California ISO
Your Link to Power
10 Year Anniversary 1998–2008

Market Issues & Performance

2007 Annual Report

Department of Market Monitoring
California Independent System Operator Corporation

ACKNOWLEDGEMENT

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Overview

Each year the Department of Market Monitoring (DMM) publishes a report on the performance of markets administered by the California Independent System Operator (CAISO). In 2008 the CAISO is celebrating the ten year anniversary of its operational launch on March 31, 1998. This report covers the period of January 1, 2007 through December 31, 2007.

For the sixth consecutive year (2002-2007), California's wholesale energy markets remained stable and competitive in 2007. This trend is predominantly due to a high level of forward energy contracting by the state's investor owned utilities, which limits their exposure to spot market price volatility, enhances competition, and facilitates new generation investment. Over the past seven years (2001-2007), approximately 14,900 MW of new generation has been added to the CAISO Control Area, enabling the retirement of 5,500 MW of older inefficient generation, resulting in a net increase of 9,400 MW of new generation. Additionally, another 1,800 MW of new generation is projected to be operational in 2008.

While very low snowpack levels in 2007 for most of the West, including California, raised concerns about hydroelectric supply availability during the critical summer months, relatively moderate summer temperatures mitigated this concern and produced generally competitive conditions with no major reliability issues. California did experience two heat waves in 2007 – both occurring over holidays, which may have tempered their effect. The first occurred over the Independence Day holiday, and the second, which set the annual peak load, occurred over Labor Day weekend. Both events were managed without any significant reliability issues. The energy markets were also generally stable and competitive during the heat waves, but did experience some escalation in prices and increased volatility – particularly in the bilateral energy and ancillary service markets. Overall, the market and operational impacts of the two heat waves were moderate compared to 2006, which saw an extraordinary heat wave that lasted three weeks in July, and reached a peak well above that seen in 2007.

From a grid operations standpoint, the most notable event of the year was the California wildfires that raged through large portions of Southern California from October 21 to 25. These fires were exceptional in terms of geographical span, number of acres burned, and number of businesses and residences impacted. They burned across Southern California, threatened generation and transmission facilities, and challenged grid stability, especially in the San Diego area. Remarkably, the CAISO, in close coordination with the Southern California utilities and assistance of the control area operator for Baja, Mexico (Comisiòn Federal de Electricidad (CFE)), was able to maintain reliable grid operation throughout the wildfire period. The wholesale market impacts from the wildfires were predominantly local in nature as various forced limitations within Southern California required real-time Out-of-Sequence dispatches as well as day-ahead unit commitment of generation at specific locations. Spot bilateral prices for Southern California did experience moderate and brief increases during this period. Congestion costs for some of the major inter-ties to Southern California increased as well, particularly in the Hour Ahead Market, where significant transmission derates occurred due to shifts in the paths of the fires. Overall, the market impacts during the fires were moderate and of short duration.

In terms of the general performance of the wholesale energy markets during the entire year, one of the primary metrics that DMM uses to gauge overall market competitiveness is a 12-month

Market Competitiveness Index (MCI), which represents a 12-month rolling average of the estimated hourly price-cost mark-ups (i.e., the difference between actual energy prices and estimated “competitive” prices derived from cost-based simulations). MCI values below $10/MWh are considered to be reflective of a workably competitive market. The monthly MCI values estimated for 2007 were well below this level for all months of the year.

The average estimated cost of wholesale energy in 2007 was $48.94/MWh of load compared to $47.52/MWh in 2006. Costs include the following components: forward scheduled energy, inter-zonal congestion, real-time imbalance energy, real-time out-of-sequence (OOS) energy redispatch premium, net Reliability Must Run (RMR) costs, ancillary services, and CAISO-related costs (transmission, reliability, and grid management charges). The increase in the costs in 2007 was primarily due to greater reliance on fossil fueled generation – due to limited hydroelectric supplies – and to increased congestion costs on major importing paths to California.

One significant positive trend that has been reported in prior annual reports has been the sharp reduction in intra-zonal congestion costs. This trend continued in 2007 with intra-zonal congestion costs dropping from $207 million in 2006 to $101 million in 2007. Intra-zonal congestion costs are comprised of three components: 1) Minimum Load Cost Compensation (MLCC) for units denied must-offer waivers, 2) real-time RMR costs, and 3) real-time redispatch costs. The decline is primarily attributable to lower MLCC payments and reduced RMR dispatch costs. MLCC costs declined by $65 million in 2007, mainly due to the completion of various transmission upgrades in Southern California during 2006. This construction caused the cost of MLCC payments in 2006 to increase, due to the need to commit units while the transmission work was being completed, but resulted in lower MLCC costs in 2007 once the upgrades, which relaxed the local constraints that previously required additional unit commitments through the must-offer waiver denial process, were complete. The cost of real-time RMR dispatches declined by $54 million in 2007. However, most of this decline was due to a reduction in RMR contracts that was enabled by the introduction of Local Resource Adequacy (RA) requirements in 2007. Thus, the cost savings from reduced RMR contracts may have been largely offset by higher RA costs, which are not accounted for in these figures. The cost savings for these two components of intra-zonal congestion costs were partially offset by an increase in the third component, real-time redispatch cost, of $13 million. The increase in this component was largely attributed to the need to redispatch units needed in the Humboldt area that were previously under RMR contracts.

The RMR costs noted above only pertain to the cost of real-time RMR energy dispatches. The total cost of RMR units, which includes both fixed cost payments and variable cost payments for day-ahead and real-time dispatches, declined substantially, from approximately $428 million in 2006 to $125 million in 2007, a reduction of approximately $303 million. This reduction is predominantly due to the reduction in the amount of capacity under RMR contracts, from approximately 9,300 MW in 2006 to 3,300 MW in 2007.

Another reliability management cost, which is relatively new, is the capacity payments made to generation units that are neither RMR units nor RA units. These capacity payments are made pursuant to the Reliability Capacity Services Tariff (RCST) and provide for both a daily capacity payment for non-RA units that are committed by the CAISO and potentially monthly capacity payments if a non-RA unit is designated by the CAISO as RCST. In 2007, the CAISO did not make any forward RCST designations but did make numerous daily capacity payments to non-RA units, amounting to approximately $26 million.

Another important market performance metric that DMM reports on each year is the extent to which spot market revenues for the entire year cover the annualized fixed cost of new generation facilities. The DMM's financial assessment of the potential revenues a new generation facility could have earned in California's spot market in 2007 indicates estimated spot market revenues fell short of the unit's annual fixed costs. The gap is significantly more pronounced given the recently released estimates from the California Energy Commission on the cost of new generation, which DMM used for purposes of this analysis. This marks the fifth straight year that the DMM's analysis found that estimated spot market revenues did not provide sufficient fixed cost recovery for new generation investment. However, the analysis for the past four years (2004-2007) does show a positive trend of net revenues increasing for a new combined cycle unit, with estimated net-market revenues in 2007 of approximately $84/kW-year and $95/kW-year for Northern and Southern California, respectively, but these estimates are well short of the estimated annualized fixed costs of $132.6/kW-year.

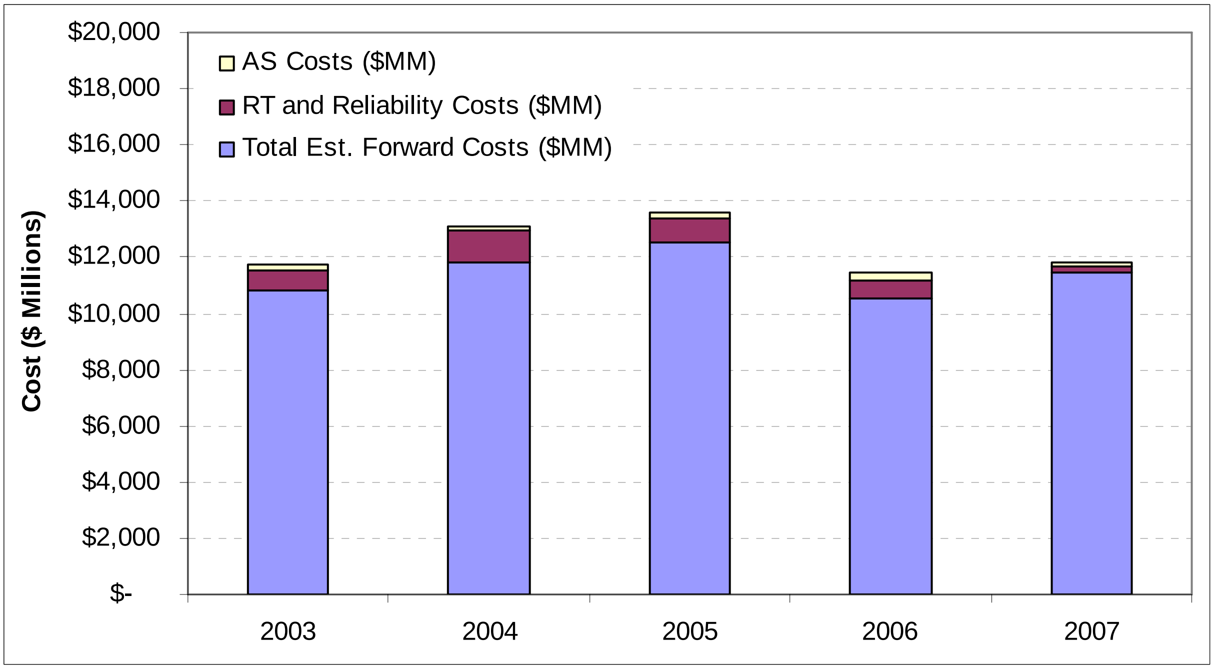
Despite the positive trend in spot market revenues, the fact that California's spot markets did not provide sufficient market revenues for fixed cost recovery five years in a row underscores the critical importance of long-term contracting as the primary means for facilitating new generation investment. While long-term contracting is critical for facilitating new investment, it must be coupled with appropriate deliverability and locational requirements to ensure new investment is occurring where it is needed. The CPUC implementation of Local Resource Adequacy Requirements in January 2007, which are based on CAISO technical studies, should help in facilitating generation development in critical areas of the grid.

Total Wholesale Energy and Ancillary Service Costs

Since 1999, the DMM has reported its estimate of annual wholesale energy costs. This provides an estimate of total wholesale market costs to load served that can be compared across years. It includes estimates of utility-retained generation costs, forward bilateral contract costs, real-time energy costs, and ancillary service reserve costs. The real-time component of costs also includes reliability costs (minimum-load compensation, out-of-sequence redispatch premiums, and fixed and variable RMR costs). These estimates do *not* include resource adequacy procurement costs, as these costs are not available to the CAISO.

As shown in Figure E.1, estimated total wholesale energy costs increased slightly in 2007, to approximately $11.8 billion (compared to $11.4 billion in 2006). The slight increase is due primarily to a greater reliance on more expensive fossil-fuel generation in 2007 due to less availability of hydroelectric energy. Total costs may have been even higher in 2007 but for generally lower natural gas prices compared to 2006.

Figure E.1 2003 – 2007 Wholesale Energy Costs



Market Rule Changes

There were two market design changes implemented in 2007. The first involved certain modifications to the current load scheduling requirement for the Day Ahead Market, and the second was the enforcement of local capacity requirements in the CPUC's Resource Adequacy program, whereby Load Serving Entities (LSEs) became required to procure capacity to satisfy specific local requirements determined by the CAISO. This more granular requirement complements the system-wide capacity requirements that were enforced beginning in June of 2006. A brief summary of the impact of each of these changes is provided below.

Day Ahead Load Scheduling Requirement

On April 24, 2007, FERC issued an order accepting several key changes to the day-ahead load scheduling requirements initially established in October 2005 under Amendment 72. The major change taking effect in 2007 was to lower the day-ahead scheduling requirement in off-peak hours from 95 to 75 percent of each SC's forecasted load. Another change provided an exemption during all hours for *de minimus* deviations below the scheduling requirement. The changes were proposed by the CAISO in response to concerns expressed by LSEs about the costs and difficulty of complying with the 95 percent scheduling requirement during all hours, and to reduce over-scheduling of load,[1] particularly during off-peak hours, which can create operational challenges in real-time.

Overall, these modifications, which were implemented on April 26, 2007, appear to have resulted in a moderate decrease in over-scheduling and a reduced need to routinely decrement energy in the Real Time Market. As expected, these impacts occurred primarily during off-peak hours. In addition, while some participants opposing a lower scheduling requirement for off-peak hours expressed concerns that these changes would cause the need to dispatch significant amounts of incremental energy in real-time, there is no evidence that such impacts materialized. A more detailed analysis and review of this change is provided in Chapter 1.

Local Resource Adequacy Requirements

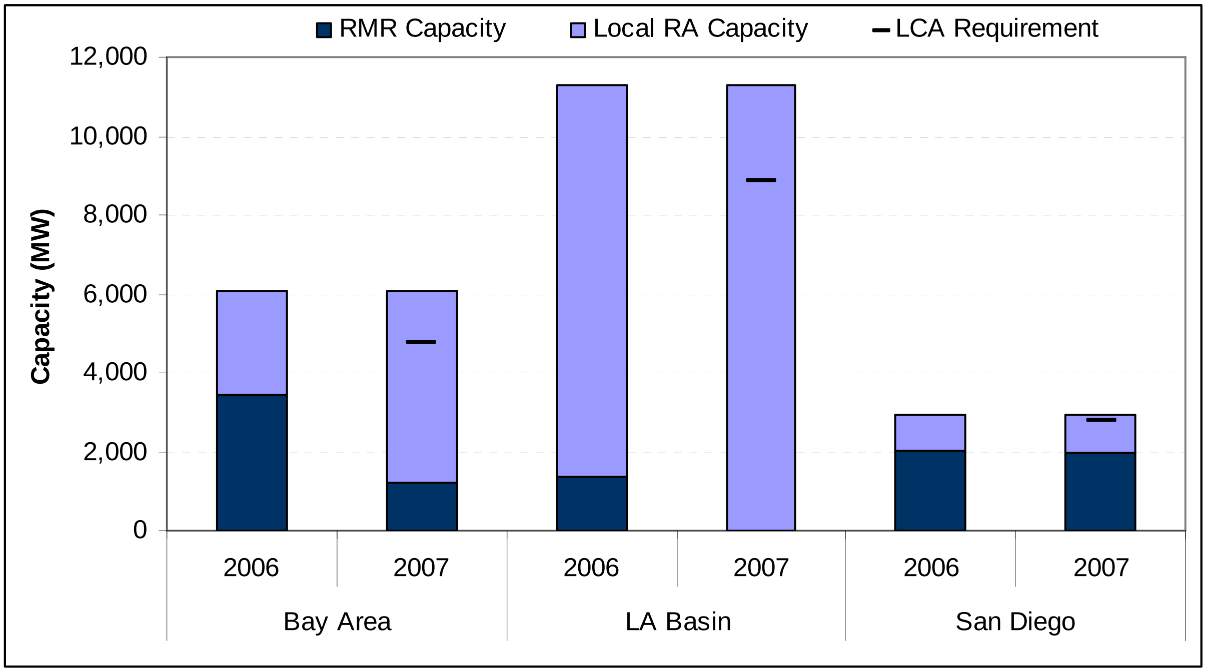
In 2006, the Resource Adequacy (RA) program developed by the CPUC became effective. This program requires that LSEs procure sufficient resources to meet their peak load along with appropriate reserve margins. In addition to the CPUC RA program, non-CPUC jurisdictional LSEs have also instituted similar capacity reserve margins. In 2006, the RA program was limited to imposing system-wide capacity requirements. In 2007, the program was expanded to include Local Resource Adequacy Requirements, which require LSEs to procure minimum levels of RA capacity within various Local Capacity Areas (LCAs), or transmission constrained “load pockets” within the CAISO system. Minimum capacity requirements for LCAs are established through technical studies performed by the CAISO based on NERC Planning Standards and any other applicable local reliability criteria.

One of the goals of the CAISO and the CPUC is to rely on capacity contracted by LSEs to meet local RA requirements, and thereby reduce reliance on RMR contracts or any other “backstop” capacity procurement that may be done by the CAISO. For example, as noted in last year’s Annual Report on Market Issues and Performance, the CAISO’s RCST provisions, which were established pursuant to a settlement filed in 2006, authorize the CAISO 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.

In 2007, substantial progress in the goal of reducing reliance on RMR contracts was achieved, as the total volume of capacity under RMR contracts was reduced from approximately 10,000 MW to only 3,300 MW. In addition, all local reliability requirements were met by units under RA and RMR contracts. Consequently, the CAISO did not need to designate any capacity under RCST provisions as a “backstop” to RA resources procured by LSEs. As shown in Figure E.2, reliance on RMR contracts in the LA Basin was eliminated in 2007, and was significantly reduced in the San Francisco Bay Area. In addition, since the minimum reliability requirement for each LCA was met through a combination of RA and RMR capacity, the CAISO did not need to designate any additional capacity through the RCST provisions.

[1] Over-scheduling can arise under this requirement because in order to meet a 95 percent scheduling requirement in all hours, Load Serving Entities would sometimes have to purchase multi-hour blocks of energy from the inter-ties, which resulted in over-scheduled load during some hours – particularly off-peak hours.

Figure E.2 Comparison of RMR and Local Resource Adequacy Capacity with Local Capacity Area (LCA) Requirements



General Market Conditions

Demand

Annual average hourly load in 2007 was moderately higher than in 2006 (Table E.1). Monthly average hourly load was significantly higher in most months of 2007, except for June and July, where average hourly load in 2007 was significantly lower than in 2006. Average hourly loads in June and July of 2007 were 3.4 percent and 5.1 percent below the monthly averages for the same months in 2006. However, average hourly loads in August 2007 were significantly higher than August 2006 (9.2 percent), due primarily to lower temperatures throughout August 2006.

Table E.1 Load Statistics for 2003 – 2007*

Year	Avg. Load (MW)	% Chg.	Annual Total Energy (GWh)	Annual Peak Load (MW)	% Chg.
2003 Actual	26,345		230,857	42,581	
2004 Actual	27,309	3.5%	239,312	45,597	7.1%
2005 Actual	26,990	-1.2%	236,483	45,562	-0.1%
2006 Actual	27,427	1.6%	240,344	50,270	10.3%
2007 Actual	27,646	0.8%	242,265	48,615	-3.3%
2003 Adjusted	25,471		223,206	41,063	
2004 Adjusted	26,436	3.7%	231,660	44,209	7.1%
2005 Adjusted	26,477	0.2%	231,994	44,260	0.1%
2006 Adjusted	27,427	3.5%	240,344	50,198	11.8%
2007 Adjusted	27,646	0.8%	242,265	48,615	-3.3%

* Adjusted figures are normalized to account for day of week, changes in the CAISO Control Area footprint, and the 2004 leap year.

Supply

Approximately 600 MW of new generation began commercial operation within the CAISO Control Area in 2007, and no generation capacity was retired from service in 2007. The CAISO projects construction of 1,810 MW of new generation in 2008, of which roughly 941 MW are expected to be commercially available prior to the anticipated summer peak season. Currently, there are no planned generation retirements in 2008; however, unlike the lengthy process for constructing a new resource, a generation owner can retire an existing resource 90 days after notifying the CAISO.

Table E.2 below shows an annual accounting of generation additions and retirements since 2001, with projected 2008 changes included along with totals across the eight year period (2001-2008). Including estimates for 2008, the total net increase in installed generation in the CAISO Control Area over the eight years spanning 2001-2008 is estimated to be approximately 11,200 MW. When accounting for an estimated 2 percent load growth over the same seven year period of approximately 7,500 MW, the net supply margin increased by roughly 3,700 MW since the energy crisis. Interestingly, Table E.2 indicates that generation additions in Southern California just kept pace with load growth and unit retirements, resulting in a minor net-loss of approximately 262 MW, but in Northern California (NP26) there was approximately a 3,950 MW increase in new generation after accounting for load growth and generation retirement.

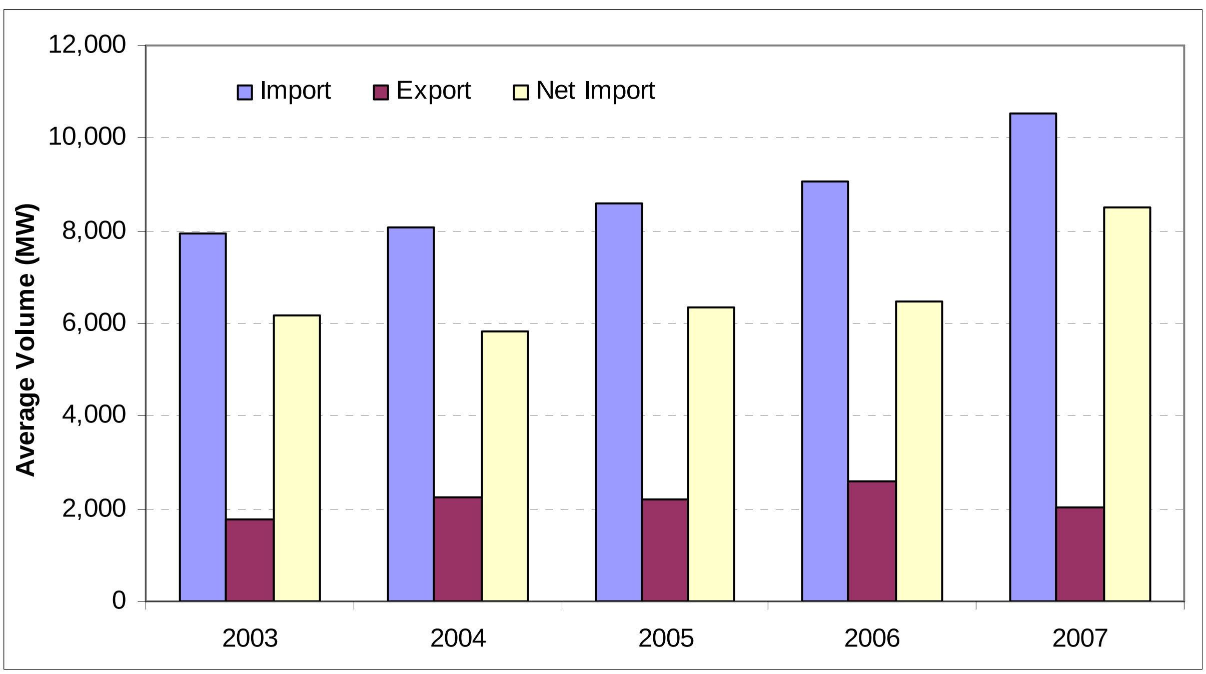
Table E.2 CAISO Generation Additions and Retirements

	2001	2002	2003	2004	2005	2006	2007	Projected 2008	Total Through 2008
SP15									
New Generation	639	478	2,247	745	2,376	434	485	826	8,230
Retirements	0	(1,162)	(1,172)	(176)	(450)	(1,320)	0	0	(4,280)
Forecasted Load Growth*	491	500	510	521	531	542	553	564	4,212
Net Change	**148**	**(1,184)**	**565**	**48**	**1,395**	**(1,428)**	**(68)**	**262**	**(262)**
NP26									
New Generation	1,328	2,400	2,583	3	919	199	112	984	8,528
Retirements	(28)	(8)	(980)	(4)	0	(215)	0	0	(1,235)
Forecasted Load Growth*	389	397	405	413	422	430	439	447	3,342
Net Change	**911**	**1,995**	**1,198**	**(414)**	**497**	**(446)**	**(326)**	**536**	**3,951**
ISO System									
New Generation	1,967	2,878	4,830	748	3,295	633	598	1,810	16,758
Retirements	(28)	(1,170)	(2,152)	(180)	(450)	(1,535)	0	0	(5,515)
Forecasted Load Growth*	880	897	915	934	953	972	991	1,011	7,554
Net Change	**1,059**	**811**	**1,763**	**(366)**	**1,892**	**(1,874)**	**(394)**	**798**	**3,689**

*Assumes 2% peak load growth.

Imports continue to play a key role in meeting demand. Figure E.3 shows average annual gross imports, exports, and net imports for the five-year period covered by 2003-2007. Average hourly gross imports increased significantly in 2007. This was primarily due to the reduced availability of hydroelectric generation within California, which resulted in more imports from the Pacific Northwest and the Southwest. Lower availability of hydroelectric generation within California may have also accounted for the reduction in annual exports also observed in 2007. Overall, hourly net-imports in 2007 averaged a little over 8,000 MWh, the highest level observed over this five year period.

Figure E.3 Average Annual Imports, Exports, and Net Imports (2003-2007)



Generation Outages

Figure E.4 depicts monthly average planned and forced outages between 2004 and 2007. Similar to previous years, planned outages were high during the first five months of the year, lower during the peak summer months, and high again in the fall months. Monthly averages of planned and forced outages in 2007 were generally comparable to 2006, with the exception of April 2006, where both planned and forced outages were exceptionally high. In this month, three nuclear resources were out for refueling (although two of these seasonal refueling outages were technically classified as forced outages), and several other large combined-cycle and steam resources were also out for annual maintenance. With plentiful hydroelectric power available at this time, the multiple planned outages during this period did not impose any reliability issues.

Figure E.4 Monthly Average Planned and Forced Outages (2004 – 2007)

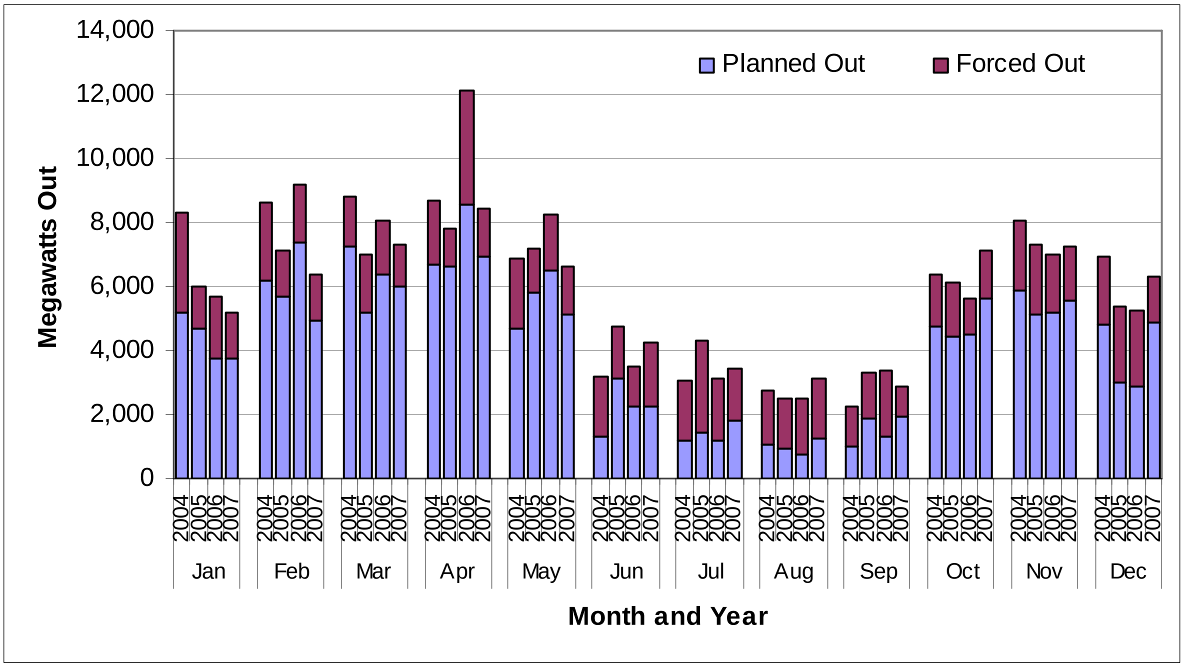
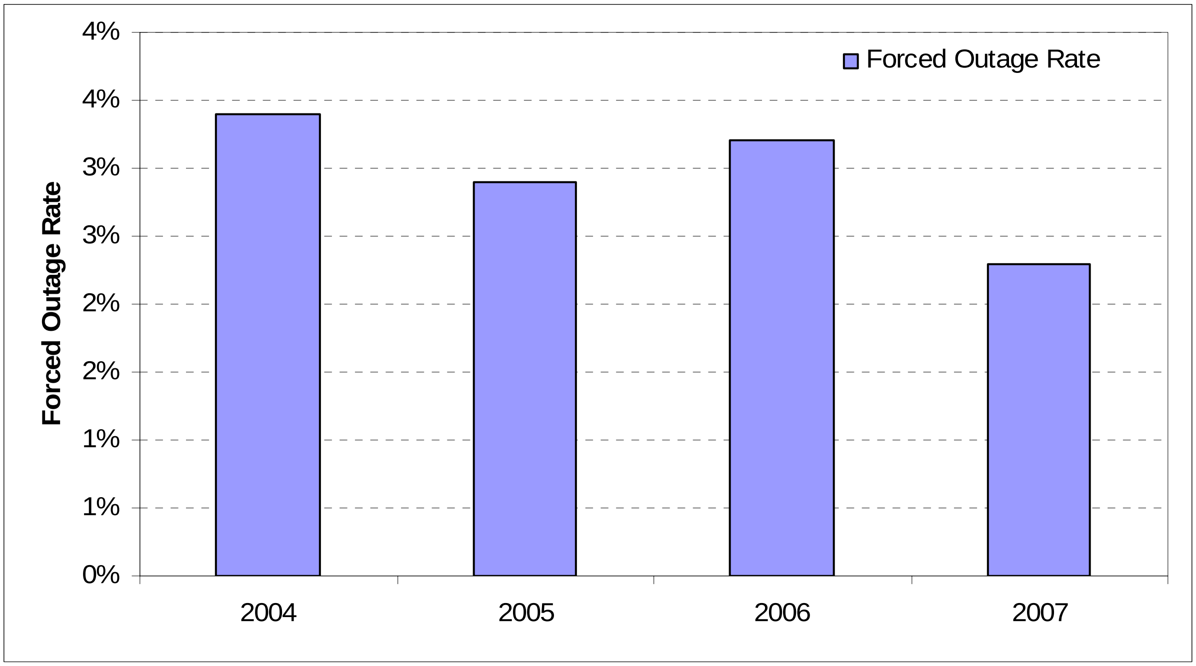


Figure E.5 compares annual forced outage rates since 2004. The annual forced outage rate in 2007 was approximately 2.6 percent, which is the lowest rate observed over this period. The decline can be partly attributable to the installation of new generation and transmission upgrades in recent years, which have enabled older, high-maintenance resources in California to be reserved for limited critical periods.[2] In addition, recent retirements of aging plants that had been outage-prone such as the Mohave coal-fired units (retired December 31, 2005) and the availability incentives provided by long-term energy contracting also contribute to lower outage rates.

[2] See Sections 2.2.3 and 2.6.4 in Chapter 2 for more information.

Figure E.5 Annual Forced Outage Rates (2004 – 2007)



Short-term Energy Market Performance

The significant number of long- to medium-term contracts entered into by the state of California in 2001, and by LSEs since then, combined with the large amount of new generation added to the Western energy markets, provided effective market power mitigation in the 2007 short-term energy markets. When LSEs are substantially hedged by longer-term fixed price energy arrangements, they substantially reduce their exposure to market power in the spot market and, more generally, high spot market prices. Adequate long-term energy contracting also reduces incentives for supply resources to try to elevate spot prices. Market power mitigation measures are in place to reduce the risk of market manipulation and opportunistic exploitation of contingencies and extreme circumstances. However, mitigation should not excessively dampen spot market volatility, as that may encourage LSEs to reduce their forward contract coverage and rely more on the spot markets.

Estimated Mark-up of Short-term Bilateral Transactions

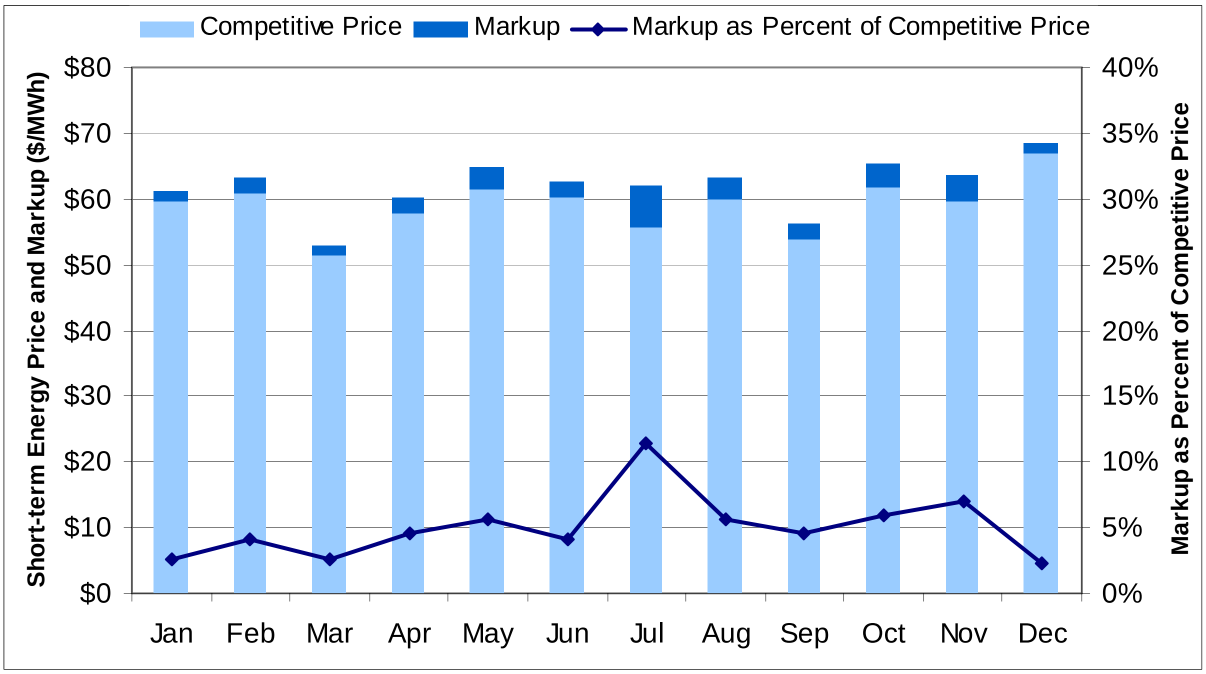
Having no formal forward energy market makes a comprehensive review of competitiveness difficult due to the lack of reporting on transactions in the short-term bilateral energy market. The CAISO has estimated mark-ups for short-term spot market transactions based on data collected from Powerdex, Inc.,[3] an independent energy information company that provides hourly wholesale power indexes in the WECC, as well as short-term purchase cost information provided by the state's three investor owned utilities. The competitive benchmark prices are calculated using a production cost model that determines the hourly system marginal cost by

[3] http://www.powerdexindexes.com/.

incorporating detailed generation unit and system cost information. Figure E.6 shows the monthly average of estimated hourly mark-ups for short-term bilateral transactions. A detailed description of the methodology and assumptions used in the analysis can be found in Chapter 2.

For 2007, monthly short-term mark-ups ranged from 2 to 11 percent, compared to 1 to 16 percent in the prior year. July was the only month when mark-ups were greater than 10 percent, corresponding to the summer high demand period. Overall, 2007 short-term forward markets functioned competitively. Though mark-ups were significant in July, they were highly correlated with high demand conditions and appear to have had minimal cost impacts to California LSEs due to the high level of hedging, which minimized spot market exposure.

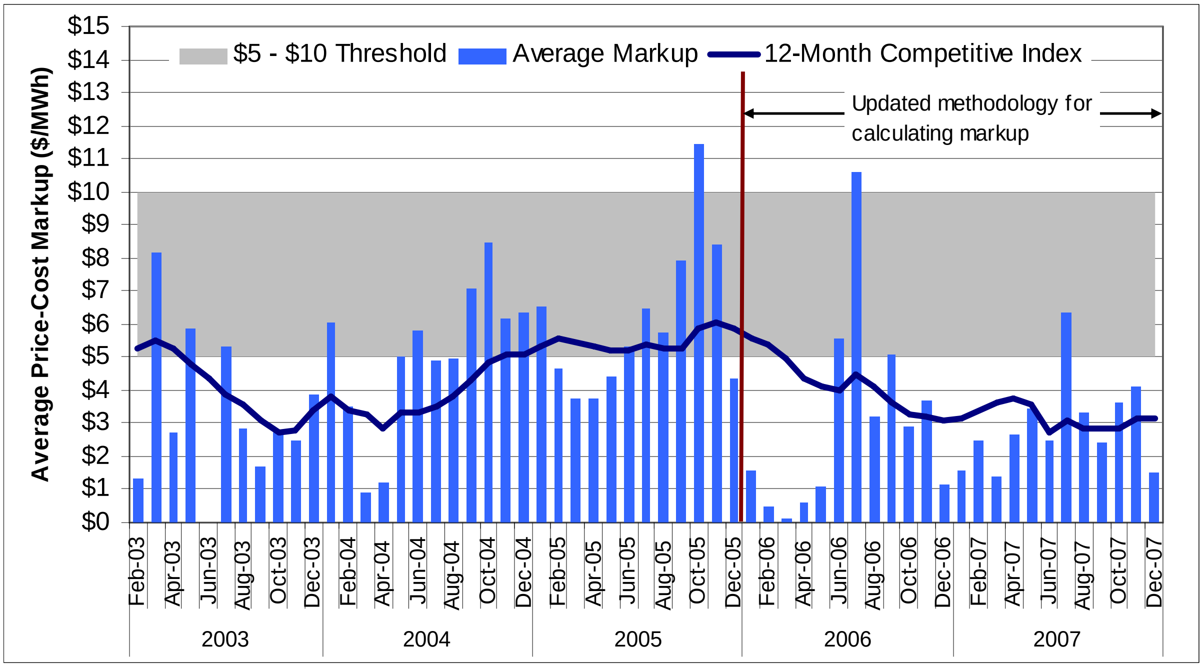
Figure E.6 Short-term Price-Cost Mark-up Index (2007)



Twelve-Month Market Competitiveness Index

Another index the CAISO uses to evaluate market competitiveness is the 12-month competitiveness index. The CAISO developed the index to measure market outcomes over a longer period of time. The index is a volume-weighted twelve-month rolling average of the short-term energy mark-up above estimated competitive baseline cost. The index provides a benchmark to measure the degree of market power exercised in the California short-term energy market during a 12-month period. Experience has shown that the market is workably competitive when the index is within a range of approximately $5 to $10/MWh or below. The index, which crossed this threshold in May 2000 and remained very high during the California energy crisis, served as a barometer for uncompetitive market conditions. The index moved back into the competitive range in May 2002 and has remained in that range through 2007. This indicates that the short-term energy market in California stabilized in late 2001 and has produced fairly competitive results over the past six years. Figure E.7 below shows the market competitiveness index values for the past five years (2003-2007).

Figure E.7 Twelve-Month Market Competitiveness Index (2003-2007)



Revenue Adequacy of New Generation

Another benchmark often used for assessing the competitiveness of markets is the degree to which spot prices support the cost of investment in new supply needed to meet growing demand and replace existing capacity that is no longer economical to operate. Typically, new generation projects would not go forward without having the output of the plant secured through long-term contractual arrangements that would cover most, if not all, of the plant's fixed costs. However, given the lack of information on prices paid in the current long-term bilateral energy and capacity markets, our analysis examined the extent to which spot markets contributed to the economics of investment in new supply capacity given observed prices over the last four years. Clearly a plant would not be built on the expectation of full cost recovery by selling solely into the CAISO's real-time imbalance energy and ancillary service markets. However, this analysis does show the trend in the level of contribution towards a new unit's fixed costs that could have been recovered in these markets over the year. Chapter 2 includes a detailed explanation of the costs and assumptions used in the analysis.

The assessment of the potential revenues a new generation facility (combined cycle or combustion turbine) could have earned in California's spot market in 2007 indicates that potential spot market revenues fell short of a new unit's annual fixed costs (Figure E.8 and Figure E.9). The gap this year is significantly more pronounced given the recently released estimates from the California Energy Commission on the cost of new generation, which were used for purposes of this analysis. The new cost estimates indicate the average annualized fixed cost of a new combined cycle generating unit is $132.6/kW-year (compared to the previous 2003 CEC estimate of $90/kW-year) and the average annualized cost of a new combustion turbine is $162.1/kW-year (compared to previous the 2003 CEC estimate of $78/kW-year). The dramatic increase is primarily due to increases in construction material costs, siting and permitting costs, and the cost of investment capital. While this result is consistent across the past four years, there is a favorable four year trend evident in the combined cycle analysis (Figure E.8). Specifically, the combined cycle analysis shows a trend of net spot market revenues increasing for both Southern (SP15) and Northern (NP15) California with estimated net revenues in 2007 of approximately $84/kW-year and $95/kW-year for Northern and Southern California, respectively, but these estimates are well short of the estimated annualized fixed costs of $132.6/kW-year. While estimated net spot market revenues also increased in 2007 for a new combustion turbine (Figure E.9), net revenues were still well below the $162.1/kW-year estimated break-even point.

Figure E.8 Financial Analysis of New CC Unit (2003-2007)

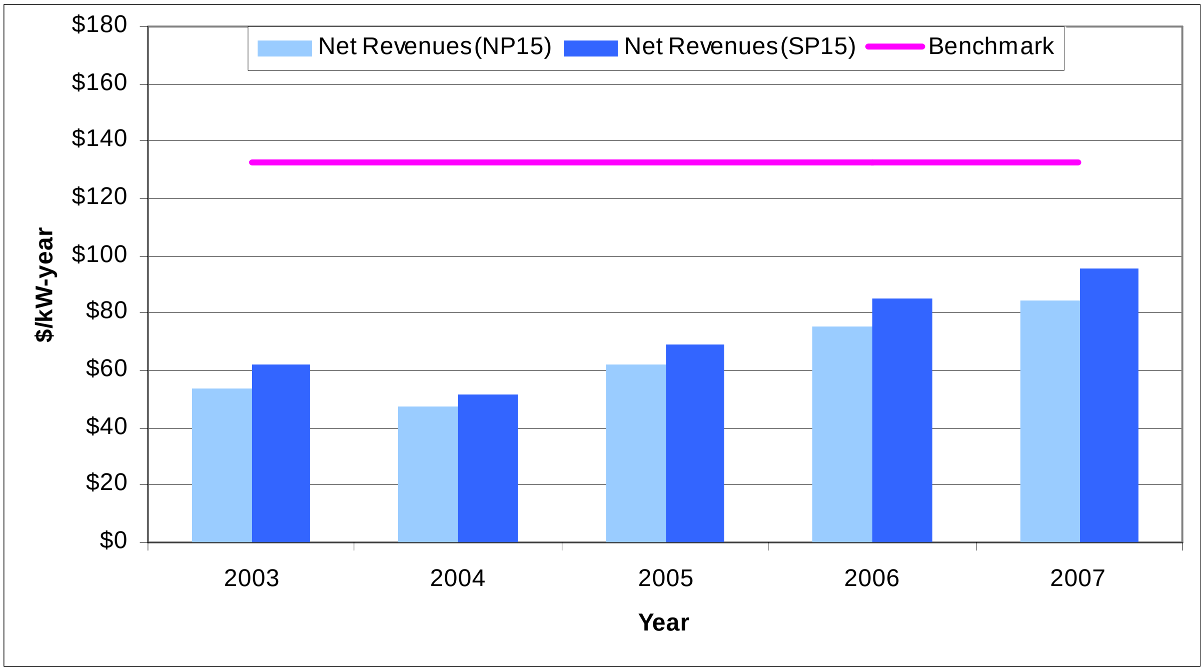
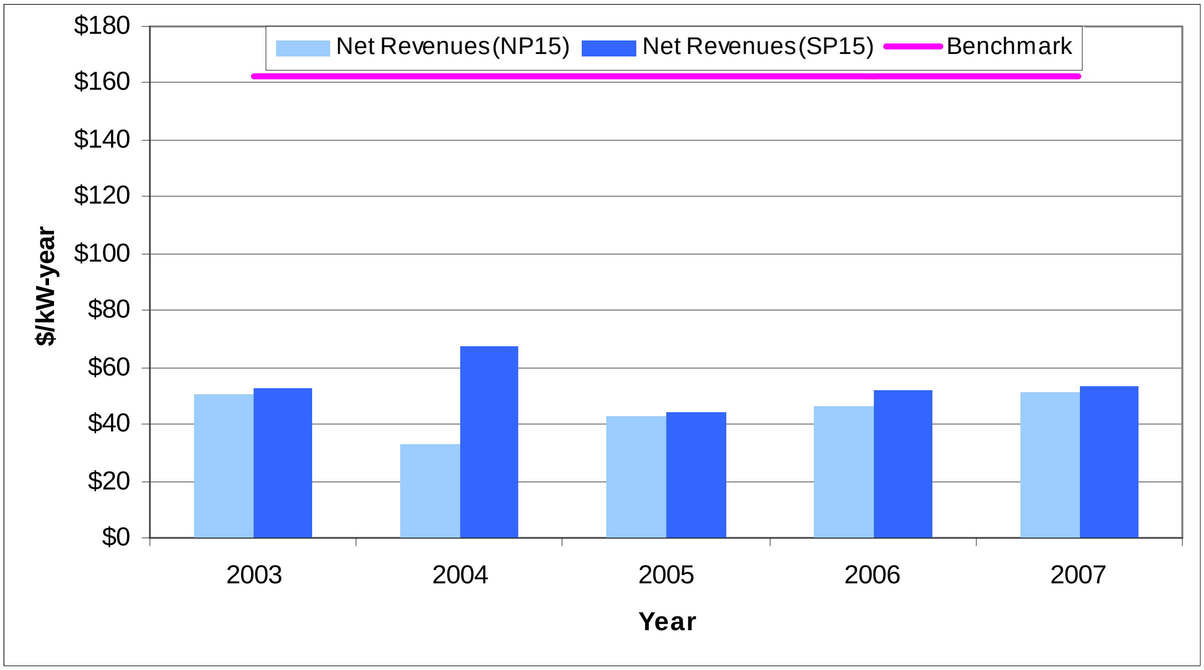


Figure E.9 Financial Analysis of New CT Unit (2003-2007)



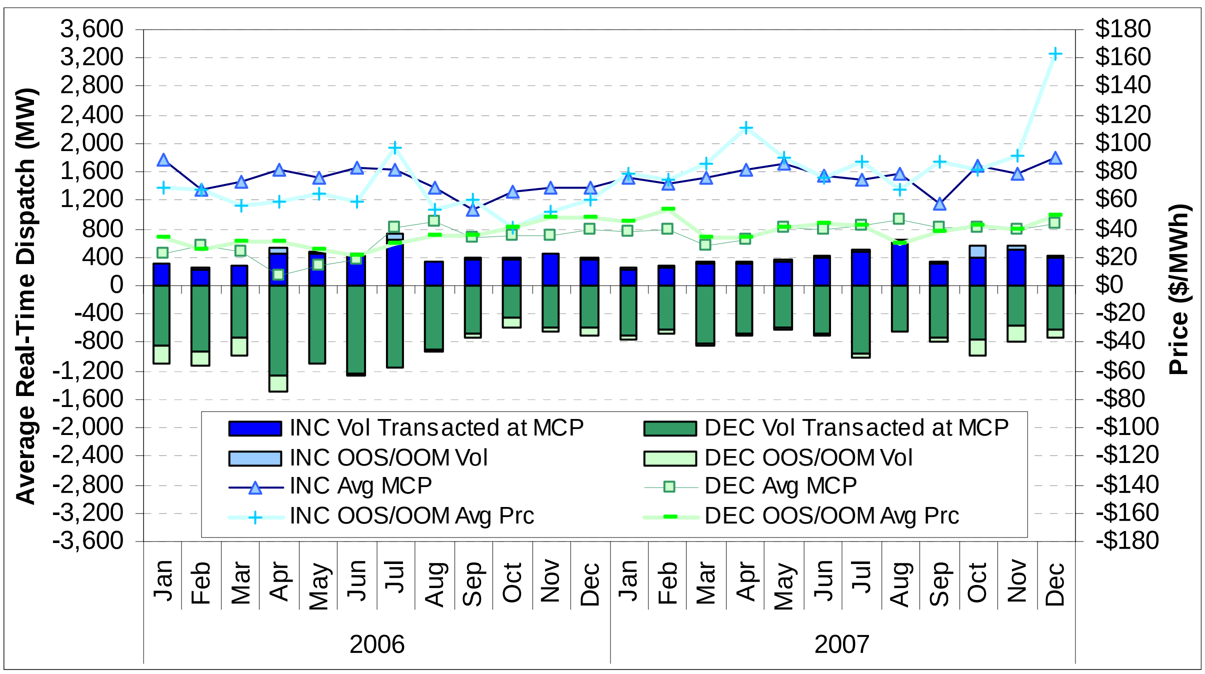
The finding that estimated spot market revenues do not provide for fixed cost recovery underscores the critical importance of long-term contracting as the primary means for facilitating new generation investment. It also suggests that there are deficiencies in the current spot market design that are limiting market revenue opportunities – although it could be alternatively argued that the spot market design is adequate and sending the right investment signal for the current market year (i.e., the generation level from a market efficiency standpoint was adequate in 2007) but the net revenues earned in 2007 are not indicative of future market revenue opportunities, which are the primary driver for new investment. In any case, future market design features that could provide better price signals for new investment include: locational marginal pricing (LMP) for spot market energy, local scarcity pricing during operating reserve deficiency hours, and possibly monthly and annual local capacity markets. The CAISO Market Redesign and Technology Upgrade (MRTU), scheduled for implementation in 2008, will provide some of these elements (LMP, some degree of scarcity pricing). Other design options (formal reserve shortage scarcity pricing mechanism and/or local capacity markets) are being considered for future adoption. In the meantime, local requirements for new generation investment should be addressed through long-term bilateral contracting under the CPUC Resource Adequacy and long-term procurement framework and similar programs for non-CPUC jurisdictional entities.

Real Time Energy Market

For the sixth year in a row, significant forward scheduling by LSEs resulted in low imbalance energy volumes throughout 2007 (Figure E.10). Real-time balancing energy was again overwhelmingly in the decremental direction as a high level of forward scheduling plus unscheduled energy from units committed under the must-offer obligation resulted in frequent over-generation in the real-time imbalance energy market. As shown in Figure E.10, the average hourly levels of decremental dispatches were fairly consistent throughout each month of 2007, averaging close to 800 MWh. In contrast, 2006 saw much higher levels of decremental dispatch during the first half of the year. The difference is most likely due to the abundance of hydroelectric generation in 2006, which frequently created over-generation conditions, requiring larger volumes of decremental dispatch.

Monthly average prices in 2007 for periods when the CAISO was issuing incremental energy dispatches were stable, averaging around $80/MWh for most of the year. Though there was a significant increase in the average cost of incremental Out-of-Sequence dispatch in December 2007, these dispatches were limited to a very small volume of energy. Average monthly prices for periods when the CAISO was issuing decremental dispatches were significantly lower, averaging approximately $40/MWh.

Figure E.10 Monthly Average Real-time Prices and Volumes (2006-2007)



Competitiveness of Real-time Energy Market

The CAISO uses a real-time price-to-cost mark-up index to measure market performance in the Real Time Market. This index compares Real Time Market prices to estimates of real-time system marginal costs. It excludes resources or certain portions of resources that were unable to respond to dispatch instructions for reasons such as physical operating constraints.[4] It is important to note that an index based upon the extremely small volume of transactions in the

[4] The original real-time price-cost mark-up index used system marginal cost based on all resources available for day-ahead scheduling. That competitive benchmark is more applicable to measure competitiveness of day-ahead and short-term energy markets. Only a subset of those resources is used in the calculation of the real-time mark-up.

Real Time Market is not indicative of overall wholesale market competitiveness.[5] Nonetheless, it provides a useful metric for Real Time Market performance.

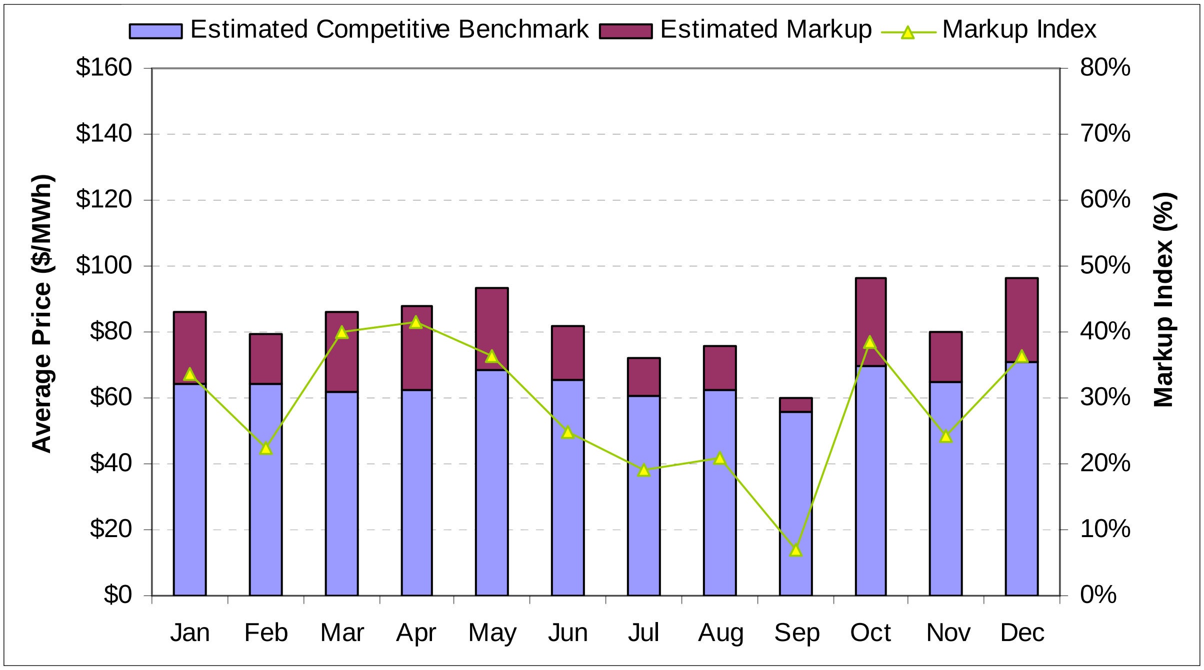
Throughout 2007, estimated monthly average mark-ups in the Real Time Market were generally higher in the off-peak months than in the peak summer months. For example, during the spring (March-May), average monthly mark-ups were in the 35-40 percent range, but declined steadily through the summer to the 10-20 percent range, then increased back to the 30-40 percent range in the fall. Mark-ups were generally lower in the summer months because there were typically more units on-line to provide real-time energy, particularly thermal units with greater ramping capability than are available in the off-peak months. Additionally, peak loads during the summer months in 2007 were fairly moderate, which in turn moderated imbalance energy demands.

While the unusually high mark-ups for the Real Time Market suggest a lack of market competition, it is important to note that the extremely small volumes of energy clearing this market (typically less than 2 percent of the load) coupled with a limited supply of 5-minute dispatchable bids makes this market extremely volatile.[6] High volatility of both price and dispatch quantities coupled with overall low market clearing volumes serve as disincentives for additional supply to enter the market. Given the very small market volumes and high volatility observed in the CAISO Real Time Market, the competitiveness of the day-ahead spot bilateral market is a much more indicative measure of overall spot market competitiveness, and, as reported above, the estimated mark-ups in the day-ahead spot market were much lower, indicating that the spot market was workably competitive in 2007.

[5] Volumes and prices in the Real Time Market are sensitive to a number of factors (i.e., uninstructed deviations, Grid Operator activities taken to mitigate local or zonal reliability issues, unscheduled flows from neighboring control areas, brief perturbations in load) that are outside of fundamental supply and demand conditions that drive market prices. For this reason, and the fact that volumes in the Real Time Market are overall quite small, we look to the spot bilateral market for more meaningful indicators of competitiveness in the wholesale market.

[6] It is important to note that real-time imbalance energy markets are inherently volatile and thus the volatility observed in the CAISO Real Time Market is not necessarily an indication of market design deficiencies.

Figure E.11 Monthly Estimated Mark-up for Real Time Incremental Imbalance Energy Market (2007)



Real-time Congestion (Intra-Zonal)

Intra-zonal congestion occurs when power flows overload the transfer capability of grid facilities within the congestion zones that are modeled and managed in the CAISO day-ahead and hour-ahead congestion management market. Intra-zonal congestion most frequently occurs in load pockets, or areas where load is concentrated with insufficient transmission to allow access to lower priced energy. Intra-zonal congestion can also occur due to generation pockets in which generation is clustered together with insufficient transmission to allow the energy to flow out of the pocket area. In both cases, the absence of sufficient transmission access to an area means that the CAISO has to resolve the problem locally, either by incrementing generation within a load pocket or by decrementing it in a generation pocket.

One significant positive trend that has been reported in prior annual reports has been the sharp reduction in intra-zonal congestion costs. This trend continued in 2007 with intra-zonal congestion costs dropping from $207 million in 2006 to $101 million in 2007. Intra-zonal congestion cost is comprised of three components: 1) Minimum Load Cost Compensation (MLCC) for units denied must-offer waivers, 2) real-time RMR costs, and 3) real-time redispatch costs. Costs for all three of these components are shown in Table E.3. The decline is primarily attributable to lower MLCC payments and reduced RMR dispatch costs. MLCC costs declined by $65 million in 2007, mainly due to the completion of various transmission upgrades in Southern California during 2006, which both raised the cost of MLCC payments in 2006 – due to the need to commit units while the transmission work was being completed – and lowered MLCC cost in 2007 once the upgrades were complete, which relaxed the local constraints that previously required additional unit commitments through the must-offer waiver denial process.

The cost of real-time RMR dispatches declined by $54 million in 2007. Most of this decline is due to a reduction in RMR contracts that was enabled by the introduction of Local Resource Adequacy (RA) requirements in 2007, thus the cost savings from reduced RMR contracts may have been largely offset by higher RA costs which are not accounted for in these figures. The cost savings for these two components of intra-zonal congestion costs in 2007 were partially offset by an increase in the third component, real-time redispatch cost, of $13 million. The increase in this component is largely attributed to the need to redispatch units needed in the Humboldt area that were previously under RMR contracts.

Table E.3 Monthly Intra-Zonal Congestion Costs by Category ($ Million)

	MLCC Costs			RT RMR Costs			RT Redispatch Costs			Total		
Month	**2005**	**2006**	**2007**	**2005**	**2006**	**2007**	**2005**	**2006**	**2007**	**2005**	**2006**	**2007**
Jan	$ 8	$ 10	$ 3	$ 3	$ 13	$ 2	$ 6	$ 4	$ 2	$ 17	$ 27	$ 6
Feb	$ 4	$ 8	$ 2	$ 3	$ 15	$ 1	$ 3	$ 2	$ 2	$ 10	$ 25	$ 4
Mar	$ 3	$ 11	$ 2	$ 5	$ 13	$ 1	$ 3	$ 3	$ 1	$ 11	$ 27	$ 4
Apr	$ 6	$ 27	$ 2	$ 5	$ 8	$ 2	$ 3	$ 6	$ 2	$ 14	$ 41	$ 6
May	$ 14	$ 12	$ 2	$ 5	$ 3	$ 1	$ 2	$ 1	$ 2	$ 21	$ 16	$ 4
Jun	$ 7	$ 15	$ 3	$ 2	$ 4	$ 1	$ 0	$ 0	$ 1	$ 9	$ 19	$ 5
Jul	$ 13	$ 14	$ 7	$ 5	$ 2	$ 1	$ 1	$ 0	$ 2	$ 19	$ 17	$ 10
Aug	$ 14	$ 5	$ 2	$ 9	$ 3	$ 1	$ 1	$ 0	$ 1	$ 24	$ 8	$ 4
Sep	$ 8	$ 3	$ 2	$ 6	$ 2	$ 0	$ 3	$ 0	$ 1	$ 17	$ 5	$ 4
Oct	$ 13	$ 1	$ 10	$ 8	$ 3	$ 6	$ 4	$ 1	$ 8	$ 25	$ 5	$ 25
Nov	$ 12	$ 1	$ 5	$ 5	$ 6	$ 3	$ 6	$ 0	$ 4	$ 23	$ 7	$ 12
Dec	$ 11	$ 2	$ 5	$ 16	$ 7	$ 8	$ 5	$ 0	$ 4	$ 32	$ 9	$ 17
Total	**$ 114**	**$ 109**	**$ 44**	**$ 72**	**$ 80**	**$ 26**	**$ 36**	**$ 17**	**$ 30**	**$ 222**	**$ 207**	**$ 101**

Ancillary Service Markets

In the Ancillary Service (A/S) Markets, prices were stable in 2007, and lower than prices in 2006. Overall, A/S prices decreased 35 percent from a weighted average price of $11.12/MW in 2006 to $7.41/MW in 2007. The average volume of each ancillary service purchased was quite similar to previous years (Figure E.12). The A/S markets also experienced a significant decline in hours of bid insufficiency in 2007 compared to the previous year. With the exception of Non-Spinning Reserve in the summer, bid deficiency occurred in less than one percent of the operating hours (102 hours) in each month for all four services, compared to six percent in 2006 (527 hours), representing an 81 percent decline in the number of bid insufficiency hours (Table E.4). In 2006, bid insufficiency in the A/S markets was particularly high due, to the abundance of hydroelectric energy which displaced thermal generation and generally reduced the available unloaded capacity for providing reserves. With much less hydroelectric energy available in 2007, more thermal units were on-line throughout the year, and more unloaded capacity was available to provide ancillary reserves. The higher frequency of bid insufficiency for Non-Spinning Reserve in July and August can be attributed to tight supply conditions and high opportunity costs during periods of high loads.

Figure E.12 Annual A/S Prices and Volumes (1999-2007)

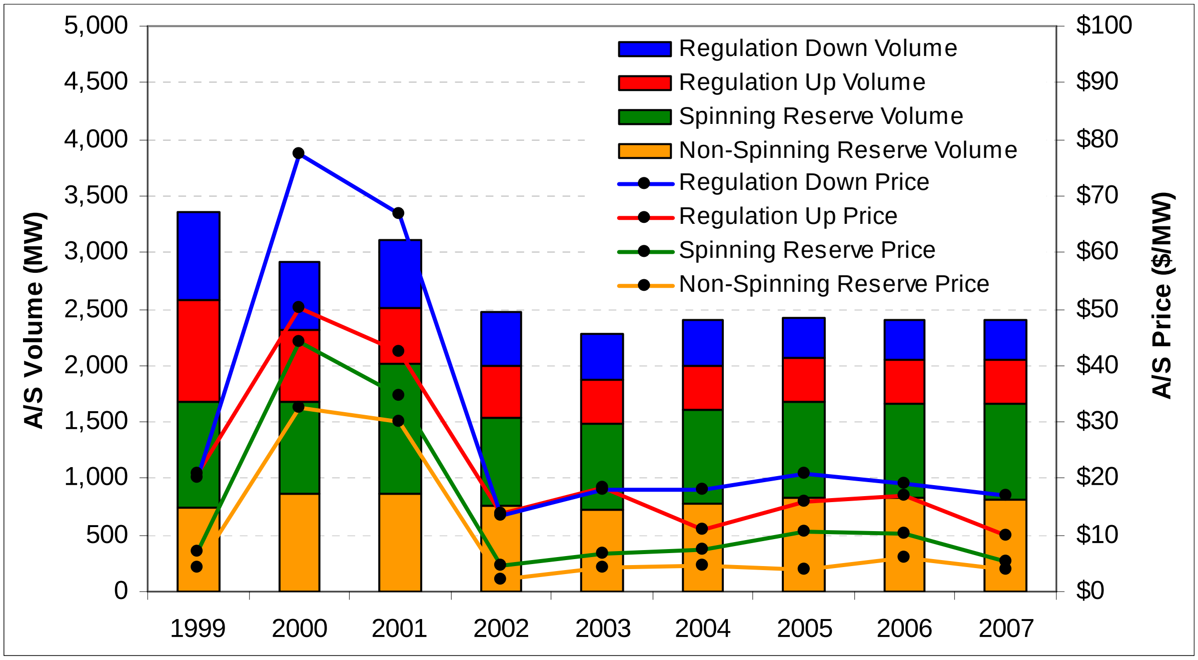


Table E.4 Ancillary Service Bid Insufficiency

	Number of Hours With Shortage				
	Regulation Up	Regulation Down	Spinning Reserve	Non-Spinning Reserve	All Services
2006	159	110	145	113	527
2007	20	11	35	36	102
Percent Δ	-87%	-90%	-76%	-68%	-81%

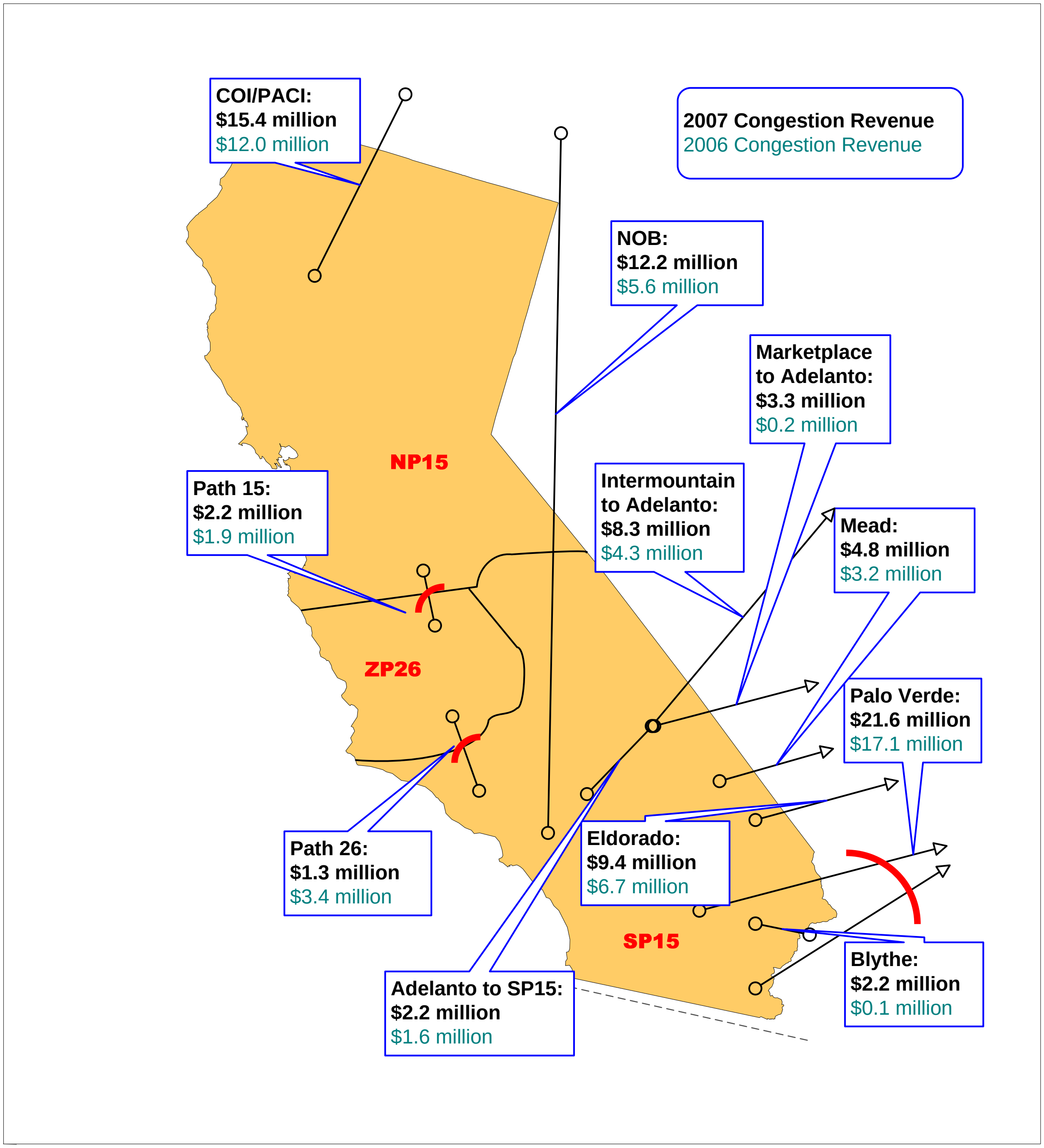
	Average Percent of Requirement Short				
	Regulation Up	Regulation Down	Spinning Reserve	Non-Spinning Reserve	All Services
2006	21%	16%	8%	15%	13%
2007	15%	7%	6%	8%	8%

Inter-Zonal Congestion Market

The CAISO Inter-Zonal Congestion Management Market was also generally stable and competitive in 2007, but inter-zonal congestion did increase significantly from 2006. Total inter-zonal congestion costs in 2007 were $85 million, significantly higher than the $56 million in 2006. Figure E.13 shows the total annual congestion costs for the most commonly congested paths in 2006 and 2007. Congestion costs on Path 15 increased from $1.9 million in 2006 to $2.2 million in 2007. Not surprisingly, Palo Verde continued to have the highest congestion costs in 2007, at $21.6 million (compared to $17.1 million in 2006, which was also the highest). Congestion costs on PACI increased to $15.4 million in 2007 (compared to $12 million in 2006), and had the highest congestion frequency, at 32 percent of total annual hours.

The increase in inter-zonal congestion frequency and costs is mostly attributed to high north-to-south flows during the spring and early summer months, coupled with transmission outages throughout the year and a few distinct events in the fall. During the spring and early summer months, congestion charges were concentrated on PACI and the Pacific DC Inter-tie, as hydro electricity was imported from the Northwest across PACI and NOB to meet California load. The pattern of higher congestion frequency and cost transitioned to Palo Verde and Eldorado in the fall months, as Northwest hydro went into the re-charge season and California shifted to rely more heavily on thermal generation from the Southwest.

Figure E.13 Major Congested Inter-ties and Congestion Costs



Summary and Conclusions

Overall, the CAISO markets and short-term bilateral energy markets were stable and competitive in 2007. This performance reflects the significant strides that California has made since the energy crisis both in terms of infrastructure enhancements (transmission and generation) as well as in forward energy contracting. Medium- to long-term forward energy contracting provides a number of critical benefits to the market. First, it protects LSEs from spot market volatility (i.e., it is an important hedging tool). Second, it shifts spot market risk to the supply side of the market, and, in so doing, largely reduces incentives for suppliers to exercise market power. Finally, it provides a means for facilitating new generation investment. When load is effectively hedged, periodic price spikes impose manageable costs to load and provide important market benefits such as incentives to avoid generation forced outages, revenues for generation fixed cost recovery, and market prices that encourage demand response programs.

In terms of the spot market signals being provided for new generation investment, the spot markets continue to produce net-market revenues that are far short of what would be needed to cover the annualized costs of new generation facilities. Typically, new generation projects would not go forward without having the output of the plant secured through long-term contractual arrangements that would cover most, if not all, of the plant's fixed costs. Nonetheless, this analysis does show the trend in the level of contribution towards a new unit's fixed costs that could have been recovered in the spot markets over the year. The fact that California's spot markets do not provide sufficient market revenues for fixed cost recovery five years in a row underscores the critical importance of long-term contracting as the primary means for facilitating new generation investment. It also suggests that there are deficiencies in the current spot market design that are limiting market revenue opportunities – although it could be alternatively argued that the spot market design is adequate and sending the right investment signal for the current market year, but the net revenue earned in 2007 is not indicative of future market revenue opportunities, which are the primary driver for new investment. In any case, future market design features that could provide better price signals and revenue opportunities for new investment include: locational marginal pricing (LMP) for spot market energy, local scarcity pricing during operating reserve deficiency hours, and possibly monthly and annual local capacity markets. The CAISO Market Redesign and Technology Upgrade (MRTU), scheduled for implementation in 2008, will provide some of these elements (LMP, some degree of scarcity pricing). Other design options (formal reserve shortage scarcity pricing mechanism and/or local capacity markets) are being seriously considered for future adoption.

While six consecutive years of stable and competitive market performance is encouraging, the industry must remain vigilant in addressing its ever growing infrastructure needs, particularly for Southern California. Though approximately 8,900 MW of new generation has been added to Southern California since the energy crisis, which enabled the retirement of 4,300 MW of older inefficient generation, net generation additions for that region have only just kept pace with load growth. Consequently, reliability needs for that region continue to be met, in part, by older less efficient generation, which cannot be sustained indefinitely. Moreover, major state environmental policies, such as greenhouse gas reductions, Renewable Portfolio Standards (RPS), and a potential ban on once-through cooling systems, will call for even more aggressive and coordinated action on addressing infrastructure issues.