST Offer of Settlement. For the purposes of this analysis capacity costs are limited when total daily capacity costs plus imbalance costs for minimum load energy (frequently mitigated adder costs not considered in this analysis) for the month exceeds the maximum monthly RCST payment reduced by PER (Table 1.1).

Figure 1.5 Maximum Potential Monthly RCST Capacity Payments in Northern California (PG&E Transmission Service Area)

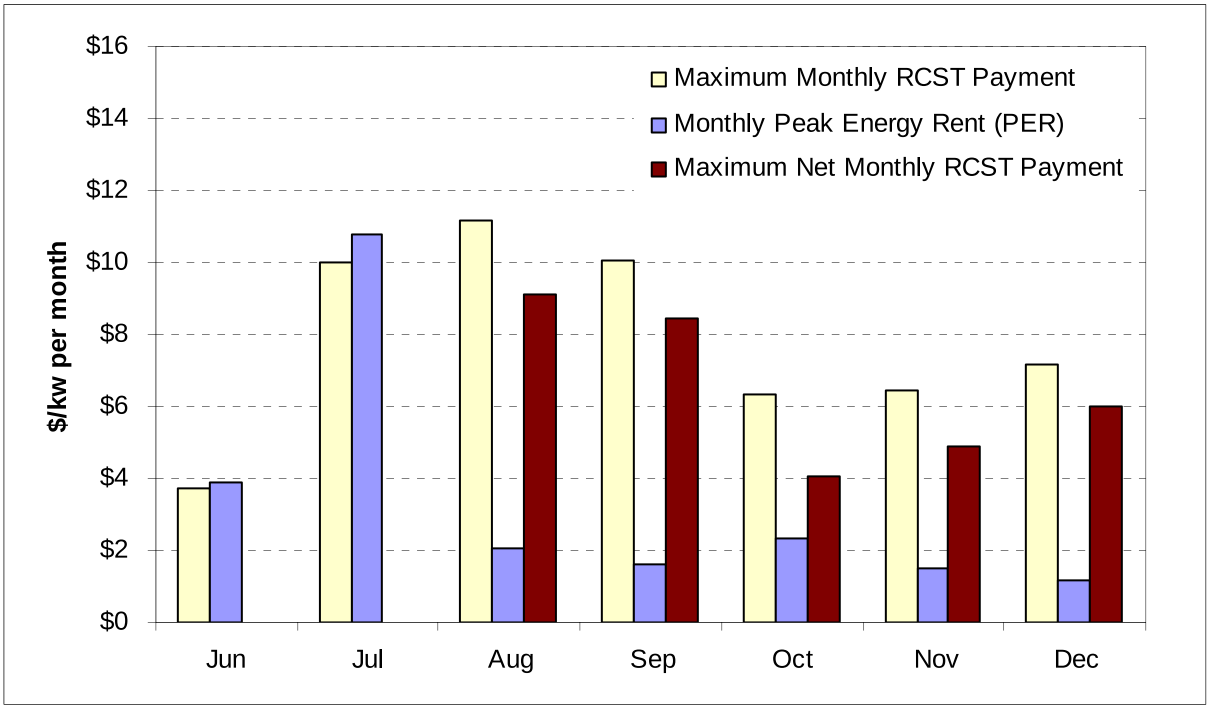
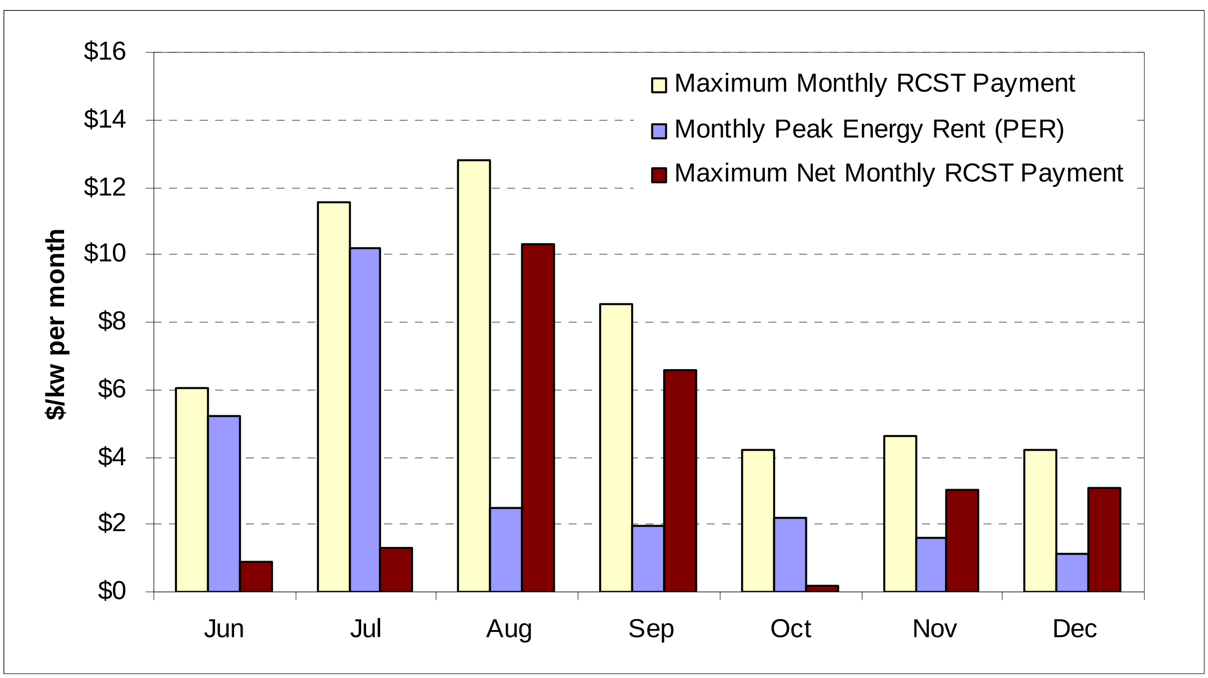


Figure 1.6 Maximum Potential Monthly RCST Capacity Payments in Southern California (SCE and SDG&E Transmission Service Areas)



With respect to the CAISO issuing waiver denials for "zonal" reasons, some market participants have argued that this capacity should be procured through the CAISO Ancillary Services Market by procuring operating reserves on a zonal basis in sufficient amounts to meet some pre-specified level of zonal reserve requirements. They further argue that the current non-market practice of meeting zonal reliability requirements through waiver denials fails to reflect the true value of the zonal capacity, and consequently fails to fairly compensate generator owners that provide this reserve capacity or provide appropriate market price signals for new generation development.

In regard to these concerns, it is important to note that the zonal reliability requirements are typically driven primarily by the need to restore power flows to path ratings after a major contingency within 20 minutes for a stability-limited path or 30-minutes for a thermally limited path. However, the current CAISO Ancillary Services Market products are 10-minute operating reserves (Spinning and Non-Spinning Reserve) and Regulation. There is currently no 20-minute or 30-minute reserve product for the CAISO to procure from the Ancillary Services Market to meet these reliability requirements. Therefore, the CAISO currently meets these zonal reliability requirements through a combination of 10-minute operating reserve, and slower-moving on-line capacity and quick start-capacity subject to a must-offer requirement in the CAISO's Real Time Market. It would not be appropriate or efficient to simply procure enough 10-minute operating reserve to meet these 20- to 30-minute zonal reserve requirements since such an approach would significantly exceed the actual reliability requirement and impose excessive ancillary service costs on LSEs. In addition, such an approach would likely lead to market power problems given the magnitude of the 20- to 30-minute reliability requirements and the limited competition at the zonal level to provide 10-minute operating reserves equal to these requirements.

If the CAISO were to design a market for 20- to 30-minute ancillary service reserve products, it may be appropriate to attempt to meet zonal reliability requirements primarily through the Ancillary Services Market.[13] However, such procurement would need to be closely monitored for market power issues to determine whether additional market power mitigation provisions are required. The CAISO is not currently planning to implement a 20- or 30-minute reserve product for either 2007 or under the initial release of MRTU in 2008. However, this issue should be given serious consideration for future MRTU releases. In the meantime, the locational value of 20- to 30-minute generating capacity will need to be captured in the current RA procurement practices and through the backstop RCST payment mechanism, which, as discussed above, provides for daily capacity payments to non-RA resources that are denied must-offer waivers. It should also be noted that, while the current CPUC RA provisions do not fully address zonal capacity requirements, the CAISO is pursuing zonal capacity requirements as part of the pending Phase 2 CPUC RA proceeding.

1.2.5 CPUC Long Term Procurement Rules

In addition to addressing short-term capacity requirements through the Resource Adequacy program, the CPUC has also required that load-serving entities under its jurisdiction develop and file 10-year long-term procurement plans (LTPPs) designed to comply with any and all

[13] An additional problem with seeking to rely only on a market to meet all reliability requirements, including stability and thermal limitations after an N-1 contingency, is the highly dynamic nature of these reliability requirements. In practice, these reliability requirements may not be determined on a day-ahead basis. However, MRTU market rules require that the CAISO seek to meet all Ancillary Service requirements in the Day Ahead Market.

policy constraints and to adequately meet bundled customer load needs. The 2006 LTPPs will need to reflect all procurement related decisions from prior CPUC rule-makings, including the following:

- Adopted Demand Response programs and attainment goals.
- Procurement “loading order” as reflected in the state agencies’ Energy Action Plan II and adopted by the CPUC.
- Identify the key planning decisions required to meet a renewable portfolio standard of 33 percent by 2020.

On December 11, 2006, CPUC jurisdictional entities submitted their long-term procurement plans to the CPUC. Intervener testimony was submitted on March 2, 2007 and reply testimony is due on April 9, 2007. The CAISO has been reviewing the LTPPs to determine whether the proposals raise any operational issues that parties should be aware of. The CPUC is expected to approve the LTPPs later in 2007.

Additionally, in a July 21, 2006 decision, the CPUC directed Southern California Edison (SCE) and Pacific Gas & Electric (PG&E) to procure 1,500 MW and 2,200 MW of new generation, respectively, and to unbundle the capacity and energy products from this new generation. It was determined that PG&E needed 1,200 MW of new peaking generation and 1,000 MW of new peaking and dispatchable generation by 2010 and that SCE would have the option of a two track approach with a “fast-track” RFO for new generation coming on-line beginning mid-2009 and a “standard track” with expected on-line dates of 2012-2013. However, if SCE does not pursue all 1,500 MW under a fast track, it must justify to the CPUC why it is appropriate to pursue some of the generation under the standard track. Under this decision, the capacity of the new generation would be allocated to each load-serving entity in the IOU’s service territory and count towards its RA requirements. The costs of the capacity would be allocated similarly. The energy product will be auctioned off by a third party. The CPUC action was taken due to the urgency for new generation investment in California and the recognition that a more permanent long-term procurement structure, that effectively addresses the need for long-term procurement and retail competition, would not be completed for some time.

1.3 Generation Additions and Retirements

1.3.1 Generation Additions and Retirements in 2006

Approximately 633 MW of new generation began commercial operation within the CAISO Control Area in 2006. The majority of new capacity in the North was wind generation (150 MW out of 199 MW total in the North). Table 1.2 shows the new generation projects that began commercial operation in 2006.[14]

[14] Note that the Palomar and Mountain View facilities, totaling 1,066 MW of new generation, were included in the 2005 generation additions in the 2005 Annual Report on Market Issues and Performance.

Table 1.2 New Generation Facilities Entering Commercial Operation in 2006

Generating Unit	Net Dependable Capacity (MW)	Commercial Operation Date	Zone ID
Buena Vista	37.6	29-Dec-06	NP26
Central Disposal Site LFG Power Plant	8.0	09-Jan-06	NP26
Santa Cruz Landfill Generating Plant	3.6	02-Feb-06	NP26
Shiloh 1 Wind Project	150.0	30-Mar-06	NP26
NP26 New Generation in 2006	***199.2***		
Kern River Units 1, 2, 3 & 4	340.0	01-Jun-06	SP26
MM Lopez Energy, LLC	6.0	28-Aug-06	SP26
MMC Chula Vista	44.0	08-Jun-06	SP26
MMC Escondido	44.0	07-Jun-06	SP26
SP26 New Generation in 2006	***434.0***		
Total New Generation in 2006	**633.2**		

Source: California ISO Grid Planning Department

Approximately 1,535 MW of generation capacity was removed from service in 2006, the majority of which was located in the SP26 congestion zone. The most notable of the retirements is the Mohave units, which were the last remaining coal-powered resources in the CAISO Control Area[15].

Table 1.3 Retired Generation Facilities in 2006

Generating Unit	Net Dependable Capacity (MW)	Zone ID
Hunters Point Units 1 & 4	215	NP26
NP26 Retired Generation in 2006	***215***	
Mohave Units 1 & 2	1,320	SP26
SP26 Retired Generation in 2006	***1,320***	
Total Retired Generation in 2006	**1,535**	

Capacity retirements considerably outpaced additions in 2006, leading to a net reduction in capacity in the CAISO control area of 902 MW as seen in Table 1.4.

[15] Though the Mohave coal-fired generating units are physically located outside of California (Southern Nevada), they were incorporated into the CAISO Control Area, which is why they are included in Table 1.3.

Table 1.4 Generation Change in 2006

Region	Generation Additions (MW)	Generation Reductions (MW)	Net Change in Generation (MW)
NP26	199	-215	-16
SP26	434	-1,320	-886
CAISO Control Area	**633**	**-1,535**	**-902**

1.3.2 Anticipated New and Retired Generation in 2007

The CAISO projects construction of 1,484 MW of new generation in 2007, of which roughly 650 MW are expected to be commercially available prior to the anticipated summer peak season. There are two 405 MW resources, the Inland Empire units shown in Table 1.5 below, that will be parallel in 2007 but are not anticipated to complete testing and begin commercial operation until 2008.

Table 1.5 Planned Generation Facilities in 2007

Generating Unit	Resource Owner / QF ID	Resource Capacity (MW)	Expected Parallel Date	Zone ID
Bottle Rock Power	Bottle Rock Power	55.0	04-Apr-07	NP26
Keller Canyon Landfill Generating Facility	Ameresco Renewables	3.8	16-Jul-07	NP26
Lake Mendocino Hydro	City of Ukiah	3.5	21-Mar-07	NP26
Marina-LFG2	Monterey Regional Waste Mgmt Dist.	2.6	01-Apr-07	NP26
MM Yolo Power LLC	Minnesota Methane	3.6	01-Jan-07	NP26
MMC Mid-sun, LLC Repower	MMC Energy	22.0	16-Jan-07	NP26
Ox Mountain Landfill Gas Generation	Ameresco Renewables	11.4	15-Aug-07	NP26
Santa Clara Wind Project	AES Seawest	24.1	23-Feb-07	NP26
Santa Maria Cogen	Wellhead Power	10.2	23-Jan-07	NP26
NP26 Planned New Generation in 2007		***136.2***		
Barre Peaker	SCE	49.0	18-Aug-07	SP26
Center Peaker	SCE	49.0	31-Jul-07	SP26
Chiquita Canyon Landfill	Ameresco Renewables	9.2	15-Nov-07	SP26
Grapeland Peaker	SCE	49.0	31-Jul-07	SP26
Inland Empire Energy Center Unit 1 & 2	GE	810.0	10/1/2007	SP26
Long Beach Unit 1	NRG	65.0	01-Jun-07	SP26
Long Beach Unit 2	NRG	65.0	01-Jun-07	SP26
Long Beach Unit 3	NRG	65.0	01-Jun-07	SP26
Long Beach Unit 4	NRG	65.0	01-Jun-07	SP26
McGrath Beach Peaker	SCE	49.0	30-Aug-07	SP26
Mira Loma Peaker	SCE	49.0	21-Aug-07	SP26
MM Tajiguas Energy, LLC	Algonquin Power	3.1	01-Apr-07	SP26
MM Tulare Energy, LLC	Minnesota Methane	1.6	01-Jan-07	SP26
Otay 3	Covanta Energy	3.8	14-Mar-07	SP26
Rancho Penasquitos Hydro Facility	San Diego County Water Authority	4.7	23-Jan-07	SP26
San Dimas Wash Hydro	San Gabriel Valley Muni. Water Dist.	1.1	01-Apr-07	SP26
West Covina 1	Minnesota Methane	3.3	01-Jan-07	SP26
West Covina 2	Minnesota Methane	6.5	01-Jan-07	SP26
SP26 Planned New Generation in 2007		***1,348.2***		
Total Planned New Generation in 2007		**1,484.4**		

Currently there are no planned generation retirements in 2007; however, unlike the lengthy process for constructing a new resource and bringing it online, a generation owner can retire an existing resource 90 days after notifying the CAISO.

Table 1.6 below shows an annual accounting of generation additions and retirements since 2001, with projected 2007 changes included along with totals across the seven year period (2001-2007).

Table 1.6 Changes in Generation Capacity Since 2001

	2001	2002	2003	2004	2005	2006	Projected 2007	Total Through 2007
SP15								
New Generation	639	478	2,247	745	2,376	434	1,348	8,267
Retirements	0	(1,162)	(1,172)	(176)	(450)	(1,320)	0	(4,280)
Forecasted Load Growth*	148	500	510	521	531	542	553	3,305
Net Change	**491**	**(1,184)**	**565**	**48**	**1,395**	**(1,428)**	**795**	**682**
NP26								
New Generation	1,328	2,400	2,583	3	919	199	136	7,568
Retirements	(28)	(8)	(980)	(4)	0	(215)	0	(1,235)
Forecasted Load Growth*	389	397	405	413	422	430	439	2,895
Net Change	**911**	**1,995**	**1,198**	**(414)**	**497**	**(446)**	**(303)**	**3,438**
ISO System								
New Generation	1,967	2,878	4,830	748	3,295	633	1,484	15,835
Retirements	(28)	(1,170)	(2,152)	(180)	(450)	(1,535)	0	(5,515)
Forecasted Load Growth*	537	897	915	934	953	972	991	6,199
Net Change	**1,402**	**811**	**1,763**	**(366)**	**1,892**	**(1,874)**	**493**	**4,121**

* Forecasted load growth is based a 2 percent peak load growth rate applied each year.

As shown in Table 1.6, there was a 902 MW net decline in installed generation in the CAISO Control Area in 2006 (633 MW new generation less 1,535 MW of unit retirements), the first net decline in installed generation in the post energy crisis period. The total net increase in installed generation in the CAISO Control Area over the seven years spanning 2001-2007 is roughly 10,000 MW and the net additions across the 2006-2007 period leaves the CAISO Control Area only a few hundred MW above the installed generation level of 2005. When adjusted for annual load growth, the net increase in installed generation drops from 10,000 MW to just over 4,100 MW over the past seven years.

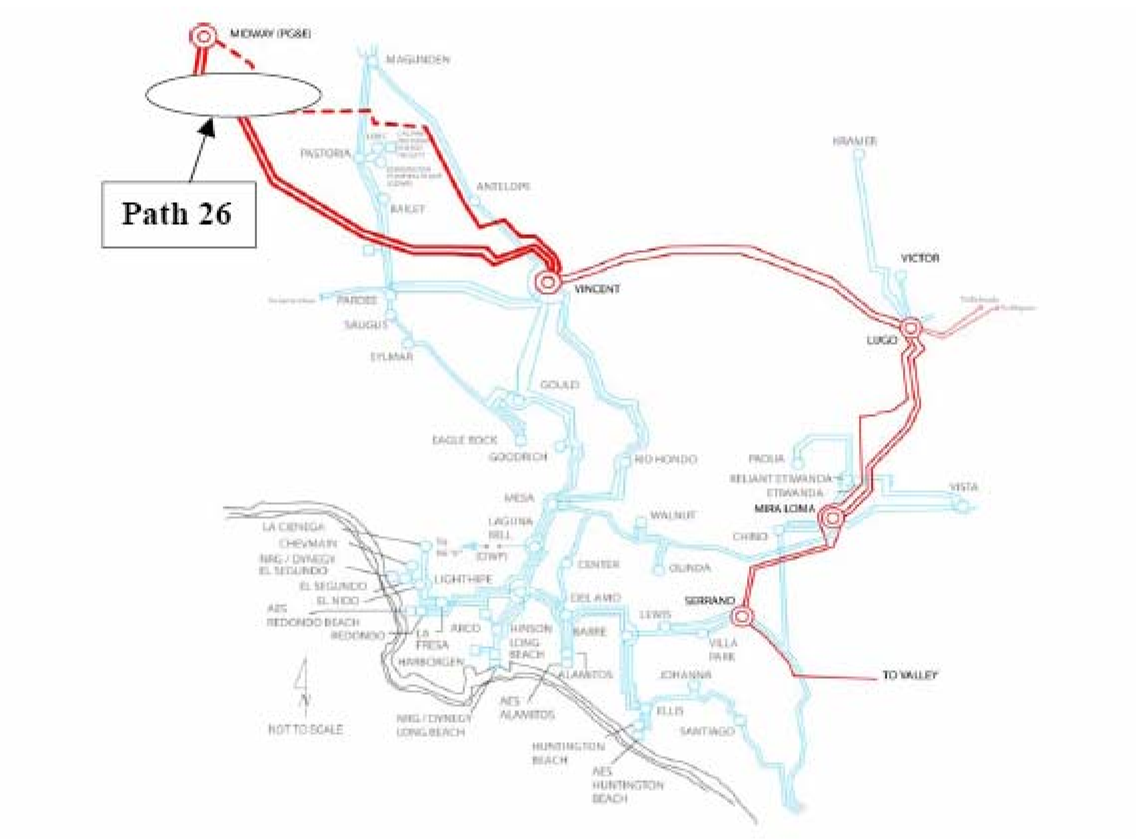
1.4 Transmission System Enhancements

1.4.1 Path 26 Remedial Action Scheme Enhancement

Path 26 consists of three 500kV lines between the Midway and Vincent substations and is a major interface and constraint for power flows between Northern and Southern California (see Figure 1.7). Path 26 originally had a bi-directional rating of 3,000 MW and had experienced substantial amounts of north-to-south congestion over the last several years. To mitigate this congestion issue, the Path 26 owners (PG&E and SCE) and the CAISO completed a WECC Rating Process to increase the WECC Accepted Rating in the north-to-south direction from 3,000 MW to 3,700 MW. This increase went into effect in June 2005. In addition, in order to mitigate anticipated congestion on Path 26 during the summer of 2005, the Path 26 owners and the CAISO requested an interim operational transfer capability (OTC) for Path 26 of 4,000 MW for the summer 2005 operating period (July – September 2005). The interim Path 26 OTC rating was granted by WECC and expired at the end of summer 2005. Path 26 operated at its WECC Accepted Rating of 3,700 MW since September 2005 through May 31, 2006.

On April 22, 2005, the CAISO submitted a report to WECC recommending a permanent increase to the north-to-south rating on Path 26 to 4,000 MW beginning in summer 2006. The new north-to-south Path 26 rating was approved by WECC on June 1, 2006.

Figure 1.7 Path 26 Midway-Vincent



1.4.2 New Jefferson-Martin Line

The Jefferson-Martin transmission project was designed to address both reliability needs within the San Francisco Peninsula area as well as environmental issues with regard to facilitating the retirement of an older generating facility located on the peninsula (Hunters Point Power Plant). The project involved installing a new 28-mile 230kV transmission line, with both overhead and underground segments, along the San Francisco Peninsula between the Jefferson and Martin substations and installing a second 230/115kV transformer at the Martin substation. The project was completed on April 29, 2006 and resulted in an additional 350 MW of transfer capability along the San Francisco Peninsula.

1.4.3 East/West of the River Upgrades

The WECC transfer ratings for the major transmission interfaces between California and the Desert Southwest, East-of-the-River (EOR) and West-of-the-River (WOR), were increased by 505 MW in 2006 to 8,055 MW and 10,623 MW, respectively. The EOR increase took effect on July 1, 2006 and the WOR increase took effect on November 8, 2006. The specific upgrades that resulted in this increase were the following:

(a) Series capacitor upgrades on the Palo Verde to Devers and Hassayampa to North Gila 500kV lines. In addition, the North Gila to Imperial Valley 500kV lines were upgraded with higher ampere ratings.

(b) A second 500/230kV transformer bank was added at the Devers Substation (SCE).

(c) 600 MVAR of dynamic voltage support was added at the Devers 500kV Bus, which was comprised of 150 MVAR of Mechanically Switched Capacitors (MSC) and 450 MVARs of Static Var Compensators (SVC).

(d) Special Protection Scheme added to mitigate for the contingency overload on the 230/161kV transformer from Imperial - Valley (SDG&E) to El Centro (IID).

The increased WECC transfer ratings resulted in a 505 MW increase on the Palo Verde Branch Group (from 2,823 MW to 3,328 MW). The increase was implemented on a conditional basis in July 2006 and was fully adopted on November 8, 2006, after the WOR increase took effect.

1.5 Administration of the Enforcement Protocol

1.5.1 Enforcement Protocols

As part of the CAISO organizational realignment in 2005, the Department of Market Monitoring (DMM) was assigned the responsibility of administering the Enforcement Protocol (EP) of the CAISO tariff. The EP was developed over a two year period from 2002 through 2004 through an effort led by the CAISO Compliance and Legal Departments. The EP is designed to provide clear Rules of Conduct specifying the behavior expected of Market Participants, and establish in advance the sanctions and other potential consequences for violations of the specified Rules of Conduct. In December 2005, FERC granted the CAISO authority to enforce penalties only for objectively identifiable violations of the CAISO tariff for which specific penalties are established in the EP. In enforcing these penalties, CAISO is not authorized to waive or modify penalties for mitigating circumstances, and may only recommend that FERC waive or modify penalties through a formal filing with the Commission. FERC rules require that all other potential violations of the CAISO tariff or FERC market rules be referred to FERC's Office of Enforcement (OE) for potential investigation and sanction.

In spring 2006, DMM initiated programs to enforce the two major objectively identifiable violations of the CAISO tariff for which specific penalties are established in the EP.

- ***Load Forecasting Requirements*.** Amendment 72 requires all Scheduling Coordinators (SCs) to submit day-ahead schedules equal to at least 95 percent of their forecasted demand for each hour of the next day. The CAISO did not seek to include a penalty for failing to meet the 95 percent scheduling requirement in Amendment 72. Instead, the CAISO's Amendment 72 filing indicated that any failure to meet this requirement may be subject to enforcement by FERC under FERC market rules, which include a general requirement that participants comply with all provisions of the CAISO tariff. However, Amendment 72 explicitly provided that failure to submit day-ahead forecast and weekly reports would be subject to sanction under the EP, which provides for a penalty of $500 for failure to submit required information. Compliance with these forecasting and reporting requirements has been virtually 100 percent since May 2006, compared to only about 75 percent in the first five months of 2006, as shown in Figure 1.8.

- ***Generation Outage Reporting*.** Due to the importance of timely and accurate outage reporting for grid reliability, the EP established significant penalties for failure to comply with the generation outage reporting requirements specified in the CAISO tariff, including penalties of up to $5,000 per outage that is not reported within 30 minutes. In advance of summer 2006, DMM implemented a program to routinely enforce these generation outage reporting requirements. However, as a result of market participant concerns about the stringency of the CAISO's existing outage reporting requirements – and DMM's lack of discretion in enforcing these requirements – DMM recommended that the CAISO submit a filing to FERC to temporarily suspend the associated penalties. In July 2006, the CAISO requested that FERC temporarily suspend the CAISO's existing outage-reporting penalties so that the CAISO could initiate a stakeholder process to modify existing reporting requirements and address stakeholder concerns. While the CAISO developed modifications to the outage reporting requirements and reporting tools scheduled for implementation in 2007, DMM continued to monitor outage reporting compliance. As shown in Figure 1.9, this monitoring indicated that outage reporting compliance has remained relatively the same over the two year period from 2005 to 2006, with an average of about 75 percent of outages reported within 30 minutes before and after DMM began notifying participants of the intent to begin enforcing this reporting requirement in April 2006. The CAISO's Outage Management Department has indicated that this level of compliance is acceptable from the standpoint of system reliability, but has reaffirmed its desire to require all outages be reported within 30 minutes. The number of outages reported did increase after DMM began notifying participants of the intent to begin enforcing this reporting requirement in April 2006, but it cannot be determined whether this increase in reporting frequency is due to increased awareness of the requirement or other factors, such as the unusually high loads experienced in summer 2006. Enforcement of the penalty provisions for late outage reporting is expected to be implemented in June 2007 once the reporting tool enhancements are put into place and market participants gain sufficient experience with these new tools.

Figure 1.8 Potential Non-Compliance with Load Forecast Submission Requirements

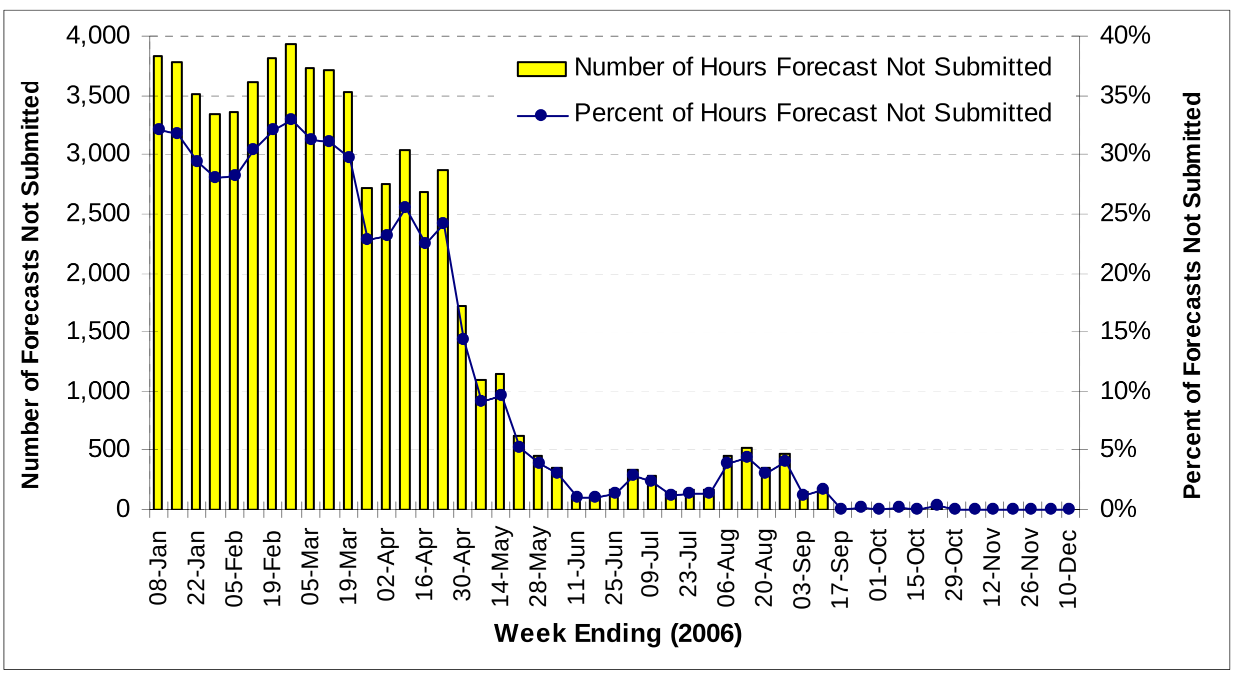


Figure 1.9 Potential Non-Compliance with 30-Minute Generation Outage Reporting Requirement