CALIFORNIA ENERGY COMMISSION

SUMMER 2006 ELECTRICITY SUPPLY AND DEMAND OUTLOOK

FINAL STAFF REPORT

April 2006
CEC-700-2006-005

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CALIFORNIA ENERGY COMMISSION

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Acknowledgements

Many thanks are due to the following individuals for their contributions and technical support to this report:

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INTRODUCTION AND SUMMARY

The *Summer 2006 Electricity Supply and Demand Outlook* provides the California Energy Commission (Energy Commission) staff's current assessment of electricity system resource adequacy in California. It evaluates the capability of the physical electricity system to provide power to meet electricity demand in specific geographic areas within California and provides a summary of the resource adequacy filings from the Investor-Owned Utilities (IOUs), municipal utilities with a peak demand of 200 megawatts (MW) or greater, and Electric Service Providers (ESPs) – collectively known as Load Serving Entities (LSEs). It does not evaluate the condition of the electricity market or the deliverability of specific economic contracts entered into by the LSEs.

This outlook examines four regions - California Statewide, California Independent System Operator (CA ISO) Control Area, CA ISO North of Path 26 (NP26), and CA ISO South of Path 26 (SP26). The CA ISO Control Area is divided into Northern and Southern California because there are transmission constraints south of the transmission segment known as Path 26 that limit the transfer of electricity from north to south. Northern California includes the Pacific Gas and Electric (PG&E) service area and participating municipal utilities in Northern California served by the CA ISO. Southern California includes Southern California Edison (SCE), San Diego Gas and Electric (SDG&E), and the Southern California municipal utilities that participate in the CA ISO. The outlook uses the high demand forecast[1] developed for the *2005 Integrated Energy Policy Report* for forecasted loads in each region.

This analysis was prepared in coordination and consultation with the California Public Utilities Commission (CPUC) and the CA ISO. A staff workshop was held on December 8, 2005, to receive stakeholder and public input on the staff draft version of the outlook. A brief summary of the changes incorporated into this final report are provided below.

Methodology Changes from 2005 and Updates to 2006 Draft Report

This assessment includes several methodology changes adopted last year as a result of comments received during our workshop on the *Summer 2005 Electricity Supply and Demand Outlook* held in March 2005. Two consistent comments from workshop participants were: (1) demand response and interruptible load programs are essential components to the planning and operation of the daily system, and these resources should be included in the outlook tables; and (2) using above-average forced outages and transmission limitations in the 1-in-2 scenario could result in the procurement of unnecessary resources. These suggestions have been incorporated into our revised methodology.

[1] *California Energy Demand 2006-2016* Revised September 2005. CEC-400-2005-034-SF-ED2

A second major change from our 2005 outlook is provided in Chapter 2. Staff continues to develop probabilistic assessments to enhance the deterministic tables that have been historically produced. The first stage included in the draft outlook studied the probabilities of variations in demand and forced generation outages in the Southern California portion of the CA ISO Control Area. These two criteria were selected for initial probabilistic analysis because higher demand from hot temperatures and generation outage fluctuations have significant impacts on the overall operation of the system and the data to estimate the probability of these factors was readily available. This report includes a probabilistic assessment of a third major uncertainty, transmission forced outages.

As a result of data collected by the CPUC to assess LSE resource adequacy, staff has added Chapter 3, which provides a brief overview of electricity Resource Adequacy (RA) for the summer months of 2006 for the LSEs. It evaluates the total capacity owned or contracted for by each class of LSE as reported in February and compares those secured resources to the forecasted summer 2006 monthly peak demand for each LSE.

Finally, in response to comments received by stakeholders during the December workshop and a request by the CPUC, Chapter 4 provides a preliminary five year outlook for each of the four regions.

Results

The 2006 summer outlook is presented in three scenarios. The first scenario calculates the planning reserve margin using the 15-17 percent reserve criteria required by the CPUC for June 2006. Planning reserves are calculated for derated generation before taking into account potential outages. Planning reserves are higher than operating reserves because they do not account for forced or planned generation outages or transmission limitations caused by congestion. The second scenario calculates operating reserves representing conditions that could be expected on an average summer day, including estimated outages. Finally, an adverse scenario is included to show possible results from several conditions that might simultaneously occur to stress the system.

Energy Commission staff expects supplies in all regions will be adequate to meet growing electricity demand and the required 7 percent operating reserves[2] under average (1-in-2 or a 50 percent probability) temperature conditions. Improved resource adequacy is due to the addition of new generation facilities since 2000, transmission improvements, increased energy efficiency, and voluntary conservation.

[2] The Western Electricity Coordination Council requires a 7 percent operating reserve for thermal resources and a 5 percent operating reserve for hydro resources.

If very hot summer demand occurs (1-in-10 or a 10 percent probability), Northern California electricity resources are expected to exceed the 7 percent reserve requirement. In the last several years, more new generation has been built in this region than in the south, and demand growth has been slower. Northern California typically reaches its summer peak during July.

The summer 2006 projection for Southern California has improved compared to 2005. Southern California resources are also expected to exceed the minimum reserve requirement under average (1-in-2) weather conditions. Under hot (1-in-10) weather conditions, demand response and interruptible programs may need to be used if adverse conditions of high zonal limitations (transmission congestion) and high forced outages occur simultaneously. No loss of firm load is expected. Peak electricity demand in Southern California usually occurs in September; however in 2005, a new record peak demand occurred in July.

Southern California areas served by the municipal utilities that are not members of the CA ISO, including Los Angeles Department of Water and Power (LADWP), Burbank Water and Power, Glendale Water and Power, and Imperial Irrigation District, appear to have adequate resources. The LADWP, in particular, should have surplus power available to provide to the rest of the region if satisfactory contractual agreements can be implemented between California's largest municipal utility and the appropriate LSE.

Northern California and Southern California monthly electricity demand and supply outlooks for summer 2006 are presented in addition to the Statewide and CA ISO Control Area Outlooks in Tables 1-1 through 1-4. Chapter 1 provides a line-by-line description of the Energy Commission staff's supporting information and assumptions used in these assessments.

On a statewide basis for all LSEs combined, procured capacity for the upcoming summer months ranged from a low of 115 percent of the sum of non-coincident peak loads in August to a high of 131 percent in June. The same conclusion holds true for each of the individual sectors (IOUs, municipal utilities, and ESPs) for every summer month except for the IOU reserve margin in August, which is only 13 percent. However, this number exceeds 90 percent of peak demand plus a 15 percent reserve margin, so that the RA requirement is still met.

Table 1-1: 2006 Detailed Monthly Electricity Outlook – California Statewide
(Megawatts)

	Resource Adequacy Planning Conventions	June	July	August	September
1	Existing Generation[1]	56,697	57,837	57,837	57,837
2	Retirements (Known)	-1,539	0	0	0
3	High Probability CA Additions	2,679	0	0	0
4	Net Interchange [2]	13,118	13,118	13,118	13,118
5	Total Net Generation (MW)	70,955	70,955	70,955	70,955
6	1-in-2 Summer Temperature Demand (Average)[3]	55,119	57,626	58,228	57,318
7	Demand Response (DR)	414	414	414	414
8	Interruptible/Curtailable Programs	1,603	1,603	1,603	1,603
9	Planning Reserve[4]	32.4%	26.6%	25.3%	27.3%
	Expected Operating Conditions				
	Total Net Generation (MW)	70,955	70,955	70,955	70,955
10	Outages (Average forced + planned)	-2,695	-2,695	-2,695	-2,695
11	Zonal Transmission Limitation[5]	-150	-150	-150	-150
12	Expected Operating Generation with Outages/Limitations[6]	68,110	68,110	68,110	68,110
13	Expected Operating Reserve Margin (1-in-2)[7]	30.2%	23.0%	21.4%	23.9%
	Adverse Conditions				
14	High Zonal Transmission Limitation	-250	-250	-250	-250
15	High Forced Outages (1 STD above average)	-1,160	-1,160	-1,160	-1,160
16	Adverse Temperature Impact (1-in-10)	-3,331	-3,502	-3,627	-3,524
17	Adverse Scenario Reserve Margin[7]	17.8%	11.4%	9.7%	12.0%
18	Adverse Scenario Reserve Margin w/DR and Interruptibles[8]	22.2%	15.5%	13.8%	16.2%
19	Resources needed to meet 7.0% Reserve (W/DR & Interruptibles)	0	0	0	0
20	Surplus Resources Above 7.0% Reserve (W/DR & Interruptibles)	7,024	4,158	3,380	4,464
21	Existing Aging Generation Without Capacity Contracts[9]	-3,388	-3,388	-3,388	-3,388

[1] Dependable capacity by station includes 1,080 MW of stations located south of Miguel.

[2] 2006 estimate of the following Net Imports: **DC imports 2,000 MW, SW imports 4,100 MW, NW imports (COI) 4,000 MW**, LADWP Control Area and IID imports 3,018 MW. **Imports with own reserves highlighted in bold.**

[3] Demand forecast completed September 2005 as part of IEPR proceeding. CEC-400-2005-034-SF-ED2.

[4] Planning Reserve calculation ((Total Generation+Demand Response+Interruptibles)/Normal Demand)-1.

[5] Based on CA ISO data.

[6] Does not include Demand Response/Interruptible Programs because reserve margins are in excess of 5% (Stage 2).

[7] Operating Reserve calculation ((Operating Generation-**Imports with Reserves**)/(Demand-**Imports with Reserves**))-1. See Footnote 2.

[8] Demand Response and Interruptibles added to Operating Generation in Reserve Margin formula from Footnote 7.

[9] Capacity is included in Line 1 and represents plants identified in 2004 CEC Staff Draft Report 100-04-005D *Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements*

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Table 1-2: 2006 Detailed Monthly Electricity Outlook – CA ISO Control Area
(Megawatts)

	Resource Adequacy Planning Conventions	June	July	August	September
1	Existing Generation[1]	45,791	46,125	46,125	46,125
2	Retirements (Known)	-1,539	0	0	0
3	High Probability CA Additions	1,873	0	0	0
4	Net Interchange [2]	10,650	10,650	10,650	10,650
5	Total Net Generation (MW)	56,775	56,775	56,775	56,775
6	1-in-2 Summer Temperature Demand (Average)[3]	44,245	46,147	46,287	45,865
7	Demand Response (DR)	414	414	414	414
8	Interruptible/Curtailable Programs	1,403	1,403	1,403	1,403
9	Planning Reserve[4]	32.4%	27.0%	26.6%	27.7%
	Expected Operating Conditions				
	Total Net Generation (MW)	56,775	56,775	56,775	56,775
10	Outages (Average forced + planned)	-2,255	-2,255	-2,255	-2,255
11	Zonal Transmission Limitation[5]	-150	-150	-150	-150
12	Expected Operating Generation with Outages/Limitations[6]	54,370	54,370	54,370	54,370
13	Expected Operating Reserve Margin (1-in-2)[7]	28.2%	21.8%	21.3%	22.7%
	Adverse Conditions				
14	High Zonal Transmission Limitation	-250	-250	-250	-250
15	High Forced Outages (1 STD above average)	-1,060	-1060	-1060	-1060
16	Adverse Temperature Impact (1-in-10)	-2,560	-2,689	-2,712	-2,713
17	Adverse Scenario Reserve Margin[7]	16.3%	10.4%	10.0%	11.2%
18	Adverse Scenario Reserve Margin w/DR and Interruptibles[8]	21.0%	14.9%	14.5%	15.7%
19	Resources needed to meet 7.0% Reserve (W/DR & Interruptibles)	0	0	0	0
20	Surplus Resources Above 7.0% Reserve (W/DR & Interruptibles)	5,384	3,210	3,036	3,487
21	Existing Aging Generation Without Capacity Contracts[9]	-3,388	-3,388	-3,388	-3,388

[1] Dependable capacity by station includes 1,080 MW of stations located south of Miguel.

[2] 2006 estimate of the following Net Imports: **DC imports 2,000 MW, SW imports 4,100 MW, NW imports (COI) 2,300 MW,** WAPA CVP 1,250 MW, LADWP Control Area imports 1,000 MW (Includes wheeled power). **Imports with own reserves highlighted in bold.**

[3] Demand forecast completed September 2005 as part of IEPR proceeding. CEC-400-2005-034-SF-ED2.

[4] Planning Reserve calculation ((Total Generation+Demand Response+Interruptibles)/Normal Demand)-1.

[5] Based on CA ISO data.

[6] Does not include Demand Response/Interruptible Programs because reserve margins are in excess of 5% (Stage 2).

[7] Operating Reserve calculation ((Operating Generation-**Imports with Reserves**)/(Demand-**Imports with Reserves**))-1. See Footnote 2.

[8] Demand Response and Interruptibles added to Operating Generation in Reserve Margin formula from Footnote 7.

[9] Capacity is included in Line 1 and represents plants identified in 2004 CEC Staff Draft Report 100-04-005D *Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements*

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Table 1-3: 2006 Detailed Monthly Electricity Outlook – CA ISO Northern Region (NP26)
(Megawatts)

	Resource Adequacy Planning Conventions	June	July	August	September
1	Existing Generation	24,470	24,417	24,417	24,417
2	Retirements (Known)	-219	0	0	0
3	High Probability CA Additions	166	0	0	0
4	Net Interchange [1]	550	550	550	550
5	Total Net Generation (MW)	24,967	24,967	24,967	24,967
6	1-in-2 Summer Temperature Demand (Average)[2]	19,964	20,395	20,121	19,384
7	Demand Response (DR)	322	322	322	322
8	Interruptible/Curtailable Programs	316	316	316	316
9	Planning Reserve[3]	28.3%	25.5%	27.3%	32.1%
	Expected Operating Conditions				
	Total Net Generation (MW)	24,967	24,967	24,967	24,967
10	Outages (Average forced + planned)	-1,100	-1,100	-1,100	-1,100
11	Zonal Transmission Limitation[4]	0	0	0	0
12	Expected Operating Generation with Outages/Limitations[5]	23,867	23,867	23,867	23,867
13	Expected Operating Reserve Margin (1-in-2)[6]	20.1%	17.5%	19.1%	23.8%
	Adverse Conditions				
14	High Zonal Transmission Limitation	0	0	0	0
15	High Forced Outages (1 STD above average)	-500	-500	-500	-500
16	Adverse Temperature Impact (1-in-10)	-654	-668	-660	-635
17	Adverse Scenario Reserve Margin[6]	13.7%	11.2%	12.8%	17.2%
18	Adverse Scenario Reserve Margin w/DR and Interruptibles[7]	16.9%	14.3%	15.9%	20.5%
19	Resources needed to meet 7.0% Reserve (W/DR & Interruptibles)	0	0	0	0
20	Surplus Resources Above 7.0% Reserve (W/DR & Interruptibles)	1,982	1,506	1,808	2,623
21	Existing Aging Generation Without Capacity Contracts[9]	-1,018	-1,018	-1,018	-1,018

[1] 2006 estimate of the following Net Imports: **NW imports (COI) 2,300 MW + WAPA CVP Entitlements 1,250 MW - exports to SP26 3,000 MW.**

[2] Demand forecast completed September 2005 as part of IEPR proceeding. CEC-400-2005-034-SF-ED2.

[3] Planning Reserve calculation ((Total Generation+Demand Response+Interruptibles)/Normal Demand)-1.

[4] Based on CA ISO data.

[5] Does not include Demand Response/Interruptible Programs because reserve margins are in excess of 5% (Stage 2).

[6] Operating Reserve calculation ((Operating Generation-**Imports with Reserves**)/(Demand-**Imports with Reserves**))-1. See Footnote 1.

[7] Demand Response and Interruptibles added to Operating Generation in Reserve Margin formula from Footnote 6.

[8] Capacity is included in Line 1 and represents plants identified in 2004 CEC Staff Draft Report 100-04-005D *Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements*

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Table 1-4: 2006 Detailed Monthly Electricity Outlook – CA ISO Southern Region (SP26)
(Megawatts)

	Resource Adequacy Planning Conventions	June	July	August	September
1	Existing Generation[1]	21,321	21,708	21,708	21,708
2	Retirements (Known)	-1,320	0	0	0
3	High Probability CA Additions	1,707	0	0	0
4	Net Interchange [2]	10,100	10,100	10,100	10,100
5	Total Net Generation (MW)	31,808	31,808	31,808	31,808
6	1-in-2 Summer Temperature Demand (Average)[3]	24,806	26,300	26,717	27,027
7	Demand Response (DR)	92	92	92	92
8	Interruptible/Curtailable Programs	1,087	1,087	1,087	1,087
9	Planning Reserve[4]	33.0%	25.4%	23.5%	22.1%
	Expected Operating Conditions				
	Total Net Generation (MW)	31,808	31,808	31,808	31,808
10	Outages (Average forced + planned)	-1,155	-1,155	-1,155	-1,155
11	Zonal Transmission Limitation[5]	-150	-150	-150	-150
12	Expected Operating Generation with Outages/Limitations[6]	30,503	30,503	30,503	30,503
13	Expected Operating Reserve Margin (1-in-2)[7]	30.5%	20.8%	18.4%	16.6%
	Adverse Conditions				
14	High Zonal Transmission Limitation	-250	-250	-250	-250
15	High Forced Outages	-560	-560	-560	-560
16	Adverse Temperature Impact (1-in-10)	-1,937	-2,054	-2,086	-2,110
17	Adverse Scenario Reserve Margin[7]	14.3%	6.0%	3.9%	2.4%
18	Adverse Scenario Reserve Margin w/DR and Interruptibles[8]	20.0%	11.3%	9.1%	7.5%
19	Resources needed to meet 7.0% Reserve (W/DR & Interruptibles)	0	0	0	0
20	Surplus Resources Above 7.0% Reserve (W/DR & Interruptibles)	2,684	960	480	122
21	Existing Aging Generation Without Capacity Contracts[9]	-2,370	-2,370	-2,370	-2,370

1 Dependable capacity by station includes 1,080 MW of stations located south of Miguel.

2 2006 estimate of the following Net Imports: **DC imports 2,000 MW, SW imports 4,100 MW,** Imports from NP26 3,000 MW, LADWP Control Area imports 1,000 MW. **Imports with own reserves highlighted in bold.**

3 September forecast showing adopted CEC 2005 IEPR high case forecast of 27,027 MW.

4 Planning Reserve calculation ((Total Generation+Demand Response+Interruptibles)/Normal Demand)-1.

5 Based on CA ISO data.

6 Does not include Demand Response/Interruptible Programs because reserve margins are in excess of 5% (Stage 2).

7 Operating Reserve calculation ((Operating Generation-**Imports with Reserves**)/(Demand-**Imports with Reserves**))-1. See Footnote 2.

8 Demand Response and Interruptibles added to Operating Generation in Reserve Margin formula from Footnote 7.

9 Capacity is included in Line 1 and represents plants identified in 2004 CEC Staff Draft Report 100-04-005D *Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements*

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CHAPTER 1: THE DETERMINISTIC APPROACH

Resource Adequacy Planning

Line 1: Existing Generation

Existing generation includes thermal and hydroelectric power plants operational as of August 1, 2005. Thermal generation consists of CA ISO control area merchant and municipal thermal resources (including non-hydro renewable), Investor-Owned Utility (IOU) retained generation, and Qualifying Facilities (QFs). The merchant thermal generation in SP26 includes 1,080 MW of contracted capacity from units located in Baja California Norte. Thermal unit capacity is derated to reflect summer operating conditions. The summer derate capacity can range from 90 to 96 percent of nameplate capacity based on the type of unit and location. The Non-CA ISO generation totals include both thermal and hydro capacity. Table 1-5 provides a more detailed breakout of existing generation.

Table 1-5: Derated Existing Generation

	SP26	NP26	TOTAL
CA ISO Control Area			
Merchant Thermal & QF	16,215	16,006	32,221
Municipal Thermal	519	182	701
IOU Retained Thermal	3,540	2,343	5,883
Derated Hydro	1,047	5,939	6,986
TOTAL CA ISO	**21,321**	**24,470**	**45,791**
Non-CA ISO	6,523	4,383	10,906
STATEWIDE TOTAL	**27,844**	**28,853**	**56,697**

Dependable hydro capacity at peak does not significantly change between a wet and a dry water year although historic data shows that dry conditions can have a significant impact on available energy production. The estimate of dependable hydro capacity that staff uses is based on low water year conditions and would only be revised slightly upward in an extremely wet year to account for additional run-of-river capacity that could be produced in June and early July by additional runoff.

This water year is shaping up as the first wet year of the millennium on the Pacific Slope. For calendar year 2006, statewide production of hydroelectric energy is forecast to be significantly above average. Water supplies in California are well above average, and the outlook this year for California's hydro generation is excellent. For the summer months, hydro generation's contributions to capacity will be very dependable, and total energy output will be above average. The chances of adverse hydro conditions occurring in California during 2006 are nil[3].

Lines 2 and 3: Retirements and Additions

Table 1-6 provides a listing of the dependable capacity of all additions and retirements included in Lines 2 and 3.

Table 1-6: 2006 Additions and Retirements

CA ISO Control Area					
SP26			**NP26**		
Additions			**Additions**		
Name	**MW**	**Expected**	**Name**	**MW**	**Expected**
Malburg	129	Oct-05	Kings River	86	Oct-05
Mountainview	1012	Jan-06	Santa Cruz Landfill	3	Jan-06
Palomar Escondido	480	Apr-06	Dependable Wind	5	Apr-06
Riverside ERC	86	May-06	Fresno Cogen Expansion 2	22	Jun-06
	1707		Diablo Canyon Rerate	50	Jun-06
				166	
Retirements (Known)			**Retirements (Known)**		
Mohave	-1320		Hunters Point 1/4	-219	
	-1320			-219	
Non-CA ISO Control Areas					
LADWP & IID Control Areas			**SMUD & TID Control Areas**		
Additions			**Additions**		
Name	**MW**	**Expected**	**Name**	**MW**	**Expected**
			Cosumnes	480	Mar-06
			Walnut Energy Center	240	Mar-06
			Ripon	86	Jun-06
				806	

Line 4: Net Interchange

Tables 1-7 thru 1-10 detail the individual components of net interchange. We estimate that hydro energy from the Pacific Northwest in 2006 will be about 105 percent of average. For LSEs, this means that substantial quantities of non-firm

[3] Based on the Staff Report, *CALIFORNIA HYDROELECTRIC ENERGY OUTLOOK* March 2006, Publication # CEC-700-2006-003, available on the Energy Commission Web site.

energy will be available for sale and export to California. Surplus energy from run-of-river plants in the Northwest will be especially abundant during May-July (when runoff peaks in the Northwest), and it will also be available in August when loads peak in California.

Table 1-7: Statewide Net Interchange

Northwest Imports (COI)[4]	4,000
Southwest Imports[4]	4,100
Pacific DC Intertie (CA ISO)[4]	2,000
LADWP and IID Control Areas	3,018
Total	**13,118**

Table 1-8: CA ISO Net Interchange

CA ISO Share of NW Imports (COI) [4]	2,300
WAPA Central Valley Imports	1,250
Southwest Imports[4]	4,100
Pacific DC Intertie (CA ISO) [4]	2,000
Net LADWP Control Area Interchange	1,000
Total	**10,650**

The NP26 net interchange includes 3,000 MW of export to SP26. The export reflects the greater need of capacity in SP26 than NP26 but does not imply that it is contractually obligated to be delivered into SP26.

Table 1-9: NP26 Net Interchange

CA ISO Share of NW Imports[4]	2,300
WAPA Central Valley Imports	1,250
Path 26 Exports	(3,000)
Total	**550**

The SP26 net interchange import numbers include increases in the Southwest imports by 400 MW above 2005 observed levels to account for capacitor upgrades on the Palo Verde-to-Devers line. The LADWP Control Area interchange value includes wheeled power (capacity it is carrying on its transmission system for use by other municipal utilities served by the CA ISO).

[4] Imports assumed to carry reserves.

Table 1-10: SP26 Net Interchange

Path 26	3,000
CA ISO Share of Pacific DC Intertie[4]	2,000
Net SW Imports[4]	4,100
Net LADWP Control Area Interchange	1,000
Total	**10,100**

Line 5: Total Net Generation

Line 5 is the sum of Lines 1-4 and represents total available capacity before outages and limitations.

Line 6: 1-in-2 Summer Temperature Demand (Average)

The demand forecast used in Line 6 is the *Statewide 1 in 2 Electric Peak Demand by Load Serving Entity (MW), High Case* in the *California Energy Demand 2006-2016 Staff Energy Demand Forecast, Revised September 2005* (*CED 2006*). A range of three forecasts was vetted in a series of workshops in the *2005 Integrated Energy Policy Report* (*IEPR*) proceedings and adopted as part of the *2005 IEPR*. Complete documentation of assumptions and methodologies are included in that report. Staff selected the high forecast to be conservative.

Energy Commission demand forecasting models account for effects of demand-side management (DSM) programs, building and appliance standards, market conditions, and price response. In the 2005 demand forecast the IOU energy efficiency targets are assumed to be funded through 2008. To avoid double counting, DSM program effects are explicitly modeled only when staff concludes that they are not accounted for by existing model assumptions. Table 1-11 details the energy efficiency impacts included in the *CED 2006*.

Table 1-11: Energy Efficiency Impacts in the *CED 2006* Statewide Peak Demand Forecast (MW)

	IOU Energy Efficiency Programs	Building & Appliance Standards
Statewide	76.3	137
CA ISO	76.3	136
NP26	26.6	26
SP26	49.7	110

Lines 7 and 8: Demand Response and Interruptible Programs

There are several mitigation measures available to the CA ISO and individual utilities to respond to adverse conditions when operating reserves fall below minimum acceptable levels. Tables 1-12 and 1-13 detail the subscribed and expected IOU demand response and interruptible programs that are established at the CPUC and/or have been contracted by an IOU. Several of these programs are new or evolving, and participation may increase before the summer peak temperatures occur. A detailed explanation of the demand response programs identified in Tables 1-9 and 1-10 follows:

I-6— SCE traditional non-firm rate: Provides discounted energy and demand charges for load subject to curtailment during Stage 2 or 3 system emergencies. Per-kWh non-compliance penalties are applied to consumption above the contracted firm service level during events.

E-19/E-20—PG&E traditional non-firm rates: Provides discounted energy and demand charges for load subject to curtailment during Stage 2 or 3 system emergencies. Per-kWh non-compliance penalties are applied to consumption above the contracted firm service level during events.

AL TOU CP—SDG&E critical peak rate: On-peak energy charges increase to $1.80/kWh during “critical peak” events, defined as Stage 2 or 3 system conditions. BIP—Base Interruptible Program: Relatively new interruptible program that offers demand charge credits for load subject to interruption during system emergencies. Significant per kWh penalties apply for non-compliance.

ACCP—Air Conditioner Cycling Program (SCE only): Residential and small- to medium-sized commercial and industrial customers receive a bill incentive to allow SCE to remotely cycle their AC during system emergencies or high demand periods. The incentive varies based on the percent time the customer is willing to have the equipment cycled off.

Smart Thermo—Smart Thermostat (SCE and SDG&E): Customers with communicating, programmable thermostats receive a bill incentive to allow the utilities to set their thermostats higher during periods of high demand or system emergencies.

OBMC—Optional Binding Mandatory Curtailment: This program exempts customers from rotating outages in exchange for partial power reductions from their entire circuit over a longer period. Specifically, customers must reduce power on their entire circuit by up to 15 percent during the entire duration of every rotating outage.

SLRP—Scheduled Load Reduction Program: Offers an energy credit in return for scheduled peak period load reductions.

RBRP—Rolling Blackout Reduction Program (SDG&E only): Offers energy credits for load reductions—obtained through self-generation—during Stage 3 system conditions. Fifteen minute response is required.

AP-I—Agricultural and Pumping Interruptible (SCE only): Provides energy credits on consumption above the contracted firm service level in exchange for emergency reductions. Per kWh penalties apply for non-compliance.

CPP-VCD— Critical Peak Pricing: CPP rates offer discounts (energy, demand, or both, depending on the particular design) in non-critical hours but charge a premium for energy consumed on a limited number of days when system conditions are forecast to be critical, typically due to high expected demand or supply shortfalls.

DBP—Demand Bidding Program: Participants are provided billing credits for load reductions during curtailment events that are "bid" in to the utility a day in advance. There is no penalty for not bidding or not fulfilling the bid obligation; however the participant would not receive a credit for that event.

CAL-DRP—California Demand Reserves Partnership: Program aggregators provide a contracted amount of load reduction during curtailment events by aggregating participant load reductions. Aggregators are paid a monthly capacity reservation charge for contracted load reduction amounts and an additional energy payment for consumption avoided during curtailment events.

C/I 20/20—20/20 for Commercial/Industrial customers (SDG&E only): A 20-percent bill credit is given to customers who reduce on-peak consumption by an average of 20 percent or greater over all critical peak days.

BEC—Business Energy Coalition: A pilot program in the PG&E service territory operated in partnership with The Energy Coalition, participants are paid a per-kW incentive to reduce load during curtailment events. The Energy Coalition works with participating customers to develop customized load reduction strategies.

"Emergency" CPP and DBP—These programs operate the same as the CPP and DBP programs except that notification to customers is made day-of instead of day-ahead. Incentives reflect the higher value of the load reduction.

Table 1-12: IOU 2006 Subscribed Demand Response and Interruptible Programs

Program	Subscribed		
	SCE	SDG&E	PG&E
I-6 or E-19/E-20	699		300
AL TOU CP and RBRP		15	
BIP	101	8	27
ACCP	424	12	
OBMC/RBRP	10	65	14
AP-I/Emergency CCP/DBP-E/DBP-E	72	12	
Smart Thermo		2	
Interruptible Sub-Total	1306	114	341
CPP Programs	2	15	45
DBP	181	31	205
CAL-DRP	160	5	248
CI 20/20 or BEC		51	10
Demand Response Sub-Total	343	102	508
Total	**1649**	**216**	**849**

Source: IOU filings under PUC R.00-10-002 and R.02-06-001.

Table 1-13: IOU 2006 Expected Demand Response and Interruptible Programs

Program	Expected		
	SCE	SDG&E	PG&E
I-6 or E-19/E-20	585.8		276.8
AL TOU CP		1.7	
BIP	60.8	0.2	25.8
ACCP	353.7	8.6	
OBMC/RBRP	10	25.2	13.5
AP-I/Emergency CCP/DBP-E/DBP-E	34	5.6	
Smart Thermo		1.4	
Interruptible Sub-Total	1044	43	316
CPP Programs	0.9	5.8	28.3
DBP	37.4	0.7	64.8
CAL-DRP	35.4	3.2	226.0
CI 20/20 or BEC		8.7	3.2
Demand Response Sub-Total	74	18	322
Total	**1118**	**61**	**638**

Source: IOU filings under PUC R.00-10-002, R.02-06-001 and D.06-03-024.

Line 9: Planning Reserve Margin

Line 9 provides the conventional planning reserve margin calculated in the same manner as in CPUC resource adequacy proceedings. The formula used to calculate the margin is:

((Total Net Generation + Demand Response + Interruptible) / Demand) – 1

Expected Operating Conditions

As system operators get closer to the operating day, they have a better sense of what unit and transmission outages are going to be. Thus, instead of having a general contingency reserve like a planning reserve, they measure an operating reserve based on estimates of what actual conditions are going to be. In this scenario, we have quantified potential outages and zonal limitations to simulate conditions this summer.

Line 10: Outages (Average Forced and Planned)

Energy Commission staff calculated potential 2006 outages using the actual 2002 thru 2005 daily outage totals for the summer peak period provided by the CA ISO. There is a significant variation in the amount of capacity that is forced out on any given day. Staff has conducted probability studies on outages in the SP26 region, and the results are presented in detail in Chapter 2. Staff made one minor change to this line since our Draft Report was published, resulting in a small increase in outage assumptions. A 5 percent forced outage rate is now assumed for additions included in Line 2. The forecast outage total also includes a small number of scheduled outages.

Line 11: Zonal Transmission Limitations

Line 11, Zonal Transmission Limitations, represents the estimate of the amount of existing capacity contained in Line 1 that is unable to serve load due to transmission constraints within Northern California or Southern California. Actual 2005 summer data was used as a baseline, and net gains from transmission upgrades were then used to reduce the limitation. For summer 2006, the CA ISO estimates NP26 should not experience any limitations. However, SP26 will likely be constrained by 150 MW consistently.

Line 12: Expected Operating Generation with Outages/Limitations

Line 12 is the sum of Lines 5, 10, and 11 and represents the total capacity available to meet load. Demand Response and Interruptible programs are not included as a resource in this line because reserve margins are above 7 percent in all regions.

Line 13: Expected Operating Reserve Margin (1-in-2)

Line 13 provides the monthly expected reserve margin under average temperature conditions. The formula used to calculate the margin is:

((Supply – Imports w/reserves) / (Demand – Imports w/reserves)) - 1

The net interchange numbers expected to carry their own reserves provided in Tables 1-7 thru 1-10.

Adverse Operating Conditions

Energy Commission and CA ISO staffs have identified potential adverse conditions that could strain the operation of the system. This scenario includes three adverse conditions occurring simultaneously: high congestion, higher-than-summer-average outages, and hot 1-in-10 temperatures. These adverse conditions, alone or in combination, would impact system operation. While there is a reasonable probability that any one adverse scenario could happen at any time, it is less likely that two or more adverse conditions will occur simultaneously. The probabilistic study in Chapter 2 provides a more in-depth analysis of the likelihood of this occurring.

Line 14: High Zonal Transmission Limitation

Line 14, High Zonal Transmission Limitations, is based on actual 2005 data and represents the high congestion periodically observed during the summer months.

Line 15: High Forced Outages

To estimate Line 15, staff used the same 2002 thru 2005 daily outage totals for the summer peak period used in Line 10 and calculated the standard deviation of all data points. The adverse forced outage condition is one standard deviation above the average. A more detailed description is included in Chapter 2.

Line 16: Adverse Temperature Impact (Hot)

The demand forecast used in Line 16 is the Statewide 1 in 10 Electric Peak Demand by LSE (MW), High Case from the CED 2006.

Lines 17 and 18: Projected Adverse Scenario Reserve Margins

Line 17 represents the reserve margin under the adverse conditions of high zonal transmission limitations, high forced outage conditions, and hot summer temperatures. It is calculated in the same manner as Line 13, adding the adverse temperature impact to demand and subtracting outages and transmission limitations from resources. Line 18 is the same calculation but includes demand response and interruptible programs as resources to mitigate low operating reserve margins. When operating reserves fall below the WECC Minimum Operating Reserve Criteria (MORC), the CA ISO will declare one of the following emergencies:

Stage 1: Actual or anticipated operating reserves are less than the MORC (about 7 percent). The public is notified, and consumers are requested to voluntarily reduce their consumption of electric energy;

Stage 2: Actual or anticipated operating reserves are less than or equal to 5 percent. The public is notified, and interruption of service to some or all selected customers may be required to avoid more severe conditions. Usually "Interruptible Customers" (those who have agreed to be curtailed during Stage 2 events in exchange for lower rates) are called upon to cut load in order to avoid involuntary load cuts;

Stage 3: Actual or anticipated operating reserves are less than or equal to 1.5 percent. This is the most severe emergency stage and indicates that, without significant CA ISO intervention, the electric system is in danger of imminent collapse. Involuntary curtailments to consumers (rotating outages) are required to maintain Operating Reserves above 1.5 percent. Rotating outage areas are decided upon by local utilities and take place in an equitable sequence. Historically, the CA ISO declared an emergency only if reserves fell below MORC for their entire control area. However, in 2005 new protocols and tariffs designed to be more responsive to the two primary sub-regions within their control were implemented.

Lines 19 and 20: Resources Needed or Surplus for 7 Percent Reserve Margin

Line 19 calculates the additional megawatts required to meet a 7 percent reserve during adverse conditions. Line 20 represents the surplus megawatts above a 7 percent reserve under the adverse scenario. Demand response and interruptible resources are included in both calculations. Based on the above assumptions, all regions are expected to have surplus resources during peak months.

Line 21: Existing Aging Generation That May Not Have Capacity Contracts

Line 21 represents the capacity from the aging power plants identified in the 2004 Energy Commission Staff Draft Report titled *Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements* (Pub. no. CEC 100-04-005D). It is a placeholder estimate for existing generation that may not have capacity contracts with an LSE and does not have 2006 RMR contracts with the CA ISO. The resource adequacy and procurement proceedings that are ongoing at the CPUC may provide or has provided an opportunity for many of these units identified in

Table 1-11 to secure capacity contracts for 2006 and beyond. Staff does not have information on individual contract status of these particular units. It is likely that the majority of the units have Liquidated Damages (LD) contracts, which are supply contracts that contain provisions for the payment of damages in the event of non-delivery, and are not backed by any specific generation facility or resource portfolio, particularly in Southern California. Staff estimates a low probability that these units will retire in 2006. These plants are included in Line 1, Existing Generation.

Table 1-14: Existing Aging Generation without Known Capacity Contracts

SP26			NP26		
Name	**MW**	**At Risk**	**Name**	**MW**	**At Risk**
Coolwater 1/2	-146	2006	Contra Costa 6	-336	2006
Mandalay 1/2	-433	2006	Pittsburg 7	-682	2006
Ormond Beach 1/2	-1491	2006		**-1018**	
Encina 4	-300	2006			
	-2370				

CHAPTER 2: THE PROBABILISTIC APPROACH

Staff continues with its development of a full probabilistic assessment to enhance the deterministic tables that have been historically produced (Tables 1-1 thru 1-4). The first stage, included in the draft report published in December, studied the probabilities of high demand and generation forced outages in the Southern California portion of the CA ISO Control Area. These two criteria were selected for initial study because data was readily available and weather and outages have significant impacts on overall system operation. The SP26 region was selected because it has the highest probability of not meeting reserve requirements under adverse conditions this summer. Staff has now incorporated the impact of forced outages of transmission lines in this report.

In the staff's deterministic tables presented in Chapter 1, supply adequacy is estimated for two operating scenarios: expected and adverse conditions. This approach has two limitations. First, there is a possibility that demand can exceed the 1-in-10 condition, or actual observed forced outages may exceed one standard deviation above the average. Second, although there is a reasonable probability that any one of the three conditions in the adverse scenario could happen at any time, it is progressively less likely that they will occur simultaneously. Adding all three simultaneously may be overly conservative and understate the likelihood of meeting expected reserve margins. This probabilistic assessment evaluates the complete range of demand as well as generation and transmission forced outage occurrences based on historical data and quantifies the possibility of three adverse conditions occurring simultaneously.

Probability of Demand

To account for the effect of temperature on demand, staff developed a temperature response adjustment for varying degrees of hotter-than-average temperatures. To develop multipliers, staff estimated the relationship between temperature and daily peaks using recorded 2004 hourly loads reported to FERC by SCE and SDG&E a three-day moving average of daily maximum temperatures weighted by the number of air conditioning units estimated to be in each region. The estimation included weekdays from June 15th through September 15th, on which the weighted average maximum temperature was above 75 degrees in SCE, or 70 degrees in SDG&E service territories. Figures 2-1 and 2-2 show the 2004 relationship between temperature and load and the estimated weather response function for SCE and SDG&E, respectively. The coefficients shown for each region, 317.33 and 66.53, indicate the MW increase in peak demand for each degree the temperature rises.

Figure 2-1: SCE Load vs. Temperature Relations

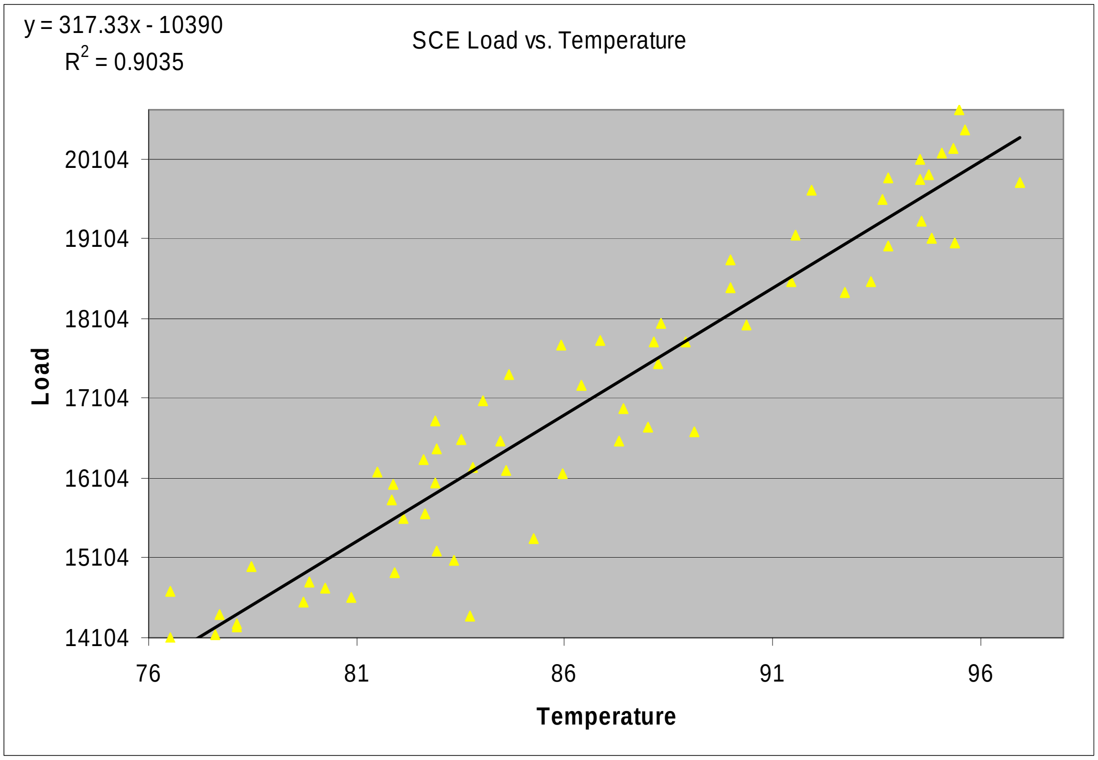
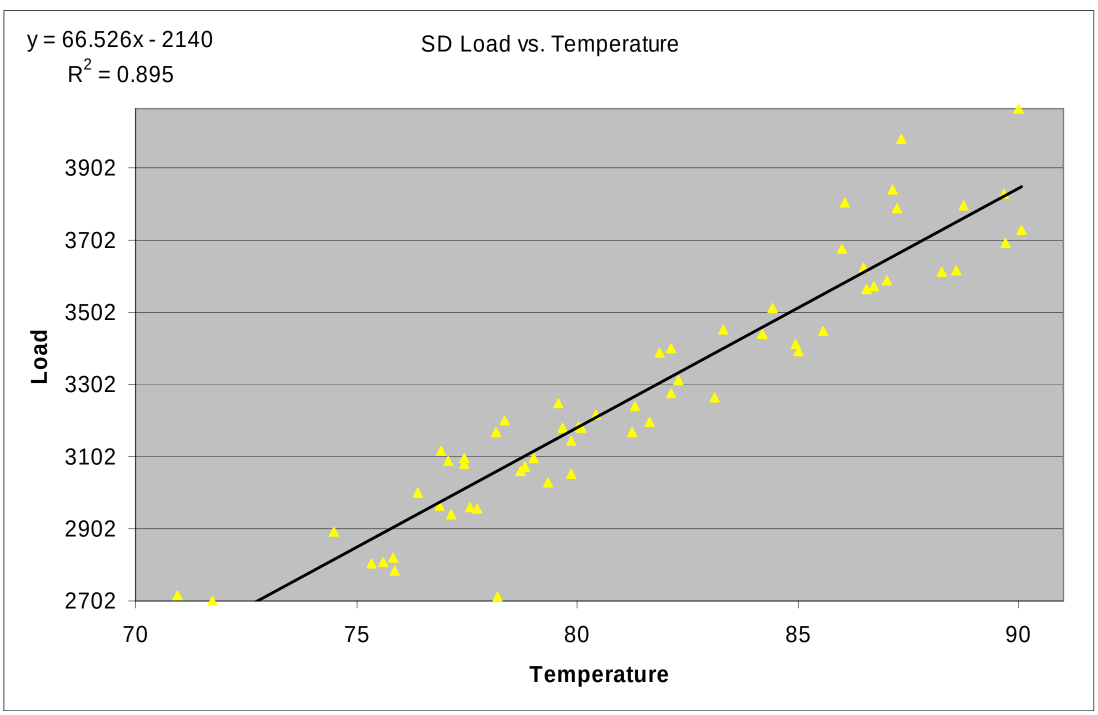


Figure 2-2: SDG&E Load vs. Temperature Relations



The estimated parameters were then applied to 54 years of historic weather data to calculate a distribution of summer 2006 peak demand possibilities. The resulting probabilistic graph for Southern California is presented in Figure 2-3. It characterizes the probability of aggregated load occurring for Southern California.

Figure 2-3: Probability of Demand CA ISO SP26 Summer 2006

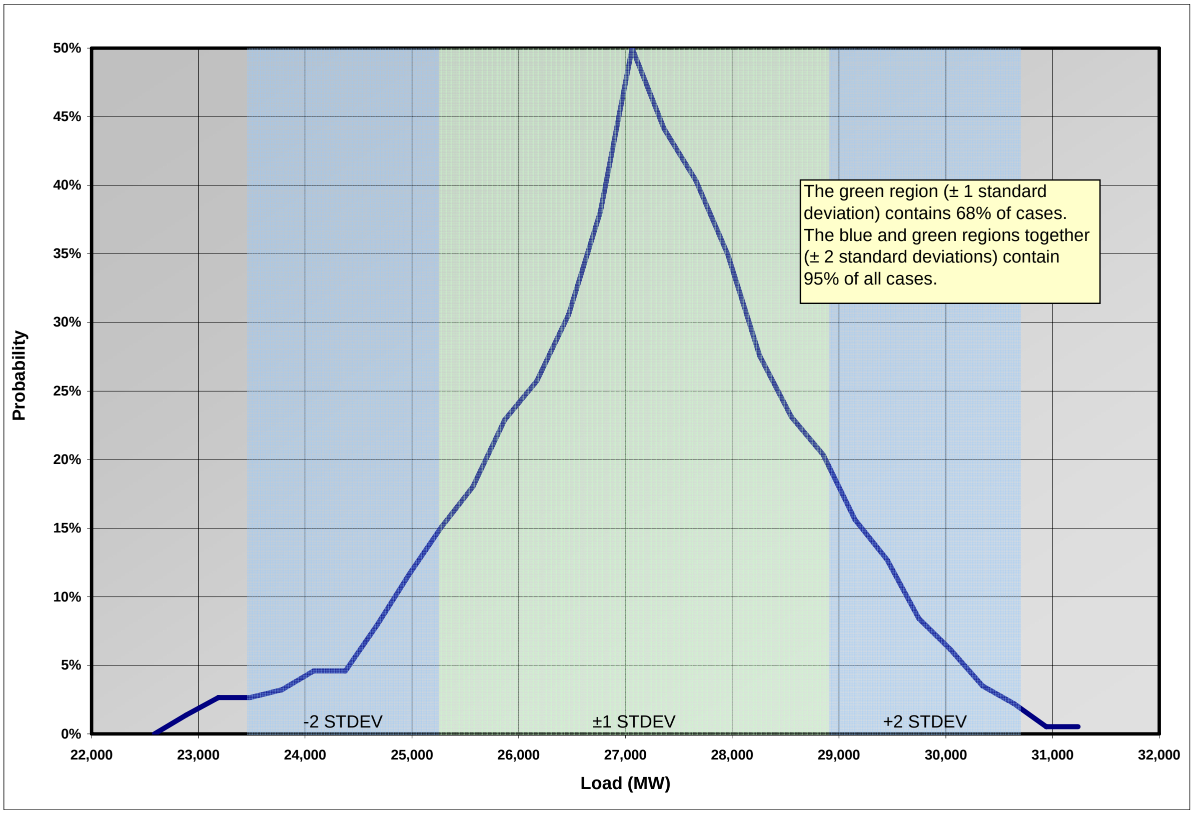


Figure 2-3 shows that the range of SP26 demand in 2006 could be as low as 22,589 MW or as high as 31,239, with a 'most likely' demand of 27,027 MW. While the forecast could be higher or lower than the mean with equal probability, for planning purposes we are more concerned with the risks associated with higher loads. Staff estimates there is a 20 percent probability that the demand will be as high as 28,875 MW, and a 2.5 percent probability that it will be as high as two standard deviations or 30,675 MW.

Probability of Generation Forced Outages

Similar to the impact and range of possible demand, the magnitude of the total available generation resources can be expected to fall within a range of uncertainty due to the variation in forced outages. Energy Commission staff calculated potential 2006 outages using actual 2002 thru 2005 daily outage totals for the summer peak period based on data provided by the CA ISO. This set of data was statistically processed, and the results are presented in Figure 2-4.

Figure 2-4: Probability of Generation Forced Outages CA ISO SP26 Summer 2006

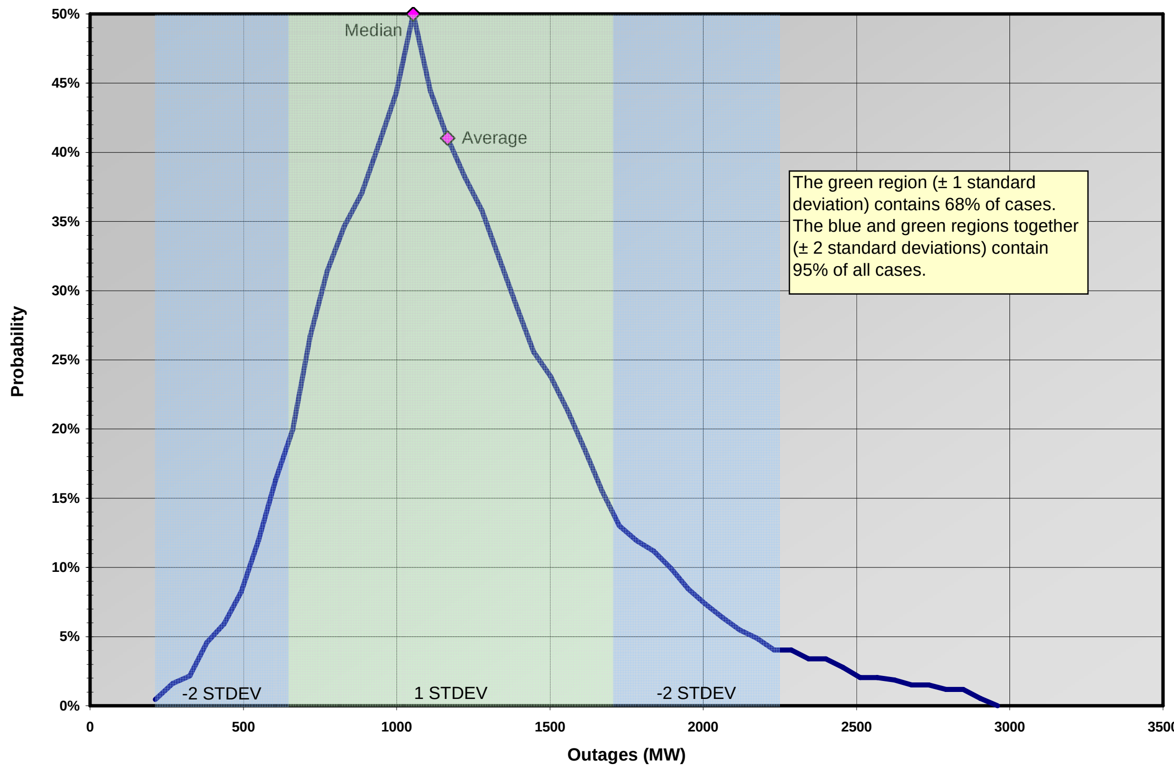


Figure 2-4 shows the range of SP26 forced outages in 2006 could be as low as 128 MW or as high as 2,875 MW, with a 'most likely' outage level of 1,115 MW. Again, for planning purposes, we are more concerned with the risks associated with the higher outages. Staff estimates a 13 percent probability that forced outages will be as high as 1,715 MW and a 4 percent probability that they will be as high as 2,260 MW.

Probability of Transmission Line Forced Outages

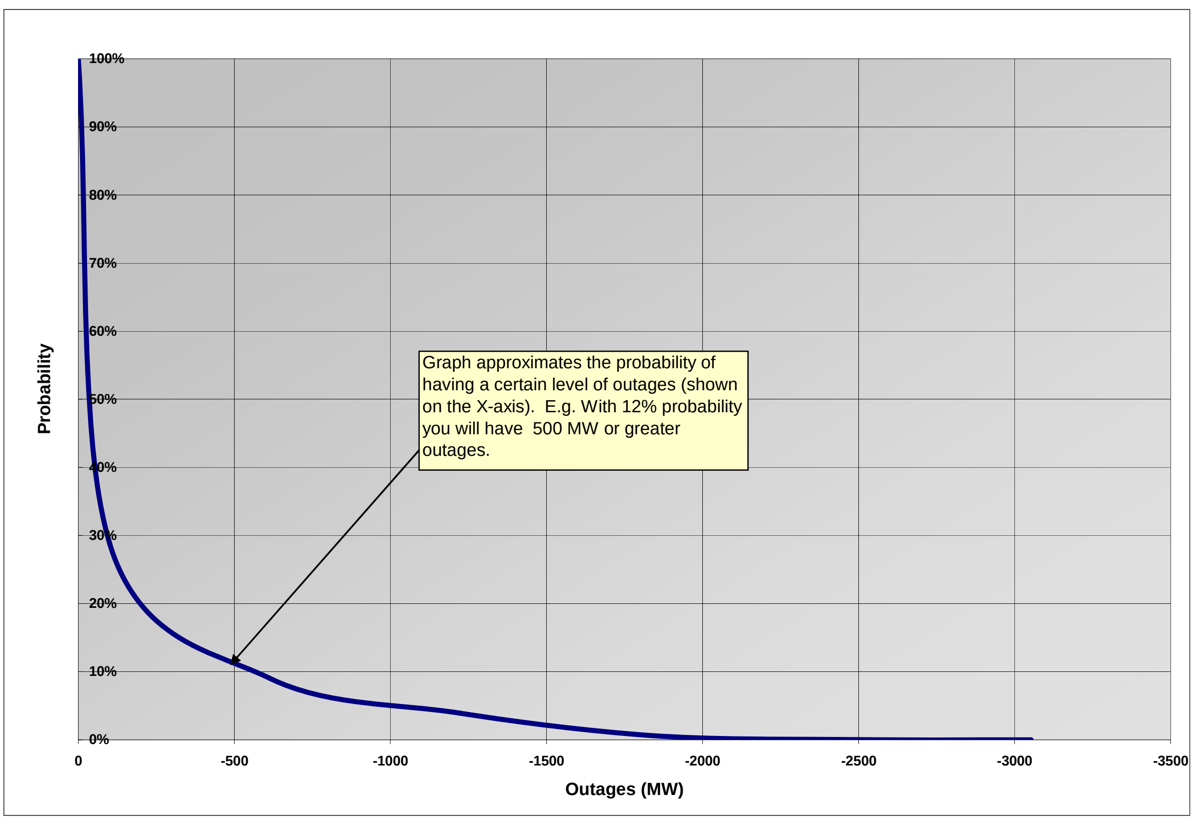
A major transmission line outage can have significant impacts on the overall operation of the system. These outages often occur with little or no warning and, in the case of the Pacific DC Intertie (PDCI), can account for as much as a 2,000 MW reduction in resources available to meet load. On August 25, 2005, the PDCI unexpectedly dropped out of service just as Southern California was approaching its daily peak load. This outage, coupled with a 2,000 MW under estimation in the day-ahead peak demand forecast, required the CA ISO to issue a Transmission

Emergency notice requesting utilities in SP26 reduce demand by shedding 900 MW of firm load and 800 MW of interruptible load for about 35 minutes.

Staff added the effects of major transmission outages in our probabilistic analysis for this report. To calculate the overall impact of these failures on the SP26 region, staff used subpoenaed data from the CA ISO to compare hourly transfer capacities with the WECC rating for each transmission line. One limitation of using this data is that this may have omitted short duration outages that were not visible between the times the transfer capacity is reported. For example, a line that trips off at 5 minutes after the hour and is restored 50 minutes later would not be visible in the dataset. As a result, the probabilistic analysis would tend to underestimate the likelihood of a transmission outage occurring.

Figure 2-5 provides the range of transmission outages observed from May 15 thru September 15 for the years 2003 thru 2005. The highest level observed during this period was 3,053 MW; however, there were no visible outages during 60 percent of the recorded hours.

Figure 2-5: Probability of Transmission Line Forced Outages CA ISO SP26 Summer 2006



Probability of Maintaining Minimum Required Operating Reserves

Cumulative Probability

Methodology

The Supply Adequacy Model (SAM) developed by Energy Commission staff allows the user to look at a wider range of future conditions and presents the results in a probabilistic format. The SAM is a multi-regional, probabilistic forecasting model that assesses resource adequacy during the coincident peak load hour for a specified region or a group of regions. It is based on the Microsoft platform and uses Excel spreadsheets in combination with Visual Basic macros language.

This pilot study focused on Southern California, starting with the baseline assumptions presented in Table 1-4 in Chapter 1. These assumptions, with the exception of demand, generation forced outages and transmission forced outages as described above, are assumed to be fixed. Generation resources are aggregated; distribution outages are not considered; and imports and exports with other regions are characterized by an aggregate capacity of net interchange. These simplifications required a modified version of the model, called SAM-A, to be developed and used in this study.

SAM-A preserved the basic principles of the original version but is simpler and takes less time to provide a result. Similar to the original version, SAM-A assesses the supply and demand balances for the coincident peak load hour in a specified region and has the capability to address uncertainty with respect to individual input variables.

The SAM-A exercises calculations in four major steps:

1. Using Monte Carlo draws, the model generates a deterministic case of input data in which each uncertainty factor (demand and forced outage) takes a random value from its respective range of possible values;
2. Evaluation of the adequacy of supply is made for each deterministic case, using spreadsheet tables;
3. The above steps are repeated for multiple cases to reasonably cover all possible combinations of the values of the uncertain factors;
4. The resulting set of cases is statistically processed to calculate:
    a. The probability that there is insufficient capacity to meet the peak demand and maintain a given reserve margin.
    b. The probability that there is sufficient capacity to meet the peak demand and maintain a given reserve margin.

Results

Figure 2-6 shows the probability of meeting the minimum operating reserve margin based on historical load/temperature data and forced generation and transmission outage data without using the mitigation tools of demand response and interruptible load programs. The critical points are those corresponding to the CA ISO stages of alert described in Chapter 1. As shown in Figure 2-6, the probabilistic forecast gives a 77.4 percent confidence that operating reserves will not be less than 7 percent, which corresponds to the CA ISO first stage of alert. The confidence level that the Southern California reserve margin will be higher than 5 percent (Stage 2) is 83.5 percent. Southern California has a 91.5 percent likelihood of being higher than 1.5 percent (Stage 3).

We also examined a case in which demand side options were employed for tight supply-demand situations. If operating conditions deteriorate and the operating reserve margin drops lower than 7 percent, the CA ISO can rely on demand response and interruptible programs. The resulting operating reserve in the region with demand response and interruptible programs included is shown in Figures 2-7 and 2-8. Demand response and interruptible load programs are included if reserve margins fall below 5 percent. With these programs, the confidence that a Stage 3 alert will not occur is approximately 97.9 percent, an increase of more than 6 percent over the case without these mitigation tools.

The results can be also interpreted in terms of risk, and the level of risk is a value that complements the confidence level. For example, based on adverse temperature and forced generation and transmission outages occurring simultaneously with sufficient time to call demand response and interruptible load programs, risk that reserve margins fall below 1.5 percent, which requires the CA ISO to call involuntary firm load shedding, is about 2 percent.

Next Steps for Probabilistic Analysis

Staff's expanded probabilistic methodology is primarily focused on the individual probability of occurrence of a number of adverse conditions and the cumulative probability of these conditions occurring simultaneously to the extent that they impact minimum reserve margins. The first modeling effort evaluated only temperature and forced generation outages. The analysis in this report includes a third adverse condition – transmission line outages. Additional adverse conditions, such as high humidity levels or transmission congestion, may be assessed in future analyses if relevant data can be obtained.

SP26 was selected for this first effort because the lowest potential reserve margins are currently in this region. The results of this analysis indicate that a similar analysis for NP26, CA ISO, or statewide regions will not identify critical areas for concern in these other regions. However, future analysis may also be completed for NP26, the CA ISO Control Area, and the statewide system as conditions change in the future.

Figure 2-6: Operating Reserves (Not Including Demand Response or Interruptible Programs) CA ISO SP26 Summer 2006

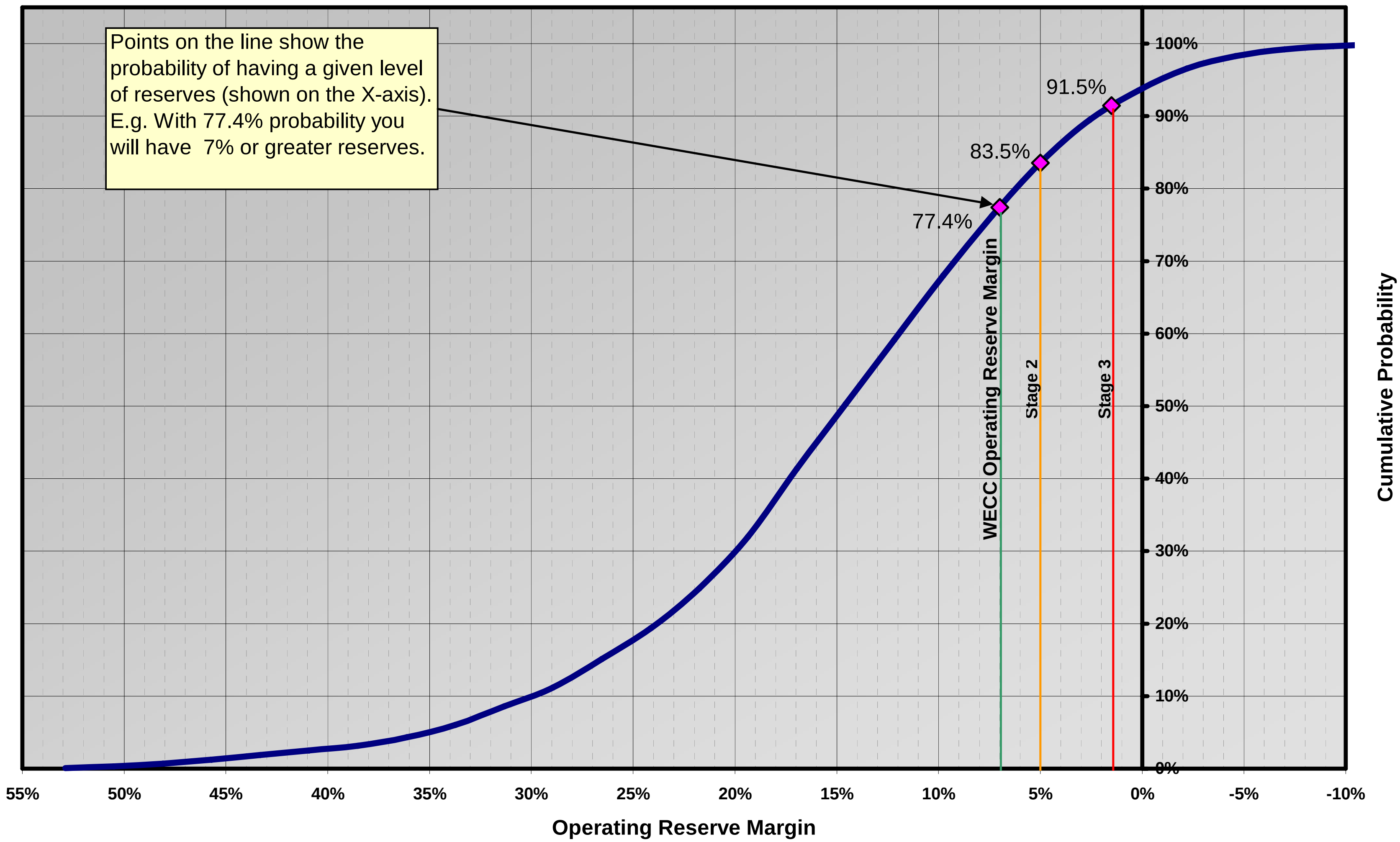


Figure 2-7: Operating Reserve Including Demand Response and Interruptible Programs
CA ISO SP26 Summer 2006

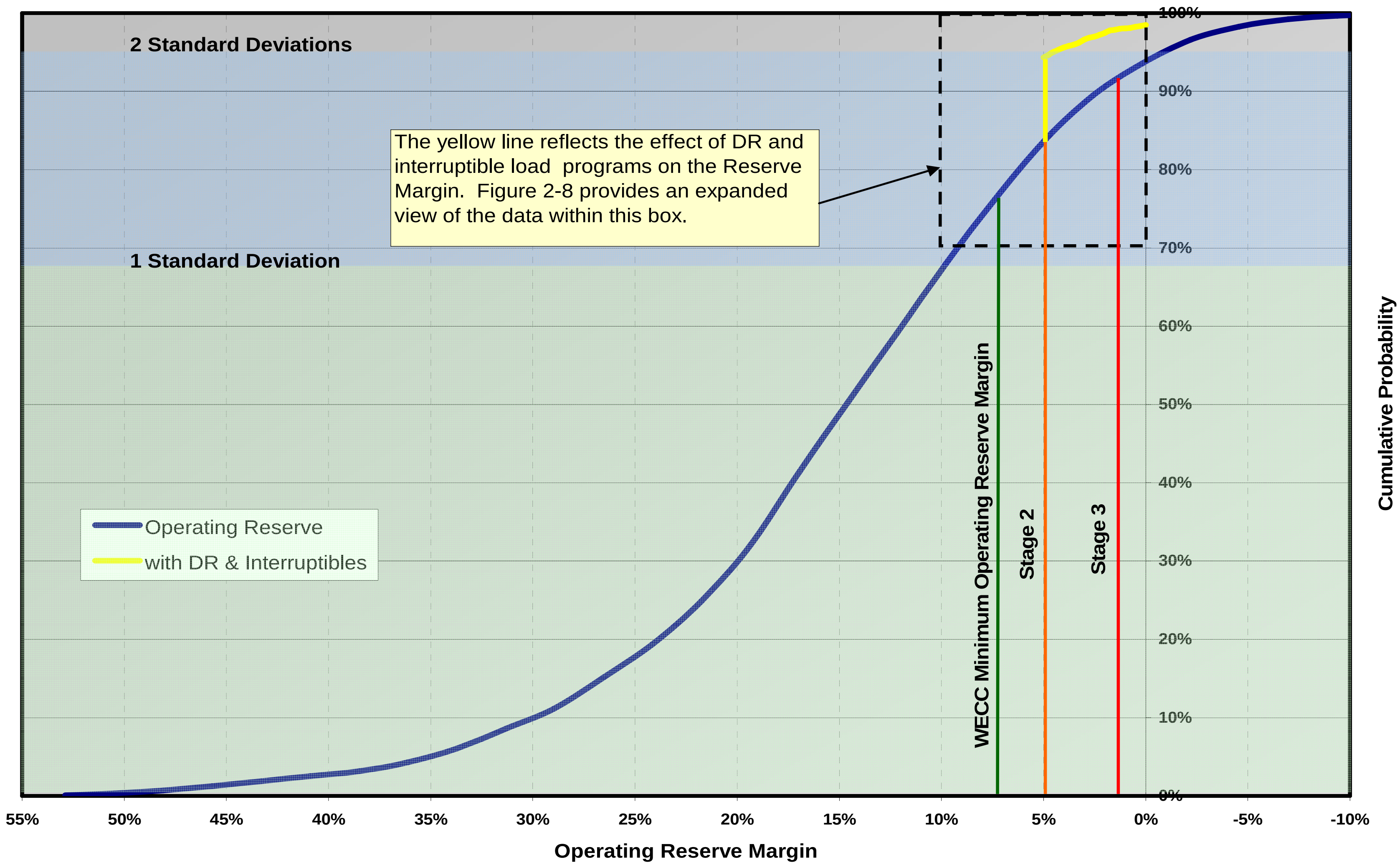
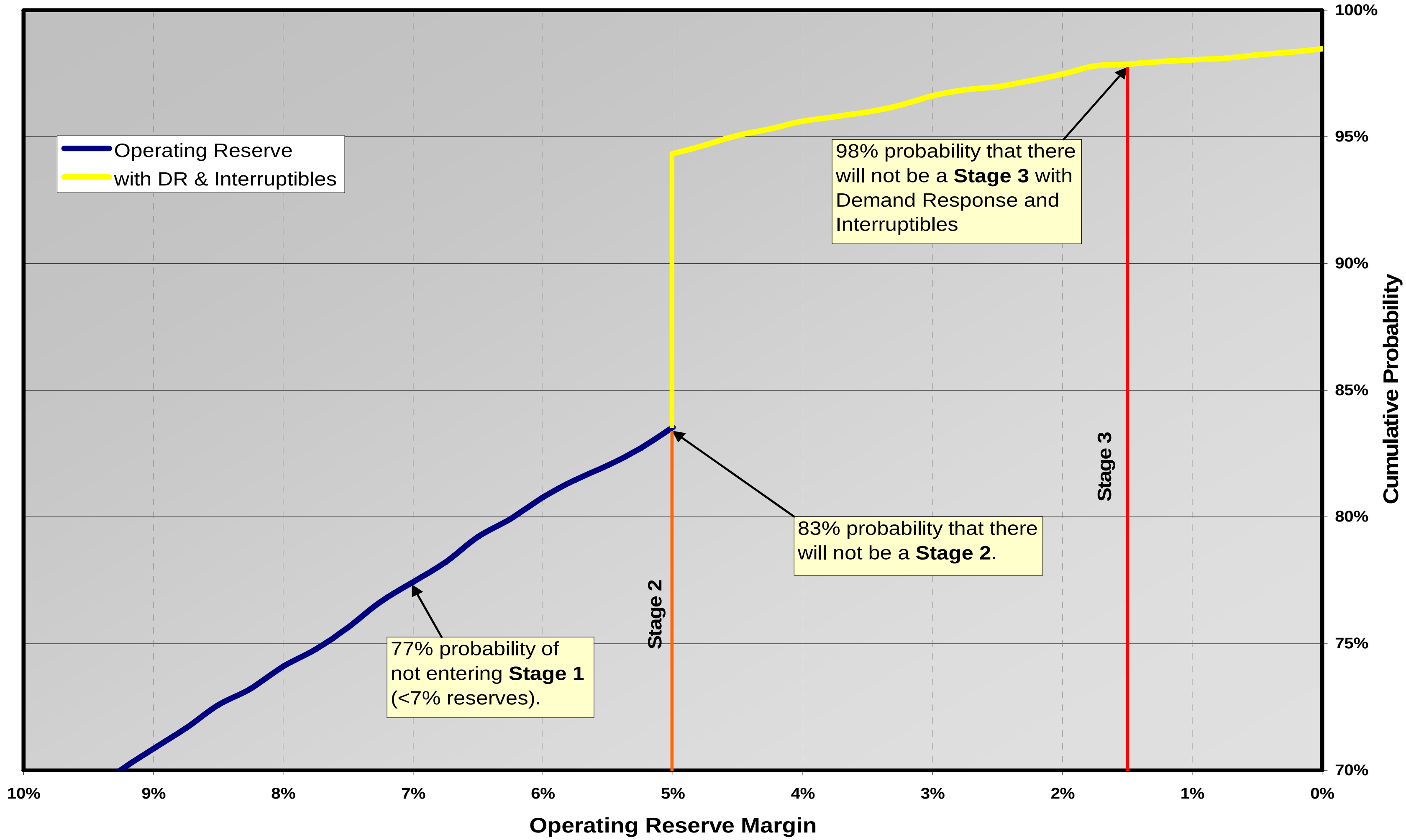


Figure 2-8: Operating Reserve Including Demand Response and Interruptible Programs
CA ISO SP26 Summer 2006



CHAPTER 3: SUMMER 2006 RESOURCE ADEQUACY

This chapter provides an overview of electricity resource adequacy (RA) for the summer months of 2006 for investor-owned utilities (IOUs), municipal utilities with a peak demand of 200 MW or greater, and electric service providers (ESPs) – collectively known as load serving entities (LSEs). It evaluates the total capacity owned or contracted for by each class of LSE as reported in February and compares those secured resources to the forecasted summer 2006 monthly peak demand for each LSE.

The recent CPUC RA decision requires IOUs and ESPs to identify 90 percent of the resources needed to meet summer (May through September) peak demands plus 15 percent planning reserve margin (approximately 103.5 percent of peak demand) by September 30th of the prior year. The scope and timing of data submittals by IOUs and ESPs for this initial filing year of 2006 differs somewhat in that June through September resource information was submitted by February 10, 2006. IOUs and ESPs are also required to demonstrate the procurement of resources equal to 115 percent of forecasted monthly peak loads by the first of the prior month.

To supplement filings made to the CPUC by IOUs and ESPs, Energy Commission staff requested that municipal utilities provide updates to their *2005 Integrated Energy Policy Report* submittals as well. Municipal utilities are not required to procure a threshold amount of resources by any specific date, but they do operate in control areas that are required to meet operating reserve standards. In addition, municipal utilities are responsible to local governing authorities and have a long history of procuring the resources necessary to meet their customers' needs for reliable service. Due to confidentiality concerns, resource- and LSE-specific data is presented together.

Summary of Reserve Margins

On a statewide basis for all LSEs combined, procured capacity for the upcoming summer months ranged from a low of 115 percent of the sum of non-coincident peak loads in August to a high of 131 percent in June (Table 3-1). The same conclusion holds true for each sector (IOUs, municipal utilities, and ESPs) for every summer month except for the IOU reserve margin in August, which is only 13 percent. However, this number still exceeds the CPUC RA requirement. As indicated in Table 3-1, ESPs show the overall lowest reserve margins, although all are still considered adequate, thus far, for each summer month.

Table 3-1
Reserve Margins for Load Serving Entities[5]
(Statewide)

Investor-Owned Utilities

	June	July	Aug	Sept
Peak Demand - MW	32,972	36,736	39,910	35,170
Total Resources - MW	43,700	45,281	45,161	43,811
Reserves - MW	10,728	8,545	5,251	8,641
Reserve Margin - %	**33**	**23**	**13**	**25**

Municipal Utilities

	June	July	Aug	Sept
Peak Demand - MW	13,045	13,976	14,223	13,450
Total Resources - MW	16,992	17,326	17,305	17,179
Reserves - MW	3,947	3,350	3,082	3,729
Reserve Margin - %	**30**	**24**	**22**	**28**

Energy Service Providers

	June	July	Aug	Sept
Peak Demand - MW	2,017	1,988	2,057	1,960
Total Resources - MW	2,385	2,336	2,384	2,318
Reserves - MW	369	348	327	358
Reserve Margin - %	**18**	**17**	**16**	**18**

CA ISO Control Area

	June	July	Aug	Sept
Peak Demand - MW	37,119	40,973	44,268	39,366
Total Resources - MW	48,807	50,457	50,430	48,989
Reserves - MW	11,688	9,485	6,162	9,623
Reserve Margin - %	**31**	**23**	**14**	**24**

All Load-Serving Entities

	June	July	Aug	Sept
Peak Demand - MW	48,033	52,700	56,191	50,580
Total Resources - MW	63,077	64,943	64,850	63,307
Reserves - MW	15,043	12,243	8,660	12,727
Reserve Margin - %	**31**	**23**	**15**	**25**

[5] Data does not include the portions of California served by PacifiCorp and Sierra Pacific Power or municipal utilities with a peak demand of less than 200 MW.

Table 3-1 also presents resource adequacy information for the entities in the CAISO control area. Reserve margins are adequate for each month within the CA ISO. Procured capacity ranges from 131 percent of the sum of non-coincident peak loads[6] in June to 114 percent in August. As indicated in Table 3-1, California's municipal utilities have, in aggregate, secured sufficient resources equal to 122 percent or more of the sum of their forecasted non-coincident peak loads in each of the four upcoming summer months. In late February, the Energy Commission received updates to 2005 Integrated Energy Policy Report submittals from 13 municipal utilities and the Northern California Power Authority. The revised filings indicated that 11 of the 14 entities had procured more than 112 percent of their forecasted summer peak load by February 24, 2006; all but one had procured more than 100 percent.

Resource Categories

Table 3-2 presents a more detailed listing of the resource categories secured by each type of LSE for August, along with the respective resource adequacy requirements and reserve margins. Utility-owned resources comprise 26.4 and 79.3 percent of IOU and municipal utility portfolios respectively, with the remainder of their portfolios composed of contractual resources. The low percentage of IOU-owned resources reflects the results of past divestiture activities. The ESPs do not own any of their own resources but maintain contracts exclusively to serve their load.

A particular category of interest includes Liquidated Damages (LD) contracts. LD contracts are the largest portion of ESP resources, comprising 54.9 percent of their total supply. In contrast, LD contracts represent 19.1 percent of IOU resources (9.5 percent of the total in the form of California Department of Water Resources (CDWR) LD contracts and 9.6 percent direct LD contracts) and just 2.6 percent of municipal utility resources.

Contracts backed by either specific units or portfolios of resources comprise 34.2 percent of IOU total resources (includes CDWR contracts), 37.4 percent of ESP resources, and 30.2 percent of municipal utility resources. IOUs also enter into contracts with several types of qualifying facilities pursuant to Federal Energy Regulatory Commission requirements. These comprise 13.6 percent of IOU total resources under procurement.

[6] An LSE's non-coincident monthly peak load reflects the maximum demand that it must meet during the month. As LSEs in northern and southern California usually experience peak demands on different days, the sum of the non-coincident peak demands is, on average, slightly higher than the coincident peak for the entities.

Table 3-2
Resource Types by Load Serving Entity (August)

	Investor Owned Utilities	Electric Service Providers	Municipal Utilities (a)
Peak Demand - MW	39,910	2,057	13,284
Reserve Margin	5,987	309	2,193
Peak Demand plus Reserve	45,897	2,366	15,477
Resource Categories			
Demand Response	1,914	63	261
Utility-Owned			
Fossil	855		8,888
Coal	720		2,223
Natural Gas	105		6,665
Oil	30		
Nuclear	4,873		516
Hydro (b)	6,213		3,289
Renewable			166
Total Utility-Owned	**11,941**	**0**	**12,859**
Contracts			
DWR	10,304		
Liquidated Damage	4,275		
Portfolio & Non-Unit Import	1,915		
Unit-Specific	4,114		
Qualifying Facilities	6,123		
Portfolio	314	274	2,152
Liquidated Damages	4,325	1,310	415
Unit-Specific	9,136	618	524
RMR Allocation	1,105	120	
Total Contracts	31,306	2,321	3,092
Total Resources	**45,161**	**2,384**	**16,211**
Resource Adequacy Requirements (c)	39,326	2,064	N/A
Planning Reserve Margin - % (d)	13.2	15.9	22.0
Total Resources minus Peak Demand	5,251	18	735

a) Without IID
b) Includes 887 MW of irrigation district hydro facilities operated by PG&E
c) Summer ‘06 RAR = (Firm Peak Requirement-Demand Response) x 1.15 x 0.9
d) Planning Reserve Margin = (Total Resources/Peak Demand) – 1

CHAPTER 4: FIVE-YEAR OUTLOOK

Figures 4-1 thru 4-4 provide preliminary five-year outlooks for each of the four regions presented in Chapter 1. Staff made several simplifying assumptions in an effort to account for the uncertainties in predicting future activities and program achievements. The starting point for these charts is the peak-month analysis from each of the 2006 tables.

The only high probability resource additions or retirements included beyond this summer are the new 153 MW Roseville Energy Park and LADWP replacing a 585 MW plant with a new 600 MW combined cycle project in 2008. The only other significant change in assumptions from year to year is the increase in peak demand. Staff again used the high case from CED 2006 to project demand over the five-year period. Using these assumptions, the only region that does not have adequate resources to maintain at least 5 percent operating reserves is SP26. The region is able to maintain a 9.5 percent operating reserve under expected conditions in 2009 yet it would need an additional 761 MW in order to maintain a 5 percent operating reserve under adverse conditions.

Figure 4-1: Five-Year Electricity Outlook - California Statewide

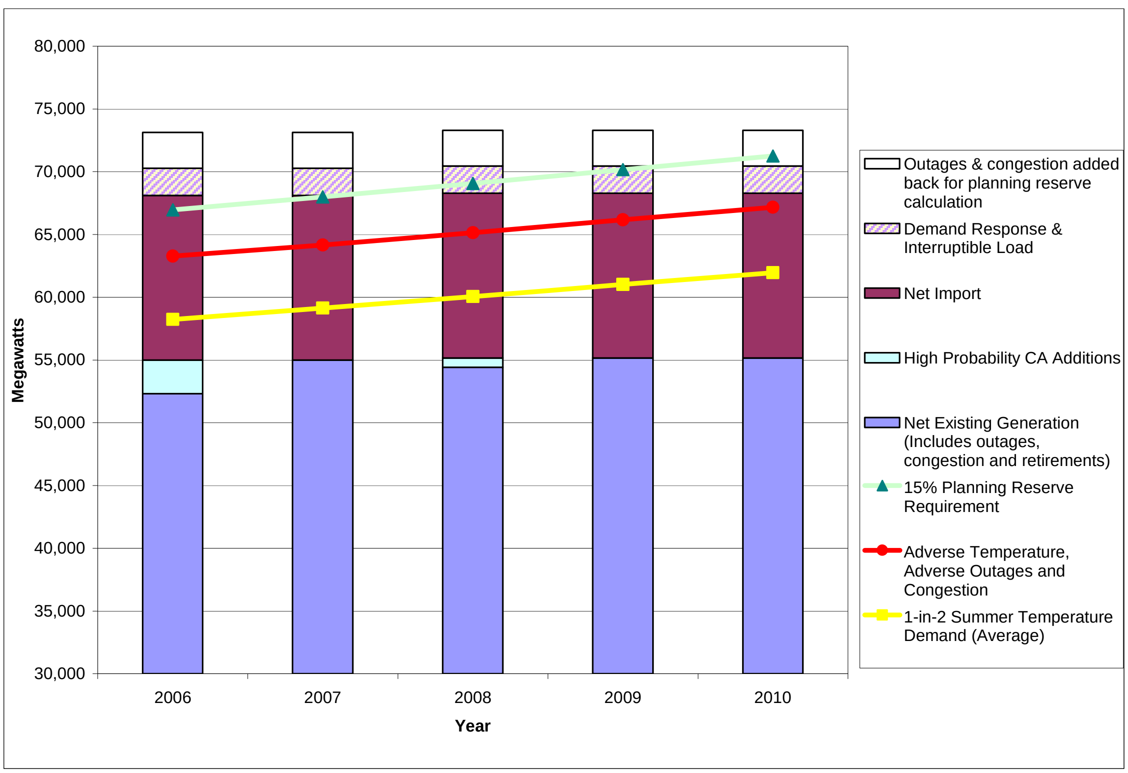


Figure 4-2: Five-Year Electricity Outlook – CA ISO

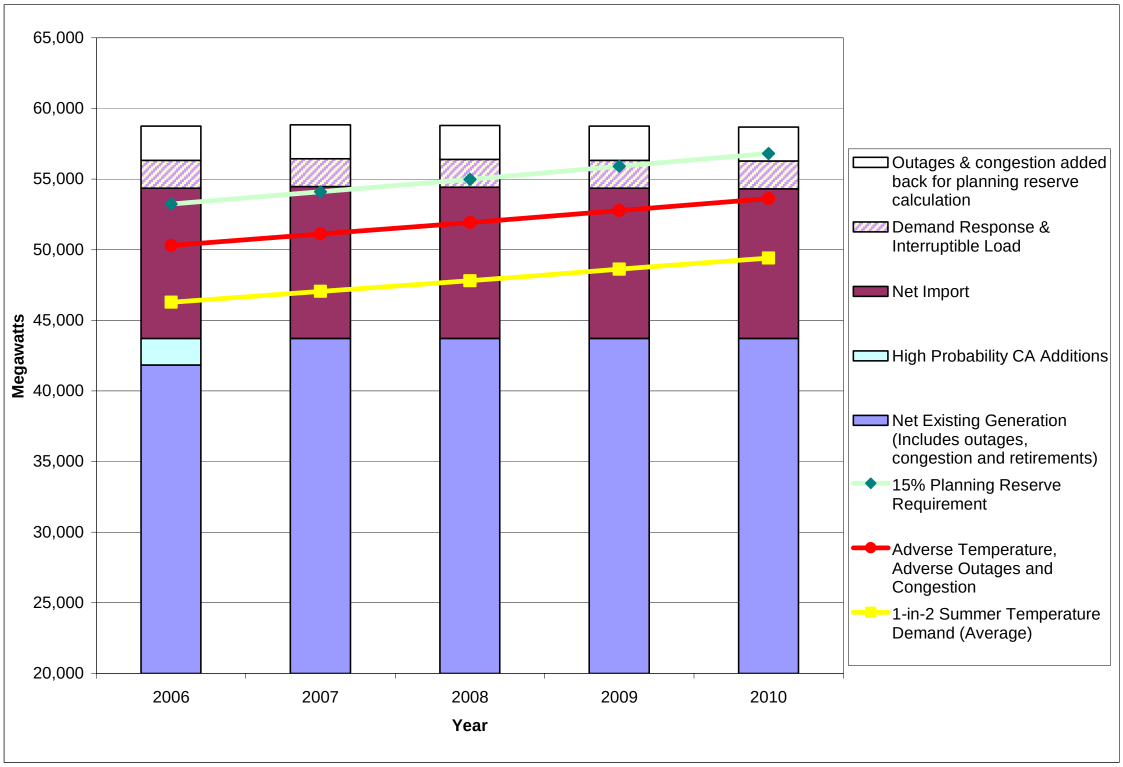


Figure 4-3: Five-Year Electricity Outlook – CA ISO NP26

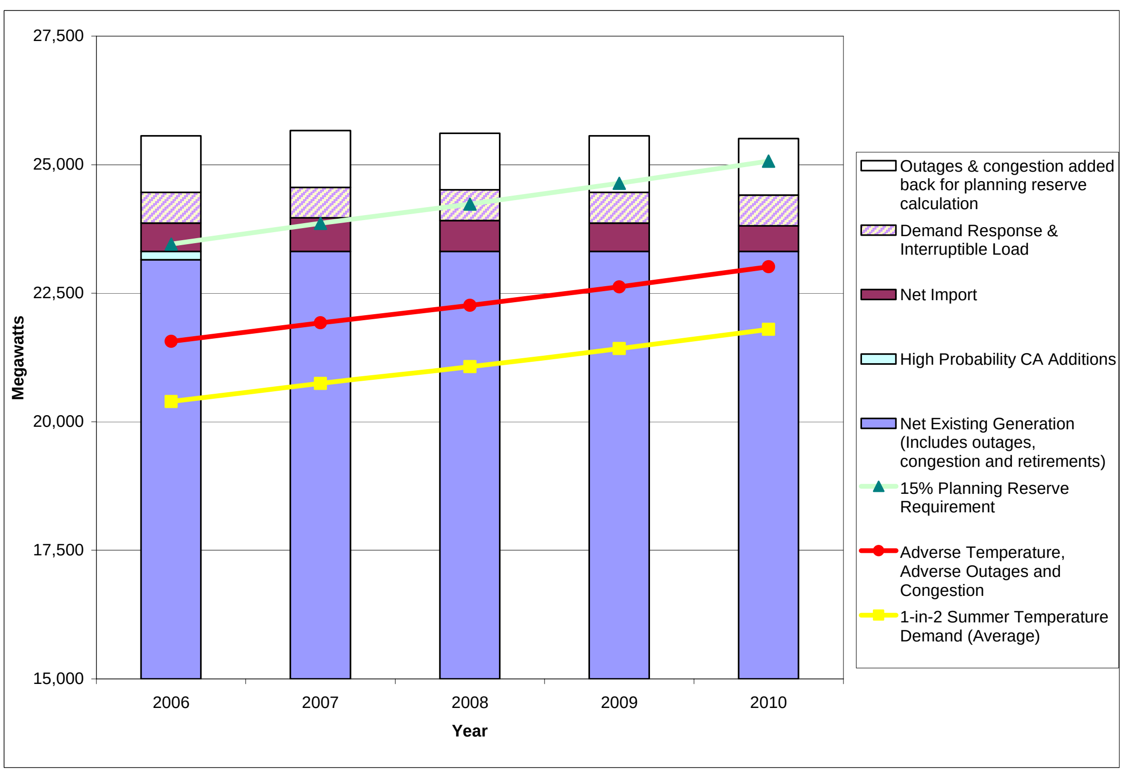


Figure 4-4: Five-Year Electricity Outlook – CA ISO SP26

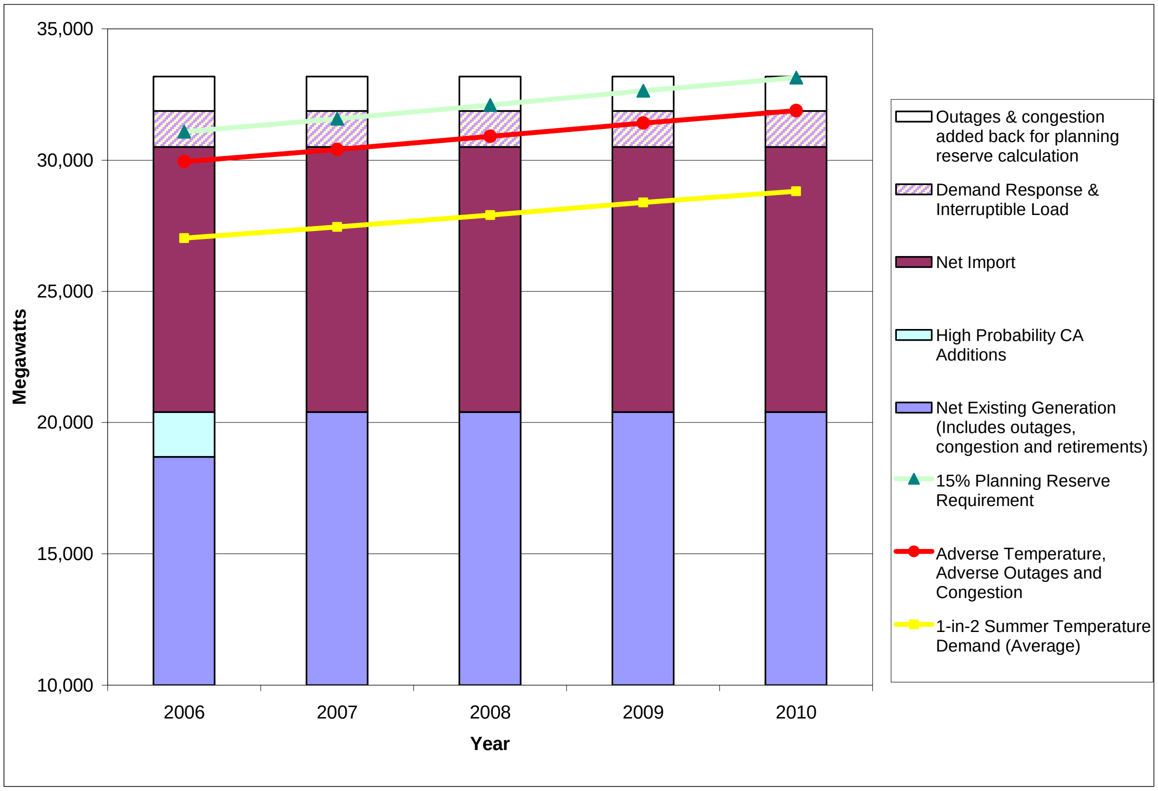


Figure 4-4 shows that the SP26 region has adequate resources to maintain a 7 percent reserve margin under expected conditions throughout the forecast period. In 2009, the region has a 16.9 percent planning reserve. This planning reserve is sufficient to provide minimum required operating reserve margins under expected conditions and, although extensive demand response and interruptible programs would be utilized under adverse conditions, is sufficient to prevent firm load curtailments. The 15.1 percent planning reserve in 2010 is adequate to provide a 7.4 percent operating reserve under expected conditions, but firm load would be curtailed in adverse conditions. Table 4-1 provides a summary of the additional capacity needed in SP26 to maintain 7 percent (Stage 1), 5 percent (Stage 2), and 1.5 percent (Stage 3) reserve margins under adverse conditions.

Table 4-1: Additional Capacity Required for Meeting Reserve Margins in SP26 Under Adverse Conditions

Reserve Margin	2007	2008	2009	2010
7 Percent	180	706	1,251	1,754
5 Percent	0	226	761	1,255
1.5 Percent	0	0	0	381