CALIFORNIA
ENERGY
COMMISSION

SUMMER 2005 ELECTRICITY SUPPLY AND DEMAND OUTLOOK

STAFF DRAFT REPORT

March 2005
CEC-700-2005-006-SD

Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

Denny Brown
Principal Author

Lynn Marshall,
Tom Gorin,
Contributing Authors

Denny Brown,
Project Manager

David Ashuckian,
Manager
ELECTRICITY ANALYSIS OFFICE

Terrence O'Brien,
Deputy Director
SYSTEMS ASSESSMENT & FACILITIES SITING

Valerie Hall,
Deputy Director
ENERGY EFFICIENCY & DEMAND ANALYSIS

Robert L. Therkelsen
Executive Director

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Introduction and Summary

The *Summer 2005 Electricity Supply and Demand Outlook* provides the California Energy Commission (Energy Commission) staff's current assessment of electricity resource adequacy in California. The analysis was prepared in close coordination and consultation with the California Public Utilities Commission (CPUC) and the California Independent System Operator (CA ISO). It evaluates the capability of the electricity system to provide power to specific geographic areas in California to meet expected electricity demand or load[1]. This report differs from previous editions prepared by the Energy Commission, which looked at statewide and CA ISO Control Area supply and demand. In addition to the Statewide Outlook (Table 1) and the CA ISO Control Area (Table 2), this assessment includes a more in-depth analysis at the regional levels -- CA ISO Northern California (Table 3) and CA ISO Southern California (Table 4).

The assessment is divided regionally into Northern and Southern California because there currently are significant transmission constraints that limit the transfer of electricity from north to south. Although a primary transmission bottleneck that existed between Northern and Southern California (Path 15 between Los Banos in Merced County and Midway Substation in Kern County) has been improved, particularly for moving power from the south to the north, the system is now constrained further south on the transmission segment known as Path 26 (SP26). This constraint affects the CA ISO's ability to deliver surplus electricity from Northern California or the Pacific Northwest to the tight Southern California market. This outlook is an update from the December 2004 assessment and incorporates new generation and retirements as well as an updated method for estimating 1-in-10 weather adjusted demand.

Energy Commission staff expects supplies will be adequate statewide to meet growing electricity demand and the required seven percent operating reserves[2] under average (1-in-2 or a 50 percent probability) temperature conditions. This is due to the addition of new generation facilities over the last six years, transmission improvements, increased energy efficiency, and voluntary conservation. In the event of average or very hot summer demand levels (1-in-10 or a 10 percent probability), Northern California (north of Path 26, or NP26) electricity resources exceed the seven percent reserve guideline recommended by the Western Electricity Coordination Council (WECC). This includes the Pacific Gas and Electric service area and participating municipal utilities in Northern California served by the CA ISO. Demand in Northern California typically reaches its summer peak during July.

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[1] This assessment does not evaluate the condition of the electricity market or the deliverability of economic contracts of individual load serving entities.

[2] The Western Electricity Coordination Council, the entity responsible for reliability in the Western United States, requires a 7 percent operating reserve. Utilities and system operators typically include a 15 percent reserve when planning their systems to meet demands under normal summer weather conditions. All investor-owned utilities in California will be required to meet this 15 percent planning reserve beginning June 2006.

In Southern California (SP26) there should be sufficient electricity reserves under normal weather conditions (1-in-2 or 50 percent probability). Peak electricity demand in Southern California usually occurs in September. Energy Commission staff is concerned, however, that SP26 will not have sufficient resources to meet electricity demands and maintain a seven percent reserve during very hot weather (1-in-10 or 10 percent probability) this summer, if additional actions are not taken. Nearly 1,800 megawatts (MW) of demand reductions or additional resources are needed to maintain a seven percent operating reserve under this scenario. This concern is focused on those portions of Southern California served by the CA ISO including the Southern California Edison (SCE), San Diego Gas and Electric (SDG&E) and CA ISO participating municipal utilities in Southern California. Areas served by the independent municipal utilities, 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 be able to make surplus power available to the rest of the region.

While constraints limiting the amount of imported electricity on the transmission system are the primary reason for these regional differences, more generation has been constructed, and has come on line in Northern California compared to Southern California, during the last several years while demand growth has been greater in the south compared to the north. Inadequate electricity reserves will become an increasingly greater concern in future years unless additional generation is built, retirements of generating units are delayed, the transmission system improved, and additional energy efficiency measures are implemented.

The Governor's Office has been working with the Energy Commission, CPUC, CA ISO, and several other agencies to develop and implement a plan of action to ensure there are sufficient electricity resources available this summer in Southern California. These resources will come from a menu of options including voluntary conservation, new demand reduction programs, accelerated construction of permitted power plants, delaying retirements, and other measures. Details of this plan were presented at a hearing before the Senate Energy Committee on February 22, 2005[3], and can be found on the Energy Commission's website [http://www.energy.ca.gov/electricity/2005_summer_forecast/].

Northern California and Southern California monthly electricity demand and supply outlooks for this coming summer are presented in addition to the Statewide and CA ISO Control Area in Tables 1 through 4. The subsequent pages of this report document the Energy Commission staff's supporting information and assumptions used in creating these assessments. Because the report focuses on adequacy of the system's electricity capacity, the assessments include some adverse conditions that might strain the resources of the system. The assessments

[3] Since the February 22, 2005 Senate Presentation, there were an additional 175 MW added to the supply side for Southern California to account for contracts identified by SCE.

consider the 10 percent probability of hotter than normal weather, high risk retirements and higher than average summer forced outages.

Hot temperatures have the single largest impact on electricity demand. Other low probability events such as transmission line outages, exceptionally high forced outages, unusually low imports, excessive congestion, and temperatures exceeding 1-in-10 probability are identified on Page 18. Acquiring additional resources to meet these extremely low probability occurrences will result in increased costs to ratepayers and potentially create additional environmental impacts. Established interruptible and demand response programs identified in Table 9 are expected to be available to respond to these additional adverse circumstances.

In addition to using the most recent information available, staff received considerable input from staff of the CA ISO, CPUC, and utilities to develop baseline assumptions. The Energy Commission's Electricity Committee will be holding a public workshop on March 21, 2005 to receive additional input and public comments on this outlook.

Staff will update this outlook in late spring as additional data and a revised demand forecast becomes available as a result of the *2005 Integrated Energy Policy Report* proceedings.

Table 1: 2005 Detailed Monthly Electricity Outlook – California Statewide

Line		June	July	August	September
1	Existing Generation[1]	53,808	53,718	54,773	54,902
2	Retirements (Known)	-850			
3	Retirements (High Risk)	-1,192			
4	High Probability CA Additions	1,952	1,055	129	1
5	Forced Outages	-3,500	-3,500	-3,500	-3,500
6	Zonal Transmission Limitation[2]	-800	-800	-800	-800
7	Net Interchange [3]	12,921	12,921	12,921	12,921
8	Total Supply (MW)	62,339	63,394	63,523	63,524
9	1-in-2 Summer Temperature Demand (Normal)	54,900	57,365	57,913	57,015
10	Projected Resource Margin (1-in-2)*	17.3%	13.3%	12.2%	14.4%
11	1-in-10 Summer Temperature Demand (Hot)	58,667	61,003	61,885	60,937
12	Projected Resource Margin (1-in-10)*	7.9%	4.9%	3.3%	5.3%
13	MW needed to meet 7.0% Reserve	0	1,045	1,860	844
14	Surplus MW above 7.0% Reserve	400	0	0	0

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

[2] Values provided by CA ISO.

[3] 2005 estimate of the following Net Imports: **DC imports 2,000 MW, SW imports 2,500 MW, NW imports (COI) 4,000 MW, North of Miguel 400 MW, LADWP Control Area imports 2,834 MW, IID Imports 184 MW** and Dynamic Resources 1,003 MW**.** **Imports supplying own reserves are in bold text.**

* Does not reflect uncertainty for "Net Interchange" or "Forced Outages" which can result in significant variation in Resource Margin. Calculated as ((Supply - **Imports with own reserves**)/(Demand - **Imports with own reserves**))-1

Table 2: 2005 Detailed Monthly Electricity Outlook – CA ISO Control Area

Line		June	July	August	September
1	Existing Generation[1]	45,969	45,457	46,512	46,641
2	Retirements (Known)	-530			
3	Retirements (High Risk)	-1,192			
4	High Probability CA Additions	1,210	1,055	129	1
5	Forced Outages	-2,800	-2,800	-2,800	-2,800
6	Zonal Transmission Limitation[2]	-800	-800	-800	-800
7	Net Interchange [3]	9,303	9,303	9,303	9,303
8	Total Supply (MW)	51,160	52,215	52,344	52,345
9	1-in-2 Summer Temperature Demand (Normal)	45,085	47,004	47,134	46,679
10	Projected Resource Margin (1-in-2)*	16.5%	13.5%	13.4%	14.8%
11	1-in-10 Summer Temperature Demand (Hot)	48,323	50,384	50,526	50,043
12	Projected Resource Margin (1-in-10)*	7.1%	4.4%	4.3%	5.5%
13	MW needed to meet 7.0% Reserve	0	1,115	1,138	621
14	Surplus MW above 7.0% Reserve	35	0	0	0

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

[2] Values provided by CA ISO.

[3] 2004 CA ISO estimates **DC imports of 1,500 MW,** Path 26 2,700 MW, **SW imports 2,500 MW,** Dynamic 1,003 MW and CEC estimate of **LADWP imports of 1,000 MW**. 2005 estimate increases **DC transfer capability by 500 MW**, Path 26 by 300 MW, **North of Miguel by 400 MW** and **Northwest (minus SMUD) 2400 MW.** Imports supplying own reserves are in bold text.

* Does not reflect uncertainty for "Net Interchange" or "Forced Outages" which can result in significant variation in Resource Margin. Calculated as ((Supply - **Imports with own reserves**)/(Demand - **Imports with own reserves**))-1

Table 3: 2005 Detailed Monthly Electricity Outlook – CA ISO Northern Region (NP26)

Line		June	July	August	September
1	Existing Generation	25,883	25,086	25,661	25,661
2	Retirements (Known)				
3	Retirements (High Risk)	-1,046			
4	High Probability CA Additions	249	575		
5	Forced Outages	-1,600	-1,600	-1,600	-1,600
6	Zonal Transmission Limitation[1]	0	0	0	0
7	Net Interchange [2]	2,400	2,400	2,400	2,400
8	Total Supply (MW)	25,886	26,461	26,461	26,461
9	1-in-2 Summer Temperature Demand (Normal)	20,839	21,289	21,003	20,233
10	Projected Resource Margin (1-in-2)*	27.4%	27.4%	29.3%	34.9%
11	1-in-10 Summer Temperature Demand (Hot)	22,230	22,710	22,405	21,584
12	Projected Resource Margin (1-in-10)*	18.4%	18.5%	20.3%	25.4%
13	MW needed to meet 7.0% Reserve in NP26	0	0	0	0
14	Surplus MW above 7.0% Reserve in NP26	2,267	2,329	2,655	3,534

[1] Values provided by CA ISO.

[2] 2004 estimates based on CA ISO provided levels of NW and SMUD interchange values during June-July 2004 and assuming flows are S-N on Path 26.

* Does not reflect uncertainty for "Net Interchange" or "Forced Outages" which can result in significant variation in Resource Margin. Calculated as ((Supply - **Imports with own reserves**)/(Demand - **Imports with own reserves**))-1

Table 4: 2005 Detailed Monthly Electricity Outlook – CA ISO Southern Region (SP26)

Line		June	July	August	September
1	Existing Generation[1]	20,086	20,371	20,851	20,980
2	Retirements (Known)	-530			
3	Retirements (High Risk)	-146			
4	High Probability CA Additions	961	480	129	1
5	Forced Outages	-1,200	-1,200	-1,200	-1,200
6	Zonal Transmission Limitation[2]	-800	-800	-800	-800
7	Net Interchange [3]	9,903	9,903	9,903	9,903
8	Total Supply (MW)	28,274	28,754	28,883	28,884
9	1-in-2 Summer Temperature Demand (Normal)	24,782	26,275	26,691	27,001
10	Projected Resource Margin (1-in-2)*	18.5%	12.2%	10.5%	8.9%
11	1-in-10 Summer Temperature Demand (Hot)	26,667	28,273	28,721	29,054
12	Projected Resource Margin (1-in-10)*	7.7%	2.1%	0.7%	-0.7%
13	MW needed/(Excess) to meet 7.0% Reserve in SP26	0	1,085	1,435	1,791
14	Surplus MW above 7.0% Reserve in SP26	153	0	0	0

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

[2] Values provided by CA ISO.

[3] 2004 CA ISO estimates **DC imports of 1,500 MW,** Path 26 2,700 MW, **SW imports 2,500 MW,** Dynamic 1,003 MW and CEC estimate of **LADWP imports of 1,000 MW**. 2005 estimate increases **DC transfer capability by 500 MW**, Path 26 by 300 MW and **North of Miguel by 400 MW**. Imports supplying own reserves are in bold text.

* Does not reflect uncertainty for "Net Interchange" or "Forced Outages" which can result in significant variation in Resource Margin. Calculated as ((Supply - **Imports with own reserves**)/(Demand - **Imports with own reserves**))-1

Discussion of Analysis

Line 1: Existing Generation

Existing generation accounts for thermal and hydro generation facilities installed as of August 1, 2004. 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). 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. Table 5 provides a more detailed breakout of existing generation.

Table 5: Derated Existing Generation

	SP26	NP26	TOTAL
CA ISO Control Area			
Merchant Thermal	12,902	12,792	25,694
Municipal Thermal	377	529	906
IOU Retained	2,996	2,343	5,339
Qualifying Facilities	2,764	2,803	5,567
Derated Hydro	1,047	7,416	8,463
TOTAL CA ISO	**20,086**	**25,883**	**45,969**
Non-CA ISO Municipal	5,845	1,994	7,839
STATEWIDE TOTAL	**25,931**	**27,877**	**53,808**

California's hydropower production system comprises a diverse mix of producers, infrastructure, dispatch policy and geography. California has 14,116 MW of installed hydropower capacity owned by: IOUs (36 percent), state/federal water projects (27 percent), municipal utility districts (24 percent), water districts (7 percent), irrigation districts (5 percent) and miscellaneous (1 percent). [Source: Resources Agency March 29, 2001 filing to the Federal Energy Regulatory Commission (FERC) in docket EL01-47-000, p. ii.] Of this total, 11,200 MW of dependable capacity is located within the CA ISO's control area.

Under normal operations, units are run within multiple constraints for water management, downstream needs and environmental concerns. However, reliability needs and system operations economics can elicit a high use of hydro for a few hours for the peak period. The historic record shows that the dependable hydropower capacity at peak does not significantly change during a low water year, but may decline during a multiple year drought.

Adding up individual units overstates the actual operational capability of the hydro system during a particular peak period. For example, multiple turbines located on a single river system cannot receive maximum water at the same time. The hydro generation capacity is derated to reflect the expected operational capability during peak demand periods.

Lines 2-4: Retirements and Additions

Table 6 provides a listing of the dependable capacity of all additions and retirements included in Lines 2, 3 and 4.

Table 6: 2005 Additions and Retirements

CA ISO Control Area

SP26 — Additions

Name	MW	Expected Online Date
Etiwanda 3	320	9/9/2004
Aggregated Renewable	2	1/1/2005
Big Bear	8	1/31/2005
Clearwater Cogen	30	1/31/2005
Paramont	2	1/31/2005
Anaheim	2	2/15/2005
Pastoria Phase 1	240	3/31/2005
Restart Mothballed Plants[*]	175	5/1/2005
Magnolia ISO Control Area	142	5/25/2005
Ramco	40	6/1/2005
Pastoria Phase 2	480	6/30/2005
Malburg	129	7/31/2005
Aggregated Renewable	1	8/31/2005
	1,571	

NP26 — Additions

Name	MW	Expected Online Date
Aggregated Renewable	1	1/1/2005
Fresno Cogen Expansion	21	2/28/2005
Pico Power	141	3/15/2005
Kings River Peaker	86	6/1/2005
Metcalf	575	6/30/2005
	824	

SP26 — Retirements

Name	MW	Date
Long Beach (Known)	-530	12/31/2004
Coolwater 1/2 (High Risk)	-146	12/31/2004
	-676	

NP26 — Retirements (High Risk)

Name	MW	Date
Pittsburg 7	-720	12/31/2004
Morro Bay 1/2 (*mothball*)	-326	
	-1,046	

Non-CA ISO Control Areas

SP26 — Additions

Name	MW	Expected Online Date
Haynes 8-10	569	1/1/2005
Magnolia LADWP Control Area	173	5/25/2005
	742	

NP26 — Additions

Name	MW	Expected Online Date

SP26 — Retirements (Known)

Name	MW	Date
Haynes 3	-222	9/1/2004
Haynes 6 derate	-98	9/1/2004
	-320	

NP26 — Retirements (High Risk)

* SCE identified during Senate Energy Committee Hearing February 22, 2005

Line 5: Forced Outages

Energy Commission staff calculated potential 2005 forced outages using the actual 2003 and 2004 average daily outage for the summer peak period provided by the CA ISO. As shown in Figures 1 and 2, there is a significant variation in the amount of capacity that can be forced out on any given day. To account for some of this variation, one standard deviation was added to the average. The forecast outage total also includes a small amount of scheduled outages.

Figure 1: NP26 Daily Peaks and Associated Forced Outages for 90 Days in Summer 2003 & 2004

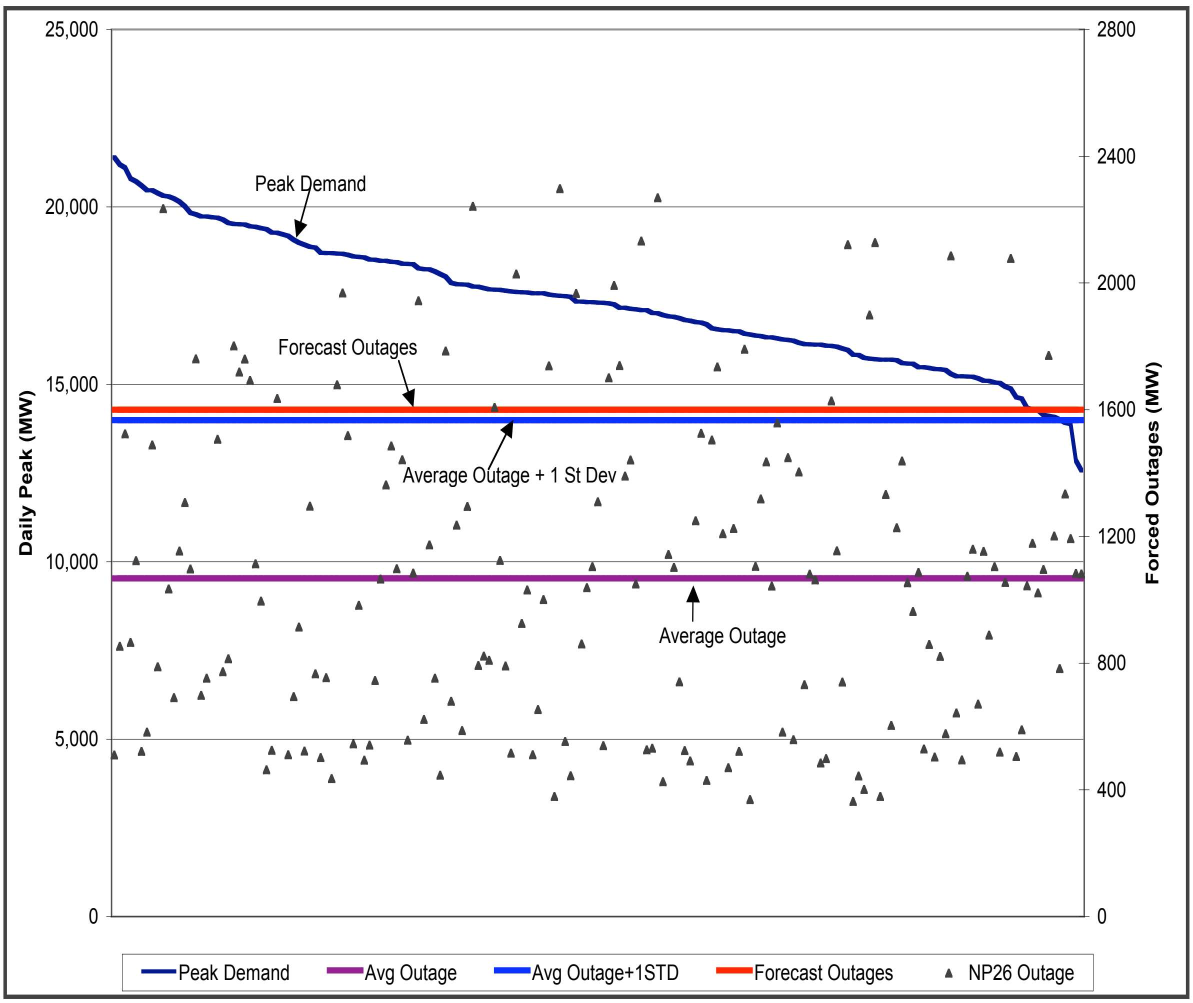
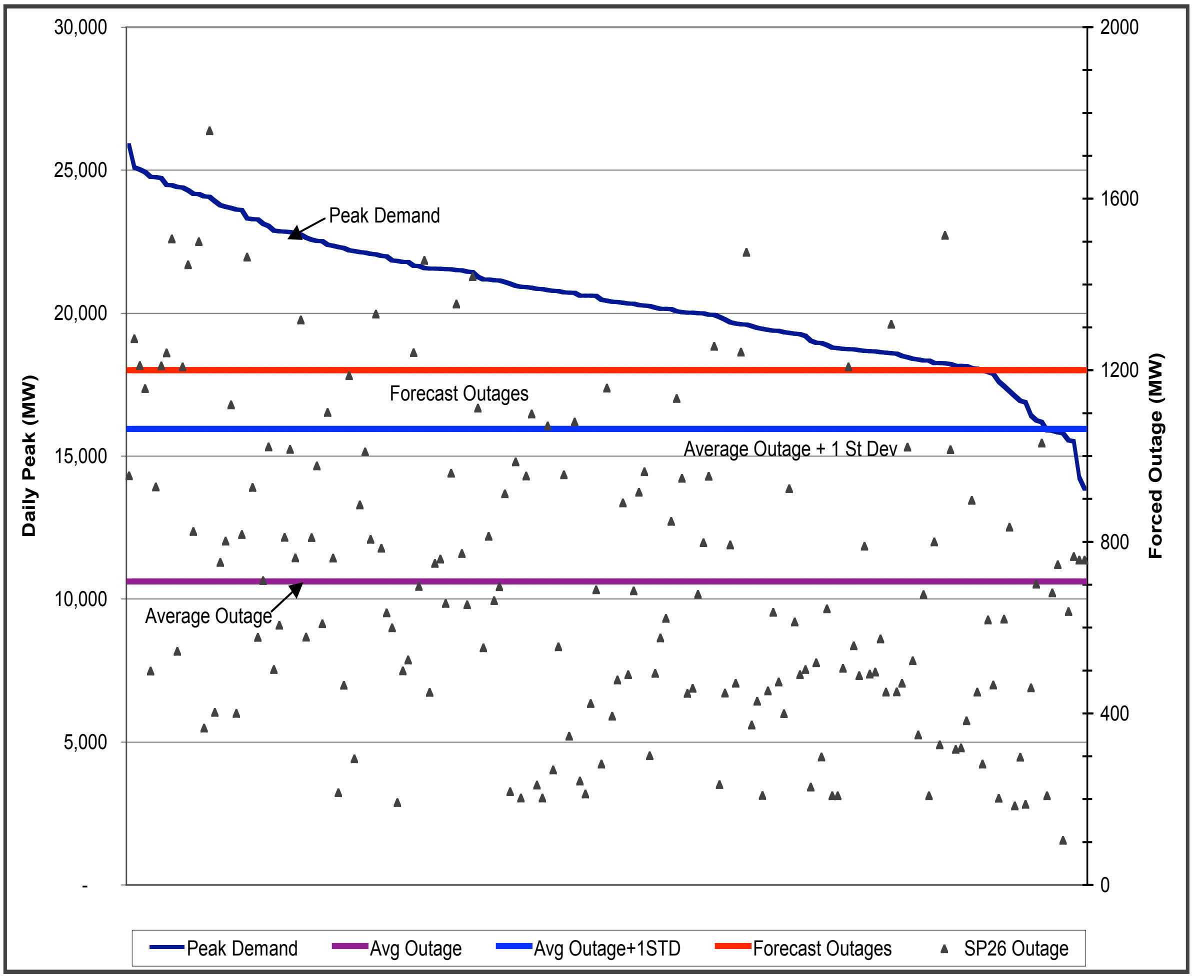


Figure 2: SP26 Daily Peaks and Associated Forced Outages for 90 Days in Summer 2003 & 2004



Line 6: Zonal Transmission Limitations

Line 6, Zonal Transmission Limitations, represents the CA ISO estimate of the amount of existing capacity contained in Line 1 that is unable to serve load due to transmission constraints within the Northern California or Southern California region. Actual 2004 summer data was used as a baseline and net gains from transmission upgrades were then used to reduce the limitation. For summer 2005, the CA ISO estimates NP26 will not experience any limitations. However, SP26 is constrained by 800 MW, most of which is a result of the 1,080 MW of contracted generation located in Mexico that cannot be fully delivered into the control area.

Line 7: Net Interchange

Net interchange data is provided by the CA ISO and is calculated by using the 2004 metered import data then subtracting out the metered exports. Tables 7 and 8 detail the individual components to Line 7. The SP26 net interchange import numbers include increases in the DC Line by 500 MW, Path 26 by 300 MW and Southwest imports by 400 MW above 2004 observed levels. Dynamic imports are resources geographically located outside of the CA ISO control area, but scheduled by the CA ISO for import. One example is SCE's ownership portion of Hoover Dam generation capacity on the border of Arizona and Nevada.

Table 7: SP26 Net Interchange

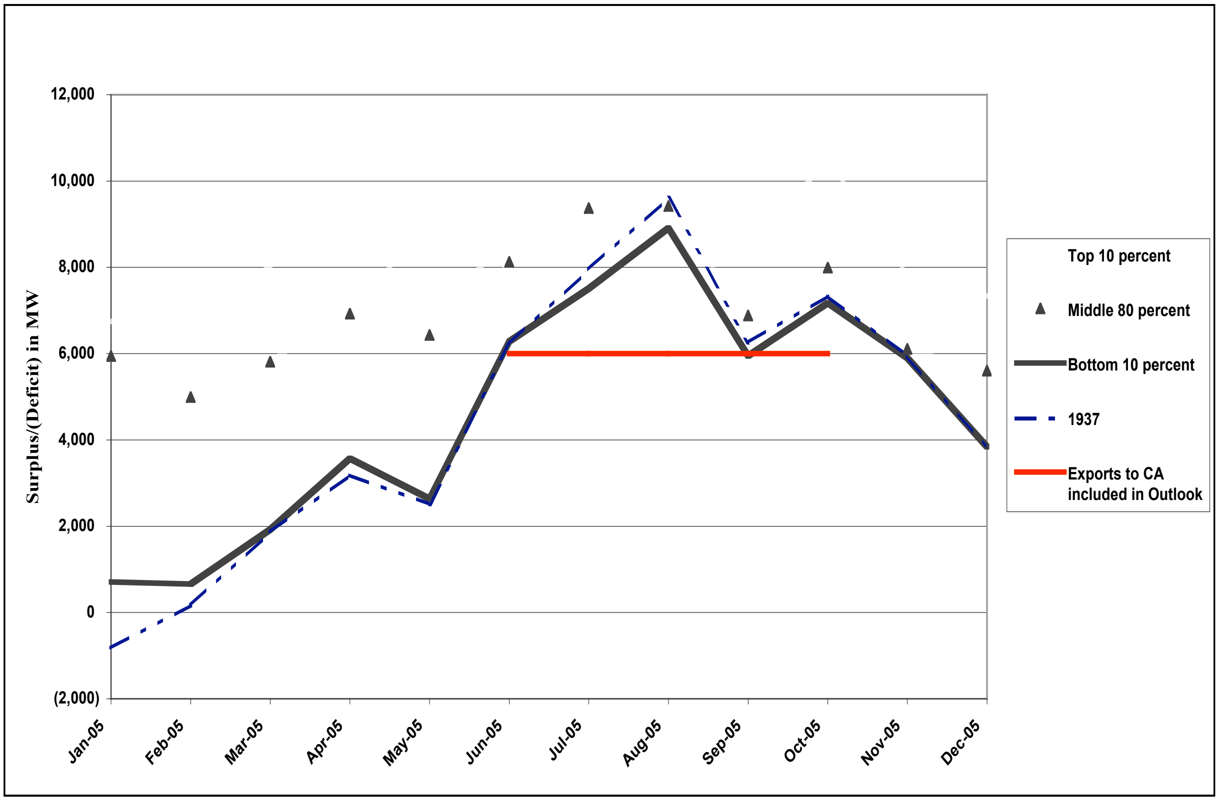
Path 26	3,000
Net of DC Line	2,000
Net SW Imports	2,900
Net Dynamics	1,003
Net LADWP Imports	1,000
Total	**9,903**

Table 8: NP26 Net Interchange

Path 26	-
Net NW Imports	4,000
Net SMUD Imports	(1,600)
Total	**2,400**

Stakeholders have expressed concerns about the ability to import electricity from the Northwest in the event drought conditions reduce hydroelectric output. While a drought would have profound impacts on the Columbia River hydro system during winter months, the historical difference between summer capacity in an average water year and dry water year has been minimal. Bonneville Power Administration (BPA) forecasts the Northwest will have a surplus of 7,952 MW in July 2005, based on 1937 water conditions, which is the driest year on record. [Source: BPA's 2003 Pacific Northwest Loads and Resources Study "White Book", July 15, 2004, p97.] Figure 3 provides the BPA 2005 monthly assessment of surplus capacity for the Northwest using four different hydro conditions.

Figure 3: BPA Forecast of Northwest Regional Surplus/Deficit by Water Year



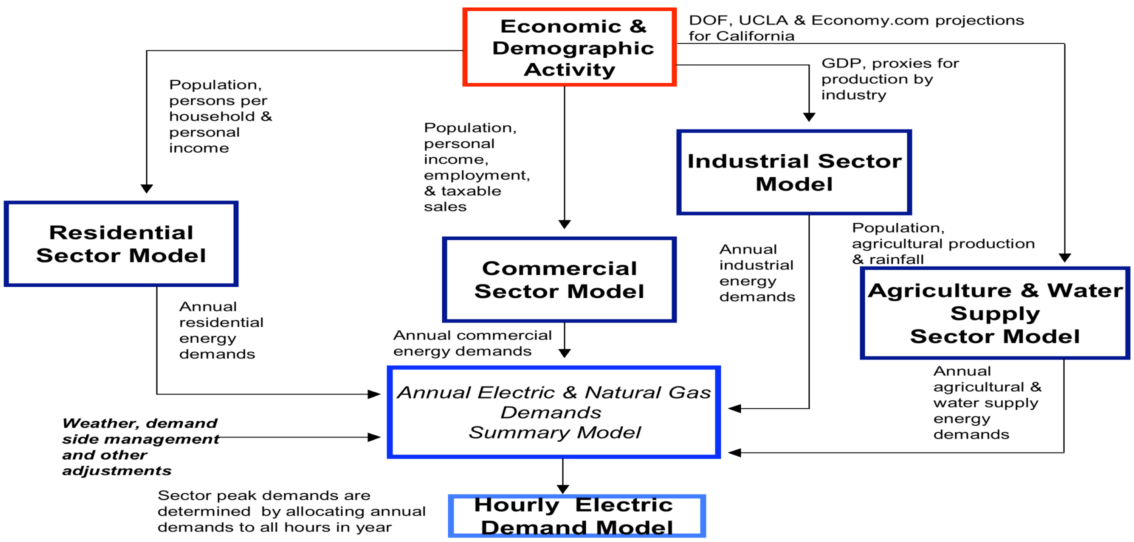
Line 8: Total Supply

Line 8 is simply the sum of Lines 1 – 7 and represents the total capacity available to meet load.

Line 9: 1-in-2 Summer Temperature Demand (Normal)

The baseline peak demand projection assumes average temperatures — temperatures that are expected to occur, on average, in one out of every two years (1-in-2). The Energy Commission's last full forecast was completed in March of 2003 as part of the *2003 Integrated Energy Policy Report* (*Energy Report*). The Energy Commission uses a combination of sector-level end use and econometric models to develop a long run forecast of annual energy consumption and peak demand. Figure 4 shows the Energy Commission's system of demand models. Key determinants of the forecast are assumptions about, population, weather, energy prices, and economic growth, including personal income, employment, and industrial sector value added. These drivers are developed at a county level and aggregated to produce a forecast of demand by utility service area.

Figure 4: Energy Commission Energy Demand Forecast Models



The *2003 Energy Report* forecast was based on energy sales data through 2001 only, and recorded peak demand through 2002. In addition, the economic assumptions used for that forecast have proved to underestimate economic growth in 2003 and 2004.

To develop an updated projection for the summer of 2005, Energy Commission staff initially recalibrated the peak forecast to reflect reported electricity sales for 2002 and 2003. Next, 2004 weather-adjusted peak demand was estimated using daily MW peaks in NP26 and SP26 and moving average daily maximum temperatures, weighted by distribution of air conditioning. Because climatic conditions during the 2004 peak (on September 8th) were unusually humid, estimates of weather-adjusted 2004 peak for Southern California use data only for June through August. For service areas in which the recalibrated forecast was not consistent with the weather-adjusted 2004 peak (SMUD and those in SP26), the 2003-2004 growth rate was modified to produce a consistent forecast for 2004. Finally, the 2005 peak was projected by applying the projected 2004-2005 growth rate from the 2003 IEPR forecast to the new 2004 peak estimate.

The Energy Commission staff is currently in the process of completing a new long run demand forecast as part of the 2005 Energy Report with results expected in late spring 2005.

Line 10: Projected 1-in-2 Resource Margins

Line 10 provides the monthly peak resource margin under average temperature conditions. The formula used to calculate the margin is:

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

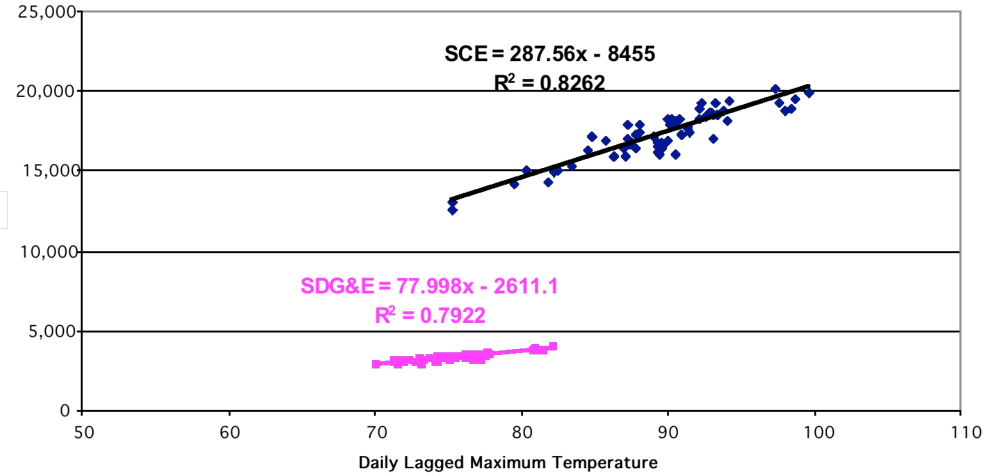
The net interchange numbers expected to carry their own reserves are Southwest, DC Line and LADWP in SP26 (5,900 MW) and total interchange in NP26 (2,500 MW).

Line 11: 1-in-10 Summer Temperature Demand (Hot)

To account for the effect of temperature on demand, the Energy Commission developed a temperature response adjustment for varying degrees of hotter than average temperatures. To account for warmer than average conditions, temperature sensitivities for 1-in-5, 1-in-10, and 1-in-40 weather conditions are applied to the baseline peak demand forecast. The 1-in-10 scenario, which has a ten percent chance of occurring in any year, increases demand by 7.6 percent in SP26 and 6.9 percent in NP26. The 7.6 percent increase in SP26 has been revised since last year, which used a 5.8 percent increase. The SP26 revision incorporates both a longer weather history and a revised methodology in defining a 1-in-10 event.

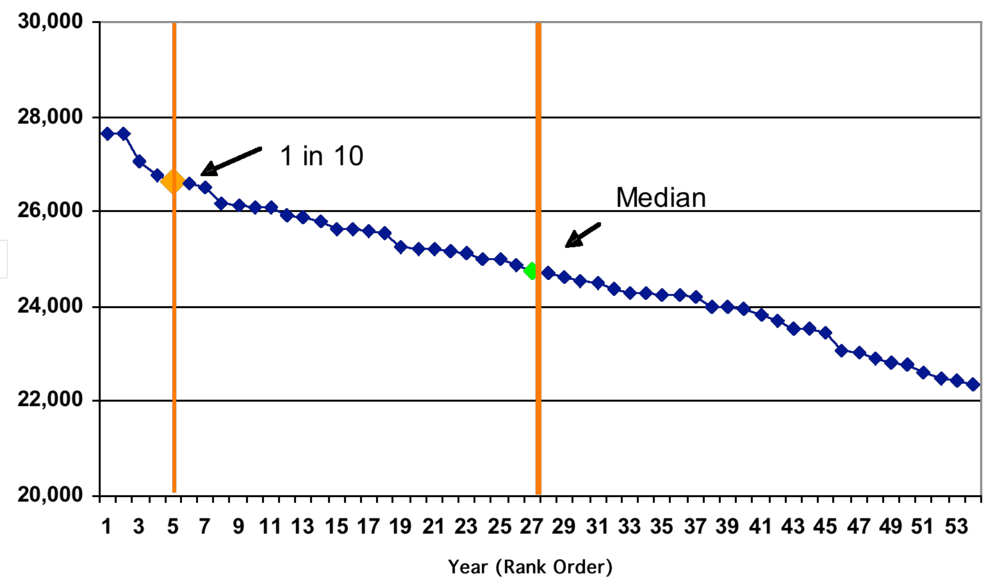
The previous 1-in-10 multiplier was developed in 1999 in an analysis of a WECC-wide 1-in-10 event assumed to occur in late August. This study approach, which was focused on the WECC system peak, was found to underestimate the temperature response in Southern California, which typically peaks in late August or September. To develop multipliers that are more appropriate for application to each utility's individual peak, staff estimated the relationship between temperature and daily peaks using recorded 2003 hourly loads reported to FERC by SCE and SDG&E, and a three-day weighted 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. Figure 5 shows the relationship between temperature and load for 2003, and the estimated weather response function. The coefficients shown (287.56 and 77.99) indicate the increase in peak demand for a one degree increase in temperature.

Figure 5: SCE and SDG&E Estimated 2003 Weather Response



The estimated parameters were then applied to 53 years of historic weather to calculate a distribution of annual peaks assuming the estimated 2003 weather response function. These annual peaks were then ranked from highest to lowest, as shown in Figure 6. The median value is the 1-in-2 peak and the 5th highest is the 1-in-10 value. This distribution is the basis for the new 7.6 percent multiplier over 1-in-2 demand.

Figure 6: SCE and SDG&E Peak Electricity Demand Based on 1950-2003 Weather (Assuming 2003 Weather Response, Rank Ordered)



Line 12: Projected 1-in-10 Resource Margins

Line 12 represents the resource margin under hot summer conditions. It is calculated in the same manner as Line 10, substituting 1-in-10 demand for normal demand. 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 general 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 five percent (5 percent). The general 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 one and one half percent (1.5 percent). This is the most severe stage of emergency 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 could only declare an emergency if reserves fell below MORC for their entire control area. They are in the process of implementing new protocols designed to be more responsive to the two primary sub-regions within their control. The CA ISO will present this protocol to stakeholders within the next 30 days and plan to have the system in place prior to this summer.

Lines 13 and 14: MW Needed or Surplus for 7 Percent Reserves in 1-in-10 Demand

Line 13 represents the additional megawatts required to meet a seven percent reserve during a 1-in-10 temperature condition. Line 14 represents the surplus megawatts above a seven percent reserve during a 1-in-10 temperature condition.

Based on the above assumptions, NP26 will have a surplus of 2,350 MW while SP26 will need almost 1,800 additional MW to maintain a seven percent reserve margin. Nearly 1,200 MW of existing demand response and load curtailment contracts could supply a portion of this 1,800 MW shortfall in the event that reserve margins fall below five percent. The remaining 600 MW will need to come in the form voluntary conservation, new demand reduction programs, expediting new generation, delaying retirements or other emergency response programs.

Adverse Conditions

Energy Commission and CA ISO staffs have identified potential adverse conditions that could strain the operation of the system. 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 outlook includes the adverse condition of high risk retirements, higher than summer average outages, and hot 1-in-10 temperatures because of its greatest impact on the system. Some additional adverse conditions that could strain the system are below.

- Transmission outages
- Exceptionally high forced outages
- Unusually low import levels
- Hotter than 1-in-10 temperatures
- Excessive congestion

Demand Response and Interruptible Programs

There are several mitigation measures available to the CA ISO and individual utilities to respond to adverse conditions and operating reserves falling below minimum acceptable levels this summer. Table 9 details the IOU demand response programs that are established at the CPUC, and/or contracted by an IOU. Several of these programs are new or evolving and participation may increase before the summer peak temperatures occur.

Table 9: Existing Interruptible and Demand Response Programs

	SP26		NP26	CA ISO
	SCE	**SDG&E**	**PG&E**	**TOTAL**
CPUC Programs				
Interruptible/Curtailable	595	2	342	**939**
Demand Bidding	72	1	39	**112**
Critical Peak Pricing	6	5	12	**23**
Power Authority Demand Response	31	5	200	**236**
Direct Load Control	256	2	45	**303**
Backup Generators	0	17	0	**17**
Total CPUC Programs	**960**	**32**	**638**	**1,630**
Other Programs				
Pumping Curtailment (10 minute response)	110			**110**
Pumping Curtailment (1 day response)	100			**100**
Total Other Programs	**210**	**0**	**0**	**210**
Existing Demand Response	**1,170**	**32**	**638**	**1,840**

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