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 2005. New market design elements in 2005 include the first full year of operation under the new Real-time Market Application software (RTMA), changes to the RTMA settlement rules for pre-dispatched inter-ties, and a 95 percent load scheduling requirement. Significant infrastructure changes include numerous generation retirements and additions, various transmission upgrades implemented in 2005 and future projects, and numerous changes to the CAISO Control Area operation. In addition, this chapter provides an update on policy efforts to address resource adequacy.

1.2 Market Design Changes

1.2.1 Real Time Market Application (RTMA)

1.2.1.1 RTMA Overview

On October 1, 2004, the CAISO implemented a new software application for running its real-time imbalance energy market. The application, Real Time Market Application (RTMA), was designed to address significant shortcomings in the prior real-time dispatch and pricing application (Balancing Energy and Ex Post Pricing, BEEP). 2005 marked the first full year of RTMA operation.

RTMA is designed to receive bids to provide real-time energy, calculate the imbalance energy requirement for the next dispatch interval, and provide an economically optimized set of dispatch instructions to meet the imbalance energy need at least cost subject to resource and transmission grid constraints. Specific enhancements to BEEP that RTMA was designed to provide include:

- Replacement of the Target Price mechanism[1] with economic dispatch (or "market clearing") of all incremental and decremental energy bids with "price overlap" (i.e.,

[1] Prior to RTMA, the Target Price mechanism was utilized by the CAISO to ensure that the system-wide bid curve representing decremental and incremental real-time energy bids submitted by all participants utilized by the BEEP software was monotonically non-decreasing. Prior to any adjustments by the Target Price mechanism, the system-wide bid curve representing decremental and incremental real-time energy bids submitted by all participants typically included some "price overlap," or decremental bids with a bid a price higher than the bid price of some the incremental bids. Such a non-monotonic bid curve would result in real-time prices that increased as the ISO switched from inc'ing energy to dec'ing energy. To avoid this, the CAISO developed a Target Price mechanism that would set the system bid curve for the overlapping portion of incremental and decremental bids of eligible resources equal to the bid price at the point where the overlapping bids intersect. This point is referred to as the "Target Price". Initially, all resources (including imports) were eligible to set the Target Price. However, due to gaming potential with this open provision, eligibility to set the Target Price was later (October 2001) restricted to generating units with Participating Generator Agreement and loads with Participating Load Agreement; moreover only capacity that could be dispatched in 10 minutes could set the Target Price.

bids to sell energy (incremental energy bids) at a price lower than the price of bids to buy energy (decremental energy bids).

- Enhanced treatment of resource operating constraints, such as ramp rates, forbidden operating ranges,[2] minimum run times, and start-up times. In addition to lowering uninstructed deviations by increasing the overall feasibility of dispatch instructions. These improvements were necessary in order for the CAISO to gain approval to implement an Uninstructed Deviations Penalty (UDP) from the Federal Energy Regulatory Commission (FERC).
- Optimization of dispatch instructions based on a two-hour "look ahead" period, rather than dispatch of bids in economic merit order for each individual interval.
- Improved system responsiveness and efficiency due to use of a 5-minute dispatch interval, rather than the previous 10-minute interval.
- Increased reliance on automated dispatch instructions.

The RTMA software uses a 120-minute time horizon to compare the load forecast, current and expected telemetry of resources in the CAISO Control Area, current and expected telemetry of transmission links to other control areas, and the current status of resources on Automatic Generation Control (AGC). From this information, RTMA will set generation levels for resources participating in the CAISO Real Time Market using an optimization that achieves least-cost dispatch while respecting generation and inter-zonal constraints.

A complementary software application, Security Constrained Unit Commitment (SCUC), determines the optimum short-term (i.e., one to two hours, the time from the current interval through the end of the next hour based on the current and next hour's bids) unit commitment of resources used in the RTMA. The SCUC software commits off-line resources with shorter start-up times into the Real Time Market for RTMA to dispatch, or, conversely, the SCUC software de-commits resources as required to prevent over-generation in real-time. The SCUC program runs prior to the beginning of the operating hour and performs an optimal hourly pre-dispatch for the next hour to meet the forecast imbalance energy requirements while minimizing the bid cost over the entire hour. The SCUC software also pre-dispatches, (i.e., dispatches prior to the operating hour), hourly inter-tie bids.

Since its implementation, several issues have been raised concerning RTMA performance. One of the major concerns cited is a perceived high degree of price and dispatch volatility. A detailed review of RTMA performance is provided in Chapter 3. One notable aspect of RTMA – settlement rules for pre-dispatched inter-tie bids, was found to be particularly problematic in early 2005 and required a Tariff modification. This issue is discussed below.

1.2.1.2 Settlement of Pre-Dispatched Inter-tie Bids under RTMA

The RTMA design included two significant modifications relating to the dispatch and settlement of import/export bids over inter-ties with neighboring control areas.

- **Market Clearing of Import/Export Bids**. One of the central features of RTMA was the establishment of a market clearing mechanism, under which bids for incremental energy to

[2] Forbidden operating ranges are those operating ranges in which a resource may not operate for an extended period, but must run through as quickly as possible. A unit therefore may not provide regulation service within a forbidden operating region, because that could require the unit to operate within the forbidden region for some period of time.

provide additional energy at a price lower than decremental bids to purchase energy would be dispatched or "cleared" against each other. RTMA applies this market clearing algorithm to all remaining bids after bids needed to meet projected CAISO imbalance energy demand are accepted. This market clearing mechanism, which is incorporated in all other major ISO market designs, was incorporated into the RTMA software to promote greater economic efficiency, encourage participation in the CAISO Real Time Market, and avoid problems with the alternative Target Price mechanism previously employed to resolve incremental and decremental bids with such price overlap.

- **Bid or Better Settlement Rule for Import/Export Bids.** A second key feature of RTMA as initially implemented was settlement of pre-dispatched import/export bids on a "bid or better" basis. Under the "bid or better" settlement rule, hourly import bids pre-dispatched by the CAISO were paid the higher of their bid price or the ex-post Market Clearing Price (MCP). The ex-post MCP is determined by clearing dispatchable bids submitted by resources within the CAISO Control Area on a 5-minute basis. Meanwhile, pre-dispatched export bids were charged the lower of their bid price or the ex-post MCP. This settlement rule was adopted to encourage participation in the real-time market by imports and exports, which are prohibited from setting the real-time market price under market rules established by the Federal Energy Regulatory Commission (FERC). Although the CAISO software pre-dispatches import/export bids that were anticipated to be lower/higher than the ex-post MCP, actual system conditions can frequently result in MCPs that are significantly lower/higher than import/export bids pre-dispatched. In cases when MCPs were lower/higher than bid prices of pre-dispatched import/export bids, additional payments or decreased charges applied to pre-dispatched import/export bids were recovered through uplift charges assessed to other CAISO participants based on uninstructed deviations and gross load.

In early 2005, the combination of these two new market design features resulted in an increasing volume of off-setting import/export bids being cleared in the CAISO markets, and increasing uplift charges being assessed under the "bid or better" settlement rule. Under the "bid or better" settlement rule, the CAISO incurred uplift charges whenever actual ex-post MCPs were either higher or lower than the projected prices used to clear import/export bids. For example, when ex-post MCPs were higher than the project prices used to clear import/export bids, uplifts were paid to pre-dispatched imports bid at prices in excess, but export bids cleared against these import bids were only charged the ex-post MCP. Conversely, when ex-post MCPs were lower than the project prices used to clear import/export bids, uplifts were paid to pre-dispatched exports bid at prices lower than the ex-post MCP, but import bids cleared against these export bids were paid the full ex-post MCP.

In spring 2005, this basic market design flaw was exacerbated by significant divergences between the projected prices used to clear import/export bids, and the actual ex-post MCPs caused by another problem with the way that the RTMA software accounted for uninstructed deviations by resources within the CAISO. Specifically, the initial RTMA software projected uninstructed deviations by assuming that resources within the CAISO would seek to return to their scheduled operating level. This approach tended to underestimate positive uninstructed energy provided by many units, such as run-of-river hydro, Qualifying Facilities (QFs), and units operating at minimum load due to must-offer waiver denials. Since the RTMA software systematically underestimated uninstructed energy from these resources, ex-post MCPs tended to be significantly lower than projected prices used in pre-dispatching import/export bids. Combined with the basic design flaw of the "bid or better" settlement rule, this systematic price divergence created excessive uplift for import/export bids dispatched due to the market clearing feature of RTMA. This flaw in how uninstructed deviations were treated in RTMA was identified relatively quickly after RTMA implementation, but due to the lead-time for development and implementation of an enhanced algorithm this problem was not fixed until March 24, 2005.

In addition, analysis of participant bidding behavior suggests that some market participants took advantage of these market design flaws and conditions by bidding imports and exports in a manner that increased the probability of having off-setting import and export bids accepted in the pre-dispatch, which resulted in uplift payments being made for the difference between bid prices and the ex-post MCP, despite the fact that no net energy was being delivered to the CAISO system as a result of these off-setting import and export bids.

As a result of the systematic and often excessive uplift charges incurred by off-setting import and export bids pre-dispatched as part of the marketing clearing feature of RTMA, the CAISO filed Amendment 66 with FERC to replace the “bid or better” settlement rule for pre-dispatched import/export bids to an “as-bid” settlement rule. Under an “as-bid” settlement, pre-dispatched import bids are paid the bid price, while pre-dispatched export bids are charged the bid price. The change to an “as-bid” settlement rule was chosen by the CAISO as a second-best option, with a preferred option being settlement of all pre-dispatched import/export bids at a separate pre-dispatch MCP that would be applied to all hourly import bids pre-dispatched. However, the single price pre-dispatch market option could not be implemented without a significant delay and expenditure of resources.

The Department of Market Monitoring (DMM) has been monitoring the impact of this market design change on market efficiency and uplift charges since implementation of the “as-bid” settlement rule on March 25, 2005. Both volumes and costs were increasing from the start of RTMA through the late-March implementation of the change in settlement of these transactions via Amendment 66. Once Amendment 66 was implemented, the volume of bids dispatched for market clearing (beyond bids pre-dispatched for meeting CAISO system imbalance needs) and the associated uplift costs declined dramatically. A detailed analysis showing the impact of this settlement rule change is provided in Chapter 3.

1.2.2 Day-Ahead Under-scheduling of Load – Amendment 72

With the onset of peak summer demand conditions in early July, CAISO Operations raised concerns about load under-scheduling in the Day Ahead Market. The concern predominately relates to shortfalls between the CAISO day-ahead forecasted load and the level of final day-ahead load schedules. To the extent such shortfalls exist, the CAISO operators need to commit additional units through the Must-Offer Obligation (MOO) waiver denial process, which puts additional administrative burdens on operational staff and introduces significant commitment uplift costs to the market. More fundamentally, it raises a concern about whether Load Serving Entities (LSEs) have adequately planned for meeting their peak load obligations.

Throughout the initial summer months, the CAISO committed significant amounts of capacity under the MOO to cover expected shortfalls in day-ahead schedules relative to day-ahead forecasted peak load. CAISO operators commit capacity to make up this shortfall to ensure that sufficient capacity is online in time to meet the next day’s peak load. During this time, day-ahead schedules had been as much as 12 percent less than the day-ahead forecast and had caused significant commitment of resources under the must-offer waiver denial process. This has resulted in daily Minimum Load Cost Compensation (MLCC) system costs in excess of $700,000 in July.

The CAISO recommendation for addressing this issue was to require LSEs to schedule no less than 95 percent of their forecast load in the Day Ahead Market so that Grid Operators would not have to commit additional units in the CAISO’s day-ahead must-offer process to ensure enough capacity was online to meet load in the Real Time Market. In late July, the three IOUs began voluntary efforts to meet the day-ahead scheduling target of 95 percent. On September 22, the CAISO filed Tariff Amendment 72 with the FERC to require all LSEs to schedule no less than 95 percent of their forecast load in the Day Ahead Market and FERC accepted the terms of the filing in an Order dated November 21, 2005.

In addition to an explicit day-ahead scheduling requirement, the CAISO began publishing more timely information regarding the potential cost of under-scheduling, namely estimates reflecting the per-MWh cost of under-scheduled load in the day-ahead timeframe in terms of MLCC resulting from the additional units that had to be committed to cover the under-scheduled load. This was done so that LSEs would consider costs to day-ahead under-scheduling that more fully reflected the actual costs of deferring procurement to the Hour Ahead or Real Time Markets.

As a result of these efforts, the CAISO has observed higher proportions of total load scheduled in the Day Ahead Market, with much fewer instances in which less than 95 percent of actual load was scheduled in the Day Ahead Market. This trend began shortly after the 95 percent scheduling practice was implemented and has continued through the first quarter of 2006 with a brief exception in November of 2005, coincident with very high natural gas prices and potential resulting shifts in spot procurement timing. As to the impact that the higher level of load scheduling has had on must-offer waiver denials, an assessment of the use of the Must-Offer Obligation to commit units to meet “System” requirements indicates that overall MOO commitments for “System” requirements are down for August-December 2005 compared to the same months in 2004. Another issue related to the scheduling requirement is whether or not the additional load scheduled in the day-ahead is met by physically feasible schedules. An indicator for this is the use of MOO unit commitments and the use of out-of-market dispatches in real-time to relieve transmission constraints. Both of these costs have declined for August-December 2005 compared to the same months in 2004, however, this may be due to other factors including transmission upgrades. A detailed assessment of load scheduling practices and the impact of Amendment 72 is provided in Chapter 2.

1.3 Generation Additions and Retirements

1.3.1 New Generation

Approximately 3,295 MW of new generation began commercial operation within the CAISO Control Area in 2005, most of which has signed Participating Generator Agreements with the CAISO. This includes 176 MW of previously mothballed generation owned by Reliant Energy Services that returned to service in 2005. A majority of the new resources constructed were natural gas-fired combustion turbine or combined cycle facilities. Table 1.1 shows the new generation projects that began commercial operation in 2005.

Table 1.1 New Generation Facilities Entering Commercial Operation in 2005

Generating Unit	*Owner or QF ID*	*Net Dependable Capacity (MW)*	*Commercial Operation Date*
El Sobrante Landfill Gas Generation	WM Energy Solutions	1.4	01-Jan-2005
Eurus Oasis Project	Eurus Energy	65	01-Jan-2005
Fresno Cogeneration Expansion Project	Fresno Cogen Partners, LP	50.5	14-Jan-2005
Sunrise Power Project Phase 3B	Sunrise Power Company, LLC	19	18-Feb-2005
Clearwater Combined Cycle Project	City of Corona	32	28-Feb-2005
Kimberlina Power Plant	Clean Energy Systems, Inc.	5.5	28-Feb-2005
Pico Combined Cycle Plant (Donald Von Raesfeld Power Plant)	Silicon Valley Power	147	18-Mar-2005
El Dorado Power House Unit 1	El Dorado Irrigation District	10	01-Apr-2005
El Dorado Power House Unit 2	El Dorado Irrigation District	10	01-Apr-2005
Pastoria Project Phase 1	Calpine	250	01-Apr-2005
Ellwood Generating Station (return from mothball status)	Reliant	56.1	01-Apr-2005
Mandalay 3 GT (return from mothball status)	Reliant	120	01-Apr-2005
Exxon Mobile Torrance Project	Exxon Mobile	85	01-Jun-2005
Metcalf Energy Center	Calpine	600	30-Jun-2005
Pastoria Project Phase 2	Calpine	500	30-Jun-2005
Miramar Energy Facility	Ramco Generation Unit	47	27-Jul-2005
KRCD Peaking Project	Kings River Conservation District	96	19-Sep-2005
Malburg Generation Station	City of Vernon	134	17-Oct-2005
Mountainview Power Project Power Block 3	Edison International	525	10-Dec-2005
Palomar Energy Project (PEP)	Palomar Energy, LLC	541	30-Oct-2005
Total Generating Capacity for 2005		**3,294.5**	

Source: California ISO Grid Planning Department

Reliant Energy Services' Mandalay 3 and Ellwood Generating Station facilities returned to service in 2005 after having been mothballed in 2003. As part of Reliant's settlement in the various Western Energy Markets investigations (PA02-2-000, EL03-59-000 et al.), Reliant committed to auctioning capacity from its Etiwanda 3 and 4, Mandalay Bay 3, and Ellwood facilities for three twelve-month periods through unit-contingent, gas tolling contracts. Failure to solicit bids resulted in Reliant mothballing these facilities. In July 2004, Reliant entered into a Reliability Must Run (RMR) agreement with the CAISO for capacity from Etiwanda 3 and 4 through December 2004. In September 2004, Reliant entered into a bilateral power-purchase agreement with Southern California Edison (SCE) for the capacity from Etiwanda 3 and 4, totaling 640 MW. In February 2005, Reliant entered into bilateral power-purchase agreements with unnamed counter-parties for the capacity from Mandalay 3 and the Ellwood Generating Facility, totaling 176 MW.

1.3.2 Retired Generation

Approximately 450 MW of generation capacity was removed from service in 2005, all of which was located in the SP15 congestion zone. Upon expiration of the long-term power purchase agreement with the California Department of Water Resources (CDWR), Dynegy determined that it was no longer economically feasible to operate its Long Beach Facilities, and retired them in 2005.

Table 1.2 Retired Generation Facilities in 2005

Generating Unit	*Capacity (MW)*
Long Beach 1, 2, 4, 5, 6, 7, and 9	450

Generation capacity in the CAISO Control Area changed by the following net amounts in 2005:

Table 1.3 Generation Change in 2005

Congestion Zone	*Generation Additions (MW)*	*Generation Reductions (MW)*	*Net Change (MW)*
NP15	913.5	0.0	913.5
SP15	2,375.5	-450.0	1,925.5
ZP26	5.5	0.0	5.5
CAISO Control Area	**3,294.5**	**-450.0**	**2,844.5**

1.3.3 Anticipated New and Retired Generation in 2006

The CAISO projects the construction of 441 MW of new generation through August 2006, of which 215 MW are expected to be commercially available prior to the anticipated summer peak season.

Table 1.4 Planned Generation Facilities in 2006

Generating Unit	*Net Dependable Capacity (MW)*	*Expected Parallel Date*
Rancho Penasquitos Hydro Facility	5	01-Mar-2006
Riverside Energy Center	96	15-Mar-2006
Chula Vista Repower	44	20-Apr-2006
Escondido Repower	44	20-Apr-2006
Otay 3	4	15-May-2006
Fresno Cogeneration Expansion Project	22	31-May-2006
Fresno Cogen ICE Unit	1	15-Jun-2006
Lake Mendocino Hydro	4	01-Jul-2006
PALCO	7	01-Jul-2006
Pastoria Expansion	159	31-Jul-2006
Bottle Rock Power	55	01-Aug-2006
Total Planned Generation in 2006	**441**	

Mohave 1 and 2 are both expected to retire in 2006. Hunters Point 1 and 4 are also expected to retire in 2006.

Table 1.5 Planned Generation Retirements in 2006

Generating Unit	*Capacity (MW)*
Mohave 1	790
Mohave 2	790
Hunters Point 1	52
Hunters Point 4	163
Total Planned Retirements for 2006	**1,795**

1.4 Transmission System Enhancements and Operational Changes

1.4.1 Inter-Zonal (Between Zone) Transmission System Enhancements

The only major inter-zonal transmission upgrade in 2005 was Path 26. The Path 26 enhancement greatly reduced congestion on Path 26 for the second half of 2005. Also notable is the Path 15 upgrade that became effective on December 7, 2004. Congestion on Path 15 was significantly lower in 2005 than in 2004 due to the upgrade.

1.4.1.1 Path 26 Enhancement

Path 26 consists of three 500kV lines, connecting the Midway and Vincent substation, between the CAISO congestion regions ZP26 and SP15. The north-to-south rating on the path has recently been increased from 3,400 MW to 3,700 MW. The Path 26 accepted rating of 3,700 MW was approved on May 2, 2005, by the Western Electricity Coordinating Council (WECC). On April 22, 2005, the CAISO submitted a Comprehensive Progress Report to the WECC's Technical Studies Subcommittee (TSS) to increase the north-south rating on Path 26 from 3,700 MW to 4,000 MW for 2005 and beyond by modifying the existing Path 26 Special Protection System (SPS). The existing SPS would be modified to curtail up to 1,400 MW of generation in the Midway area and about 500 MW of load in Southern California to mitigate contingency line overloading on the Midway – Vincent No. 3 500kV line in the event of a double line contingency (N-2) of the Midway – Vincent Nos. 1 and 2 500kV lines. The submission of the progress report placed the project in Phase 2 of the WECC path rating process.

1.4.1.2 Path 15 Upgrades

Before its upgrade in 2004, Path 15 consisted of two 500kV transmission lines between Pacific Gas and Electric (PG&E)'s Los Banos Substation on California's Central Valley (the northern terminus of the path) and the Gates Substation (the southern terminus of the path). Path 15 was one of the State's worst transmission bottlenecks. Table 1.6 summarizes the total congestion cost on Path 15 during the past six years.

Table 1.6 Historical Inter-Zonal Congestion Cost on Path 15

Year	Congestion Cost ($)	
2000	$	170,781,477
2001	$	43,260,325
2002	$	483,300
2003	$	689,856
2004	$	9,763,589
2005	$	2,177,498

In June 2002, the CAISO Governing Board unanimously approved the Path 15 Upgrade Project as a necessary and cost-effective addition to the CAISO Controlled Grid. The Path 15 Upgrade Project consisted primarily of a new, single, 83-mile, 500kV transmission line and associated substation facilities extending between the Los Banos Substation and the Gates Substation. The $300 million project was a partnership between PG&E, the Western Area Power Administration (WAPA), and a private company called Trans-Elect. WAPA set new towers and conductors, and PG&E upgraded substations on either end of the new line. PG&E, WAPA, and Trans-Elect each own a portion of the transmission rights to the new line and the CAISO operational control of the new facility along with the original Path 15 infrastructure. The new line increased the Path 15 capacity from 3,900 MW to 5,400 MW for the south-to-north direction.

The long-awaited Path 15 Upgrade was completed and turned over to the CAISO's operation on December 7, 2004. Upgrade of Path 15 started commercial use at 12:01am on December 22 in the Hour Ahead Market and the Day Ahead Market use began on December 23. The upgrade of Path 15 significantly reduced congestion cost and increased flows on the path especially during peak hours. The maximum hourly final flow was 4,747 MW in 2005 (south-to-north direction), which is a 25 percent increase compared to the maximum hourly flow in 2004.

1.4.2 Intra-Zonal (Within Zone) Transmission System Enhancements

1.4.2.1 "South of Lugo" Upgrades

South of Lugo transmission facilities have historically experienced significant Intra-Zonal Congestion. The constraint consists of three 500 kV lines that emanate from the Lugo substation and feed into the LA Basin area. The path operates under the N-2 operating criteria, meaning that if any two lines fail, the remaining line has to be able to absorb the energy that shifts onto it.

The internal limit on this grouping of lines was 4,400 MW. On May 27, 2004, the CAISO upgraded the path rating of 4,400 MW to 4,800 MW. On July 29, 2004, CAISO upgraded the rating from 4,800 to 5,100 MW (depending on grid conditions). The CAISO planned further upgrades for 2005 and these were completed on June 22, 2005. SCE added equipment that allowed the CAISO to boost the rated capacity of the grid in the Victorville/Norco/Ontario area by 500 MW to 5,600 MW. The upgrade reduced congestion and increased available supply to the LA Basin.

1.4.2.2 Pastoria Reconductoring

Transmission lines South of Pastoria, specifically the Pastoria – Pardee 220 kV line, Pastoria – Bailey – Pardee 220 kV line, and Pastoria – Warne – Pardee 220 kV line were inadequate to accommodate the output from the new generation that was installed in the region in 2005 along with output from the existing Big Creek hydroelectric facility, creating a generation pocket that, at times, resulted in excess redispatch costs associated with managing Intra-Zonal Congestion at South of Pastoria. To better accommodate the additional generation, SCE began a reconductoring of both the Pastoria – Pardee line and the Pastoria – Bailey line, which will help relieve congestion coming out of the generation pocket going forward. The reconductoring work is expected to be finished for the Pastoria – Pardee line in March 2006, and for the Pastoria – Bailey line in June 2006.

1.4.2.3 New Miguel-Mission Line

The Miguel substation and its associated congestion has been one of the CAISO's most significant intra-zonal problems since July 2003. The nature of the constraint has been twofold. First, the substation was limited by the 500/230 step-down transformer bank capacity at the Miguel substation itself. This limit was approximately 1,120 MW. Second, the substation was limited by the N-2 criteria on the two 230 kV lines emanating from the substation, meaning that if both of these lines tripped the remaining 138 kV system had to absorb the total energy. This limit was 1,100 MW.

In the second half of 2004, a number of upgrades were made to the system in the vicinity of the Miguel substation. A new 500/230 step-down transformer bank was added to the substation, new series capacitors were added to the Southwest Power Link (SWPL) line that feeds into the substation which results in reduced line impedance and increased power flow, and a small part of the 138 kV system was re-conductored. This new equipment went into service on October 31, 2004. Unfortunately, this did not significantly change the capacity of the substation. The static rating of the substation increased from 1,100 MW to 1,200 MW and the dynamic rating increased from 1,400 MW to 1,500 MW. The new 500/230 transformer bank resulted in more power reaching Miguel, so the Miguel congestion remained a significant cost issue and intra-zonal constraint. In addition, the N-2 criteria still remain as significant constraints.

The energization of the new Miguel Mission #2 230 kV line on June 6, 2005 further reduced the congestion in the Miguel-Mission area. This project involved taking one of the pre-existing 69 kV lines and increasing its voltage to 230 kV prior to the building of the second line. With CAISO approval and support, SDG&E accelerated the installation of a new 230 kV transmission line in an existing transmission corridor between the Miguel Substation near Chula Vista and the Mission Substation in Mission Valley in the San Diego area, increasing the capacity by 400 MW. The original in-service date for the project was June 2006. SDG&E shaved about a year off the project timeline.

All three upgrades (Path 26, South of Lugo, and the New Miguel-Mission line) together increased transmission capacity into Southern California by 1,000 MW.

1.4.3 Future Transmission Upgrades

The CAISO is responsible for evaluating the need for all potential transmission upgrades to promote economic efficiency and maintain system reliability. The CAISO developed clear standards both for reliability-based project evaluation and for economic-based project evaluation. More specifically, the CAISO developed the TEAM (Transmission Economic

Assessment Methodology) for economic-based project evaluation and has applied TEAM (or simplified TEAM) to a number of transmission projects and identified some economically beneficial projects. Some of the future transmission upgrades that the CAISO identified and approved are discussed in the following sessions.

1.4.3.1 STEP Short-Term Transmission Upgrades

The CAISO applied the simplified version of TEAM and identified a number of short-term transmission projects in the southwest region to be economically beneficial to the CAISO ratepayers. On June 18, 2004, the CAISO Board approved the Southwest Transmission Expansion Plan (STEP) short-term transmission upgrades for the southern portion of the CAISO grid. The proposed upgrades include the following:

- Series capacitors upgrades on the Hassayampa – North Gila – Imperial Valley 500 kV line from 1,200 MW (1,400 A) to a minimum of 1,900 MW (2,200 A). The Hassayampa – North Gila – Imperial Valley 500 kV line brings power from Arizona into the San Diego area.
- Series capacitors upgrades on the Palo Verde – Devers 500 kV line from 1,645 MW (1,900 A) to a minimum of 2,340 MW (2,700 A). The Palo Verde – Devers 500 kV line delivers power from Arizona into the Greater LA Basin.
- Devers 500/230 kV #2 transformer installation. This project includes the installation of a second 500/230 kV 1120 MVA transformer at Devers Substation. The installation of the second transformer is necessary to take full advantage of the series capacitor upgrades on the Palo Verde – Devers 500 kV line. Without the second Devers transformer, it would not be possible to increase the Palo Verde – Devers 500 kV line transfer capability significantly beyond its current rating.
- Dynamic Voltage Support Installation at Devers Substation. Dynamic voltage support is necessary to enable an increase in the imported energy while maintaining acceptable voltage conditions under the most limiting outage conditions.
- Series Capacitor and Phase-Shifting Transformer Installation at Imperial Valley Substation. The installation of the transformer is necessary to take full advantage of the series capacitor upgrades and to increase the operational flexibility of the system.
- Small West of Devers Upgrade such as installation of a series reactor on the Devers – San Bernardino No. 1 230 kV line.

The proposed STEP short-term transmission upgrades are planned to be completed by summer 2006.

1.4.3.2 New Palo Verde – Devers No. 2 500 kV Line

From July 2004 - February 2005, TEAM was used to evaluate the Palo Verde – Devers No. 2 500 kV line (PVD2). The PVD2 project was initially proposed by SCE and was identified as a potentially beneficial transmission expansion through the STEP process. The PVD2 project includes a new 230 mile 500 kV line between Harquahala Switchyard (near Palo Verde) and SCE's Devers Substation, rebuilding and reconductoring four 230 kV lines west of Devers, and voltage support facilities at the Devers area. On February 24, 2005, the CAISO Board approved the PVD2 project. Subsequently, CAISO and SCE filed with the California Public Utilities Commission (CPUC) in the matter of the application of SCE for a Certificate of Public Convenience and Necessity (CPCN). The CPUC is currently reviewing the case. If the CPUC approves the CPCN for the project as expected, the project could be on line in 2009, providing an additional 1,200 MW of transmission capacity from Arizona to Southern California.

1.4.4 Operational Changes

On November 30, 2005, the CAISO implemented the new Scheduling Applications (SA) Network Model C1, effective for the trade date December 1, 2005. This new scheduling/market model incorporated 5 major control area footprint change requests and the establishment of four new Metered Subsystems (MSS). Major changes are summarized as follows:

1.4.4.1 The COTP Transition to the SMUD Control Area

The new C1 model implemented the transfer of the California-Oregon Transmission Project (COTP) 500kV Transmission line. The CAISO's prior California-Oregon Intertie (COI) branch group consisted of 3 transmission lines, one of which is the COTP transmission line. The COTP project has elected to move the line to the Sacramento Municipal Utility District (SMUD) Control Area. The two remaining lines are referred to as the Pacific Alternating Current Intertie (PACI) lines. To reflect this transition, the COI branch group is renamed to the PACI branch group. The COI branch group consisted of the CAPJAK_5_OLINDA and the MALIN_5_RNDMT intertie points. The CAPJAK_5_OLINDA intertie will no longer be a scheduling point, and the MALIN_5_RNDMTN will be the only remaining tie that will transfer to the new PACI branch group. There are no physical line changes in the SA Network Model but a redrawing of the CAISO and SMUD Control Area boundaries was required. The result is the addition of two new interties and expiration of four interties.

Table 1.7 New and Expired Interties due to COTP Transition to SMUD

New Interties Effective 12/1/2005	Expired Interties Effective 12/1/2005
TRACY5_5_PGAE	CAPJAK_5_OLIDA
TRACY5_5_COTP	OLNDWA_2_OLIND5
	TRACYPP_2_TRACY5
	TRACYPP_2_WESTL

1.4.4.2 Modesto Irrigation District Transition

The Modesto Irrigation District (MID) elected to move to the SMUD Control Area. There will be two new interties from the MID control area transmission: WESTLY_2_TESLA and STNDFD_1_STNCSF.

1.4.4.3 Turlock Irrigation District Transition

The Turlock Irrigation District (TID) has elected to become an independent Control Area. There will be two new interties for TID in the CAISO Control Area: OAKTID_1_OAKCSF and WESTLY_2_LOSBNS.

1.4.4.4 Plumas-Sierra Interconnection

NCPA's Plumas substation was interconnected with SPPCO's Sierra substation at the Marble substation. The new C1 model created the New Plumas-Sierra Marble Substation Intertie Between the CAISO and Sierra Pacific Power Control Area. The new intertie for the Plumas-Sierra interconnection is MBLSPP_6_MARBLE.

1.4.4.5 New Metered Subsystem

There will be one new Metered Subsystem (MSS) for the City of Colton.

1.4.4.6 Utility Distribution Company to MSS Conversion

There will be three Utility Distribution Companies (UDCs) converting to MSS arrangements: City of Pasadena (implementation early 2006), City of Anaheim, and City of Vernon (implementation early 2006).

1.4.4.7 Pilot Pseudo Tie for the Calpine's Sutter Plant

Sutter Power Plant is a generation plant re-incorporated into the CAISO Control Area as a CAISO Participating Generator. The Sutter Power Plant is physically remote from the contiguous portion of the CAISO Control Area, and is located in an area where it is totally surrounded by the SMUD Control Area. The new C1 model implemented the Sutter Power Plant as a Pseudo Tie Pilot (a/k/a Remote Tie) resource in the SA Network Model. More specifically, a congestion zone SUTR inside of the NP15 zone is created and Sutter generator is modeled inside the SUTR zone. Also a branch group (between SUTR and NP15) is created as SUTTER_BG. The path limits are associated with the existing Tracy-Tesla 230kV intertie between SMUD and CAISO for the Calpine Sutter Generator, which is interconnected with the Western 230kV system within SMUD.

Table 1.8 and Table 1.9 provide a listing of the expired and new CAISO Branch Groups that resulted from these operational changes.

Table 1.8 New Branch Groups Due to Operational Changes

Branch Group	From Zone	To Zone	Interconnecting Control Area	Tie Point	Effective
MARBLESUB_BG	SR5	NP15	SPP	MBLSPP_6_MARBLE	new on 12/1/2005
OAKDALSUB_BG	TDZ1	NP15	TID	OAKTID_1_OAKCSF	new on 12/1/2005
PACI	NW1	NP15	BPA	MALIN_5_RNDMTN	new on 12/1/2005
STNDFDSTN_BG	SMDK	NP15	SMUD	STNDFD_1_STNCSF	new on 12/1/2005
SUTTRLOFF_BG	SMDM	SUTR	N/A	SUTTER_2_LAYOFF	new on 12/1/2005
SUTTRNP15_BG	SUTR	NP15	N/A		new on 12/1/2005
TRACYCOTP_BG	SMDH	NP15	SMUD	TRACY5_5_COTP	new on 12/1/2005
TRACYPGAE_BG	SMDL	NP15	SMUD	TRACY5_5_PGAE	new on 12/1/2005
WSLYTESLA_BG	SMDJ	NP15	SMUD	WESTLY_2_TESLA	new on 12/1/2005
WSTLYLSBN_BG	TDZ2	NP15	TID	WESTLY_2_LOSBNS	new on 12/1/2005

Table 1.9 Expired Branch Groups Due to Operational Changes

Branch Group	From Zone	To Zone	Interconnecting Control Area	Tie Point	Effective
COI _BG	NW1	NP15	BPA	MALIN_5_RNDMTN, CAPJAK_5_OLINDA	expired on 12/1/2005
OLNDAWAPA_BG	SMD1	NP15	SMUD	OLNDWA_2_OLIND5	expired on 12/1/2006
TRACYWAPA_BG	SMD4	NP15	SMUD	TRCYPP_2_TRACY5	expired on 12/1/2007
TRCYWSTLY_BG	SMD6	NP15	SMUD	TRCYPP_2_WESTLY	expired on 12/1/2008

1.5 Resource Adequacy - 2006 and Beyond

1.5.1 Resource Adequacy Requirements

The California Public Utilities Commission (CPUC) has been developing a capacity-based Resource Adequacy (RA) program that requires LSEs to procure specific levels of contracted for generation and demand products on an annual and monthly basis. This RA program is specifically designed to further system and local grid reliability by providing generation resources a revenue source to contribute towards fixed cost recovery and provide a revenue framework that will facilitate new generation investment in California.

The RA framework was intended to address reliability at two levels. The first is reliability at the system level, where the focus is on maintaining enough generation capacity to meet total peak system load with additional capacity in reserve to address forecast error and contingencies. The second is reliability at the local level, where generation resources need to be in place to meet load and provide reliability services in established transmission-constrained areas. Both of these RA 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 SP15.

On October 27, 2005, the CPUC issued its *Opinion on Resource Adequacy Requirements* (Decision (D.) 05-010-042), "October Order", that laid additional detail regarding implementation of the RA program on June 1, 2006.[3] While the October Order made specific determinations on many of the design elements for the RA program, the following is a list of features important to this discussion:

- The RA requirement applies to system-level needs given that local requirements were deferred until procurement year 2007 after further development of the record.
- LSEs are required to procure enough (deliverable) capacity to cover 115 percent to 117 percent of forecast peak demand.
- Liquidated Damages (LD) contracts qualify to be counted toward meeting the system-level RA requirements, however these contracts will be phased out of the program between now and 2009.

[3] See CPUC Opinion on Resource Adequacy Requirements at http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/50731.pdf.

- Resources that have sold RA capacity must make all of their capacity available to the CAISO markets.

This first stage in RA implementation provides a good framework for improving reliability, providing an additional source of revenue for cost recovery in the short-term, and providing a contracting and revenue framework that will incent investment in new generation. It is critical, however, that the CPUC continue its progress toward addressing short-term and long-term reliability at the local or regional level. Many of the existing resources that are located in traditional load pockets, or in areas that require resident generation to provide transmission congestion relief, are older higher-cost units. Many of these resources are located at points on the transmission grid where they are required both to meet load in that area and to provide reliability support. For these resources, cost recovery is critical to insure that these resources do not retire and leave these local reliability areas capacity deficient. In the same vein, providing incentives and opportunities for investment in new generation (or re-powering existing facilities) in these same constrained areas is vital to turning over the pool of existing aging generation resources and improving the efficiency of that pool.

Regarding the 2006 implementation of the RA requirement, the absence of a local capacity requirement coupled with the allowance of LD contracts creates a potential for LSEs to meet their system RA requirements by contracting with resources other than those described above, namely older higher-cost resources that provide needed support in local reliability areas. The potential consequence of this is that, given insufficient cost recovery opportunity provided by spot markets in California over the past several years, these resources may not receive sufficient revenues to justify maintaining operation. While the lack of local capacity requirements in 2006 creates this potential concern, an initial review of the 2006 annual system capacity RA showings indicates that many of the resources needed for local reliability needs have in fact been contracted with as part of the LSE's RA requirements.

The CPUC has established that a local RA requirement will be implemented for the 2007 procurement period, and that the use of LD contracts toward meeting system RA requirements will be largely phased out by 2009. It is anticipated that these two features of the RA program will mitigate the threat that resources critical to the maintenance of local and regional reliability will choose to retire given the inability of the California spot markets over the past several years to provide sufficient revenues to justify maintaining their operation. Over the longer term, the RA program as well as the CAISO's coordinated grid planning process is intended to provide the incentives to replace such units with more efficient generation to serve local reliability purposes or to construct additional transmission upgrades that can be installed to relieve the limiting factors creating these local reliability areas in the first instance. Nevertheless, for 2006 and beyond, there still exists a potential revenue adequacy issue that may impact the availability of resources in the CAISO Control Area. Given this concern, the CAISO may need to have an alternative interim backstop contracting mechanism, other than RMR contracts - due to their limited application, to ensure that generating units that are critical for reliability remain in operation.