California Public Utilities Commission

2008 Resource Adequacy Report

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2008 Resource Adequacy Report

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Table of Acronyms

AS	Ancillary Services
CAISO	California Independent System Operator
CAM	Cost-Allocation Methodology
CCGT	Combined Cycle Gas Turbine
CEC	California Energy Commission
DA	Direct Access
DASR	Direct Access Service Request
DG	Distributed Generation
DR	Demand Response
DSM	Demand Side Management
EAF	Equivalent Availability Factor
ED	Energy Division
EFORd	Equivalent Forced Outage Rate of demand
ELCC	Effective Load Carrying Capacity
ERRA	Energy Resource Recovery Account

ESP	Electricity Service Provider
ETC	Existing Transmission Contract
FERC	Federal Energy Regulatory Commission
FOH	Forced Outage Hours
HE	Hour Ending
ICPM	Interim Capacity Procurement Mechanism
IOU	Investor Owned Utility
LD	Liquidated Damages
LI	Load Impact
LOLP	Loss of Load Probability
LSE	Load Serving Entity
MCC	Maximum Cumulative Capacity
MOO	Must Offer Obligation
NCF	Net Capacity Factor
NDC	Net Dependable Capacity
NERC	North American Reliability Corporation
NQC	Net Qualifying Capacity
PRM	Planning Reserve Margin
QC	Qualifying Capacity
QF	Qualifying Facility
RA	Resource Adequacy
RAR	Resource Adequacy Requirement
RMR	Reliability Must Run
RPS	Renewable Portfolio Standard
SCP	Standard Capacity Product
SFTP	Secure File Transfer Protocol
TAC	Transmission Access Charge
TCPM	Transitional Capacity Procurement Mechanism
TIC	Total Installed Capacity
ULR	Use Limited Resources

1 Executive Summary

The intent of the Resource Adequacy (RA) program is to ensure that sufficient capacity is available to meet the needs of California Public Utilities Commission (CPUC) jurisdictional Load Serving Entities (LSEs)[1]. LSEs provide RA capacity to the California Independent System Operator (CAISO) to reliably operate the electric grid; CPUC jurisdictional LSEs provided 49,153 megawatts (MW) of RA capacity to CAISO during the forecasted peak month of August 2008. This Report provides a review of the CPUC's RA program, summarizing RA program experience during the 2008 RA compliance year. While this report does not make explicit policy recommendations, it is intended to provide factual information relevant to current RA rulemakings (R.05-12-013 and R.08-01-025) and ongoing implementation of the RA program in California.

During 2008, no outages or other significant reliability problems occurred within the CAISO due to availability of adequate generating resources. CAISO relied substantially on RA resources to ensure this high level of electric reliability. The trend, noted in the 2007 Resource Adequacy Report, toward reduced use of backstop procurement by CAISO via Reliability Must-Run (RMR) and Federal Energy Regulatory Commission Must-Offer Obligation (FERC MOO) continued during 2008 resulting in further reductions in out of market procurement costs. CAISO's FERC MOO costs in 2008 are only one percent of the 2006 value. This decline in backstop procurement to meet operational needs is a key metric of the success of the RA program.

An important driver of this successful reduction in backstop procurement is that RA is increasingly focused on precise reliability needs in addition to a system energy perspective. During each month of 2008 CPUC jurisdictional LSEs provided at least 23,958 MW of RA capacity from physical resources in specific local areas. CPUC created one new local area in Big Creek/Ventura for the RA program and adopted procurement requirements to ensure generation availability in the load pocket. Another feature for 2008 is the new Path 26 Counting Constraint which ensures that adequate RA capacity is available on both sides of Path 26 so that reliable service is maintained without risk of overloading Path 26, the transmission connection between Pacific Gas and Electric's and Southern California Edison's service territories.

2 2008 Load Forecast and Resource Adequacy Program Requirements

Each year, the RA program requires LSEs to submit a series of filings including load forecasts and compliance showings. Generally, there are two rounds of year-ahead filings due in September and October and twelve month-ahead filings. Each compliance filing is preceded by a load forecast for the same period.

[1] Commission Jurisdictional LSEs include all Investor Owned Utilities (IOUs) Electricity Service Providers (ESPs) and Community Choice Aggregators (CCAs)

2.1 Yearly and Monthly Load Forecast Process

The RA program relies on load forecasts supplied and checked by the California Energy Commission (CEC) as the foundation for each LSE's RAR. The load forecast used in the RA program for system is the most recent CEC "1 in 2" monthly load forecast that is available as of the time the Resource Adequacy Requirement (RAR) is established for the compliance year.

In order to establish the System RAR, CEC staff reviewed load forecasts submitted by each LSE, reconciled those load forecasts against its own forecast (from May 2007) for the entire Investor Owned Utility (IOU) service territories, and generated an individual load forecast for each LSE for each month of 2008. For the 2008 Year-Ahead System RA filings due in October of 2007, CPUC staff mailed an individual load forecast to each LSE by certified mail in July of 2007. This is summarized in Table 1 below.

According to the RA program rules, LSEs can submit monthly load forecasts to the CEC to show any changes in load expected due to load migration. The CEC then checks the revised load forecasts to make sure they remain plausible and are within a tolerance level to the statewide forecast, then supplies each LSE with its adjusted monthly load forecast. The monthly load forecast adjustments are summarized in Table 2.

2.1.1 Yearly Load Forecast in 2008

The CPUC RA obligation is based on two levels of load forecasting done by the LSEs and the CEC. D.05-10-042 requires LSEs to submit historical sales figures and a projected forecast for the following year, based on a reasonable assumption of load growth and customer retention. These forecasts are submitted to the CEC and CPUC for evaluation. The CEC worked to clean the data, adjust for transmission losses, and adjust the IOU load for customers returning from direct access. The CEC developed a trigger for a plausibility adjustment when the aggregate of LSE load forecasts in an IOU service area failed to match the CEC's own load forecast for that IOU service area. As specified by D.05-10-042, adjustments were made to account for the impact of energy efficiency (EE), distributed generation, (DG) and coincidence of peak. Table 1 shows the aggregate LSE submissions for 2008 and the adjustments that were made across all three IOU service areas. These adjustments include plausibility adjustments to account for customer retention, demand side management adjustments, and an adjustment to add load in aggregate to bring the total forecasts to within one percent of the CEC's service area forecasts. Finally, aggregate service area forecasts are adjusted for coincidence. An outline of the process of completing these adjustments was supplied by the CEC during workshops in January of 2009.

Steps in implementing RA Year Ahead Forecast Adjustments – presented by CEC staff in January 2009.

1. Adopt CEC Service Area forecasts
2. Develop reference direct access total forecast by service area based on Direct Access Service Request (DASR) activity and LSE forecasts.

3. Develop reference current peak demand estimate for each LSE based on DASR activity, month-ahead load forecasts, and other data.
4. Compare IOU forecasts to CEC forecast. Where IOU forecasts are significantly inconsistent with CEC forecast for reasons other than load migration, adjust IOU forecasts individually.
5. Compare ESP forecast to current peak demand estimate from step 3. If the difference is greater than the tolerance threshold (i.e., forecast is less than 90-95 percent of current loads), staff evaluates the reasonableness of the forecast. Additional information may be requested from the ESP. Based on this evaluation a plausibility adjustment may be applied to bring the forecast up to an appropriate level.
6. Apply adjustments for incremental effects of demand side programs.
7. Apply the pro rata adjustment to bring the total of the forecasts to within 1 percent of the CEC service area forecast.
8. Evaluate the reasonableness of the pro rata adjustment for each LSE and service area. For example, if the IOU and CEC forecasts are close, the IOU pro rata adjustment should not exceed the amount of load that is forecast to return to bundled service, developed in step 2.
9. If step 8 indicates pro rata adjustment is too large, repeat step 5-8 as needed.
10. Apply coincidence adjustments.

Because the historic and forecast data submitted by participating LSEs contain market sensitive information, results are discussed and presented in aggregate.

Table 1. 2008 Aggregated Load Forecast Data (MW)

2008 RA FORECAST ADJUSTMENTS												
	MONTHS											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ENERGY COMMISSION FORECAST												
Total	29,627	29,710	29,352	30,331	35,597	38,667	43,326	45,976	41,323	35,570	30,769	31,809
	100.232%	97.330%	97.714%	97.637%	99.209%	97.654%	96.915%	98.542%	97.084%	98.504%	96.822%	96.875%
AGGREGATE SUBMITTED FORECASTS												
Total	29,248	28,316	28,144	28,987	34,634	37,082	41,298	45,502	39,428	34,411	29,243	30,360
CEC Adjustment for Plausibility/Migrating load												
	470	627	562	655	705	702	716	(173)	713	649	568	472
NET SERVICE AREA DEMAND SIDE MANAGEMENT ADJUSTMENT												
Total	(22)	(25)	(25)	(27)	(24)	(25)	(24)	(23)	(23)	(23)	(20)	(18)
NET MW SHORT												
Total	(150)	458	357	413	139	458	839	350	729	220	634	631
Revised LSE FORECASTS Before Coincidence Adjustment												
Total	29,545	29,375	29,038	30,027	35,454	38,218	42,828	45,656	40,847	35,258	30,425	31,445
Final LSE FORECASTS ADJUSTED FOR COINCIDENCE – Used for RA Procurement Requirements												
Total	29,039	28,775	27,827	28,858	33,620	36,294	42,168	44,734	40,281	32,948	29,019	31,105

Source: CEC Staff aggregate Load Forecast adjustments

2.1.2 Monthly Load Migration Adjustments in 2008

D.05-10-042 outlined a process to adjust an LSE's load forecast on a monthly basis. The CEC and CPUC administered the program in 2008. The LSEs were directed to submit revised forecasts two months prior to the filing month, which is one month prior to the RA Monthly filing due date. These load forecast adjustments are solely for the purposes of accounting for load migration.

The overall pattern of aggregate monthly LSE migration adjustments changed from 2007 compliance year to 2008 compliance year. As in previous years, there was a net increase in total monthly RA requirements as a result of LSE forecast adjustments but the aggregate adjustments were significantly lower and concentrated in different months than in previous years. Load forecast adjustments increased RA requirements in all months of 2008 compliance year generally by one to two percent, which was less than the approximately three percent increases in 2007 compliance year.

Table 2 shows adjustments between 84 and 490 MW in 2008. This is a significant change from the load adjustment of 859 MW that occurred during the peak months of 2007. Also contrasting with previous years, the largest net increases in aggregate forecast load due to migration adjustments were concentrated in the winter and spring months instead of the May through November period seen in 2007.

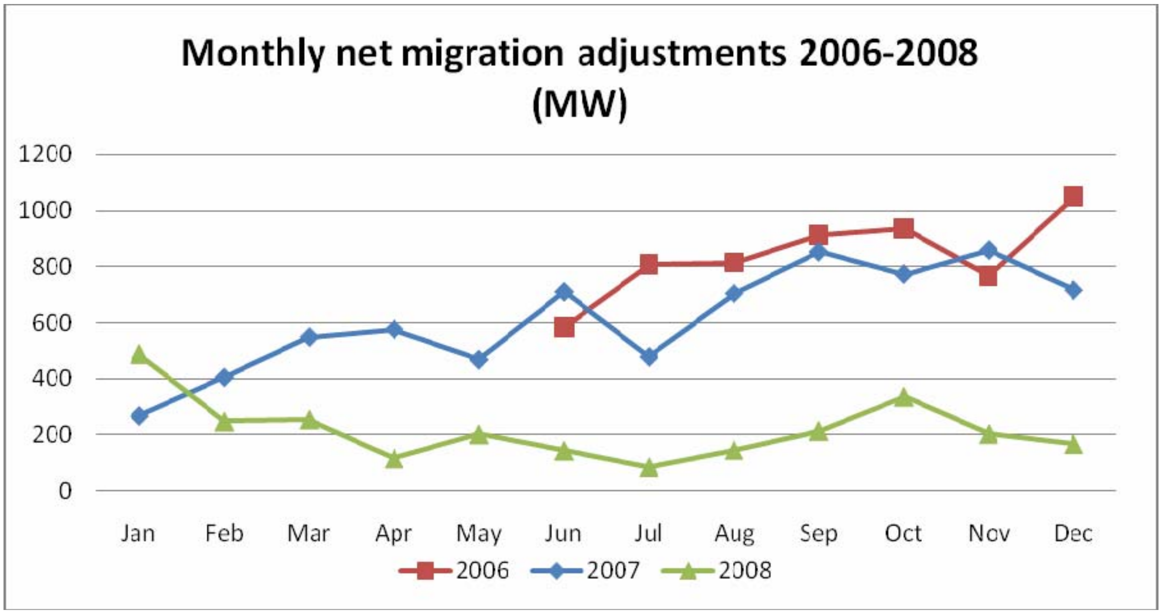
Table 2. Summary of Load Forecast Adjustments in 2008 (in MW)

	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	Total Forecasts sent out in Jul. 2007	29,039	28,775	27,827	28,858	33,620	36,294	42,168	44,734	40,281	32,948	29,019	31,105
2	2008 Monthly Load Forecast adjustments	490	248	255	115	202	143	84	146	214	336	203	167
3	Total forecast used in 2008 monthly RA filings	29,529	29,023	28,082	28,973	33,822	36,437	42,252	44,880	40,495	33,284	29,222	31,272
4	Line 3 as percentage of Line 1	102%	101%	101%	100%	101%	100%	100%	100%	101%	101%	101%	101%

Source – Aggregated Load Forecast Adjustments submitted to the CEC and CPUC through 2008

Figure 1 illustrates the trend in monthly net migration adjustments made to LSE forecasts during compliance years 2006-2008. The Month Ahead RA filing process began in June 2006. Overall there has been a large decrease in net load adjustments since 2006, averaging in a 78 percent decrease in net adjustments comparing the months of June through December 2006 with the months of June through December 2008. In addition, 2008 compliance year saw the exit of an LSE (APS Energy Services) from the market in California.

Figure 1 Monthly Net Migration Adjustments from 2006-2008



Source: Monthly Forecast adjustments submitted by LSEs, 2006-2008

As with previous compliance years, the CEC has been required to significantly adjust LSE Year Ahead forecasts due to implausible LSE customer retention assumptions. The methodology the CEC uses to adjust for plausibility is explained in Section 2.1.1. Eight ESPs and two IOUs did not require plausibility adjustments in any month of either 2008 or 2009 compliance year. Correspondingly, plausibility adjustments are concentrated in a relatively small number of LSEs. One IOU required a large downward adjustment in August of 2008 and 2009 compliance year and four ESPs required large upward plausibility adjustments in several months over the same period. Only three ESPs were responsible for the entirety of all upward plausibility adjustments, and a single ESP required on average 73 percent of all upwards plausibility adjustments in 2008 compliance year. Of the three ESPs that required plausibility adjustments in 2008 compliance year, two of them also required a plausibility adjustment in the 2009 year- ahead forecast. Overall, the monthly load migration adjustments were significantly decreased from previous years, and plausibility adjustments contributed more significantly to total adjustments made to LSE forecasts.

2.2 2008 System RA Requirements for CPUC Jurisdictional LSEs

For every month of 2008, CPUC-jurisdictional LSEs have satisfied their individual and collective system RAR. The total MWs of RA resources[2] procured exceeded the total System RAR by between 1 percent and 25 percent, depending on the month.

During the forecasted, but not actual, peak month of August 2008, the CPUC's jurisdictional LSEs were collectively required to procure 48,533 MW of resources. Collectively, the LSEs procured 101 percent of the total System RAR, or 49,153 MW,

[2] RA Resources include unit specific in-state physical generation, imports, LD contracts, Demand Response programs, and DWR contracts.

which represents 828 MW in reserves beyond that required by the RA program. Table 3 shows CPUC jurisdictional RA procurement for each month of 2008; LSE individual forecasts are summed each month after being adjusted for load migration, resources are compared to the resulting RA obligation, and resources procured as percentage of RA obligation and forecast peak demand is shown to the right of the table. The Demand Response resources are subtracted from load before the Planning Reserve Margin (PRM)[3] is applied to create the RA obligation, and non-DR resources are compared to the resulting RA obligation. Compliance is represented by procurement over 100 percent of the RA obligation and over 115 percent of the peak demand forecasts. The Demand Response listed includes a small amount of non-IOU DR resources listed independent of the amount that is part of the annual IOU DR allocation.

Table 3. 2008 RA Filing Summary for CPUC Jurisdictional Entities (MWs)

A	B	C	D	E	F	G	H
2008	Demand Forecast[1]	Demand Response[2]	Net Demand	RAR[3]	Total Resources Reported[4]	Resources Reported as % of RAR	Resources Reported as % of Net Demand
			D=B-C	*E=D*1.15*		*G=F/E*	*H=F/D*
Jan	29,529	2048	27,174	31,603	39626	125%	146%
Feb	29,023	2048	26,975	31,021	37816	122%	140%
Mar	28,082	2047	26,035	29,940	34821	116%	134%
Apr	28,973	2047	26,926	30,965	36136	117%	134%
May	33,822	2396	31,426	36,140	40547	112%	129%
Jun	36,437	2629	33,808	38,879	44125	113%	131%
Jul	42,252	2670	39,582	45,519	48771	107%	123%
Aug	44,880	2677	42,203	48,533	49153	101%	116%
Sep	40,495	2653	37,842	43,518	47463	109%	125%
Oct	33,284	2348	30,936	35,576	38445	108%	124%
Nov	29,222	2043	27,179	31,256	34871	112%	128%
Dec	31,272	2046	29,226	33,610	40544	121%	139%

Source: Aggregated LSE Monthly RA Filings[5]

2.3 Local RA Program

Beginning for the 2007 compliance year, LSEs demonstrate annually that they have acquired adequate generation capacity within defined, transmission-constrained areas. New Local RA obligations were established in D.07-06-029 that added a new Local Area, Big Creek/Ventura beginning in 2008 compliance year. Aggregation of Local Areas in SCE service territory was not approved for 2008 compliance year, and

[3] The planning reserve margin accounts for load forecast errors, resource outages, and other issues that can affect forecast need.

[4] The amount in this column differs from Total Resource Adequacy Capacity in Appendix 1 in that Table 3 does not add DR to other resources procured, while Appendix 1 includes DR in the total RA Capacity Column

[5] The Monthly CEC Load Forecast is the same forecast as applicable to the Monthly Filings, from Line 3 in Table 2.

LSEs are ordered to procure generation in LA Basin and Big Creek/Ventura separately, although aggregation of Other PG&E Local Areas was preserved for 2008 compliance year. Other aspects of the Local RA program remained unchanged.[6]

2.3.1 Local RA Procurement in 2008

Pursuant to the CAISO 2008 Local Capacity Technical Analysis[7], D.07-06-029 established 2008 compliance year Local RA obligations and LSEs were ordered to procure Local RA capacity in each of five Local Areas defined by the CPUC in fulfillment of their Local RA obligations. Big Creek/Ventura was added to LA Basin, San Diego, Greater Bay Area, and Other PG&E Local Areas as a new Local Area for 2008 compliance year. Overall Local RA procurement for 2008 is summarized in Table 4. 2008 year-ahead Local RA filings were due October 31st, 2007. CPUC jurisdictional LSEs procured Local RA Resources sufficient to meet CPUC jurisdictional Local RA obligations in all five Local Areas of California in 2008, with procurement exceeding Local RA by seven percent overall for all Local Areas and from one to eleven percent in each Local Area.

Table 4. Local RA procurement in 2008

Local Areas in 2008	Total LCR	CPUC jurisdictional Local RAR	Minimum Physical Resources Reported[8]	Local RMR/DR credit claimed	Min monthly procurement as percent of Local RAR[9]
LA Basin	10,130	9,228	8,730	1,015	106%
Big Creek/Ventura	3,658	3,332	3,146	232	101%
San Diego	2,919	2,912	2,627	564	110%
Greater Bay Area	4,688	4,350	3,868	899	110%
Other PG&E Local Areas	5,904	5,477	5,587	485	111%
Totals	27,299	25,299	23,958	3,195	107%

Source: Aggregated 2008 Local RA filings

2.4 Total RA Resources Available to CAISO in 2008

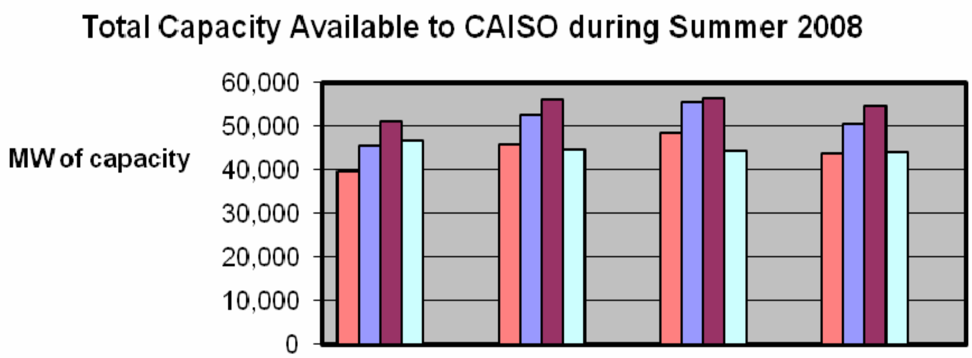
The CAISO administered their Interim Reliability Requirements Program Tariff in coordination with the CPUC's RA Program beginning in 2006 and continuing into 2008. In addition to CPUC jurisdictional LSEs, the CAISO also received RA filings from non-jurisdictional LSEs that added to the capacity available to the CAISO.

Figure 2 compares the total LSE forecasts used for compliance across the CAISO against the CAISO Procurement obligation, total RA procured by LSEs within CAISO, and the actual CAISO peak load in the summer months of 2008. In all months capacity available to CAISO exceeded the monthly peak load. Actual peak load for 2008 occurred

[6] The Local RA program is discussed in Section 3.3 of the 2007 Resource Adequacy Report
[7] LCR studies and materials for 2008 and previous years is posted at the following link: Posted online via the following link: http://www.caiso.com/1c44/1c44b8e0380a0.html
[8] RA procurement varies monthly. The figures presented here represent the minimum procured in any month.
[9] Amounts greater than 100 percent indicate procurement beyond local RA requirements which are designed to ensure local area reliability.

in June of 2008 when capacity resources procured by all LSEs (CPUC jurisdictional and non-CPUC jurisdictional) totaled 51,038 MW of resources to meet 46,789 MW of actual CAISO peak load. However, the actual peak load in June exceeded the aggregate RA obligation of LSEs within the CAISO. If LSEs had not provided more RA resources than required during June, it is possible that backstop procurement would have been needed to maintain reliability. System RA procurement including Demand Response resources across the CAISO ranged between 51,038 MW (June) and 56,544 MW (August), or between 102 percent and 112 percent of CAISO total procurement obligations.

Figure 2. Total CAISO Summer 2008 Forward Procurement Obligation and Forward Procurement vs. LSE Demand Forecast and Actual Monthly Peak Demand (MW)



	Jun-08	Jul-08	Aug-08	Sep-08
Load Forecasts used for compliance	39,697	45,844	48,417	43,908
Month Ahead Commitment Obligation	45,651	52,720	55,679	50,494
Total Capacity available to CAISO (MW)	51,038	56,155	56,544	54,654
Actual Peak Loads	46,814	44,622	44,511	44,185
CAISO Capacity available as percent of actual peak load	109%	126%	127%	124%
CAISO Capacity available as percent of Month-Ahead Commitment Obligation (100% or Greater is Compliant)	112%	107%	102%	108%

Summer 2008

Source: Aggregated data compiled from CAISO RCST Analysis and checked against Monthly RA Filings

Table 13 (Appendix 1) illustrates total procurement during the summer of 2008 for all LSEs by contract type and relates procurement to the CAISO procurement obligation. The data represented in Figure 1 derives from Table 13. Significantly, 65 percent to 69 percent of all procured resources for summer 2008 were unit specific non-DWR physical resources within the CAISO; this is higher than in 2007 by around 4 percentage points. Seven percent to 11 percent were non-DWR imports and about 5 percent were non-DWR Liquidated Damages contracts. The remaining 20 to 23 percent is comprised of DWR and other resources.

3 Counting RA Resources

During the development of the RA program, the Commission established counting conventions for the different resource types which are summarized in previous Commission decisions. The Net Qualifying Capacity (NQC) for each resource is computed based on the counting conventions for the applicable resource type. Each year, the CAISO posts on their website the NQC for each resource that is eligible to sell NQC to CPUC jurisdictional LSEs. This has been done for compliance years 2006 to 2009.[10] Significant new resources were added to the NQC list for 2008, including the Long Beach and Mesquite Power generating units, the peakers built by SCE, and a number of smaller units. In total, over 2,000 MW of new capacity was added to the NQC list for 2008, including both new resources and incremental additions to existing resources.

3.1 Introduction to Net Qualifying Capacity

NQC is the amount of a resource's capacity that can be counted for RA compliance filings. Qualifying Capacity (QC) represents the maximum capacity eligible to be counted for meeting the CPUC's RAR, prior to assessing the deliverability of the resource.[11] The CAISO adjusts QC for deliverability; the resulting value is the NQC. QC counting conventions vary by resource type, as described throughout this section, but it is intended to reflect the expected capacity value that will be available to the CAISO during periods of system peak demand. An overview of Net Qualifying Capacity can be found in the 2006 RA report. Examples of QC counting rules include:

- Thermal resources: QC values are the net dependable capacity of the resource.
- Hydro resources: QC values for each month are the capacity available during that month in a 1-in-5 dry year. The operational definition of a 1-in-5 dry year is the 4th driest of the most recent 20 years of available data.
- Intermittent resources, including wind, solar, biomass, and as-available cogeneration: QC values are calculated for each month of the year based on historic performance. The counting convention for wind resources varies by the length of performance data available. Counting conventions for new intermittent resources of other resource types are not defined. For wind units with:
    - At Least Three Years of Data: A three-year rolling average of actual production during the SO1 (Standard Offer 1) Peak period.[12]
    - Between Two and Three Years of Data: A three-year average of SO1 production will be used for months with sufficient available data; a two-year average will be used for other months.[13]

[10] NQC information, including the NQC list for 2008 is posted here: http://www.caiso.com/1796/179688b22c970.html

[11] Most QC counting rules were adopted in D.04-10-035, by reference to the CPUC Workshop Report on Resource Adequacy Issues, June 15, 2004, Section 5.0. However, some additions and revisions have been made in subsequent RA decisions as referenced below.

[12] D.05-10-042, Section 7.7

[13] D.07-06-029, Section 9.2

- Less than Two Years of Data: The average production factor in the Transmission Access Charge (TAC) area multiplied by the unit's NDC will be used in place of unit-specific data in the three-year formula.[14] For example, if the average wind unit production in the TAC area as a percent of NDC during June of year 1was 23 percent, year 2 was 22 percent, and year 3 was 24 percent, and the new unit production for June was 21 percent of NDC for year 3, the unit's QC for June would be 22 percent of its NDC ((23 + 22 + 21)/3 = 22).
- New Units: The average wind production factor in the TAC area multiplied by the unit's NDC will be used for all data points in the three-year formula, as shown above.[15]

3.2 Establishment of CAISO'S NQC Values for 2008

Significant changes have occurred to the NQC list since posting the list began for the 2006 compliance year. Several new resources have been added, the format of the list has changed, and now there is more information posted on the list such as Zonal and Local Area designation. The update of the NQC list was completed for the following adjustments:

- Updated values for resources whose counting conventions include historical data (e.g. wind and solar without backup resources).
- Updated values for resources with erroneous or missing NQC that may have been listed in error in the previous NQC posting. This update included modifications to the NQC by the CAISO pursuant to its testing and verification authority under section 40.5.2 of its Tariff.
- Added Zonal and Big Creek/Ventura Local Area designations, to support the implementation in the 2008 compliance year of the Local RA Program and implementation for the 2008 compliance year of the Path 26 counting constraint.

The timeline for the 2008 NQC update is summarized in Table 5.

[14] Ibid.
[15] Ibid.

Table 5. 2008 NQC Timeline

April 24, 2007	CPUC issues a data request to IOUs for QC values of renewable & QF resources. To be received by May 15, 2007.
May 15, 2007	CEC receives all data for QC values of renewable & QF resources.
May 18, 2007	CAISO issues market notice for annual NQC update & notice for resource owners and scheduling coordinators to submit NQC information for changes and updates only. To be received by June 11th.
June 6, 2007	CEC provides CAISO updated QC values of renewable and QF resources.
June 11, 2007	Final date for CAISO to receive data from resource owners & scheduling coordinators.
June 29, 2007	CAISO updates the annual NQC list for RA compliance year 2008.
July 9, 2007	CAISO issues market notice confirming that NQC values have been updated for RA compliance year 2008.

3.3 Aggregate NQC Values 2006, 2007, 2008, and 2009

Table 6 shows aggregate NQC values from the CAISO NQC list for 2006-2009. In compiling the totals, most facilities were given a single, year-round NQC value. Some facilities such as wind and solar units without backup were given twelve monthly NQC values due to performance variations between months. For those facilities that were given monthly NQC values, this table uses August NQC values for the annual total.

Table 6. NQC for 2006-2009

Year	Total NQC	Total Number of Scheduling Resource IDs	Net NQC change	Scheduling Resource ID additions
2006	46,687	563		
2007	46,504	572	-183	9
2008	48,056	600	1,552	30
2009	48,899	613	843	13

Source: CAISO NQC lists

While the total NQC available for purchase in 2008 increased due primarily to over 1000 MW of new resources, the increase for 2009 is largely due to increased capacity from existing resources.

3.4 Import Allocations for 2008

The CAISO allocated available import capacity to CPUC jurisdictional and non-CPUC jurisdictional LSEs to ensure the State was not relying on more imports than could be accommodated by the current transmission system. Throughout the summer of 2008, the CAISO allocated 12,889 MW out of 17,196 MW of import capacity to LSEs, while 4,307 MW was allocated to existing transmission contracts (ETCs). In their monthly RA filings, all LSEs in CAISO reported between 3,923 and 7,317 MW of import capacity. Table 7 shows the aggregated amount of import allocation provided to LSEs. It also shows the amount of import allocations used and the difference between the allocations and the amount used. LSE's showed a preference for instate generation, using between 27 and 62 percent of their total import allocations during the summer of 2008, down significantly from 2007's range of 45 to 65 percent. Imports represented between 8 and 13 percent of all RA capacity.

Table 7. 2008 Import Allocations and Usage (MW)

	June	July	August	Sept.
Import Allocations provided to LSEs for use in RA filings	12,889	12,889	12,889	12,889
Import Allocations provided for ETCs	4,307	4,307	4,307	4,307
Total Import Capability	17,196	17,196	17,196	17,196
Imports shown by CPUC jurisdictional LSEs	--	--	--	--
Unit-Specific	1,172	2,149	2,506	2,502
Non-Unit Specific	945	1,495	1,560	1,157
DWR contracts	300	1,631	1,444	1,489
Imports shown by non-CPUC jurisdictional LSEs	--	--	--	--
Unit-Specific	714	800	804	825
Non-Unit Specific	792	1,044	1,003	857
Total Imports shown	3,923	7,119	7,317	6,830
CPUC-Jurisdictional Allocations not used in RA Filings:	6,407	3,549	3,314	3,676

Source: Import Allocation information posted on the CAISO website as well as aggregate RA filing information

4 Use of RA and RMR resources by the CAISO in 2008

RA resources provide the CAISO with almost all of the capacity needed to reliably operate the system. However, some local needs may not be resolved by RA resources alone and CAISO is able to designate Reliability Must Run (RMR) resources for local reliability requirements. The local RA program has dramatically reduced RMR designations. CAISO's use of the FERC Must-Offer Obligation (FERC MOO) has declined dramatically since the inception of the RA program; CAISO's FERC MOO costs are down 99 percent in 2008 relative to 2006.

4.1 Reliability Must Run Designations in 2008

RMR resources are designated by the CAISO as needed for Local Reliability. Generating resources with existing RMR contracts must be redesignated by the CAISO for the next compliance year and presented to the CAISO Board of Governors for approval by October 1st of each year while designations for new RMR contracts are more flexible. RMR resources are placed into two classes: Condition 1 contracts are allowed to operate in the market even if not dispatched by the CAISO for reliability purposes, and Condition 2 units are generally not allowed to operate in the market but are under the full dispatch of the CAISO for reliability purposes. Both types of RMR contracts are paid for by all customers in the transmission area, but Condition 1 units are able to competitively earn revenue in the market in addition to the capacity payments made under the RMR Agreement.

In D.06-06-064 the CPUC decided that capacity from Condition 1 RMR contracts will be allocated to LSEs to count only towards the LSE's Local RA obligation, while Condition 2 RMR units may be counted towards both the System and Local RAR obligations. Since they are able to participate in the market, Condition 1 units are allowed to sell their System RA credit to a third party, typically through a "wrap around" contract. RMR units with RA contracts that set the fixed cost recovery via the RMR contract to $0 are not allocated to LSEs and are able to count towards the RAR of the LSE that has entered into RA contracts with them.

Pursuant to the stated policy preference of the Commission, Local RA began to supplant RMR contracting for the 2007 compliance year and a significant decline was seen in 2007 RMR designations. That trend continued for 2008 and 2009 compliance year. Table 8 provides a summary of the CAISO's 2007, 2008, and 2009 RMR designations. Pursuant to Local RA Filings, the CAISO began to reduce their level of RMR designations; 6,781 MW of capacity was released from RMR contracts for 2007 compliance year, 731 MW of capacity mostly in the PG&E service territory was released for 2008 compliance year, and another 982 MW of capacity was released in SDGE territory for 2009 compliance year. In addition the CAISO began to transition some RMR contracts to other types of dual fuel or blackstart interim agreements. These reduced RMR designations even further. Finally, some RMR units filed with FERC to terminate their designation after the CAISO Board of Governors meetings and that represents another opportunity to reduce CAISO reliance on RMR agreements. Each year in August or September, the Board of Governors authorizes CAISO staff to renew RMR contracts with certain generators needed for local reliability. Subsequently, CAISO and CPUC receive preliminary local RA filings and evaluate which of these authorized RMR contracts are not needed because the relevant units have RA contracts. In Table 8, the difference between the CAISO Board Memo and the actual RMR allocations represents the amount of RMR contracts avoided by RA requirements.

The CPUC has stated a policy preference to minimize the use of RMR contracts and a policy preference towards reliance on LSE-based procurement fostered through Local RAR, rather than the RMR process.[16] The Commission has also recognized that the shift from predominant reliance on RMR to predominant reliance on LSE procurement will require a transition period; therefore RMR will remain a factor going forward. Pursuant to CPUC decision, the CPUC will allocate RMR capacity to all LSEs serving load in the transmission area where the RMR resource is located.

[16] California Public Utilities Commission D.06-06-064, Section 3.3.7.1.

Table 8. RMR designations and RMR allocations for 2007-2009

Year		PG&E	SCE	SDG&E	Total
2007	**Compliance Year CAISO Board Memo**	2,034	0	1,961	**3,995**
	Compliance year RMR allocations[17]	792	0	1,961	**2,753**
	Difference (i.e. decrease)[18]	1,242	0	0	**1,242**
2008	**Compliance Year CAISO Board Memo**	1,303	0	1,961	**3,264**
	Compliance year RMR allocations	749	0	277	**1,026**
	Difference (i.e. decrease)	554	0	1,685	**2,239**
2009	**Compliance year CAISO Board of Governors**	1,304	0	979	**2,283**
	Compliance year RMR allocations	555	0	132	**687**
	Difference (i.e. decrease)	749	0	847	**1,596**

Source: CAISO Board of governors meetings for 10/18/06, 10/17/2007, and 10/29/08

4.2 Use of FERCMOO and RAMOO by Unit Location: 2006-2008

In order to meet reliability needs, the CAISO is often forced to commit generating units using FERC approved tariff authority. Prior to the implementation of the RA program in summer of 2006, the CAISO utilized the FERC Must Offer Obligation (FERC MOO) commitment authority. The RA Must Offer Obligation (RA MOO) included in RA contracts provided the CAISO with alternate commitment authority, and began to supplant FERC MOO beginning in 2006, and continuing into 2008. In addition, beginning in 2008, the CAISO is able to rely on interim backstop authority under the TCPM tariff.

Now that the RA Program is implemented on system and local levels, the frequency of FERC MOO commitments decreased while commitments under RA MOO now fill a larger part of the CAISO needs. Generating units from across the CAISO provide capacity to meet a variety of CAISO system needs.

It is important to note that commitment results do not represent the totality of generating capacity available to CAISO to meet operating requirements. The tables that follow do not include unit self-schedules, which are self-commitments, and it is unclear whether the tables completely account for RMR dispatch. The tables only illustrate CAISO commitment decisions.

Table 9 illustrates the annual breakdown of CAISO unit commitments (a unit commitment occurs when CAISO dispatches a unit that did not self schedule), by FERC MOO and RA MOO, and with 2008, by TCPM and shows the trend in costs and committed capacity from 2006 to 2008. In general there has been an 18 percent decrease in overall costs of commitment despite a 3 percent increase in total capacity committed since the implementation of the RA Program; there has been a sharp shift from FERC MOO to RA MOO, resulting in a 99 percent drop in FERC MOO costs and 95 percent

[17] Some individual units were released after the Board of Governors meeting in recognition of Final RA filings, and some RMR contracts were for $0 fixed costs, meaning the capacity was not allocated to LSEs
[18] This total includes both RMR condition 1 and RMR condition 2 contracts

drop in capacity committed from 2006 to 2008. Commitments under MOO can be as short as a single day, so the size of a commitment is measured in MW-days.

Table 9 and Table 10 jointly show a strong decrease in costs in 2007 relative to 2006 followed by an increase in 2008. Although this trend is complicated, it may partly be explained by the mild summer of 2007 and an increasing commitment of expensive local area resources.

It is important to note that commitment results do not represent the totality of generating capacity available to CAISO to meet operating requirements. The tables that follow do not include unit self-schedules, which are self-commitments, and it is unclear whether the tables that follow completely account for RMR dispatch. The tables that follow only illustrate CAISO commitment decisions.

Table 9. Change in CAISO Commitment from summer 2006-2008

Costs ($) or Capacity (MW days)	Commitment Charge Type	All Months of 2006	All Months of 2007	All Months of 2008	Change 2007-2008	Change 2006-2008
Min Load Costs	**FERCMOO**	$91,424,669	$16,024,597	$554,285	-97%	-99%
MinCapacity	**FERCMOO**	65,221	13,078	3,498	-73%	-95%
Min Load Costs	**RA**	$29,322,339	$38,594,041	$98,354,063	155%	235%
MinCapacity	**RA**	50,959	76,806	115,256	50%	126%
Min Load Costs	**TCPM**	$0	$0	$517,846	NA	NA
MinCapacity	**TCPM**	0	0	872	NA	NA
Min Load Costs	**Total**	$120,747,008	$54,618,638	$99,426,194	82%	-18%
MinCapacity	**Total**	116,180	89,885	119,627	33%	3%

Source: CAISO Commitment Results, 2006-2008

Table 10 illustrates the diversity of unit commitment results broken down by Local Area from 2006 through 2008. While it is important to note that the table only illustrates unit location and does not imply that units in Local Areas were committed for local reliability needs, it is notable that units located in Humboldt, Kern, and North Coast/North Bay seem relatively less likely to be committed overall than units in LA Basin, San Diego, and others outside the Local Area. There is also a notable rise in commitment results in San Diego, although this can be partially attributed to a transition from RMR contracts in San Diego to RA contracts signed by individual LSEs. 2007 also witnessed a drop in overall commitment, evidenced by an 82 percent rise from 2007 to 2008, but only a 7 percent rise in total costs from 2006 to 2008.

Table 10. CAISO Commitment 2006-2008 be Local Area

Local Area	Summer 2006	Non-Summer 2006	Summer 2007	Non-Summer 2007	Summer 2008	Non-Summer 2008	Change Summer 2007-Summer 2008	Change Summer 2006-Summer 2008
LA Basin	$43,924,462	$59,449,006	$18,797,715	$12,846,087	$43,608,608	$13,792,094	132%	-1%
Fresno	$157,272	$247,005	$195,496	$818,989	$287,975	$163,042	47%	83%
San Diego	$1,032,300	$369,853	$2,099,982	$5,056,188	$11,162,469	$15,025,485	432%	981%
Bay Area	$7,225,589	$25,205	$1,321,653	$519,842	$1,753,814	$1,292,172	33%	-76%
BG-Ventura	$6,276,761	$1,034,629	$11,897,695	$567,748	$3,661,345	$4,202,522	-69%	-42%
Kern	$0	$0	$2,417	$2	$5,164	$6,419	114%	NA
Sierra	$4,135	$8,333	$3,576	$35,001	$4,429	$37,787	24%	7%
Humboldt	$41	$8	$8,737	$2,616	$0	$58	-100%	-100%
Stockton	$942	$0	$9,204	$4,810	$54,991	$25,113	497%	5736%
NCNB	$0	$0	$0	$0	$0	$0	0%	0%
Non-Local	$501,384	$490,085	$310,528	$120,353	$2,549,992	$1,792,717	721%	409%
CAISO Total	$59,122,885	$61,624,122	$34,647,004	$19,971,634	$63,088,787	$36,337,407	82%	7%
Annual Total	**$120,747,008**		**$54,618,638**		**$99,426,194**		82%	-18%

Source : CAISO Commitment Data 2006-2008

4.3 Use of MOO by Charge Type: 2006-2008

In addition to breaking down commitment results by type of offer obligations, commitment results are also broken down by charge code. The CAISO commits units to meet certain operating contingencies, loosely described as system, local, and zonal contingencies. Table 11 below illustrates the trend of commitment results by charge type from 2006 to 2008. Results are broken down into summer and non-summer periods, and by total capacity committed and by total costs. The table makes clear that 2007 is unique in low levels of commitments, and that comparison of 2006 to 2008 shows smaller overall fluctuation. Total capacity committed and total cost changed by less than 5% each between 2006 and 2008, although the change is far greater between 2007 and 2008. There is also a change in the distribution of capacity committed, in that there was a overall decline in system capacity committed both by capacity (-23%) and by total cost (-30%) between 2006 and 2008, while there is an increase in zonal capacity committed both by total capacity (+39%) and total cost (+67%).

Table 11. Annual Commitment Costs and Capacity by Charge Type 2006-2008

Costs ($) or Capacity (MW days)	Summer 2006	Non-Summer 2006	Summer 2007	Non-Summer 2007	Summer 2008	Non-Summer 2008	Change Summer 2007-Summer 2008	Change Summer 2006-Summer 2008
System Capacity (MW)	32,818	18,666	24,942	20,785	25,261	21,627	1%	-23%
System Cost ($)	$12,491,035	$4,357,774	$9,317,325	$2,905,581	$8,700,751	$2,264,977	-7%	-30%
Local Capacity (MW)	22,825	6,430	9,304	8,966	22,645	17,976	143%	-1%
Local Cost ($)	$35,700,916	$13,426,132	$13,299,613	$8,316,643	$31,767,276	$21,156,306	139%	-11%
Zonal Capacity (MW)	14,216	26,301	14,946	12,844	19,699	12,259	32%	39%
Zonal Cost ($)	$13,483,323	$46,571,510	$13,072,799	$9,542,708	$22,476,960	$12,913,048	72%	67%
Total Capacity (MW)	69,859	51,396	49,192	42,594	67,605	51,862	37%	-3%
Total Cost ($)	$61,675,273	$64,355,416	$35,689,738	$20,764,933	$62,944,987	$36,334,332	76%	2%

Source: CAISO Commitment Results 2006-2008

5 Compliance with RAR in 2008

CPUC staff continued the implementation of the RA program during 2008 and built on the experience of 2006 and 2007. There were three big changes for the 2008 RA program. D.07-06-029 added two changes to the local RA program by creating a new local area, Big Creek/Ventura, and establishing a Path 26 counting constraint for compliance year 2008. The Path 26 counting constraint, which is described in detail in the 2007 RA Report, requires that LSEs have sufficient “Path 26 allocations” in order to count for RA any units which are located on the opposite side of Path 26 from their load.

Early in 2008, LSEs continued to use Advice Letters for compliance filings, as described below and in the 2007 RA Report. Beginning during the summer of 2008, LSEs submitted compliance filings to Energy Division via an electronic Secure File Transfer Protocol (SFTP) system and Energy Division hosted a July 24 workshop that discussed the electronic system. Beginning with year-ahead RA filings for 2009, the transition to SFTP was completed and RA compliance filings via Advice Letter were no longer required.

5.1 Overview of the RA Filing Process

The 2008 System and Local RA filing templates and guides built on the 2007 templates and guides. Final versions of these were issued to the LSEs on July 16, 2007, although a correction was issued later. LSEs were responsible for submitting two year-ahead filings for 2008. As with 2007 implementation, all filings continued to be submitted simultaneously to the CAISO, CPUC, and CEC.

- **Preliminary Local RA Filing:** Due September 19, 2007: this filing was to demonstrate which of the Local RA and RMR resources each LSE had under contract for 2008, so as to offset possible CAISO RMR procurement.
- **Final 2008 System and Local RA Filing:** Due November 2, 2007: this filing is to demonstrate that the LSEs have procured sufficiently to meet their Year-Ahead System RA obligation of 90 percent procurement for the months of May through September 2008, and to demonstrate that they have met their Local RA obligations in the 5 Local Areas (Big Creek/Ventura, LA Basin, San Diego, Greater Bay Area, and Other PG&E Local Areas). Templates and guides for compliance filing were sent to the LSEs on July 16, 2007.
- The System and Local templates for the 2009 compliance year were issued on August 13, 2008.

Energy Division evaluates many RA filings each year, issues resource allocations, and continually works with LSEs to improve the RA administration process. Two LSEs ceased operations during 2008 compliance year, and another ceased to serve retail load in 2009 compliance year. This means Energy Division currently receives 13 filings each year from 12 LSEs, totaling 156 filings per year. In addition to the load forecasting duties the CEC performs and the supply plan validations that the CAISO performs, Energy Division staff perform duties in preparation for each compliance year including Demand Response allocations, Local RA allocations, and CAM and RMR allocations. As knowledge in the market has increased and as filing requirements have become more simplified, time and work requirements have decreased. However with the possible reopening of the DA market as well as the inclusion of the small and multi-jurisdictional LSEs in the RA program, there is the possibility of a growth in that burden as the Energy Division would need to educate new LSEs upon entrance into the program.

5.2 Compliance Review Process

The CPUC checked the filings for compliance by verifying that each LSE's submittal was accurate, timely, and satisfied all requirements. The CAISO reviewed the filings to check whether the RA filings submitted by LSEs were consistent with the supply plans submitted by generators and used the submittals to let the operations staff know which units were under contract and available. The CEC reviewed the filings and the historical load information provided by the LSEs for the appropriate time period to determine the accuracy of those filings matching load forecasts.

In 2008, CPUC Staff continued to work closely with LSEs to resolve any questions regarding the RA filing process and templates. CPUC Staff has been able to develop answers to numerous questions raised by LSEs that have special or unique circumstances. Working closely with LSEs has contributed significantly to reducing errors or omissions in the filings. Examples of questions brought to CPUC Staff include: treatment of NQC for new resources, treatment of NQC for resources when initial NQC list was inaccurate, treatment of NQC associated with a scheduled outage, and discrepancies between the CEC's and LSE's load forecast. It is the hope of CPUC Staff that this process of working with the LSEs to reconcile differences and make revisions will continue to lead to fewer questions in the future and make the RA filing process smoother. CPUC Staff, in a coordinated effort with the CEC and CAISO, has reviewed all compliance filings received to date according to a comprehensive procedure that includes verifying timely arrival of the filings, matching resources listed against those of the NQC list, confirming compliance with local and Path 26 requirements, and requesting corrections. The CAISO collects and organizes supply plans submitted by generators, and helps Energy Division compare the supply plans to the LSE filings. Once compliance is verified, Energy Division approves filings and returns materials to the LSEs.

5.3 Compliance Issues

The essence of the RAR program is mandatory LSE acquisition of capacity to meet load and capacity reserve requirements. The short timeframes necessary to verify that adequate capacity has been procured and to complete backstop procurement if necessary, creates a need for filings to arrive on time and be correct. Errors in filings result in delays in verification of resources that can result in unnecessary backstop procurement. Non-compliance occurs if either an LSE files with a procurement deficiency, meaning they have not met their RA obligations, or does not file at all, files late, or not in the manner required. These types of non-compliance generally lead to enforcement actions or citations. Although CPUC staff has not witnessed a situation where backstop procurement by the CAISO has resulted from CPUC jurisdictional LSE procurement deficiencies, the situation may occur if compliance is not strictly enforced. Additionally, errors and deficiencies require staff to spend time investigating and determining the cause of the situation, and then working with the LSE to remedy problems. Due to the administrative obligations of the RA Program, Energy Division Staff has worked to simplify and streamline filing procedures, and now accepts RA Filings electronically via a Secure FTP application. CPUC staff has also done significant outreach to LSEs to educate them as to filing procedures, and strives to clear up any confusion prior to filing deadlines.

5.3.1 Compliance of RA Filings

Overall compliance in 2008 has been similar to the successful pattern seen in previous years, including administration of the Path 26 Counting Constraint and the Local RA program with only a few citation or enforcement actions necessary. Table 12 summarizes enforcement actions and citations taken so far since inception of the RA program in 2006. Unfortunately, the number of citations issued per year is increasing. At the time of writing this report, the only enforcement case associated with RA compliance year 2008 is still pending against Calpine Power America-CA, LLC related to a procurement deficiency in Local RA Filings.[19] In addition, the Commission has issued 12 citations total and collected $21,500 in payments from LSEs on these citations. Recent changes to the citation program associated with RA are discussed in Section 7.4 of this report.

Enforcement action was taken against Constellation New Energy in 2007 for failure to comply with the 2007 Year-Ahead Local RA obligation. Constellation failed to

[19] http://docs.cpuc.ca.gov/published/proceedings/I0901017.htm

comply by listing an incomplete and unexecuted contact in their filing as a valid RA resource. This represented the first enforcement action taken under the RA Program, and the Commission reached a settlement with the LSE for $107,500. Recently the Commission opened I.09-01-017 against Calpine Power America-CA, LLC related to a procurement deficiency in the 2008 Local RA Filings[20].

Table 12. Enforcement Summary Pursuant to the RA program since 2006

Compliance Year	**2006**	**2007**	**2008**	**Total**
Citations issued	1	3	7	11
LSEs cited	Commerce Energy	3Phases Renewables; Commerce Energy; American Utilities Network	3Phases Renewables (2)[21]; Commerce Energy (2); Corona Department of Water & Power; Sempra Energy; Shell Energy;	
Penalties paid	$1,500	$5,000	$14,500	$21,000
Enforcement Cases	0	1	1	2
Penalties paid	0	$107,500	Pending	$107,500

Source – Energy Division enforcement records

Although 2008 saw a large improvement in the quality of the RA filings, recurrent minor errors still consume staff time and delay the processing of filings. These errors include: filing late, listing units that are within 60 days of commercial operation date, filing information for the incorrect month, filing units that were affected by the outage counting protocol, inaccurate reporting of demand response, RMR, or import allocations, incorrect CAISO resource IDs, and a number of other small errors. There is also the continued need to monitor administrative issues such as filing dates and filing procedures.

In order to expedite filings and prevent further errors, the Commission approved D. 08-06-031 which, among other refinements, approved the use of electronic filing procedures and the use of a more automated reporting template that will prevent many of the errors seen in previous years. So far into 2009 compliance year, Energy Division staff is noticing vast improvement in efficiency of filing, and in the reduction of minor errors that require correction. In addition, Energy Division staff is able to consult with LSEs on filing dates when files have not arrived and LSEs may be able to submit the filing on time.

5.3.2 Load Forecast Compliance

After the compliance year, the CEC has continued to review load forecasts for a given compliance period against actual observed loads from that period; while so far there has been no enforcement action taken in response to any repeated pattern of forecast discrepancy for any particular LSEs, there are those that continue to require plausibility adjustments each year. However, plausibility adjustments are not done across the board and some LSEs require greater adjustments than others. In the case that the plausibility

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[20] The docket card for this proceeding can be accessed here: http://docs.cpuc.ca.gov/published/proceedings/I0901017.htm

[21] A 3rd citation was rescinded

adjustments are large enough that CEC needs to adjust total load forecasts in preparation for the year-ahead filing, confusion and error may be created.

This subject received extensive discussion at the recent RA workshops held by Energy Division staff in January 2009. In the future LSEs may be subject to penalties if a pattern emerges of continued significant differences between actual historical information and load forecasts.

6 Forced outages

Since the RA Program requires LSEs to demonstrate procurement of valid RA capacity, the RA Program is reliant on generation procured to be available and online when the CAISO needs to commit it. For that reason, measurement and evaluation of generator performance is a necessary component of the RA program, including attention to forced and scheduled generator outages. The CAISO wide forced outage rate for 2008 was 3.1%.[22] Forced outage rates are an important consideration in RA concepts such as the planning reserve margin and standard capacity product. For a more detailed analysis of California forced outage rates see appendix 2, a white paper on forced outage rates from the Commission's Consumer Protection and Safety Division.

7 Changes to the RA Program for 2009

The Commission further refined the RA program in 2009 compliance year in D.08-06-031. This decision modified rules for counting new resources for RA purposes. Implementation of this change may be explored in a possible 2009 RA report issued after the 2009 compliance year, while a short description of their specifics is given below. Further, as described above, the RA program transitioned to electronic submittal of compliance filings in place of Advice Letters.

7.1 Counting new resources

Two proposals were adopted in the D.08-06-031: first, any unit which is known to CAISO and CPUC to have achieved commercial operation status by the due date of an RA filing is eligible to be counted on that filing and second, any under-construction unit (which has not achieved commercial operation status) in a local area may be counted for local RA if the LSE also lists another, single, local unit that it will substitute by listing on every monthly RA filing until the new unit achieves commercial operation. Under the new rules, no under-construction units have been counted for 2009 local RA. However, some new units have been listed for system RA in the first RA filing after achieving commercial operation.

7.2 Electronic filing

As discussed earlier in this report, during 2008, the CPUC RA program tested an electronic submission of compliance filings instead of Advice Letter filings. Electronic submission of compliance filings via Secure FTP (SFTP) is required for all RA filings for compliance year 2009. The detailed procedures are described in the 2009 RA Guide.[23]

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[22] See appendix 2 for more detail.
[23] Guides and Templates are Posted on the CPUC website here:
http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_guides_2008-09.htm__

For each filing, LSEs log in to the CPUC's SFTP server and upload a completed template to CPUC Staff at rafiling@cpuc.ca.gov. The LSE receives a confirmation email when Staff downloads the filing. Periodically, CPUC Staff sends password protected compliance templates to LSEs containing updated allocation figures to be used for compliance purposes.

7.3 MRTU Implementation

In addition to changes to the RA program via Commission rulemaking and Commission decision, MRTU implementation will have effects on the RA program. For example, the MRTU tariff that will become effective upon implementation codifies the Local Residual Procurement analysis and process that the CAISO will undertake annually after evaluation of the Local RA filings, and the nature of backstop changes with the elimination of FERC MOO and the implementation of the Interim Capacity Procurement Mechanism (ICPM).

Once MRTU is implemented, elements of the CAISO tariff will codify the process that the CAISO will follow to receive, analyze, and act upon annual Local RA Filings received from LSEs. In particular, the tariff provides firm dates for submission of LSE filings including non-CPUC jurisdictional LSE RA filings, firm dates for announcement of any collective deficiencies in Local RA procurement caused by deficiencies or effectiveness factors, and gives firm dates for LSEs to submit additional procurement to the CAISO before the CAISO engages in backstop procurement. Under the MRTU tariff the CAISO requires all LSEs to file annual Resource Adequacy Plans no later than October 1 of each year reflecting the Local Capacity Area Resources procured. Local Regulatory Authorities such as the CPUC can set their own dates, and the CPUC will set their own due date pursuant to the CPUC RA Program. The CAISO will review all annual LSE RA Plans that show the Local Capacity Area Resources that have been procured, to determine whether any collective deficiency exists. If the CAISO determines that a need for ICPM Capacity exists, the CAISO will issue a Market Notice no later than sixty (60) days before the beginning of the Resource Adequacy Compliance Year identifying the deficient Local Capacity Area and quantity of deficiency. Where only specific resources are effective to resolve the Reliability Criteria deficiency, the CAISO will provide the identity of such resources. No later than thirty (30) days before the beginning of the Resource Adequacy Compliance Year, any Scheduling Coordinator may submit a revised annual Resource Adequacy Plan demonstrating procurement of additional Local Capacity Area Resources consistent with the Market Notice issued by the CAISO. More information regarding backstop procurement and the interaction of CAISO's tariff with the CPUC's RA program can be found in the CAISO's Business Practice Manuals posted on the CAISO website.[24]

The advantages of codifying dates include firmness and clarity to parties, but disadvantages may include lack of ability to change dates if the CPUC RA program is modified. It will be necessary to report to stakeholders any observations from MRTU implementation including effects on CAISO procurement or the RA program from codifying this process which until now had been more flexible.

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[24] CAISO business Practice Manuals are available here: http://www.caiso.com/17ba/17baa8bc1ce20.html

In addition to the codification discussed above, another major change will be in the nature of daily dispatch. Section 5 of this report discusses CAISO commitment results and compares RA MOO to FERC MOO. Under MRTU, as FERC MOO is eliminated, the nature of CAISO backstop will change. In place of FERC MOO, terms of the CAISO's ICPM or Exceptional Dispatch will govern CAISO backstop during the compliance year. Three provisions of ICPM are most notable. First, ICPM requires the CAISO to designate a unit for a minimum of 30 days, or until the unit becomes an RA unit pursuant to a contract with an LSE. RMR will still be available to CAISO for annual designations in cases of units that are not able to economically participate in the market, but in cases of monthly or daily dispatch, the CAISO will need to designate and pay capacity differently and for longer time frames than the FERC MOO currently enables the CAISO to do. ICPM will be a 30 day designation, or for the remainder of a 30 day period until the unit becomes an RA unit. There are also restrictions on repeated designations that may change the pattern of CAISO unit commitment.

Secondly, the CAISO will be able to designate a partial amount of a unit's capacity as needed for reliability as opposed to current FERC MOO provisions which require designation of an entire unit's capacity including minimum load costs. It is possible that there may be greater flexibility to the nature of CAISO commitments when partial units can be utilized wit regards localized or small magnitude reliability needs. Lastly, the CAISO will be required to post reports that explain every ICPM designation within a certain time frame. Currently FERC MOO designations are not disclosed to the market the way that the ICPM designations are, and this added information may inform parties as to particular CAISO needs and commitment patterns, thus enabling market participants to plan and predict resource planning more closely around CAISO day to day needs.

In light of the changes discussed above it is unclear what the effects will be in relation to CAISO commitment. Energy Division staff along with the rest of the market will monitor the implementation of MRTU and gather observations and experience with ICPM and Exceptional Dispatch and how the rest of MRTU interacts with the RA Program. Energy Division staff will study and report their observations as Energy Division is able to discern trends and gain insight into the market.

7.4 Enforcement via Resolution E-4195

In November 2008, the CPUC made changes to the citation program by adopting Resolution E-4195,[25] which replaces Resolution E-4017. The resolution "transfers authority to draft and issue citations from Energy Division to Commission Staff as a whole, broadens the scope of the Resolution to encompass all LSEs that are potentially subject to RA obligations, and adds a Specified Violation for failure to meet RA obligations with a small procurement deficiency."[26] Resolution E-4195 does not modify the RA program itself; it merely modifies the citation and enforcement rules.

[25] http://docs.cpuc.ca.gov/WORD_PDF/FINAL_RESOLUTION/93662.PDF
[26] Res. E-4195, pg 1.

8 Appendix 1 - Total CAISO LSE Procurement as Percentage of Total Obligation

Table 13. Total CAISO LSE Procurement as Percentage of Total CAISO Obligation

Month 2008	Type of LSE	Peak Demand Forecast	Forward Commitment Obligation [Peak Demand + PRM]	I. Physical Resources in CAISO	II. Unit Contingent Import Contracts	III. Non-Unit Contingent Import Contracts	IV. LD Contracts	V. Dispatchable DR	RMR Capacity	DWR contracts	Total Resource Adequacy Capacity	RA Capacity as Percentage of Obligation
Jun-08	CPUC LSEs	36,438	41,903	32,834	1,172	945	2,382	2,629	298	6,495	47,149	113%
	Non-CPUC LSEs	3,259	3,748	2,009	714	792	311	55			3,890	104%
	Total RA capacity	39,696	45,651	34,843	1,886	1,737	2,693	2,684	298	6,495	51,038	112%
	% of Capacity			68%	4%	3%	5%	5%	1%	13%	100%	
Jul-08	CPUC LSEs	42,252	48,590	34,380	2,149	1,495	2,557	2,670	298	7,893	51,842	107%
	Non-CPUC LSEs	3,517	4,045	1,966	800	1,044	429	66			4,314	107%
	Total RA capacity	45,769	52,634	36,345	2,949	2,539	2,986	2,736	298	7,893	56,156	107%
	% of Capacity			65%	5%	5%	5%	5%	1%	14%	100%	
Aug-08	CPUC LSEs	44,880	51,611	34,546	2,506	1,560	2,555	2,677	298	7,688	52,232	101%
	Non-CPUC LSEs	3,537	4,068	1,964	804	1,003	416	109			4,312	106%
	Total RA capacity	48,417	55,679	36,510	3,309	2,563	2,971	2,786	298	7,688	56,544	102%
	% of Capacity			65%	6%	5%	5%	5%	1%	14%	100%	
Sep-08	CPUC LSEs	40,495	46,569	33,217	2,502	1,157	2,555	2,653	298	7,734	50,514	108%
	Non-CPUC LSEs	3,415	3,927	1,961	825	857	372	109			4,140	105%
	Total RA capacity	43,909	50,496	35,178	3,327	2,014	2,927	2,762	298	7,734	54,654	108%
	% of Capacity			64%	6%	4%	5%	5%	1%	14%	100%	

Source: Aggregated RA data collected by CPUC along with RCST data from CAISO for the summer of 2008

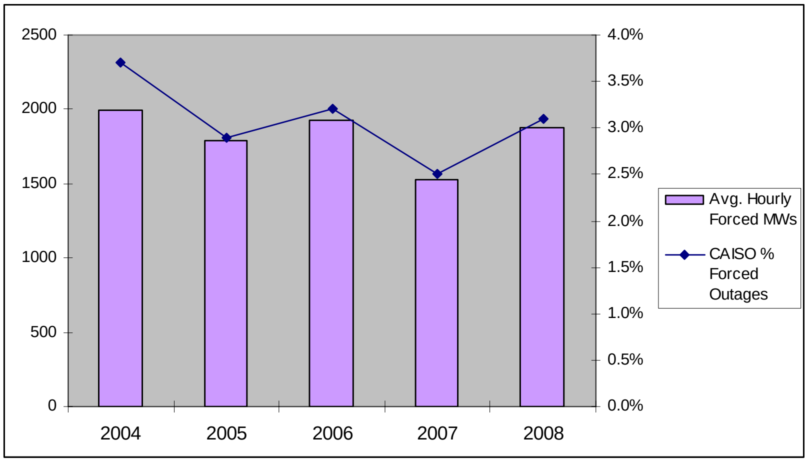
9 Appendix 2 - Forced Outages

The CAISO calculates a forced outage rate of 3.1% for 2008, and 2.98% for the last five years (2004-2008), illustrated in Table 14 below.

Table 14. CAISO Forced Outage Rates

	Forced Outages (% of CAISO System TIC)
2001	9.0%
2002	5.6%
2003	4.0%
2004	3.4%
2005	2.9%
2006	3.2%
2007	2.5%
2008	3.1%

Figure 3. Historical Forced Outages in CAISO

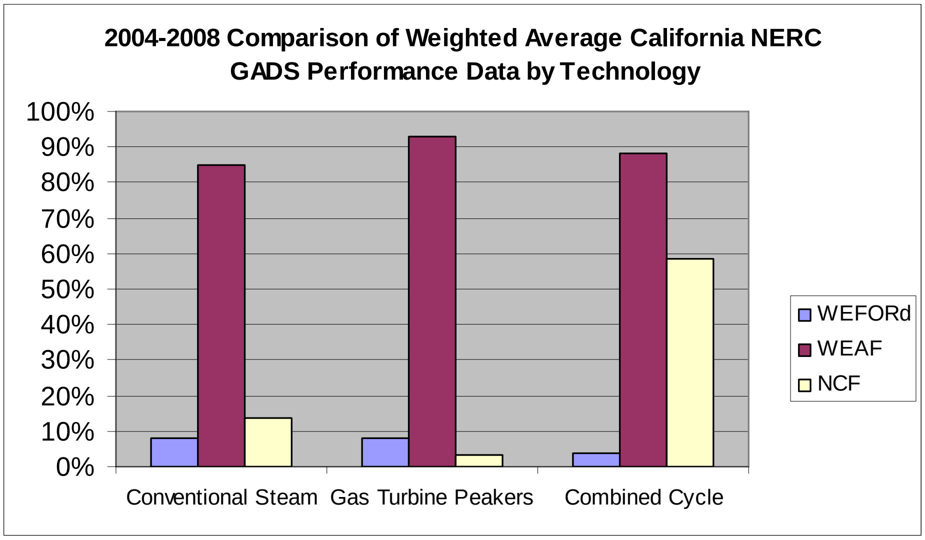


The CAISO's methodology presents average hourly forced outage MWs as a percent of CAISO System Total Installed Capacity (TIC) for each year.[27]

The Commission's General Order (G.O.) 167 requires most plants to self-report specific performance data to the North American Reliability Corporation (NERC).[28] NERC maintains the most comprehensive power plant database in the world, and collects performance data from about 5,300 generating units worldwide. While CPUC staff has identified plant-specific discrepancies between the NERC and CAISO outage data, both sources confirm an overall decrease in forced outage rates since 2004.[29]

NERC developed multiple performance factors to measure individual and aggregate plant reliability for a broad range of technologies and fuel sources. The three most relevant factors measure a plant's forced outage rates (EFORd), availability (EAF), and capacity factor (NCF). The following chart compares the three weighted average NERC performance factors (WEFORd, WEAF, and NCF) for California generators by fossil-fuel technology, followed by a description of each factor's value and desirable measure[30]. For optimal performance, a plant strives to achieve high availability and production levels, and a low outage rate.

Figure 4. Performance Factors by Technology



The **Equivalent Availability Factor (EAF**) indicates the percentage of time that a unit is capable of providing generation. California conventional steam units, natural gas peakers, or new combined cycle units, on average, are available and operational at least 85% of the time.

[27] California ISO Department of Market Monitoring (CAISO DMM). 2007 Annual Report, Market Issues and Performance. 19-20. Includes fossil fuel, renewables, nuclear plants, and QFs.
[28] Thermal plants, 10 MWs and greater, self-report data to NERC.
[29] Includes 2008 data from 100 of 186 steam, combined cycle, and combustion turbine peaking units which currently self-report to NERC.
[30] NCF calculates a ratio comparing a plant's energy output to its output at maximum capacity; it is a capacity weighted equation.

Conversely, a high **Equivalent Forced Outage Rate of demand (EFORd)** value indicates a high level of forced outages. EFORd calculates the percentage of time that a unit is out of service during periods it should be available. The weighted average EFORd for all technologies is below 8%, with combined cycle plants performing the most reliably.

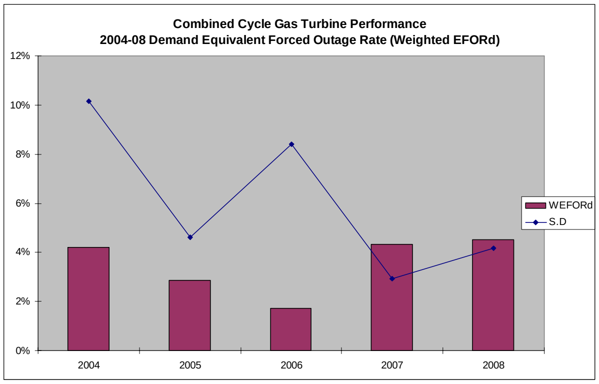
The **Net Capacity Factor (NCF)** measures the actual energy generated by a unit, relative to the amount of power the unit can produce at maximum operating capacity. Newer combined cycle units operate at a much higher capacity factor than gas turbine peakers or conventional steam boiler driven steam plants. Gas turbine peakers demonstrate a lower capacity factor than plants designed to serve base-load. By design, peakers ramp quickly to meet high demand, such as peak load during the summer. For that reason, peakers typically run infrequently, or for short, variable periods of time.

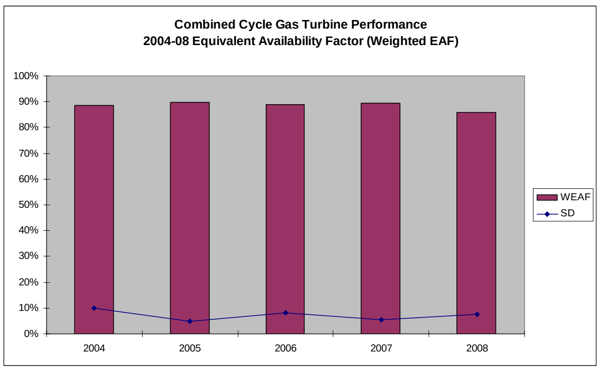
Conventional steam plants operate at a NCF of less than 15%, somewhere between combined cycle and peaker plants. California's conventional steam plants were designed 30-60 years ago for continuous operation, to serve base load, and were used that way for many years. Due to their older technology, California's steam plants do not operate as cost-efficiently as new combined cycle power plants, and therefore do not run as often. They cycle (change load) often and are used in a manner for which they were not designed. As a result, the plants are less reliable.

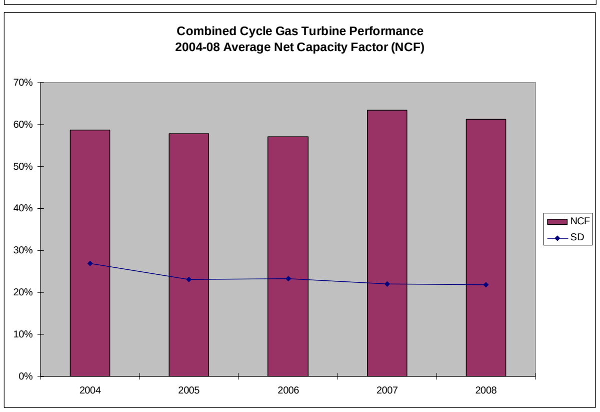
The following charts depict year to year GADS performance and standard deviation by technology, for the three weighted indices. The graphs show that the standard deviation values for WEFORd and NCF exceed those of the mean, which indicates great variability and dispersion in the recorded data compared to the mean. EAF values, which are greater than EFORd and NCF values, have the least relative variability.

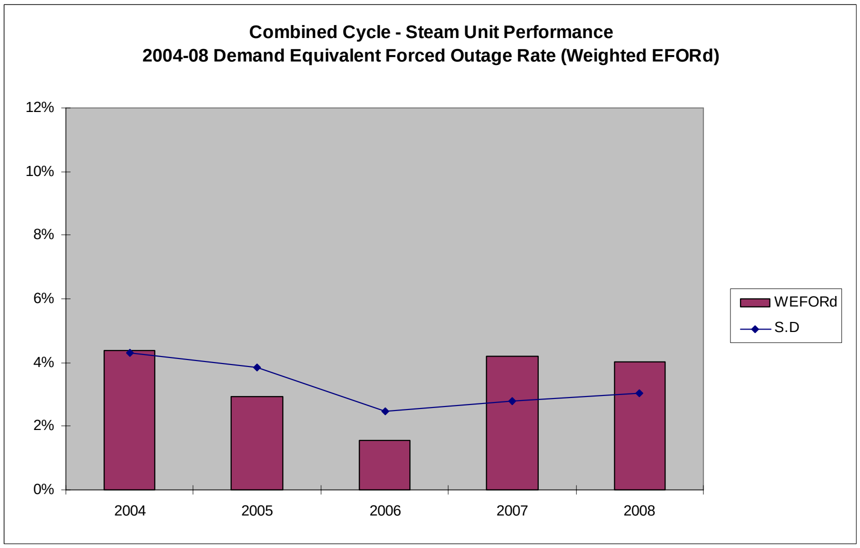
9.1 Combined Cycle Plants

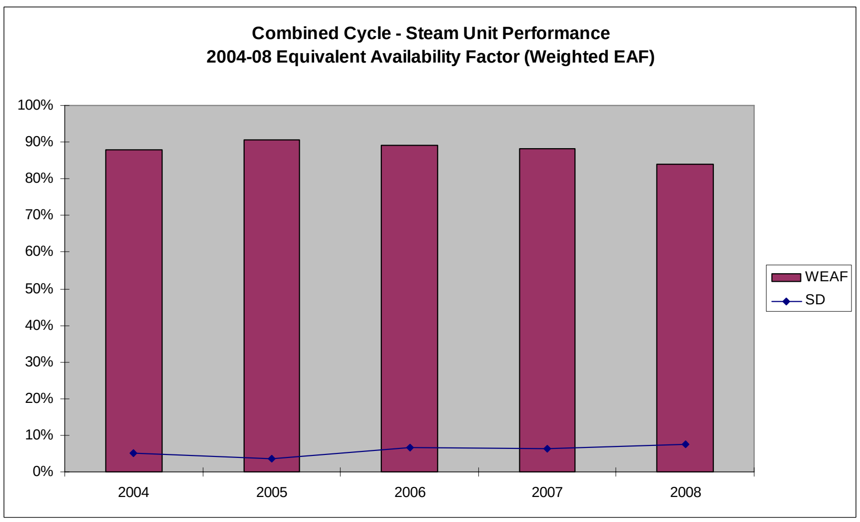
Between 2004 and 2008, combined cycle plants maintained a higher, constant level of productivity than gas turbine peakers or conventional steam plants. Combined cycle power plants consist of both gas turbines connected to generators and steam turbines connected to generators. Most combined cycle plants report both their gas turbine and steam turbine performance separately to NERC. On average, combined-cycle steam units perform similarly to combined cycle gas turbine (CCGT) units. EFORd increased in 2007 and 2008, for CCGTs, in part because during that period forced outage hours (FOH) increased.

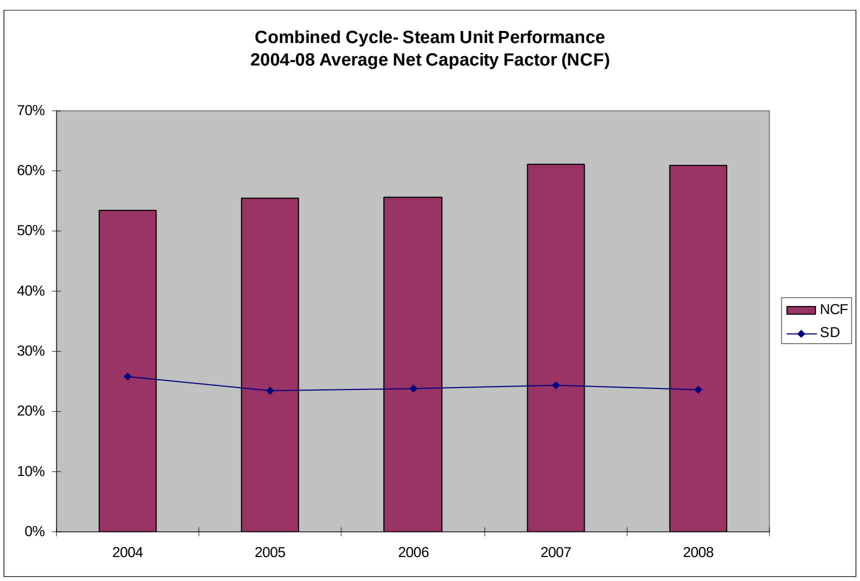

Combined Cycle Gas Turbine Performance
2004-08 Demand Equivalent Forced Outage Rate (Weighted EFORd)
12%
10%
8%
6%
4%
2%
0%
2004
2005
2006
2007
2008
WEFORd
S.D


Combined Cycle Gas Turbine Performance
2004-08 Equivalent Availability Factor (Weighted EAF)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
2004
2005
2006
2007
2008
WEAF
SD


Combined Cycle Gas Turbine Performance
2004-08 Average Net Capacity Factor (NCF)
70%
60%
50%
40%
30%
20%
10%
0%
2004
2005
2006
2007
2008
NCF
SD

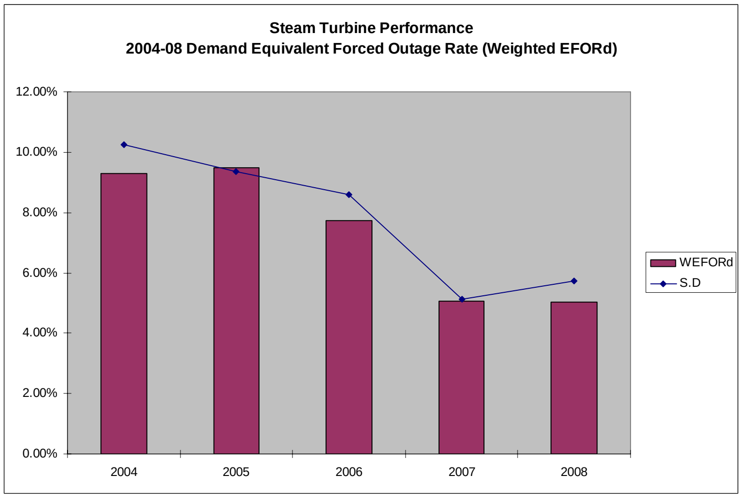

Combined Cycle - Steam Unit Performance
2004-08 Demand Equivalent Forced Outage Rate (Weighted EFORd)
12%
10%
8%
6%
4%
2%
0%
2004
2005
2006
2007
2008
WEFORd
S.D

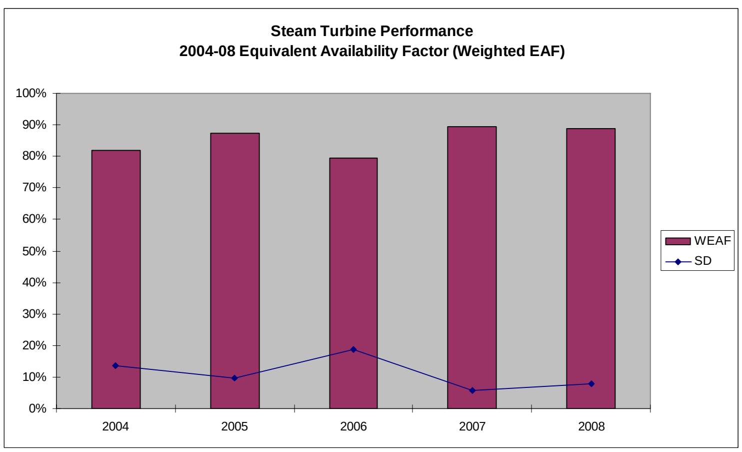

Combined Cycle - Steam Unit Performance
2004-08 Equivalent Availability Factor (Weighted EAF)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
2004
2005
2006
2007
2008
WEAF
SD

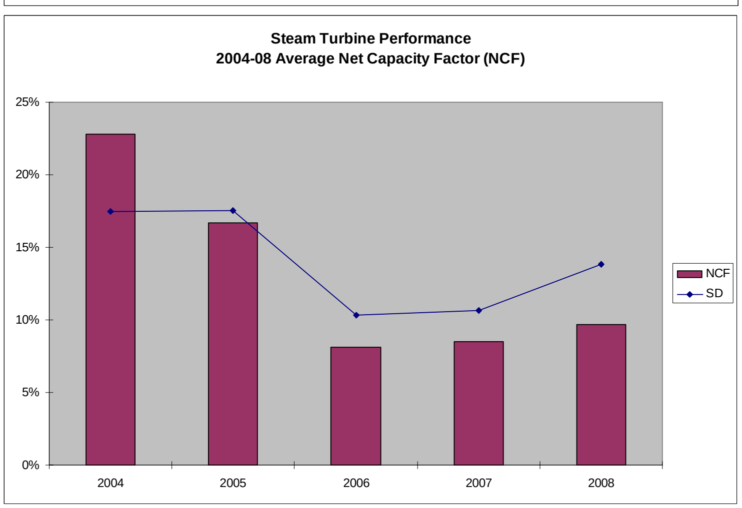

Combined Cycle- Steam Unit Performance
2004-08 Average Net Capacity Factor (NCF)
70%
60%
50%
40%
30%
20%
10%
0%
2004
2005
2006
2007
2008
NCF
SD

9.2 Steam Plants

Since 2005, forced outage rates decreased. NCF values for steam plants also decreased from 2004-08, consistent with the use of aging plants as cycling units rather than base-load.







9.3 Gas Turbine Peaker Plants

The average EFORd increased from 2004 to 2008, due to increased FOHs. Plants ran 30% less in 2008 than 2004. EAF averaged 93% over five years. Self-reported NCF values, already low in 2004 at 4.22%, decreased to 2.9% in 2008.