CALIFORNIA ISO

California Independent
System Operator

California ISO

2003 Summer Assessment

April 11, 2003

Operations Engineering
California ISO
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I. Executive Summary

This report was prepared in response to the North American Electric Reliability Council (NERC) and Western Electricity Coordinating Council (WECC) request for an assessment of reliability and adequacy for the anticipated 2003 Summer Season for the California Independent System Operator (ISO) Control Area. The report includes operating forecasts of monthly peak demand levels, a resource adequacy assessment, and an assessment of the ISO controlled transmission system for the summer 2003 period (May 2003 to October 2003). In addition, this report includes a ten year ISO Coincidental Peak Demand and Energy Forecast, a "Non-Coincidental Peak Loads and Resource Assessment by Region", and a "Summary of ISO Historical Resources for Energy".

The resource forecast in this report assumes availability of resources for the 2003 Summer Season will be similar to recent historical operations. Possible curtailments due to natural gas limitations are not known and are not considered. The accuracy of these assumptions influence the accuracy of this assessment and impact the ability of the ISO to ensure reliable operation of the grid. In the CAISO filings to the California Public Utility Commission (CPUC) Docket No. R.01-10-024 and Federal Energy Regulatory Commission (FERC) Docket No. ER02-1656-000, the ISO supported the concept of imposing a reporting obligation on suppliers and load serving entities. Under such a mechanism, suppliers and load serving entities would report the amount of capacity they have under contract and the amount of capacity they have available for contracting. The CAISO continues to support the development of a statewide resource adequacy process to ensure that the CAISO has the information needed for reliable operation of the grid.

Barring major generation or transmission outages, the ISO anticipates there will be adequate resources available to meet the forecasted peak demand, and meet minimum operating reserve requirements. In addition, the ISO anticipates that the transmission system should demonstrate adequate reliability performance during the projected peak demand periods.

Demand Forecast

ISO Control Area Coincidental Demand Forecast

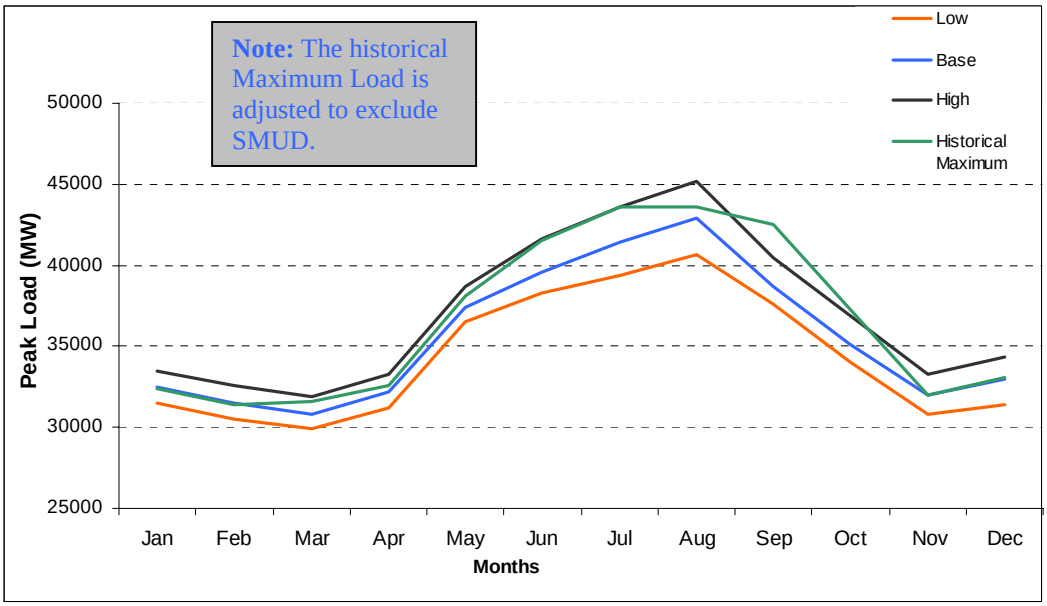
Three scenarios were analyzed to develop a range in which the ISO anticipates the 2003 summer peak demand will fall. The base scenario of the forecast for the summer peak is 42,894 MW[1]. The actual demand is anticipated to fall into a range between the low forecast of 40,624 MW and the high forecast of 45,185 MW. Estimated Operational Reserve requirements for the base scenario of the forecast are shown in Table I-1.

[1] The base case forecast assumes the peak during the summer month will occur in the month of August. The summer peak may occur anytime between the months of June and September.

The ISO anticipates that the 2003 summer peak demand will be higher than the 2002 summer peak demand of 42,441 MW but less than the July 1999 all-time peak demand of 43,554 MW[2].

Figure I-A compares the summer 2003 monthly peak demand forecasts with the all-time monthly peak.

Figure I-A
Historical Maximum and Forecasted Monthly Peak Range
(The base scenario of the Peak Load Forecast is developed assuming normal weather conditions. The actual demand is anticipated to range between the Forecast Low for moderate conditions and the Forecast High for extreme conditions.)



Resource Assessment

The total installed generating capacity identified in the ISO Control Area – including net dynamically scheduled generation - is 53,998 MW as of March 10, 2003. The capacity available to serve load for the forecast peak month (August 2003) is 44,821 MW after consideration of new generation expected prior to the summer season, and generation limitations (de-rates). The ISO anticipates import levels from the Northwest will be low due to the below normal Northwest snow-pack conditions, however imports from the Southwest are forecasted to increase slightly due to new generation. Net import levels are expected to be approximately 3,700 MW during the peak periods.

There was 2,764 MW of new generation capacity that went commercial in the ISO control area in the year 2002. Of that, 93.4 MW was added after September 2002, which marks the end of the 2002 summer season. As of March 10, 2003, 908 MW of new

[2] The all time peak demand of 43,554 MW is adjusted to exclude SMUD load.

generation capacity in the ISO control area went commercial this year. There is 2,697 MW of new generation capacity that is currently under construction with short construction and permit time or is currently in testing and is scheduled to be commercial prior to June 2003. An additional 644 MW[3] are scheduled to be commercially available by year-end 2003.

In 2002 the ISO was notified of 1,409 MW of generation capacity that either retired or mothballed. Of that, 148 MW retired prior to the 2002 summer season and the remaining retired after the summer 2002 season.

Transmission Assessment

The ISO anticipates that the transmission system is sufficient to meet WECC and NERC reliability criteria during peak demand periods under forecasted operating conditions. However, there are numerous transmission constraints that the ISO must mitigate during various operating conditions using the ISO's congestion management procedures or Reliability Must Run (RMR) generation. Major transmission path constraints that often require flow mitigation actions during summer peak demand periods include the Southwest Power Link (SWPL), Path 26, South of Lugo, total Southern California Import Transmission (SCIT), and the California-Oregon Intertie (COI).

Two generation projects have been located in Mexico but connected such that they are within the ISO control area. Also, a number of major generation projects have been added outside the ISO control area mainly in the Southwest and one in Mexico. However, transmission additions have not kept pace with the new generation additions. As a result, there are limitations on the total simultaneous generation levels and/or import levels. Therefore, the additional "Peak Load" that can be served this summer will not be as much as the additional generation capacity available this summer from Mexico and the Southwest.

Other local area transmission limitations exist throughout the ISO control area under various operating conditions. In these areas, operating problems can arise under various combinations of generation and/or transmission outages. Detailed descriptions of known bulk system and local area transmission constraints are included in Section V.

Load and Resource Balance Assessment

Table I-1 summarizes forecasted supply-and-demand conditions from May 2003 through October 2003 for the base scenario of the peak load forecast, which assumes normal hydro conditions and typical weather patterns. Refer to Section I of this report for a detailed explanation of the assumptions used in this analysis.

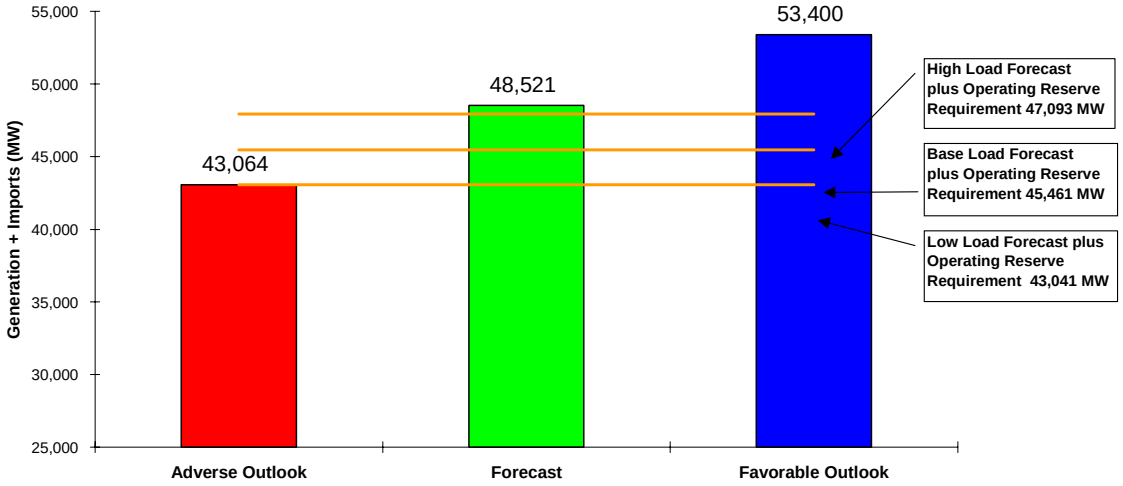
[3] The additional new generation expected before the end of the year 2003 has been de-rated by 275 MW for Transmission constraints and 150 MW for wind capacity limitations. The existing de-rate for line limitations on the Los Esteros plant (45 MW) is anticipated to be removed in July when the 115 kV line work in the San Jose area is complete.

Table I-1
Peak Load and Resource Forecast Summary for
May 2003 through October 2003

(MW)	**May-03**	**Jun-03**	**Jul-03**	**Aug-03**	**Sep-03**	**Oct-03**
Forecasted Peak Demand - (Base Case)	37,386	39,577	41,477	42,894	38,708	35,132
Operating Reserve Requirement	2,124	2,269	2,493	2,587	2,212	1,976
Total Generator Capacity including Dynamic Schedules	55,200	56,694	56,766	57,566	57,716	57,719
Total Generation Limitations	(15,323)	(12,411)	(12,003)	(12,745)	(14,608)	(17,397)
Estimated Control Area Resource Capacity (at time of peak)	39,877	44,283	44,763	44,821	43,108	40,322
Expected Net Imports	5,200	5,200	3,700	3,700	5,200	5,200
Surplus / Deficiency (After Imports)	5,567	7,637	4,493	3,040	7,389	8,414

Actual operating conditions (i.e., demand levels, availability of resources, import levels, transmission capacity, etc.) can vary significantly on any given day. Figure I-B illustrates the potential variability in assumptions for adverse, forecasted, and favorable system conditions.

Figure I-B
ISO Control Area Summer 2003 Capacity Outlook



(MW)	Adverse Outlook	Forecast	Favorable Outlook
Net Dependable Thermal, Pump Storage, & Dynamics	30,571	31,571	32,571
Non Participating Thermal and Solar Generation (including Muni)	3,500	4,384	6,000
Hydro Generation	4,970	5,970	6,470
New Generation	2,421	3,294	3,354
Imports	2,000	3,700	5,200
Environmental Constraints	(398)	(398)	(195)
Total	**43,064 MW**	**48,521 MW**	**53,400 MW**

In the event the ISO experiences higher than anticipated forced outages of resources, transmission limitations, demand levels, or lower import levels, such that the surplus capacity is depleted, the ISO has approximately 2,571 MW of emergency mitigation measures that could be implemented prior to curtailing firm load. Emergency mitigation measures include 1,321 MW of interruptible demand programs, and approximately 1,250 MW of non-spinning reserves that can be converted to energy. When the ISO converts non-spinning reserves to energy, the ISO must rely on its ability to shed firm load to meet the non-spinning reserve requirements.

While the assessment indicates that adequate resources are planned to be available to meet the 2003 summer peak, there is concern that the existing surplus capacity (i.e., operating margins) may evaporate over the next few years. Numerous generation projects planned for completion in the next few years have been cancelled or delayed. In

addition, several older generating units have not committed to installing required emission controls and may retire or become non-operational as environmental regulations become more restrictive.

II. ISO Control Area Peak Load and Resource Forecast Summary for Summer 2003

Table II-1 provides an itemized breakdown of the ISO Peak Load and Resource Forecast Summary for May 2003 to October 2003.

Table II-1
Peak Load and Resource Forecast Summary for
May 2003 through October 2003

	(MW)	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03
1	Forecasted Peak Demand - (Base Case)	37,386	39,577	41,477	42,894	38,708	35,132
2	Operating Reserve Requirement	2,124	2,269	2,493	2,587	2,212	1,976
3	Estimated Control Area Capacity Requirement	39,510	41,846	43,970	45,481	40,920	37,108
	Capacity						
4	Maximum Net Dependable Capacity of Participating Thermal Units	30,967	30,967	30,967	30,967	30,967	30,967
5	Maximum Capacity of Non-Participating Thermal Units	8,013	8,013	8,013	8,013	8,013	8,013
6	Maximum Capacity of Non-Participating Muni Thermal Units	402	402	402	402	402	402
7	Maximum Capacity of Solar Units	469	469	469	469	469	469
8	Maximum Net Dependable Capacity of Pump Storage Units	2,760	2,760	2,760	2,760	2,760	2,760
9	Maximum Capacity of Hydro Units	8,470	8,470	8,470	8,470	8,470	8,470
10	Maximum Capacity of Wind Units	1,675	1,675	1,675	1,675	1,675	1,675
11	Accumulative New Generation Capacity (after March 10, 2003)	1,203	2,697	2,769	3,569	3,719	3,722
12	**Total Capacity of Generators located in the ISO Control Area**	**53,959**	**55,453**	**55,525**	**56,325**	**56,475**	**56,478**
13	Net Dynamic Schedules into the ISO Control Area	1,241	1,241	1,241	1,241	1,241	1,241
14	**Total Generator Capacity including Dynamic Schedules**	**55,200**	**56,694**	**56,766**	**57,566**	**57,716**	**57,719**
	De-Rates						
15	Scheduled Participating Thermal Outages	(4,203)	(798)	(430)	(382)	(1,580)	(2,862)
16	Scheduled Pump Storage Outages	(547)	(40)	-	(15)	(30)	(537)
17	Estimated Forced Outages (Participating Thermal including Pumped Storage)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)	(3,000)
18	Estimated Non-Participating Thermal and Solar Limitations	(4,500)	(4,500)	(4,500)	(4,500)	(4,500)	(4,500)
19	Estimated Hydro Limitations	(1,000)	(2,000)	(2,000)	(2,500)	(3,000)	(4,000)
20	Wind Limitations	(1,675)	(1,675)	(1,675)	(1,675)	(1,675)	(1,675)
21	Accumulative New Generation Limitations	-	-		(275)	(425)	(425)
22	Accumulative Retirements	-	-	-	-	-	-
23	Environmental Constraints	(398)	(398)	(398)	(398)	(398)	(398)
24	**Total Generation Limitations**	**(15,323)**	**(12,411)**	**(12,003)**	**(12,745)**	**(14,608)**	**(17,397)**
25	Estimated Control Area Resource Capacity (at time of peak)	39,877	44,283	44,763	44,821	43,108	40,322
26	Surplus / Deficiency (Before Imports)	367	2,437	793	(660)	2,189	3,214
27	Expected Existing Net Imports (Excluding Dynamics)	5,000	5,000	3,500	3,500	5,000	5,000
28	Accumulative New Imports from Non ISO Control Area New Generation	200	200	200	200	200	200
29	**Surplus / Deficiency (After Imports)**	**5,567**	**7,637**	**4,493**	**3,040**	**7,389**	**8,414**

The following is a brief commentary regarding each line item.

1. **Forecasted Peak Demand (Base Case)** – Estimated monthly peak demand (including transmission losses) is based on historical demand levels, economic demographics, and typical weather conditions. This estimate does not include adjustments for proposed interruptible reduction programs or other conservation programs. This forecast is based on a best estimate of most likely operating conditions.
2. **Operating Reserve Requirement** – Estimated minimum WECC Operating Reserve requirement based on the current criteria.
3. **Estimated Control Area Capacity Requirement** – Sum of "Forecast Peak Demand" and "Operating Reserve Requirements".
4. **Maximum Net Dependable Capacity of Participating Thermal Units –** Estimated maximum Net Dependable Capacity (NDC) of thermal generation resources that are located within the ISO Control Area and whose owners have signed a Participating Generator Agreement (PGA) or Metered Subsystem Agreement (MSA) with the ISO as of March 10, 2003. Participating Thermal Units are counted regardless of whether they are scheduled inside or outside the ISO Control Area. The NDC does not include contractual or ownership rights of resources located outside of the ISO Control Area. The maximum NDC is not adjusted to account for reduced energy production as a result of outages, environmental limitations, geothermal steam fields, etc.
5. **Maximum Capacity of Non-Participating Thermal Units –** The Non-Participating thermal generators' (those generators who have not signed a PGA or MSA) total capacity reported to the ISO as of March 10, 2003, prior to de-rates for actual availability.
6. **Maximum Capacity of Non-Participating Muni Thermal Units –** The Non-Participating Municipal (Muni) thermal generators' (those generators who have not signed a PGA or MSA) total capacity reported to the ISO as of March 10, 2003, prior to de-rates for actual availability.
7. **Maximum Capacity of Solar Units –** The solar generators' total capacity reported to the ISO as of March 10, 2003, prior to de-rates for actual availability.
8. **Maximum Net Dependable Capacity of Pumped Storage Units –** Estimated maximum NDC generation capacity of pump storage resources that are located within the ISO Control Area as of March 10, 2003. Outages of pumped storage resources are reflected in the Scheduled Pumped Storage Outages on Item 16 and Forced Outages on Item 17.
9. **Maximum Capacity of Hydro Units –** The Run-of-River and Pond Storage hydro generators' total capacity reported to the ISO as of March 10, 2003 prior to de-rates for hydro limitations. Note that Pump Storage generation was previously included in this line item on previous Seasonal Assessments and is a now separately itemized. De-rates for hydro limitations at the time of monthly peak are shown in Item 19.

10. **Maximum Capacity of Wind Units –** The total wind turbine capacity reported to the ISO as of March 10, 2003, prior to de-rates for wind.

11. **Accumulative New Generation Capacity–** Accumulative new generation capacity includes all facilities that are expected to be located and operational within the ISO Control Area. A list of new generating resources, plant capacity and projected commercial operation dates are included in Section III, Table III-4 entitled, "Planned Commercial Generation Capacity Addition for March 2003 to December 2003." The Net Dependable Capacity has been de-rated to include any constraints in the transmission system that limit the ISO to obtain the full generation capacity of the plant.

12. **Total Capacity of generators located in the ISO Control Area –** The sum of all generators located in the ISO Control Area prior to de-rates (sum of Items 4 through 11).

13. **Net Dynamic Schedules into the ISO Control Area –** Estimated maximum dynamically scheduled capacity into and out of the ISO Control Area. The dynamic schedules include both IOU and Municipal shares of Palo Verde, Four Corners, Hoover, and Yuma Cogeneration Project that are scheduled into the ISO Control Area; and Mojave's generation that is scheduled out of the ISO Control Area. Refer to Section III for a listing of units that comprise the Dynamic Schedules. Outages of generators dynamically scheduled are reflected in the Scheduled Participating Thermal Outages on Item 15. The forced outages are included in Item 17.

14. **Total Generation Capacity including Dynamic Schedules –** The sum of all generators located in the ISO Control Area prior to de-rates and the net of generators that are dynamically scheduled into the ISO Control Area.[4]

15. **Scheduled Participating Thermal Outages –** Participating thermal generators and pump storage generators' scheduled outages includes all planned outages logged in the "Scheduling and Logging for the ISO and California" database (SLIC) as of February 20, 2003. Outages for Hydro and Non-Participating generators are not included. For planning purposes, this assessment used the maximum expected outages for each month since the monthly peak can occur on any day of the month.

16. **Scheduled Pumped Storage Outages –** Pump Storage generators' scheduled outages includes all planned outages logged in SLIC as of February 20, 2003. For planning purposes, this assessment used the maximum expected outages for each month, between the hours of noon to 6:00 PM, since the monthly peak can occur on any day of the month.

    Note: The pump storage limitations on previous assessments where included in the Hydro Limitation. Pump Storage limitations on all future assessments will be the recorded outages from SLIC and associated forced outages.

[4] Net Dynamic Schedules includes generation scheduled into the ISO Control Area and the Mojave generation scheduled out of the ISO Control Area.

17. **Forced Outages (Participating Thermal and Pump Storage) –** The average of forced outages over the last 2 years from SLIC.

18. **Estimated Non-Participating Thermal and Solar Limitations –** The de-rate for Non-Participating (including Non-Participating Muni Thermal) and solar generation is based on actual historical Non-Participating and Non-Participating Muni thermal generation operating levels recorded through the ISO Energy Management System (EMS). The NDC for these units is the difference between the Maximum Capacity of Non-Participating and Non-Participating Muni thermal and solar units (Item 5, 6, and 7) and this limitation. The limitation for these units is attributed to: load netted behind metering; station service load; lack of EMS visibility on smaller resources; retired or de-rated unit capabilities; maintenance; cloud conditions; and reduced capacity levels of steam for geothermal resources.

19. **Estimated Hydro Limitations –** The estimated hydro capacity limitations shown in Table II-1 are based on hydro capacity limitations previously experienced during similar months. Refer to Section III, Figure III-C. The NDC for hydro units is the difference between the Maximum Capacity of hydro units (Item 9) and this limitation. Capacity of Hydro resources are limited during certain times of the day and/or month for a variety of reasons including interplay between hydro units on common river system, environmental constraints, and regulation of water releases.

20. **Wind Limitations –** Wind capacity is an important resource to serve load in the ISO Control Area. Wind generation has, on occasion, provided over 1,300 MW of environmentally clean capacity. However, historical operating levels of wind generation during summer peak conditions are very low because the wind is generally stagnant on the hottest summer days. Wind capacity is fully de-rated because it is not dependable during the summer peak.

21. **Accumulative New Generation Limitations –** The new generation limitations are the limitations that restrict plants from delivering full capacity as a result of transmission constraints, and wind limitations.

22. **Accumulative Retirements –** In 2002, there were 1,409 MW of units that were retired or mothballed. The ISO has not been notified of any further retirements that will occur prior to the end of the year 2003.

23. **Environmental Constraints** – Temporary shutdowns or de-rates of generators at time of daily peak due to the plant's inability to meet environmental mandates such as air quality, water, and noise limits that are ordered by an authorized agency.

24. **Total Generation Limitations** - The sum of all generation limitations that effect generators located in the ISO Control Area prior to de-rates and the net of generators that are dynamically scheduled into the ISO Control Area.

25. **Estimated Control Area Resource Capacity (at time of peak) –** The forecasted total available generation capacity (including dynamic schedules) located within the ISO Control Area after adjusting for estimated outages, and other capacity limitations (Item 14 less Item 24).

26. **Surplus/Deficiency (Before Imports) –** Represents total estimated capacity surplus or deficiency served by control area generation and dynamic schedules prior to net imports.
27. **Expected Existing Net Imports (Excluding Dynamics) –** The forecast for existing net imports is based on historical import levels. Figure III-F shows the level of net imports (excluding dynamic schedules) observed in the summer of 2001 and 2002 at the time of daily peak.
28. **Expected New Generation Imports -** Expected net increase of imports due to generation built outside the state of California.
29. **Surplus/Deficiency (After Imports) –** The estimated surplus or deficiency in capacity during peak-load period is based on the assumptions detailed above. This capacity does not take into account load conservation or demand relief measures. The effects of other conservation efforts by the State cannot be dependably predicted and are not included in this assessment.

Emergency Resource Deficiency Mitigation Measures

In the event of a resource deficiency, the ISO will convert non-spinning reserve to energy and call on interruptible load customers prior to interrupting firm load. When Non-Spinning Reserves are converted to energy, the ISO relies on the ability to shed load to meet the WECC Reliability Criteria for non-spinning reserves. It is expected that approximately 1,250 MW of non-spinning reserve and 1,321 MW of interruptible demand will be available for use from the Utility Distribution Companies (UDC) for mitigation of emergencies during Summer 2003.

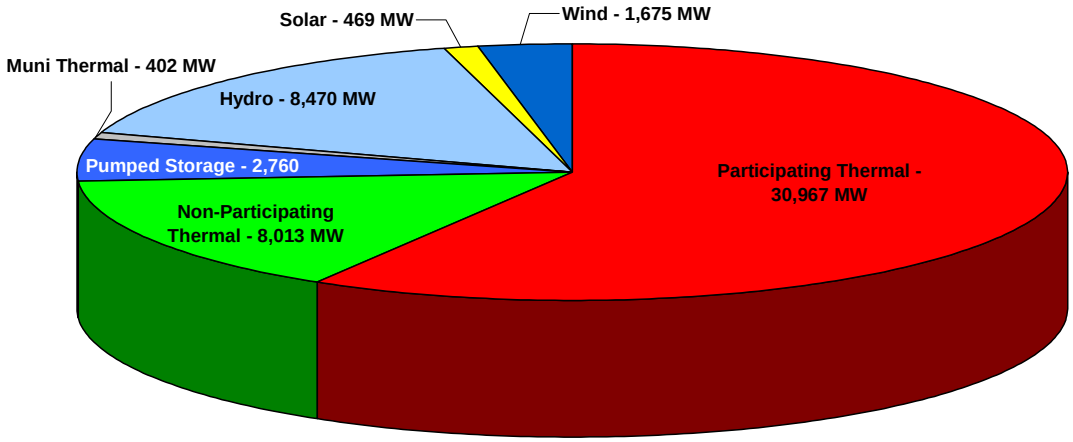
III. ISO Control Area Resources

Total Control Area Generation

The reported capacity of all generators located within the ISO Control Area as of March 2003 is shown in Figure III-A. The capacity that the ISO expects to have available during summer peaks is adjusted to account for scheduled and forced outages, hydro limitations, wind, geothermal steam fields, and environmental conditions that restrict the full available capacity of the generating resources. The reported capacity of generators located within the ISO Control Area is comprised of:

- **Participating Thermal Generating Units** de-rated for actual scheduled and historical forced outages.
- **Pumped Storage Generating Units** de-rated for actual scheduled and historical forced outages.
- **Non-Participating Thermal Generating Units** de-rated based on historical operating levels.
- **Non-Participating Municipal Thermal Generating Units** de-rated based on historical operating levels.
- **Solar Generating Units** de-rated based on historical operating levels.
- **Hydro Generating Units** de-rated based on historical operating levels.
- **Wind Turbines** are not considered a dependable source of energy during summer system peaks and are fully de-rated.

Figure III-A
ISO Control Area Generation by Major Category
(As of March 10, 2003 before de-rates for availability)



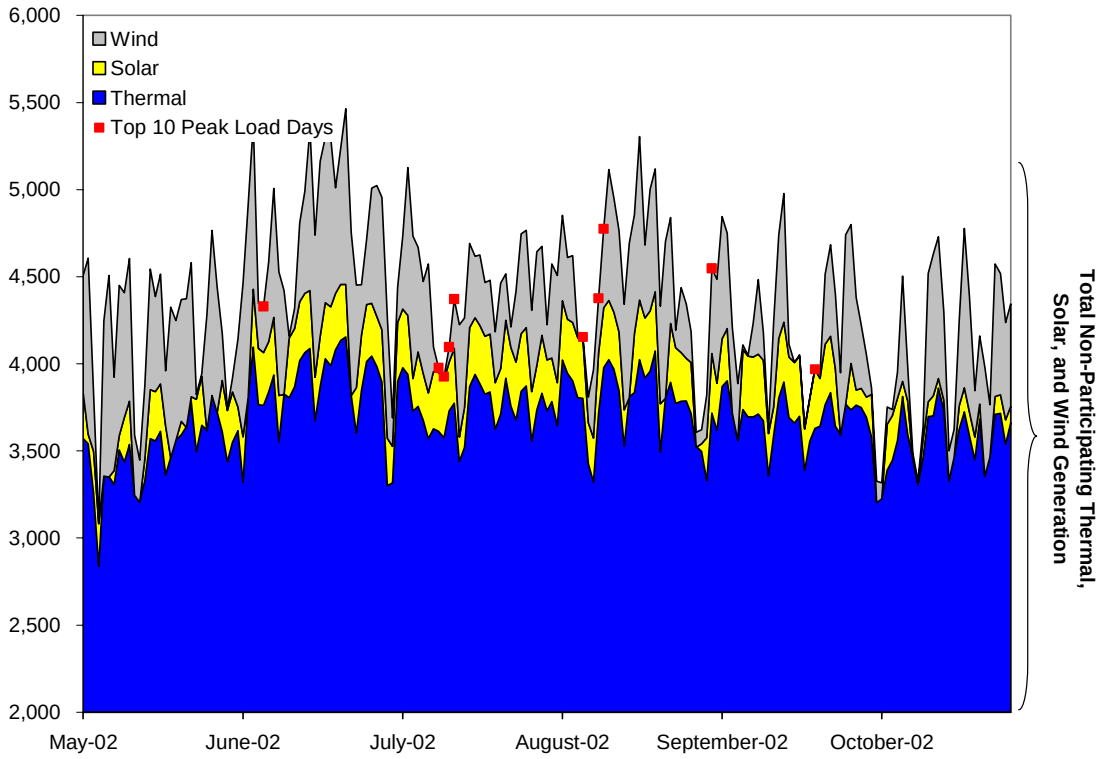
Participating Thermal Units are defined as the thermal generating facilities within the ISO's Control Area that have signed a Participating Generator Agreement or Metered Subsystem Agreement. The thermal category is predominantly base-load large thermal, nuclear, and peaking generation. The Participating Generator Agreement requires these generators to report all outages and de-rates to the ISO. The available capacity for Participating Generator Units is the reported Net Dependable Capacity less scheduled outages reported to SLIC and estimated forced outages based on historical records.

Pumped Storage Generating Units are defined as the pump storage generating facilities within the ISO's Control Area. All Pumped storage generating units outages and de-rates are reported to the ISO. The available capacity for Participating Generator Units is the reported Net Dependable Capacity less scheduled outages reported to the ISO and estimated forced outages based on historical records.

Non-Participating Thermal (including Muni) and Solar Generating Units are units that generate power in the ISO Control Area whose owners have not signed a Participating Generator Agreement. The full capacity of Non-Participating thermal and Solar Units is not considered dependable and is de-rated to account for actual anticipated generation output. Of the Non-Participating generators, there are 2,160 MW of generation capacity that the ISO does not have visibility on, or did not provide any capacity to the ISO grid at the time of daily peak during the Summer 2002 (i.e., self generating facilities, non-reported retired units).

The Non-Participating thermal units (including Non-Participating Muni units) and Solar units are not required to report outages to the ISO; thus the future available capacity is estimated based on historical operating levels. During similar months last year, the Non-Participating thermal and solar generators operated at approximately 4,300 MW each month (as shown in Figure III-B).

Figure III-B
Non-Participating Thermal Generation (including Muni's) and Solar Generation at Time of Daily Peak for June 2002 to October 2002
(The red dots mark the 10 highest load days during the summer months.)



QF Availability

There are 12,240 MW of Qualifying Facilities (QF) in the ISO Control Area whose capacity is counted in Participating, Non-participating thermal, wind, solar, or hydro units. All of the Non-participating thermal units (8,013 MW), and the solar units (469 MW) are QF's whose owners have signed long-term power sale contracts with one of the Investor Owned Utilities. A large number of these generators exist primarily for self-provision of the owner's on-site energy requirements. Half of the technology that makes up Non-Participating Generator units is industrial co-generation.[5]

In addition, there are 1,984 MW of QF Participating Thermal units, 280 MW of QF Hydro units, and 1,494 MW of QF Wind units.

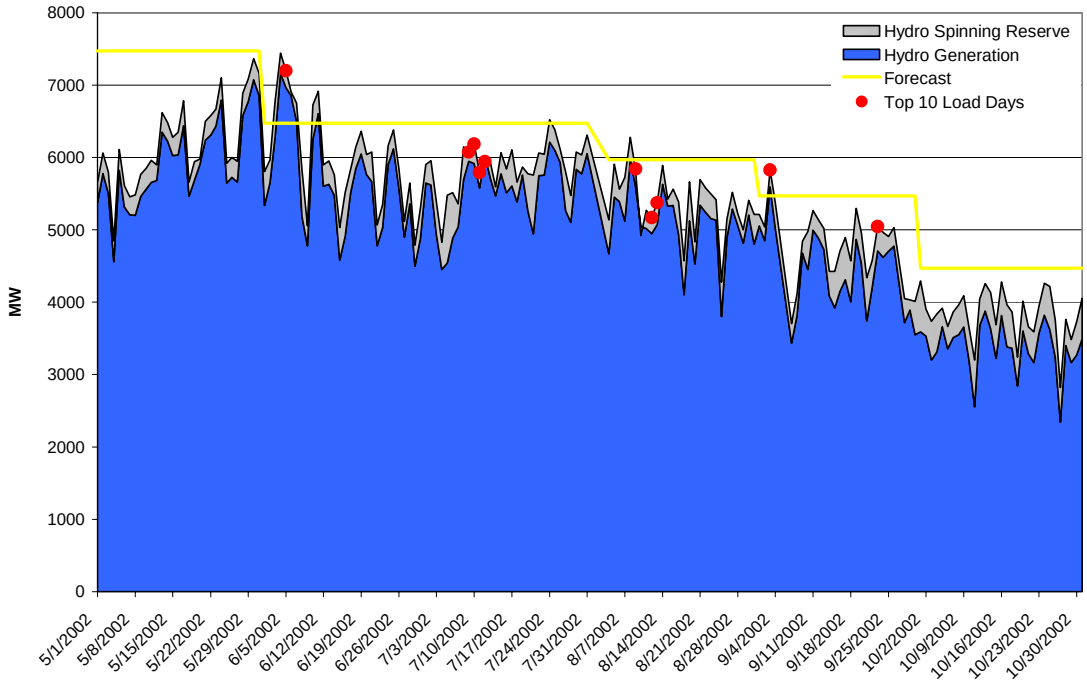
Hydro Availability

The hydro limitation for all hydro units in the ISO Control Area is based on actual hydro operating levels and scheduled reserves previously experienced during similar months.

[5] Industrial co-generation can be described as a host process that generates a byproduct (e.g., gas), which in turn, is used to fuel a generator to create two or more forms of energy including electricity for on-site load and the power grid and a second energy form such as steam for its own process.

Figure III-C is a graph of total hydro at the time of daily peak for Summer 2002.Using historical generation levels, the ISO Control Area hydro generation (8,470 MW) is de-rated by: 1,000 MW in May; 2,000 MW in June and July; 2,500 MW in August; 3,000 MW in September; and 4,000 MW in October.

Figure III-C
Hydro Generation at the Time of Daily Peak for
May 2002 through October 2002
(Does not include Hoover or Pump Storage Units)



Wind Availability

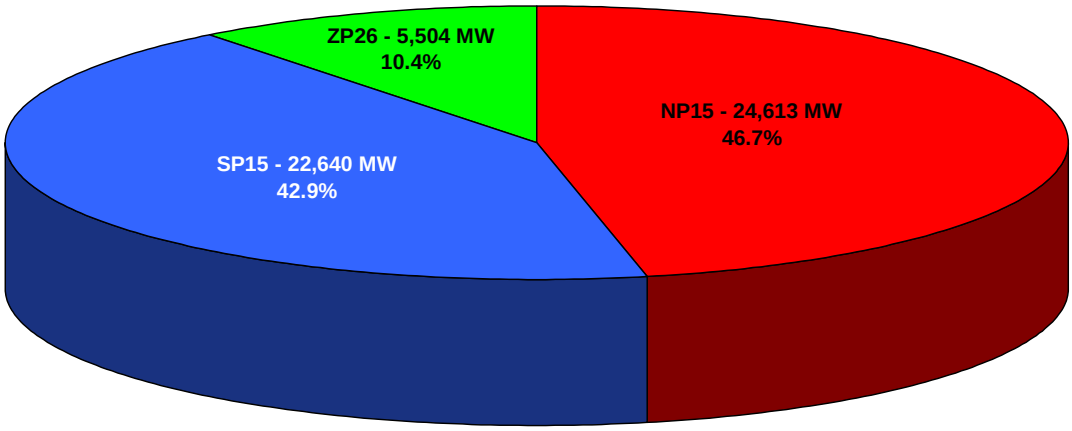
Wind generation has, on occasion, provided over 1,300 MW of environmentally clean capacity during the summer season. However, as shown in Figure III-B ["Non-Participating and Muni Generation at Time of Daily Peak for May 2002 to October 2002"], historically the wind generation is not dependable at the time of summer control are peaks. The ISO does not include the wind generation as dependable capacity in this assessment.

ISO Control Area Generation Capacity by Congestion Zone

Figure III-D provides a graphical depiction of the maximum ISO Control Area generation capacity by Congestion Zone. A map that outlines the ISO's Congestion Zones and Demand Zones can be found on the ISO Internet web site at the following address:

Http://www.caiso.com/marketops/technical/index.html

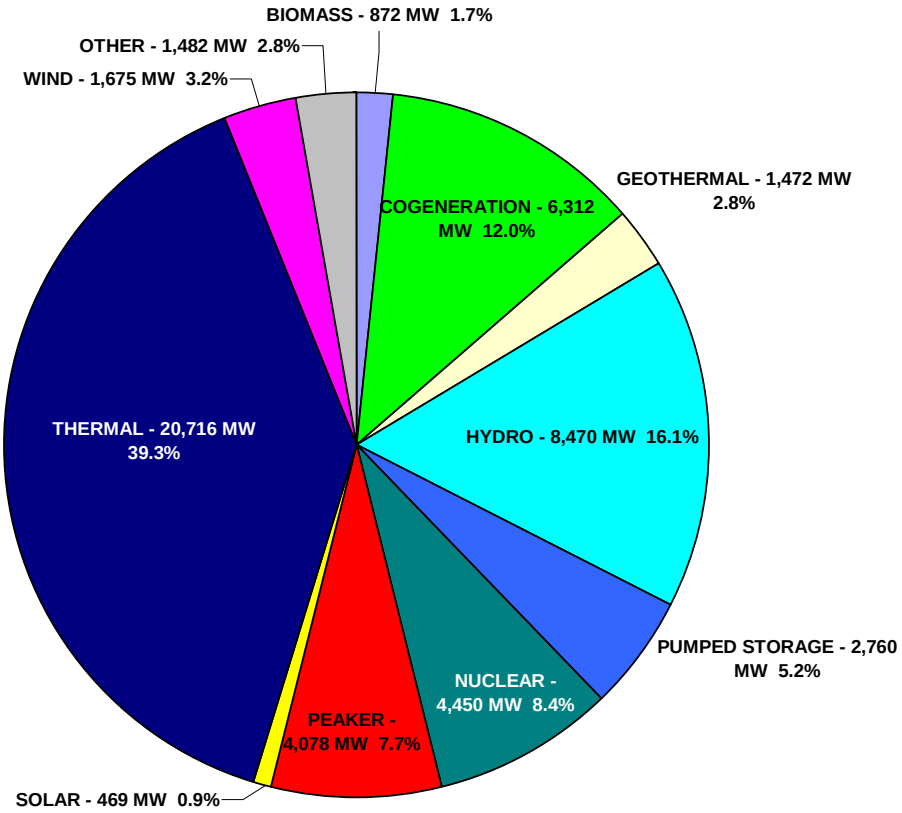
Figure III-D
ISO Control Area Generation Capacity by Congestion Zone
(As of March 10, 2003 before de-rates for availability)



ISO Control Area Generation Capacity by Technology

Figure III-E is a summary of the generation resources within the ISO Control Area by technology. For the convenience of the reader, an electronic copy of the master ISO Control Area generating capability list (in MS Excel 97 format) current through March 10, 2003 will be posted along with the 2003 Summer Assessment report on the ISO Internet web site. A revised ISO Control Area generating capability list that includes changes since March 10, 2003 is posted on the ISO Internet web site under http://www.caiso.com/thegrid/operations. This table is updated periodically to represent new generators, retirements, and NDC of the plants.

Figure III-E
ISO Control Area Generation by Technology
(As of March 10, 2003 before de-rates for availability)



ISO Control Area New Generation

New Generation Installed in 2002

Detailed in Table III-1 is a listing of the new generation facilities installed within the ISO Control Area in 2002. Detailed in Table III-2 is a listing of the new generation facilities that have become commercially available in the ISO Control Area thus far during the year 2003. Table III-3 summarizes new generation since 2001 for each control area. The generation at the Los Esteros Critical Energy Facility that went commercial on March 7, 2003 may need to be curtailed by 45 MW due to construction work of 115 KV lines in the San Jose area. The full capacity of this facility is 195 MW. The unit is de-rated to 150 MW until completion of the transmission required to support the full capacity of this plant.

At the time the ISO 2002/2003 Winter Assessment was published, 2,771 MW of new generation had been made commercially available from January 2002 through October 2002. The ISO had anticipated that there would be an additional 1,787 MW available by March 10, 2003, of which 48% has been installed and the remaining 52% has been delayed.

Table III-1
New Generation Facilities Installed Within the ISO Control Area in 2002

2002 Generation Capacity Additions								
	Generating Unit	Net Dependable Capacity (MW)	ISO Classification	Fuel Type	Control Zone	Congestion Zone	Owner or QF ID	Commercial Date
1	Gates	49.9	Peaker	N. Gas	ZP 26	PGE4	Wellhead	12/27/2001
2	King City Energy Center, LLC	48.7	Peaker	N. Gas	NP 15	PGE3	Calpine	1/14/2002
3	Gilroy Energy Center - Unit 3	48.7	Peaker	N. Gas	NP 15	PGE3	Calpine	2/28/2002
4	Midsun Generation Facility	21.3	Cogeneration	N. Gas	ZP 26	PGE4	Energy Transfer-Hanover Ventures LP	4/15/2002
5	Olinda Landfill II	2.5	Biomass	N. Gas	NP 15	PGE3	Ridgewood Power Management	5/1/2002
6	El Cajon, LLC	55.0	Peaker	N. Gas	SP 15	SDG1	Cal Peak	5/29/2002
7	Springs Generation Project	44.0	Peaker	N. Gas	SP 15	SCE1	Riverside Public Utilities	6/13/2002
8	Delta Energy Center	845.2	Thermal	N. Gas	NP 15	PGE3	Calpine	6/17/2002
9	Vaca Dixon, LLC	55.0	Peaker	N. Gas	NP 15	PGE3	Cal Peak	6/21/2002
10	Moss Landing Generating Project - Unit 1	510.0	Thermal	N. Gas	NP 15	PGE3	Duke Energy	7/1/2002
11	Yuba City Energy Center	48.7	Cogeneration	N. Gas	NP 15	PGE3	Calpine	7/1/2002
12	Henrietta Peaking Project - Unit 1	50.0	Peaker	N. Gas	NP 15	PGE3	GWF Energy	7/1/2002
13	Moss Landing Generating Project - Unit 2	510.0	Thermal	N. Gas	NP 15	PGE3	Duke Energy	7/11/2002
14	Henrietta Peaking Project - Unit 2	50.0	Peaker	N. Gas	NP 15	PGE3	GWF Energy	7/1/2002
15	Huntington Beach - Unit 3	225.0	Thermal	N. Gas	SP 15	SCE1	AES	7/30/2002
16	Cabazon Wind Generation	41.0	Wind	Wind	SP 15	SCE1	Cabazon Wind Partners	8/31/2002
17	Whitewater Hill Wind Project	64.5	Wind	Wind	SP 15	SCE1	Whitewater Energy Corporation	8/31/2002
18	Marina Landfill	1.0	Biomass	Land Fill Gas	NP 15	PGE3	Waste Management District	9/12/2002
19	Valero Refining Company - Unit 1	44.7	Peaker	N. Gas	NP 15	PGE3	Colton Power	10/18/2002
20	Feather River	48.7	Peaker	N. Gas	NP 15	PGE3	Calpine	12/23/2002
Total Capacity Commercial in 2002		***2,764***						

Table III-2
New Generation Facilities Installed Within the ISO Control Area YTD 2003

2003 Generation Capacity Additions YTD								
	Generating Unit	Net Dependable Capacity (MW)	ISO Classification	Fuel Type	Control Zone	Congestion Zone	Owner or QF ID	Commercial Date
1	Creed Energy Center	48.7	Peaker	N. Gas	NP 15	PGE3	Calpine	1/6/2003
2	Goosehaven Energy Center	48.7	Peaker	N. Gas	NP 15	PGE3	Calpine	1/6/2003
3	Lambie Energy Center	48.7	Peaker	N. Gas	NP 15	PGE3	Calpine	1/6/2003
4	La Paloma Unit 1	260.0	Thermal	N. Gas	ZP 26	PGE4	La Paloma Generating Company	1/10/2003
5	La Paloma Unit 3	260.0	Thermal	N. Gas	ZP 26	PGE4	La Paloma Generating Company	1/13/2003
6	THUMS Generation	47.0	Peaker	N. Gas	SP 15	SCE1	THUMS Long Beach Company	2/1/2003
7	Los Esteros Critical Energy Facility, Unit 1-4	195.0	Peaker	N. Gas	NP 15	PGE4	Calpine	3/7/2003
Total Capacity Commercial in 2003 as of March 1		***908***						

Table III-3
New Generation Facilities Installed Within the ISO Control Area by Zone in 2001 through YTD 2003 *(through March 10, 2003)*

Control Zone	2001 Capacity (MW)	2002 Capacity (MW)	YTD 2003 Capacity (MW)
NP15	1,550	2,263	341
SP15	685	430	47
ZP26	338	71	520
Total	2,573	2,764	908

Expected Additional Generation Capacity Addition in 2003

As of March 10, 2003, it has been reported to the ISO that there are an additional 2,697 MW of generation scheduled to be commercially available to the ISO by the beginning of the 2003 summer season (June 2003). Table III-4 lists all planned generation capacity additions scheduled to be commercial through December 2003. The ISO considers only those projects that have started construction in the forecast. New generation schedules are dynamic and subject to change.

Table III-4
Planned Commercial Generation Capacity Additions for March 2003 to December 2003

COD = Commercial Operation Date

Developer	Generation Project	PTO Area	COD Estimated on Summer Assessment	COD Estimated Winter Assessment	Plant Capacity	Derated for Transmission Constraints at Time of Peak	ISO Net Dependable Capacity	Construction Status	Notes
PG&E NEG	La Paloma Generating Project, Unit 2	PGAE	3/6/2003	*11/1/2002*	255.0		255.0	Complete	
PG&E NEG	La Paloma Generating Project, Unit 4	PGAE	3/6/2003	*12/17/2002*	255.0		255.0	Complete	
GWF	Tracy Peaking Unit 1	PGAE	3/28/2002		83.0		83.0	Complete	
Calpine	Wolfskill Energy Center	PGAE	4/1/2003	*1/30/2003*	48.7		48.7	Complete	
NM Mid Valley Genco, LLC	Mid Valley	SCE	4/1/2003	*1/13/2003*	2.5		2.5	90% Complete	
InterGen	Central La Rosita II, Phase 1	SDGE	4/10/2003	*12/30/2002*	160.0		160.0	Complete	All units at Imperial Valley (Central La Rosita and Termoelectrica De Mexicali units) are constrained at peak conditions to approximatley 800 MW.
NM Colton Genco, LLC	Colton	SCE	4/15/2003	*1/13/2003*	1.2		1.2	95% Complete	Not ISO Participant - under Rule 21.
GWF	Tracy Peaking Unit 2	PGAE	4/12/2003		83.0		83.0	Complete	
InterGen	Central La Rosita I	SDGE	4/30/2003	*1/1/2003*	160.0		160.0	Complete	All units at Imperial Valley (Central La Rosita and Termoelectrica De Mexicali units) are constrained at peak conditions to approximatley 800 MW.
InterGen	Central La Rosita II, Phase 2	SDGE	4/30/2003	*4/30/2003*	155.0		155.0	Complete	All units at Imperial Valley (Central La Rosita and Termoelectrica De Mexicali units) are constrained at peak conditions to approximatley 800 MW.
Sempra Energy Resources	Elk Hills Generating Project	PGAE	5/1/2003	*3/1/2003*	549.0		549.0	Complete	
Modesto Irrigation District	Woodland Generation Station #2	PGAE	5/1/2003		80.0		80.0	Complete	
Constellation Power	High Desert Power Project	SCE	5/6/2003	*4/1/2003*	865.0		865.0	Complete	
Calpine	Riverview Energy Center (GP Antioch)	PGAE	6/1/2003	*4/15/2003*	48.7		48.7	60% Complete	
NM Milliken Genco, LLC	Milliken	SCE	6/1/2003	*1/13/2003*	2.5		2.5	30% Complete	
El Dorado Irrigation District	El Dorado Power House U1	PGAE	6/1/2003	*5/1/2003*	10.0		10.0	90% Complete	
El Dorado Irrigation District	El Dorado Power House U2	PGAE	6/1/2003	*5/15/2003*	10.0		10.0	80% Complete	
Edison Mission Energy	Sunrise Power Project, Phase II	PGAE	7/1/2003		200.0		200.0	80% Complete	
Termoelectrica De Mexicali	Termoelectrica De Mexicali	SDGE	7/3/2003		600.0	275.0	325.0	Complete	All units at Imperial Valley (Central La Rosita and Termoelectrica De Mexicali units) are constrained at peak conditions to approximatley 800 MW. The 275 MW constraint is not directly associated withTermoelectrica De Mexicali but is associated with total generation and imports at Imperial Valley.
FPL Energy	High Winds	PGAE	8/1/2003		150.0	150.0	-	10% Complete	Wind Turbines - fully de-rated for available capacity at time of daily peak.
Fresno Cogen Partners,LP	Fresno Cogen Expansion	PGAE	9/1/2003		70.0		70.0	Not Started	
Waste Management Energy Solutions	El Sobranta	SCE	9/1/2003		2.7		2.7	10% Complete	
Calpine	Pastoria Project	SCE	12/1/2003		250.0	-	250.0	40% Complete	Transmission constraints are anticipated under conditions with low load and high generation from Big Creek.
Mammoth Pacific, LP	Casa Diablo 4	SCE	12/1/2003	*1/1/2004*	16.5		16.5	Not Started	

Expected Net Dependable Capacity that has initiated construction after derates for transmission limitations.	Total ISO	PGAE	SCE	SDGE
Accumulative Total Available April 2003	**593**	**593**	-	-
Accumulative Total Available May 2003	**1,203**	**725**	**4**	**475**
Accumulative Total Available June 2003	**2,697**	**1,354**	**869**	**475**
Accumulative Total Available July 2003	**2,769**	**1,422**	**871**	**475**
Accumulative Total Available August 2003	**3,294**	**1,622**	**871**	**800**
Accumulative Total Available September 2003	**3,294**	**1,622**	**871**	**800**
Accumulative Total Available October 2003	**3,296**	**1,622**	**874**	**800**

Total Additional Expected Capacity for 2003 *(units that have initiated construction)*	***17,146***
Total Capacity that has not started construction	*70.0*
Total Capacity that has unknown construction	-

Retirements

The ISO was notified that 1,409 MW of units retired or were mothballed from the ISO Control Area during the year 2002. Of that, 1,261 MW have retired or mothballed since the 2002 summer season.

The following is a list of all units that notified the ISO that they would not operate after October 2002:

• High Grove Units 1-4	148 MW	Retired early '02
• Huntington Beach 5	128 MW	
• Naval Station 1	22 MW	
• Naval Training Center	15 MW	
• North Island 1	21 MW	
• North Island 2	21 MW	
• San Bernardino Units 1 & 2	126 MW	
• San Gorgonio Hydro	2 MW	
• Georgia Pacific Lumber	8 MW	
• Etiwanda 1 & 2	264 MW	
• Broadway 1 & 2	93 MW	
• El Segundo 1 & 2	339 MW	
• South Bay Unit 4	222 MW	

The following is a list of generation that the ISO anticipates will not be available in future years.

2004 Retirement	Glenarm Units 1&2	46 MW
	Etiwanda Unit 5	120 MW
	Alamitos Unit 7	134 MW
	Pittsburg Units 1-4	625 MW
2005 Retirement	Hunters Point 4	163 MW
2006 Retirement	Mohave	1,580 MW

The Hunters Point 4 unit may be able to run up through 2007. The decision is pending.

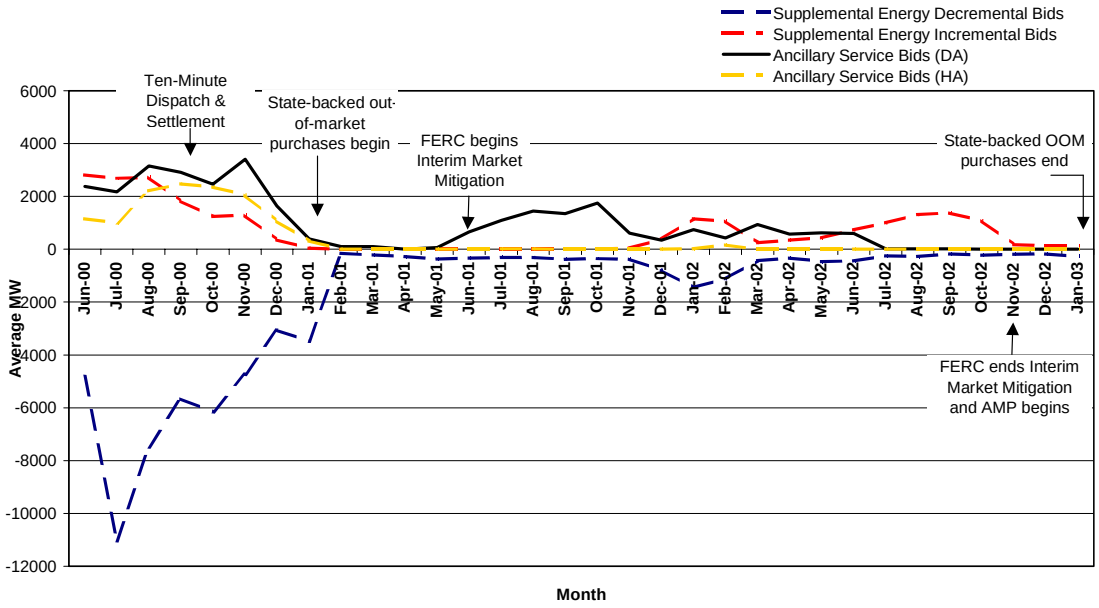
Net Interchange

Imports from Existing Generation located outside the ISO Control Area

The Net Interchange Capacity available to serve load in California may vary with economic conditions, transmission transfer capacity, neighboring control areas load requirements, and snow-pack conditions in the Northwest and throughout the WECC region.

The ISO uses ancillary services and supplemental energy bids from imports to meet real time capacity requirements. As economic conditions have become less favorable – the ancillary service and supplemental energy bids have decreased as shown if Figure III-F.

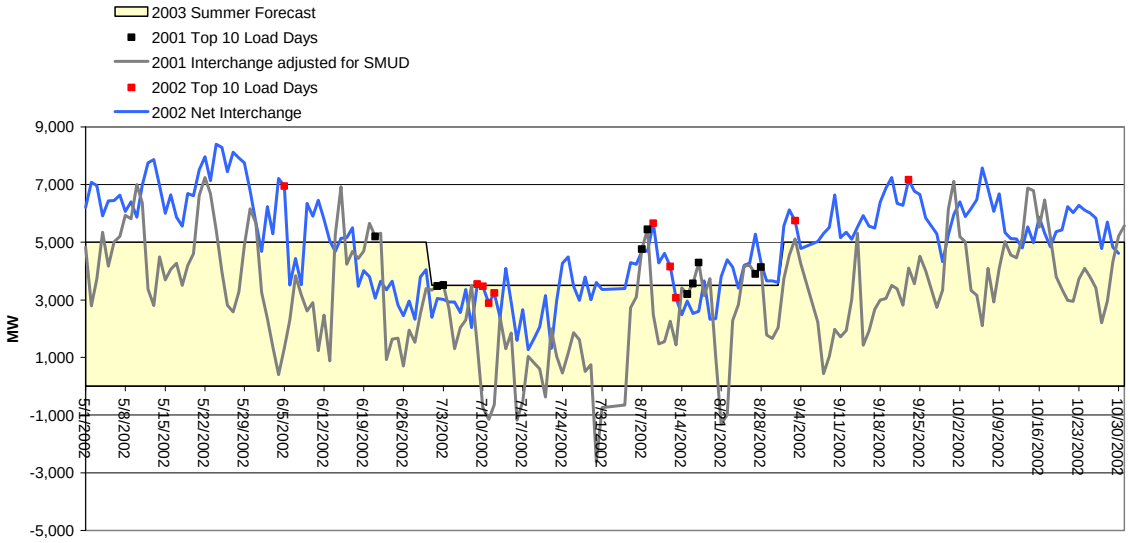
Figure III-F
Ancillary Service and Supplemental Energy Bids Offered from Imports



The Summer 2003 Forecast is based on the level of net imports during the time of daily peak for the last two years and Northwest snow-pack conditions for this last winter. The Net Interchange for Summer 2001 and Summer 2002, and the Summer 2003 Forecast are shown in Figure III-G. The top ten days that the ISO Control Area system-wide peaks have occurred are marked with the red dot for Summer 2002 and a black dot for Summer 2001.

The Northwest snow-pack conditions as of March 2003 are at approximately 70% of normal in most river basins. The Northwest snow-pack conditions during the winter prior to the summer 2001 season where at approximately 60% of average, and prior to the summer 2002 season were slightly above 100% of average. The level of imports is similar for both 2001 and 2002 at the top ten days that load was at its highest level in the ISO Control Area.

Figure III-G
Net Interchange at the Time of Daily Peak for
Summer 2001 and Summer 2002



Imports from New Generation

New generation capacity outside of the ISO Control Area has increased significantly since the 2002 summer season. However, the ISO anticipates the net imports will only increase by approximately 200 MW due to transmission constraints.

Table III-5
Capacity of New Generation Built Outside of State
(Capacity shown is referenced to estimate new import levels. The new generation capacity is rounded and is based on data reported to the WECC.)

	Approximate additional capacity constructed since Summer 2002	Approximate additional capacity currently being constructed and anticipated to be commercially available prior to the 2003 Summer	Forecasted Increase in ISO Imports
Southwest	600 MW	3,100 MW	200 MW
Mexico	0 MW	575 MW	0 MW
Northwest	500 MW	600 MW	0 MW

- Despite significant levels of new generation in the region, imports from the Southwest are anticipated to increase by only 200 MW due to limitations to simultaneous generation into Imperial Valley and existing levels of flows on the South West Power Link.

- The generation in Mexico is constrained due to transmission limitations at Imperial Valley. The new nomogram in the region does not allow the simultaneous generation into Imperial Valley and imports from Mexico to exceed 800 MW.
- The generation in the Northwest may be constrained due to limitations on the California Oregon Intertie (COI). In addition, the Northwest relies heavily on hydro generation and currently has low snow-packs due to a warm winter. Because of that, the ISO does not anticipate that net imports from the NW will increase from last years import levels due to the new generation in the Northwest due to these reasons.

DWR Contracts

Approximately 30% of the 2003 summer peak demand will be served with contracts signed by the Department of Water and Resources (DWR) under Assembly Bill 1 of the First Extraordinary Session (AB X1, Stats. 2001, Ch.4), which authorized the DWR to purchase electricity and sell it to the retail customers of the utilities (with the utilities acting, in effect, as DWR's billing agent). A small portion of the contracts (approximately 200 MW) likely comes from generation outside of the state. A majority of the contracts will expire in the years 2010 and 2011. On December 31, 2002, the DWR's authority to make the purchase under this bill expired and the contract obligations were transferred to the Investor Owned Utilities (PG&E, SCE, and SDG&E).

Dynamic Schedules

Dynamic schedules generally refer to generation resources geographically located in one control area, which are scheduled with a second and separate control area on a real-time basis.

The following units comprise the combined maximum capacity of dynamically scheduled resources available to the ISO.

• SCE's share of Hoover (14.2%)	277 MW
• City of Riverside's share of Hoover	30 MW
• SCE's share of Four Corners 4 & 5 (48%)	753 MW
• SCE's share of Palo Verde (15.8%)	579 MW
• Metropolitan Water District's share of Hoover (12.7%)	248 MW
• Yuma Cogeneration	49 MW
• 44% of Mojave scheduled outside of the ISO Control Area	(695 MW)

The combined maximum capacity of dynamically scheduled resources available to the ISO is 1,241 MW. Other utilities have the right to dynamic schedule generation from

Hoover, however have not exercised the dynamic schedules and statically scheduled the generation in the year 2002.[6]

It should be noted that the total capacity of Mojave has been included as part of the ISO Control Area Net Dependable Generating Capacity. There is 44% of Mojave's generating capability that is dynamically scheduled out of the ISO Control Area to three other control areas: those of Los Angeles Department of Water and Power (LDWP), Salt River Project (SRP), and Nevada Power Company (NEVP).

Air Quality Issues

California power plants are required to operate in accordance with environmental regulations set forth by the Environmental Protection Agency (EPA) Region 9, the California Air Resources Board (CARB), local Air Quality Management and Air Pollution Control Districts (AQMDs and APCDs), and the Department of Fish and Game. The regulations set standards for oxides of nitrogen (NOx), volatile organic compounds (VOC), particulate matter less than 10 microns (PM10), oxides of sulfur (SOX), and carbon monoxide (CO), and water release temperatures.

Regulation Standards vary in nature such that some generating units are required to operate under one or more criteria that limit annual, daily, or monthly operating hours, or de-rated capacity levels.

Four Air Quality Management District rules that were implemented prior to 2002 have increasingly stringent standards in future years. These rules are: South Coast AQMD Rule 2009, Bay Area AQMD Rule 9-11, San Diego County AQMD Rule 69, and San Luis Obispo County APCD Rule 429.

Some older generators may chose to retire or lay up/mothball units due to economic reasons and forego the retrofit required to meet the new standards. In each district, there may be plans to replace some of these units with clean, more efficient generators.

- **South Coast AQMD Rule 2009 –** This rule applies to existing electric utilities whose aggregate generation capacity with the same ownership is at least 50 MW. Under this rule, peaking units must implement Best Available Retrofit Control Technology (BARCT) for NOx by year-end 2003. All other units were to implement best available retrofit control technology (BARCT) by year-end 2002. In the South Coast AQMD, 606 MW retired in 2002 and 264 MW were mothballed for a latter evaluation of economic feasibility of recovering the cost of SCR installation.

- **Bay Area Air Quality Management District Rule 9-11** - Rule 9-11 has increasingly stringent emission limitations for NOx from existing electric generating steam boilers. The current NOx emission rate limit is 0.057 lb/MMBTU (~ 47 ppm). At the beginning of the years 2004, and 2005, the limitations are tightened to 0.037

[6] The following utilities have obtained rights to dynamically schedule generation from Hoover: City of Anaheim (40 MW), City of Vernon (22 MW), City of Azusa (4 MW), City of Banning (2 MW), and City of Colton (3 MW). These utilities statically scheduled the generation from Hoover in the year 2002.

lb/MBTU and 0.018 lb/MMBTU (approximately 31 ppm, and 15 ppm, respectively). The latter, final limit is equivalent to the BARCT level of 5 ppmv, dry basis, at 15% O^2. There could be a loss of 625 MW that serves the San Francisco Bay Area at the beginning of the year 2004 due to the potential shutdown of units in the Bay Area because of old age, reliability, and cost concerns; including the need for additional emission control retrofits. The ISO is also projecting a loss of an additional 1,198 MW in the Bay Area in January 2005. There is a potential that Hunters Point 4 does not retire at the end of the year 2004 and can continue to run using emissions credits through January 2007.

- **San Diego County AQMD Rule 69 –** Rule 69 applies to electric steam generating boilers with a maximum heat input capacity of 100 million BTUs or greater. Rule 69 sets allowable emission rates of 0.15 lbs NOx/MW-hr during natural gas firing, and 0.4 lbs NOx/MW-hr during oil firing, for the nine existing boilers at the South Bay and Encina power plants. Compliance was required by January 1, 2001; however, a variance was granted to allow the new power plant owners additional time to meet these limits. Currently, seven of the nine units have been retrofitted with Selective Catalytic Reduction Technology (SCR) to comply with these limits. One of the two remaining units will be completed by March 2003, and the final unit is scheduled to have SCR installation complete by May 2003.

- **San Luis Obispo County APCD Rule 429 –** Rule 429 applies to one plant in the San Luis Obispo County APCD that was de-rated by 20 MW to meet 2003 standards that lower NOx emissions levels from 3.50 tons per day to 2.50 tons per day. Currently, flue gas re-circulation and Low NOx burners are operating on 680 MWs of the 1,021 MW total (two 340 MW units). NOx emissions from these units will allow them to run a little less than 21 hours per day. This plant also has two 165 MW units built in the 1950s that have some minor burner modifications, which bring their NOx emissions to more than double the two larger units. Applications have been submitted to replace all four units; local authorities and the CEC are currently reviewing the application. There are no permits in place to retrofit the current units with selective catalytic reduction.

IV. ISO Control Area System Wide Load

2003 ISO Control Area Summer Peak Demand Forecast

Demand for electricity is influenced by various economic and non-economic factors. The methodology used to forecast monthly peak loads is based on multiple statistical simulation models that consider the economic, demographic and weather assumptions for the forecasting horizon. Major energy related events, pronounced trends in economic conditions, temperature, and change in consumers' energy consumption behaviors are considered to determine a range in which the ISO Control Area demand may fall.

The ISO 2003 summer base scenario of the peak demand forecast was developed using the following assumptions:

- Normal weather conditions,
- Weak economic conditions for the State of California,
- Increased unemployment rate,
- Declining activities in the technology sector,
- Increased consumer electric energy prices.

Given the uncertainty in predicting all the demand-determining factors such as energy prices, conservation efforts, weather conditions, and economic outlooks, etc., the actual demand in any given period is likely to vary significantly. Thus, a range forecast for an expected load is more meaningful and desirable from a statistical reasonableness and a decision-making point of view.

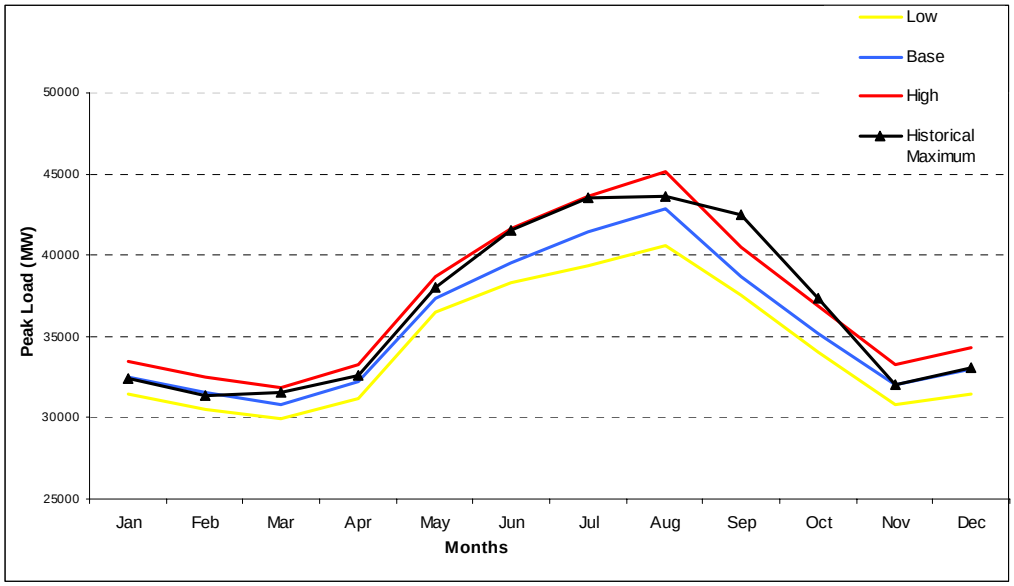
The three Load Forecast curves shown in Figure IV-A have a 95% confidence interval and were developed using the following assumptions:

- The High Case load forecast scenario assumes that the California economy will grow at a rate of 2.0% annually, and the temperature will be 10% higher above the weighted average peak hour temperature over the last 5 years.

- The Base Case or Baseline (most likely) operating load forecast was developed assuming that the California economy will grow at a rate of 1.25% annually, and the temperature will be at the weighted average peak hour temperature over the last 5 years.

- The Low Case scenario assumes that the California economy will grow less than one percent (0.05%), and the temperatures will be 10% below the weighted average peak hour temperature over the last 5 years.

Figure IV-A
Peak Demand Forecasts and Historical Demand for the ISO Control Area



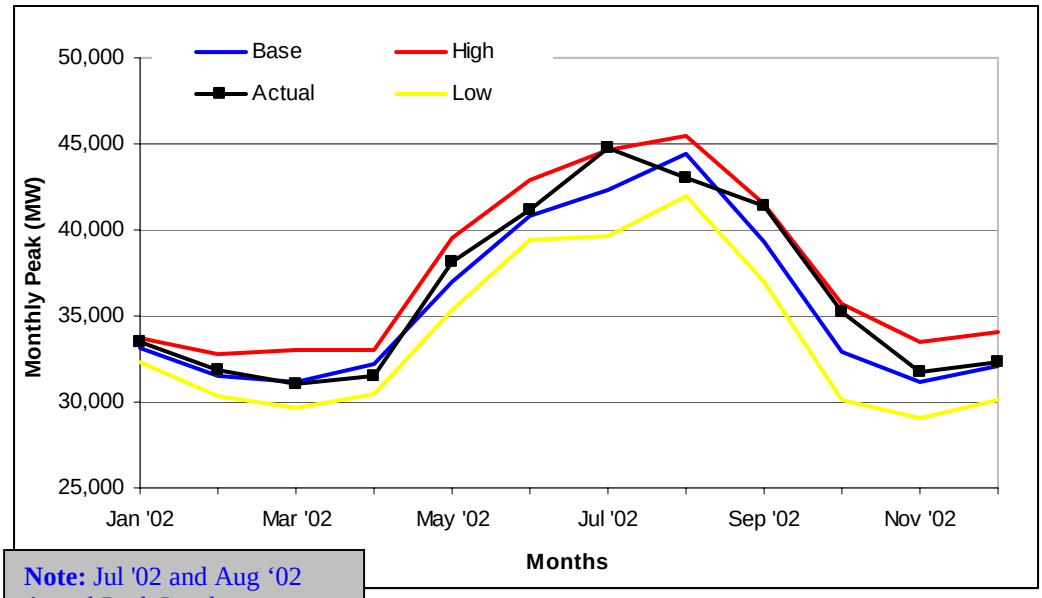
The Table IV-1 represents the ISO demand forecast by months for the three scenarios. The table also shows the dates and the historical maximum monthly peaks for a comparative evaluation.

Table IV-1
Peak Demand Forecasts and Historical Demand for the ISO Control Area
(Annual Peaks are in bold print)

	Peak Load Forecasts (MW)			Historical Peak Load (1998-2002)		
Month	**Low Scenario**	**Base Scenario**	**High Scenario**	**Date of Historical Peak**	**Historical Maximum (1998-2002) MW**	
					SMUD	**No SMUD**
January 2003	31,495	32,519	33,503	1/29/02	33,488	32,377
February 2003	30,474	31,529	32,531	2/22/00	32,394	31,353
March 2003	29,920	30,830	31,847	3/7/00	32,552	31,556
April 2003	31,220	32,188	33,281	4/13/00	33,991	32,598
May 2003	36,504	37,386	38,675	05/22/00	39,808	38,041
June 2003	38, 274	39,577	41,646	06/14/00	43,630	41,555
July 2003	39,375	41,477	43,624	07/12/99	**45,884**	**43,554**
August 2003	**40,624**	**42,894**	**45,185**	08/03/98	45,811	43,636
September 2003	37,569	38,708	40,455	09/03/98	44,442	42,536
October 2003	34,048	35,132	36,889	10/01/01	38,806	37,352
November 2003	30,788	32,037	33,293	11/27/00	33,338	32,033
December 2003	31,437	32,995	34,333	12/13/99	34,432	33,040

Deviations from the forecast can be seen when comparing the 2002 forecast to actual conditions, as shown in Figure IV-B. The variation from the base forecast is primarily due to an unexpected heat wave that occurred earlier than the normal heat wave pattern.

Figure IV-B
Actual Peak Demand vs. 2002 Monthly Peak Demand Forecast Range for January – December 2002



Note: Jul '02 and Aug '02 Actual Peak Loads were adjusted for SMUD. The System Peak occurred in July not in August as anticipated.

ISO Control Area Historical Peak Demand Levels

Table IV-2 shows the actual monthly instantaneous peak demand levels with estimated load interruptions added to actual peak demand served. On June 19, 2002 Sacramento Municipal Utility District (SMUD) became its own control area. ISO Control Area peak demand prior to June 2002 includes the SMUD load. Historical peak demand levels illustrate that the 2002 system peak demand (after being adjusted upward for SMUD - 45,220 MW) was lower than the historical peak demand (45,884 MW) experienced in the year 1999. The peak demand was 0.06% lower in the year 2002 as compared to the year 2000.

Table IV-2
Actual Monthly Instantaneous Peak Demand for June 1998 to December 2002
ISO Control Area
(Peak demand levels prior to June 2002 include SMUD Load. SMUD became its own control area on June 19, 2002 and thus the SMUD load is not included in the ISO Control Area Instantaneous Peak Demand.)

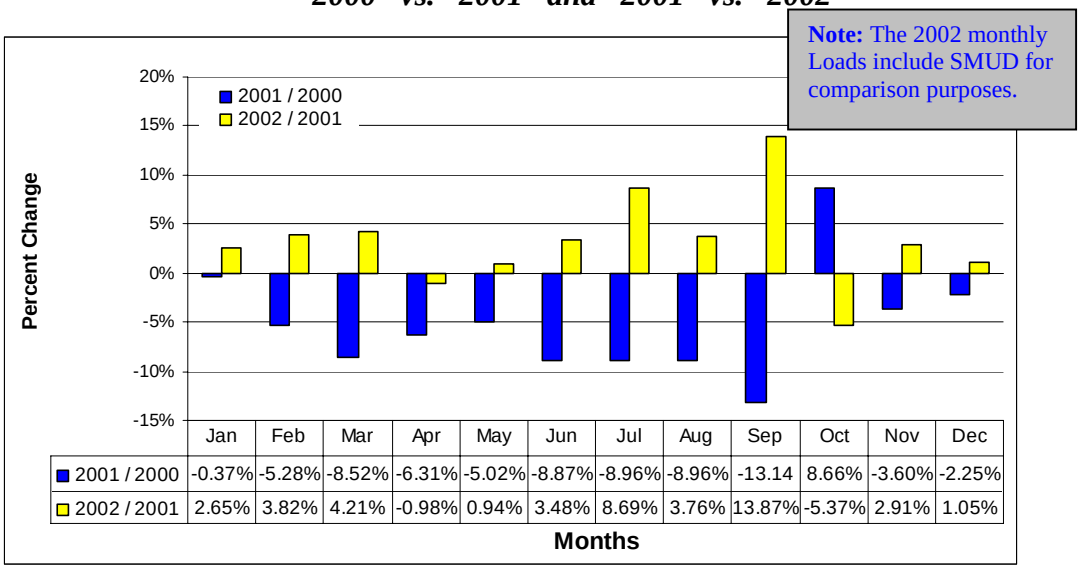
(MW)												
Year	January	February	March	April	May	June	July	August	September	October	November	December
1998						33,688	43,394	45,811	44,442	31,208	30,846	33,264
1999	31,419	31,532	31,146	31,174	34,698	40,937	45,884	44,005	40,188	36,772	32,860	34,432
2000	32,744	32,394	32,552	33,911	39,808	43,630	45,245	45,494	43,740	35,712	33,338	34,115
2001	32,623	30,683	29,778	31,770	37,808	39,762	41,192	41,419	37,993	38,805	32,138	33,347
2002	33,488	31,854	31,033	31,460	38,165	41,146	42,441	40,803	41,358	35,269	31,770	32,307
							SMUD is not part of ISO Control Area Load					

Change in Peak Demand

Figure IV-C shows the percentage change in monthly peak demand levels from the years of 2000-to-2001 and 2001-to-2002 period respectively for the ISO Control Area. The monthly changes in peak demand levels were positive in 2002 (relative to 2001) for all months except April and October. In 2001, monthly changes in peak demands from 2000 were negative - except for the month of October, where the peak demand increased to a historical maximum level because of a later than normal heat wave.

The September 2002 peak demand was 13.87% higher than the previous years peak demand. During September 2002, California experienced high temperatures (95 ^{0}F to 107 ^{0}F) across the State at the peak period.

Figure IV-C
Monthly Change in Peak Loads
ISO Control Area
"2000" vs. "2001" and "2001" vs. "2002"

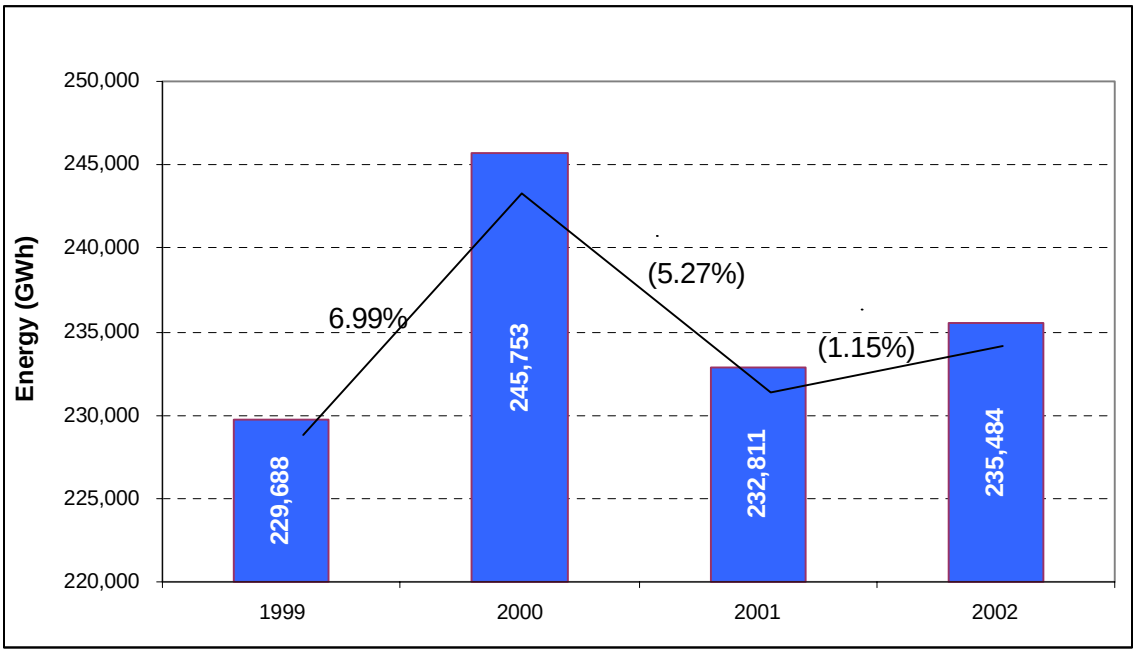


	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2001 / 2000	-0.37%	-5.28%	-8.52%	-6.31%	-5.02%	-8.87%	-8.96%	-8.96%	-13.14	8.66%	-3.60%	-2.25%
2002 / 2001	2.65%	3.82%	4.21%	-0.98%	0.94%	3.48%	8.69%	3.76%	13.87%	-5.37%	2.91%	1.05%

Historical Energy Growth

Figure IV-D represents the historical annual energy consumption, and an annual growth rate for the ISO Control Area during the1999-2002 period.

Figure IV-D
Annual Change in Energy Consumption
ISO Control Area
1999 to 2002



Ten-Year Forecast

A ten-year peak load forecast by month is shown in Table IV-3. The methodology used to forecast monthly peak loads is based on multiple statistical models that incorporate the last four year weighted average economic, demographic, and weather measurements. Any changes in assumptions or unforeseen circumstances may vary the forecasted results from actual loads. Risks and uncertainties in forecasting increase as the forecast period increases.

Table IV-3
Monthly Peak Load Forecast for the ISO Control Area (Base Case)

(MW)												
Year	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
2003	32,519	31,529	30,830	32,188	37,386	39,577	41,477	42,894	38,708	35,132	32,037	32,995
2004	34,867	32,786	32,541	33,481	38,338	42,184	43,637	45,794	40,501	35,661	33,843	34,855
2005	35,578	33,472	33,.230	34,165	39,040	42,875	44,289	46,477	41,144	36,328	34,524	35,528
2006	36,304	34,173	33,933	34,863	39,756	43,578	44,951	47,171	41,796	37,007	35,218	36,213
2007	37,044	34,888	34,651	35,575	40,485	44,293	45,623	47,875	42,459	37,699	35,927	36,912
2008	37,799	35,618	35,385	36,302	41,227	45,019	46,305	48,589	43,132	38,404	36,649	37,624
2009	38,570	36,363	36,134	37,044	41,982	45,757	46,998	49,314	43,816	39,123	37,386	38,350
2010	39,356	37,124	36,898	37,801	42,752	46,507	47,700	50,049	44,510	39,854	38,138	39,090
2011	40,158	37,900	37,679	38,574	43,535	47,270	48,413	50,796	45,216	40,600	38,905	39,845
2012	40,977	38,694	38,477	39,362	44,333	48,044	49,137	51,554	45,933	41,359	39,688	40,614
2013	41,813	39,483	39,261	40,165	45,237	49,024	50,139	52,605	46,870	42,202	40,497	41,442

Table IV-4 shows forecasted monthly energy consumption. The ten-year forecast for monthly energy growth is based on monthly load factors and the annual average compounded growth rate measured over the last four years.

Table IV-4
Monthly Energy Forecast for the ISO Control Area

(GWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**June**	**July**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2003	20,356	18,257	19,799	19,263	20,611	20,738	21,419	23,617	20,327	20,034	19,504	19,195
2004	20,802	18,514	20,078	19,535	21,287	21,453	21,823	24,082	20,603	20,388	19,764	19,615
2005	21,178	18,849	20,441	19,888	21,672	21,841	22,218	24,517	20,975	20,756	20,121	19,970
2006	21,561	19,190	20,811	20,248	22,064	22,236	22,620	24,961	21,355	21,132	20,485	20,331
2007	21,952	19,538	21,189	20,615	22,464	22,639	23,030	25,413	21,742	21,515	20,857	20,700
2008	22,351	19,893	21,573	20,989	22,872	23,050	23,448	25,875	22,137	21,906	21,235	21,076
2009	22,757	20,255	21,966	21,371	23,288	23,470	23,875	26,346	22,540	22,304	21,622	21,459
2010	23,172	20,624	22,366	21,761	23,712	23,897	24,310	26,826	22,950	22,711	22,016	21,850
2011	23,595	21,000	22,774	22,158	24,145	24,333	24,754	27,315	23,369	23,125	22,418	22,249
2012	24,026	21,384	23,191	22,563	24,587	24,778	25,206	27,815	23,797	23,548	22,827	22,656
2013	24,466	21,776	23,615	22,976	25,037	25,232	25,668	28,324	24,232	23,979	23,246	23,071

Some of the factors (e.g., changes in public policies, frequency of rate increases, and slow economic growth noted above) are likely to have some continuing effects on the system load demand. The impacts of unforeseen events, uncertain weather conditions or economic crisis are difficult to determine or predict.

Interruptible Load Programs

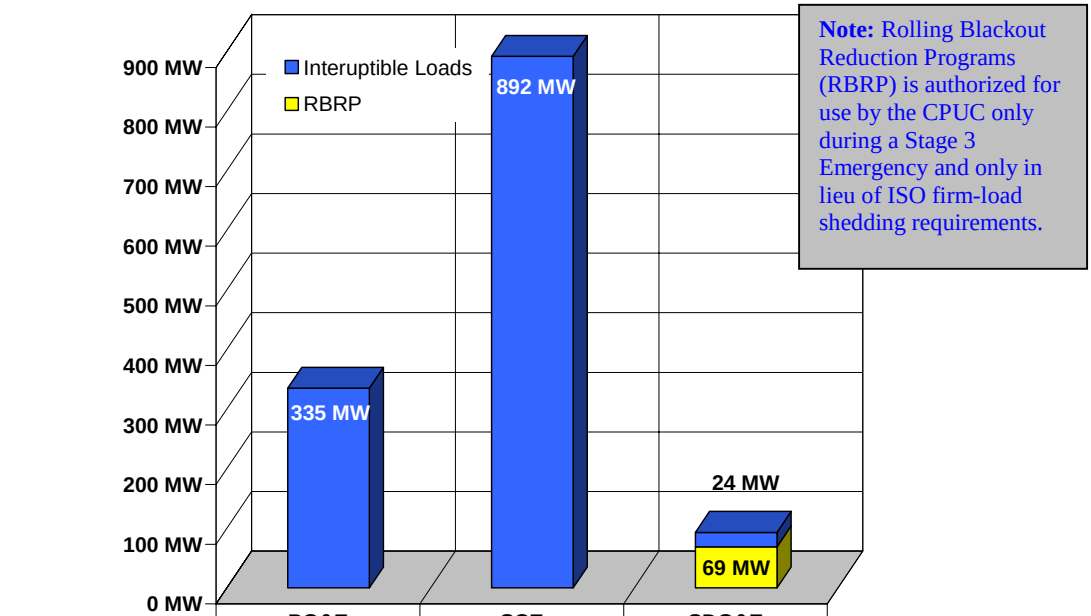
Interruptible Load programs offer system operators alternative means of balancing generation with load. By reducing demand, operators can directly offset the need for

additional generation supply. This alternative provides an effective and meaningful resource to address supply deficiencies and emergency conditions, as was the case in the year 2001.

Participation in interruptible load programs decreased as customers' reluctance to bear the risk of service disruption increased. In previous years, various programs provided up to 2,800 MW of interruptible load capacity. However, the same programs provided only 1,600 MW capacity in 2001, and 1,409 MW capacity in 2002. For the summer 2003, only 1,321 MW of interruptible load reduction capacity is available. Of the capacity available in the Summer of 2003, there are 69 MW of Rolling Blackout Reduction Programs (RBRP) that are authorized for use by the CPUC only during a Stage 3 Emergency and only in lieu of ISO firm-load shedding requirements. Figure IV-E shows the total load-reduction programs by Service Territory.

While the interruptible load programs account for the majority of load reduction capacity, program restrictions limit their availability to the ISO. These restrictions include limitations on the number of activations per day (which for most may not exceed one) and the number of activations per year for most programs. Customers participating in the interruptible load programs are limited to commercial, industrial, agricultural, and air conditioning loads.

Figure IV-E
Interruptible Load Program Capacity by Service Territory
Summer 2003



	PG&E	SCE	SDG&E
Interuptible Loads	335 MW	892 MW	24 MW
RBRP	0 MW	0 MW	69 MW

In addition to the interruptible load programs, participants can submit firm load interruption bids to the ISO. The California Department of Water Resources (DWR)

participate in this program by submitting bids to interrupt State water pumps. Historically, the ISO was able to mitigate reserve shortages by dispatching the interruption of over 300 MW of DWR pumps.

V. Transmission Assessment

Introduction

In general, the transmission system is expected to demonstrate adequate operating margins for the Summer 2003. Use of the transmission system is directly related to load conditions, net import levels, and generating levels of resources. The ISO Control Grid is made up of transmission systems consisting of numerous utilities and was constructed over the last 100 years. Generation has been added to the system over this same period by both utilities and investors. There are as many differences in the design, and in the operations requirements as there are interconnection points. In addition, over the years, a variety of agencies have also influenced the planning, design, location and approval of new projects. The ISO on a daily basis is responsible for overseeing and managing reliability within the ISO Control Grid, and within the interconnected control area. The ISO works closely with generators and utilities to maintain reliability of the grid. Reliable Must Run (RMR) contracts with generators in congested areas are used to maintain local reliability. Managing the system each year becomes more and more difficult—as system loads increase, as new generation comes on line, and as the addition of major capacities adjourn lagging behind the system needs. The following sections provide a brief assessment of the bulk transmission, and local area grid conditions within the ISO Control Area for the Summer 2003 period.

Bulk Transmission Operating Transfer Capability

In WECC, Operating Transfer Capability (OTC) limits are established on a seasonal basis through a process administered by the WECC OTC Policy Committee. The critical paths in the California-Mexico (CA-MX) sub-region, and the 2003 Summer maximum Operating Transfer Capabilities are:

- California-Oregon Intertie (COI) – 4,800 MW North-to-South and 3,675 MW South-to-North
- Pacific Direct Current Intertie (PDCI) – 3,100 MW North-to-South and 3,100 MW (2,200 MW Scheduling Limit) South-to-North
- Southern California Import Transmission (SCIT) – 15,200 MW
- Path 26 – 3,000 MW North-to-South, 3,000 MW South-to-North
  A station fire at the Vincent substation on March 21, 2003 destroyed one of the 3 500/220 kV transformers. It is expected that for most of the summer, Vincent substation will be operating with the remaining 2 500/220 kV transformers. This configuration will limit the Path 26 North-to-South OTC to 2,500 MW. Special operating procedures have been established to operate the system reliably for this configuration. The OTC of Path 26 in the North-to-South direction will return to3,000 MW when the third 500/220 kV transformer is in-service[7].
- Path 15 – 3,950 South-to-North
- Path 45 (408 MW North-to-South, 800 MW South-to-North)

[7] It is estimated that the third bank at the Vincent substation will be replace at the end of July at the earliest.

The COI, PDCI, SWPL, WOR, and SCIT Operating Transfer Capabilities limit imports into the CA-MX sub-region. Path 45 OTC limits transfers between SDG&E and the Comision Federal de Electricidad (CFE) in Mexico. Path 15 OTC limits South-to-North flow within the PG&E area, while the Path 26 OTC limits flow on the Midway-Vincent Lines (between SCE and PG&E service territories).

East-of-River (Path 49) and Hassayampa-North Gila flow is expected to increase this summer with expected new generation coming on line at Hassyampa. The capacity of Path 49 will be sufficient to import energy from the east.

The SCIT OTC will increase from 14,500 to 15,200 this summer.

Forecasted Local Area Grid Conditions

The ISO Operations Engineering team continues to analyze the seasonal grid conditions for local areas, and update operating procedures (as needed) to address special seasonal conditions, constraints, and/or recent changes in the local area systems. Operating procedures are reviewed and revised with the objective of improving system reliability, minimizing the complexity of operation, maximizing operational flexibility and minimizing operating costs.

During summer peak, generation resources on the ISO Grid are generally not limited by congestion within the 60-230 kV local area subtransmission systems. (Two exceptions are the recent surge of new generators in the San Diego/Mexico area and the Los Esteros Critical Energy Facility in the PG&E service territory.) Specifically, congestion concerns and heavy loading of outlying transmission lines commonly result when high generation output occurs concurrently with low local area loads and/or local outages of transmission facilities. These congestion bottlenecks are typically mitigated by increasing or limiting generation on either side of the constraint. In 2002 , the ISO identified over 50 routinely-occurring local area bottlenecks[8]; some require a minimum amount of generation (often addressed through Reliability Must-Run units) while others require curtailment of generation (real-time intra-zonal congestion). The summer 2003 status for various constrained areas is summarized below.

Humboldt Area

Humboldt is primarily a winter peaking area. However, during summer months the Humboldt area still faces stability, voltage collapse, and thermal overload issues. These problems are further compounded by the reduced level of availability of the area generation due to age, generator maintenance outages, and potential shortages or limitations of fuel (natural gas, oil, wood chip). The ISO continues to work with PG&E to improve local area reliability by maintaining an adequate level of local area generation, and pursuing generation and transmission improvement projects.

[8] Additional constraints frequently arise as temporary conditions during local area clearances.

San Francisco Peninsula and Greater Bay Area

For Summer 2003, the Greater San Francisco Bay Area (Bay Area) will once again experience numerous upgrades/changes. Major projects expected by June 2003 include:

- Tesla 500/230kV, 1122MVA Transformer #6 in June 2003 (Completion of 2002 Project)
- Metcalf 500/230kV, 1122MVA Transformer #13 in May 2003
- Metcalf 230/115kV, 420MVA Transformer #4 in May 2003
- Monta Vista 230/115kV, 420 MVA Transformer #3 completed in March 2003
- Pittsburg 230/115kV, 420MVA Transformer #12 replacement in May 2003
- Los Esteros 230/115 kV substation in July 2003
- San Jose B-FMC Jct. 115kV line reconductoring in July 2003
- Pittsburg-Martinez 115kV line reconductoring in April 2003
- Ravenswood-San Mateo 230kV #2 line bundling (completed in December 2002)
- Retirement of Newark synchronous condensers #3-8 (January 2003)
- Tri Valley Project, new 230kV facilities in May 2003

The new 195 MW Los Esteros Critical Energy Facility, Units 1-4 is limited due to incomplete transmission additions. Until construction of the transmission is complete, the generator may need to be curtailed by 45 MW during high temperature, peak load conditions with no transmission outages. When all the City of Santa Clara generating units are on line, the unit will need to be curtailed by 98 MW.

Initial analysis indicates that although these transmission changes generally improve some performance aspects of the Bay Area system, there remain a few select contingencies where the Bay Area could still experience local transmission line and transformer bank overloads, and/or low local area voltages. In particular, combinations of high generation patterns in this area coupled with low local area loads are prone to heavy transmission line loadings and congestion concerns. Studies are currently in progress, to update the San Francisco and Bay Area procedures (and any local response plans), to reflect these new changes in the transmission system.

Fresno Area and Southern PG&E Area

No significant thermal overloads or under-voltage problems are anticipated for the Fresno and Southern PG&E Area under normal operating conditions. However, some isolated overload or voltage concerns in local 70kV or 115kV areas are expected, mainly due to transformer outages. The ISO Operations Engineering team is working closely with the PG&E Planning and Operations groups to improve the current situation. Other changes include reinforcement of a number of 115 kV transmission lines, expected to be complete in the Fresno area before Summer 2003. This reinforcement work is needed to help accommodate the output of multiple new Fresno generation projects, including the recent addition of at least six new gas turbines (20-50 MW each). Other new local generation additions include La Paloma Units 1-4, and the Elk Hills project.

Southern California Edison (SCE) Area
There is a potential for overload on the South of Lugo path during normal system conditions in the 2003 summer season. The maximum allowable flow on South of Lugo is 4,400 MW for 2003 summer. With the loss of 770 MW of generation in the SCE area[9], the chance of overloading south of Lugo path is increased.

The following is a list of transmission upgrades scheduled for completion by June 1, 2003:

- The third Valley 500/115 kV transformer bank;
- 79 MVAR shunt cap each at Mesa, Laguna Bell and La Fresa substations.

These transmission projects generally improve the performance and operating flexibility of the SCE system, and mitigate forecasted reliability concerns within the local area.

San Diego Gas and Electric (SDG&E) Area
Due to transmission limitations, about a 1000 MW of the summer peak load can only be met from the additional 1070 MW of new generation coming into ISO's Imperial Valley substation from Mexico, 590 MW[10] of new generation coming into CFE's LA Rosita substation and over 3000 MW[11] of new generation coming in Arizona at Hassayampa. A new nomogram will limit the combined generation from Imperial Valley and imports from CFE to 800 MW. The nomogram will also allow only 200 MW of additional (above previous years) imports from Arizona on the SWPL.

The 1070 MW generation coming into ISO's Imperial Valley Substation from Mexico consists of two power plants of 600 MW and 470 MW[9]. There are no additional transmission lines (besides the generator interconnection lines) and very little equipment upgrades. Special Protection Systems (SPS's) to trip the new generation have been installed to allow generation from these plants

Due to severe transmission constraints, a new operating nomogram has been developed to identify the area of reliable operation under the simultaneous IV Generation and import/export from Arizona, Comision Federal de Electricidad and/or Imperial Irrigation District.

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[9] The following generation in the SCE area retired or mothballed in 2002: High Grove units 1-4; San Benardino units 1&2; Etiwanda units 1&2; El Segundo units 1&2; Broadway units 1&2.

[10] There is an export bus between La Rosita I (Ciclo Combinado Mexicali) 750 MW plant located in CFE control area and the LA Rosita 2 plant connected to Imperial Valley in ISO control area. This allows one 160 MW CT to be switched from CFE control area to La Rosita 2 Plant in ISO control Area. When the 160 MW CT is switched to the export bus, the capacity of La Rosita I (Ciclo Combindado Mexicali) plant in CFE control area is 590 MW and the capacity of La Rosita 2 plant in ISO control area is 470 MW.

[11] There is over 3,000 MW of new generation that is being built in the Arizona, which exceeds Arizona's load growth.

Internal to SDG&E, a new 230 kV breaker and a half bus scheme with transmission line re-arrangement have been recently added at San Luis Rey 230 kV substation. As a result, scheduling of outages in-and-around this area will be less restrictive and require less RMR generation. The reconductoring of transmission line 649F (Border Tap - Otay Lake Tap 69 kV line) is anticipated to be complete by June 2003. This will significantly reduce the frequency of the Border Peakers Remedial Action Scheme (RAS) from operating.

VI. Description of the ISO Control Area[12]

The ISO is a non-profit public benefit corporation organized under the laws of the State of California and responsible for the reliable operation of a grid comprising the transmission system of investor owned utilities in California including Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas and Electric Company (SDG&E), and a number of Municipal Utilities. The ISO also coordinates competitive ancillary services and real-time electricity markets in California.

The ISO provides service to generators, Participating Transmission Operators, Utility Distribution Companies, Metered Subsystems, and other load serving entities. ISO Control Area (shown in Figure VI-A below) geographically includes most, but not all, of California.

The Participating Transmission Operators (PTO) in the ISO Control Area are:

- PG&E
- SCE
- SDG&E
- City of Vernon
- City of Anaheim
- City of Azusa
- City of Banning
- City of Riverside

All PTO's are also Utility Distribution Companies (UDC). In addition to the PTO's other UDC's are:

- City of Pasadena
- Lassen Municipal Utility District

Metered Subsystem (MSS) customers in the ISO Control area are:

- Northern California Power Authority
- The City of Roseville
- Silicon Valley Power

Other Load Serving Entities that the ISO provides services for are:

- Western Area Power Administration
- The California Department of Water Resources
- The Metropoliton Water District of Southern California
- Modesto Irrigation District
- Turlock Irrigation District
- City of Redding
- City of Shasta Lake

[12] A control area is defined as a geographic area that regulates its generation in order to balance load and maintain planned interchange schedules with other control areas and assists in controlling the frequency of the interconnected system in accordance with WECC and NERC criteria.

- City of Colton
- Port of Oakland
- Merced Irrigation District
- City of Hercules
- McAllister Ranch Irrigation Distrity, and
- City of Industry

In addition, there are a few smaller customers that are load serving entities or transmission operators that are not mentioned here.

Other Control Areas within the state that are not in the ISO Control Area are Los Angeles Department of Water and Power (LDWP), PacifiCorp (PAC), Imperial Irrigation District (IID), Sierra Pacific Power (SPP), and Sacramento Municipal Utility District (SMUD). These Control Areas are shaded in dark brown in Figure VI-A.

Table VI-A
ISO Control Area

VII. Non-Coincidental Peak Load and Resource Assessment by Region

The ISO is responsible for providing reliable operation of the transmission system for all Participating Transmission Operators (PTO), Utility Distribution Companies (UDC), Metered Subsystems (MSS), and other Load Serving Entities that fall within the ISO Control Area. This report includes a regional assessment for greater congestion granularity. The three regions whose transmission was managed by Investor Owned Utilities (IOUS) prior to the formation of the ISO are Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas and Electric (SDG&E).

Each of these regions has internal constraints that may limit power flow between Service Territories.

> **The Pacific Gas and Electric (PG&E)** region includes PG&E as well as Northern California Power Authority (NCPA), City of Roseville, Silicon Valley Power (SVP), Modesto Irrigation District, Turlock Irrigation District, Western Area Power Administration (WAPA), City of Redding, City of Palo Alto, and City of Shasta Lake areas.
>
> **The Southern California Edison (SCE)** region includes SCE load as well as load in the Metropolitan Water District, and City of Banning, City of Anaheim, City of Azusa, City of Riverside, City of Colton, and City of Vernon areas.
>
> **San Diego Gas and Electric (SDG&E)** represents the third service territory.

Future assessments will provide a greater granularity assessment of the region South and North of Path 15, the PTOs, and the MSSs.

Figure VII-A
Regions within the ISO Control Area[13]

Pacific Gas and Electric Peak Load and Resource Forecast

For the Summer 2003, it is expected that the generation resources in the PG&E region, including the new generation that is currently being constructed, could potentially serve the entire PG&E region forecasted peak capacity requirement without imports. The previous all time summer peak capacity requirement for the PG&E region was 21,833 MW in June 2000[14]. The anticipated Summer 2003 peak demand of 21,414 MW is a value less than previous years. The decline in Information Technology Business sector mostly affects the demand for electricity in the Pacific Gas and Electric region.

Table VII-1 provides a summary of the PG&E region peak load and resource forecast for May 2003 to October 2003.

[13] A Map that details the ISO Deamnd Zone can be found at *http://www.caiso.com/docs/1999/11/16/1999111609190129611.pdf*

[14] The all time peak load for PG&E of 21,833 MW does not include SMUD load.

Table VII-1
PG&E Region Peak Load and Resource Forecast Summary for Summer 2003

	(MW)	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03
1	Forecasted Peak Demand - (Base Case)	17,966	20,511	21,414	21,366	18,829	16,071
2	Operating Reserve Requirement	2,038	2,079	2,084	2,097	2,107	2,107
3	Estimated Service Area Capacity Requirement	20,004	22,590	23,498	23,463	20,936	18,178
	Capacity						
4	Maximum Net Dependable Capacity of Participating Thermal Units	15,499	15,499	15,499	15,499	15,499	15,499
5	Maximum Capacity of Non-Participating Thermal Units	3,647	3,647	3,647	3,647	3,647	3,647
6	Maximum Capacity of Muni Thermal Units	358	358	358	358	358	358
7	Maximum Capacity of Solar Units	-	-	-	-	-	-
8	Maximum Net Dependable Capacity of Pump Storage Units	2,527	2,527	2,527	2,527	2,527	2,527
9	Maximum Capacity of Hydro Units	7,170	7,170	7,170	7,170	7,170	7,170
10	Maximum Capacity of Wind Units	945	945	945	945	945	945
11	Accumulative New Generation Capacity (after March 10, 2003)	725	1,354	1,422	1,622	1,772	1,772
12	**Total Capacity of Generators located in the ISO Control Area**	**30,871**	**31,500**	**31,568**	**31,768**	**31,918**	**31,918**
13	Net Dynamic Schedules into the PGAE Service Area	-	-	-	-	-	-
14	**Total Generation Capacity including Dynamic Schedules**	**30,871**	**31,500**	**31,568**	**31,768**	**31,918**	**31,918**
	De-Rates						
15	Scheduled Participating Thermal Outages	(1,890)	(105)	(53)	-	(312)	(643)
16	Scheduled Pump Storage Outages	(547)	(40)	-	(15)	(30)	(537)
17	Estimated Forced Outages (Participating Thermal including Pumped Storage)	(1,603)	(1,603)	(1,603)	(1,603)	(1,603)	(1,603)
18	Estimated Non-Participating and Muni Thermal Limitations	(2,142)	(2,142)	(2,142)	(2,142)	(2,142)	(2,142)
19	Estimated Hydro Limitations	(847)	(1,693)	(1,693)	(2,116)	(2,540)	(3,386)
20	Wind Limitations	(945)	(945)	(945)	(945)	(945)	(945)
21	Accumulative New Generation Limitations			-	-	(150)	(150)
22	Accumulative Retirements	-	-	-	-	-	-
23	Environmental Constraints	(195)	(195)	(195)	(195)	(195)	(195)
24	**Total Generation Limitations**	**(8,169)**	**(6,724)**	**(6,632)**	**(7,017)**	**(7,917)**	**(9,602)**
25	Estimated Control Area Resource Capacity (at time of peak)	22,702	24,777	24,937	24,752	24,001	22,316
26	**Net Import Requirement**	**(2,698)**	**(2,187)**	**(1,439)**	**(1,289)**	**(3,066)**	**(4,139)**

Note: The PG&E, SCE, and SDG&E region Peak Load forecast are non-coincidental to the Total ISO Control Area Peak Load forecast.

Although the ISO forecasts generation surplus in the PG&E region, local transmission constraints require that 24% of the generation capacity has a Reliable Must Run Contract (RMR) to maintain local area reliability.

Southern California Edison Company Peak Load and Resource Forecast

The resource mixture to serve the SCE region is made up of local generation, dynamically scheduled imports for SCE-owned generation outside of the ISO Control Area, and imports from other Service Territories and/or control areas outside of the ISO.

Southern California counties around Los Angeles, Riverside, Orange and San Diego are expected to have economic expansion. The unemployment rate in these counties ranges from 4 to 5.5 percent, far below the State average (6.4%). An increase in investments is expected for commercial construction, defense and security technologies, and the residential housing sector. Although the ISO anticipates the overall State demand for electricity to decrease, the 2003 peak demand for the SCE region is anticipated to increase to 19,448 MW. (The previous all time summer peak for SCE was 19,329 MW in July 2000.)

Table VII-2 provides a summary of the SCE region peak load and resource forecast for May 2003 to October 2003.

Table VII-2
SCE Region Peak Load and Resource Forecast Summary for Summer 2003

	(MW)	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03
1	Forecasted Peak Demand - (Base Case)	16,574	17,606	18,808	18,851	19,448	17,130
2	Operating Reserve Requirement	1,417	1,474	1,474	1,474	1,474	1,474
3	Estimated Service Area Capacity Requirement	17,991	19,080	20,282	20,325	20,922	18,604
	Capacity						
4	Maximum Net Dependable Capacity of Participating Thermal Units	13,478	13,478	13,478	13,478	13,478	13,478
5	Maximum Capacity of Non-Participating Thermal Units	4,020	4,020	4,020	4,020	4,020	4,020
6	Maximum Capacity of Muni Thermal Units	44	44	44	44	44	44
7	Maximum Capacity of Solar Units	469	469	469	469	469	469
8	Maximum Net Dependable Capacity of Pump Storage Units	233	233	233	233	233	233
9	Maximum Capacity of Hydro Units	1,301	1,301	1,301	1,301	1,301	1,301
10	Maximum Capacity of Wind Units	729	729	729	729	729	729
11	Accumulative New Generation Capacity (after March 10, 2003)	4	869	871	871	871	874
12	**Total Capacity of Generators located in the ISO Control Area**	**20,278**	**21,143**	**21,145**	**21,145**	**21,145**	**21,148**
13	Net Dynamic Schedules into the PGAE Service Area	1,192	1,192	1,192	1,192	1,192	1,192
14	**Total Generation Capacity including Dynamic Schedules**	**21,470**	**22,335**	**22,337**	**22,337**	**22,337**	**22,340**
	De-Rates						
15	Scheduled Participating Thermal Outages	(1,833)	(367)	(47)	(47)	(1,268)	(1,818)
16	Scheduled Pump Storage Outages						
17	Estimated Forced Outages (Participating Thermal including Pumped Storage)	(1,220)	(1,220)	(1,220)	(1,220)	(1,220)	(1,220)
18	Estimated Non-Participating and Muni Thermal Limitations	(2,173)	(2,173)	(2,173)	(2,173)	(2,173)	(2,173)
19	Estimated Hydro Limitations	(154)	(307)	(307)	(384)	(461)	(614)
20	Wind Limitations	(729)	(729)	(729)	(729)	(729)	(729)
21	Accumulative New Generation Limitations			-	-	-	-
22	Accumulative Retirements	-	-	-	-	-	-
23	Environmental Constraints	(203)	(203)	(203)	(203)	(203)	(203)
24	**Total Generation Limitations**	**(6,312)**	**(4,999)**	**(4,679)**	**(4,756)**	**(6,054)**	**(6,757)**
25	Estimated Control Area Resource Capacity (at time of peak)	15,158	17,336	17,658	17,581	16,283	15,583
26	**Net Import Requirement**	**2,833**	**1,744**	**2,624**	**2,744**	**4,639**	**3,022**

The SCE region transmission constraints are less than those seen in the PG&E and SDG&E regions, with 2% of the total generation capacity being under an RMR contract to maintain local area reliability.

San Diego Gas and Electric Peak Load and Resource Forecast

The resource mixture to serve the SDG&E region is made up of local generation, dynamically scheduled imports for SDG&E owned generation outside of the ISO Control Area, and imports from other regions and/or control areas outside of the ISO. New generation in the SDG&E region has increased significantly; however, transmission constraints are expected to limit the ISO from realizing the full capacity of these resources.

The 2003 peak demand for electricity in the SDG&E region is expected to increase to 3,828 MW due to economic expansion in San Diego because of defense and security-related investments. The previous all time summer peak for SDG&E was 3,970 MW in August 1998.

Table VII-3 provides a summary of the SDG&E region peak load and resource forecast for May 2003 to October 2003.

Table VII-3
SDG&E Service Territory Peak Load and Resource Forecast Summary for Summer 2003

	(MW)	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03
1	Forecasted Peak Demand - (Base Case)	3,031	3,172	3,395	3,769	3,828	3,141
2	Operating Reserve Requirement	189	189	189	228	228	228
3	Estimated Service Area Capacity Requirement	3,220	3,361	3,584	3,997	4,056	3,369
	Capacity						
4	Maximum Net Dependable Capacity of Participating Thermal Units	1,991	1,991	1,991	1,991	1,991	1,991
5	Maximum Capacity of Non-Participating Thermal Units	345	345	345	345	345	345
6	Maximum Capacity of Muni Thermal Units	-	-	-	-	-	-
7	Maximum Capacity of Solar Units	0	0	0	0	0	0
8	Maximum Net Dependable Capacity of Pump Storage Units	-	-	-	-	-	-
9	Maximum Capacity of Hydro Units	-	-	-	-	-	-
10	Maximum Capacity of Wind Units	-	-	-	-	-	-
11	Accumulative New Generation Capacity (after March 10, 2003)	475	475	475	1,075	1,075	1,075
12	**Total Capacity of Generators located in the ISO Control Area**	**2,811**	**2,811**	**2,811**	**3,411**	**3,411**	**3,411**
13	Net Dynamic Schedules into the SDGE Service Area	49	49	49	49	49	49
14	**Total Generation Capacity including Dynamic Schedules**	**2,860**	**2,860**	**2,860**	**3,460**	**3,460**	**3,460**
	De-Rates						
15	Scheduled Participating Thermal Outages	(797)	(330)	(330)	(330)	-	(505)
16	Scheduled Pump Storage Outages	-	-	-	-	-	-
17	Estimated Forced Outages (Participating Thermal including Pumped Storage)	(177)	(177)	(177)	(177)	(177)	(177)
18	Estimated Non-Participating and Muni Thermal Limitations	(184)	(184)	(184)	(184)	(184)	(184)
19	Estimated Hydro Limitations	-	-	-	-	-	-
20	Wind Limitations	-	-	-	-	-	-
21	Accumulative New Generation Limitations				(275)	(425)	(575)
22	Accumulative Retirements	-	-	-	-	-	-
23	Environmental Constraints	-	-	-	-	-	-
24	**Total Generation Limitations**	**(1,158)**	**(692)**	**(692)**	**(967)**	**(787)**	**(1,442)**
25	Estimated Control Area Resource Capacity (at time of peak)	1,702	2,169	2,169	2,494	2,674	2,019
26	**Net Import Requirement**	**1,518**	**1,192**	**1,415**	**1,504**	**1,383**	**1,351**

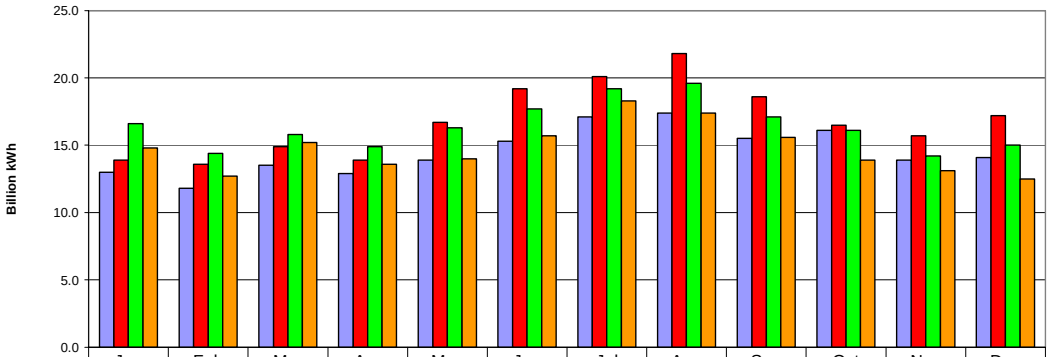
The SDG&E region transmission constraints require 70% of the current internal generation capacity to have a RMR contract to maintain local area reliability. Much of the new generation being built in the SDG&E region is constrained due to transmission limitations.

VIII. Summary of ISO Historical Resources for Energy

Historical Generation

The actual total monthly energy produced by generating facilities within the ISO Control Area was lower in 2002 than for the corresponding same month in 2001 (See Figure VIII-A). Over the past four years, the highest monthly total energy generated from resources within the ISO Control Area was 20.73 billion kWh in August 2000[15]. By comparison, the energy generated in the year 2002 during August is 17.4 billion kWh, or 16% less than this all time high.

Figure VIII-A
Monthly Generation Comparison from 1999 through 2002
(Generation after June 19,2002 does not include SMUD generation)



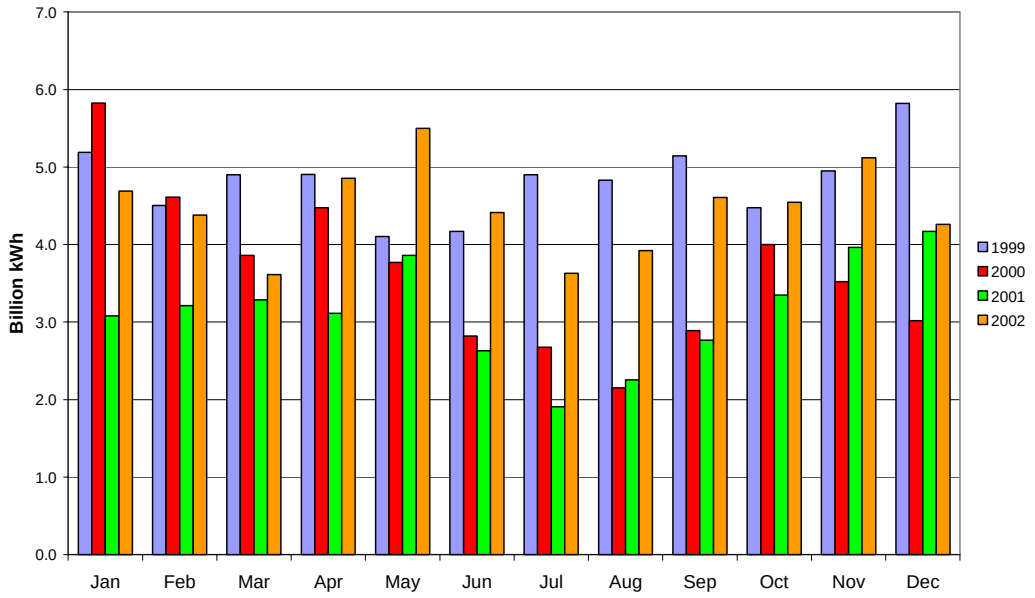
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1999	13.0	11.8	13.5	12.9	13.9	15.3	17.1	17.4	15.5	16.1	13.9	14.1
2000	13.9	13.6	14.9	13.9	16.7	19.2	20.1	21.8	18.6	16.5	15.7	17.2
2001	16.6	14.4	15.8	14.9	16.3	17.7	19.2	19.6	17.1	16.1	14.2	15.0
2002	14.8	12.7	15.2	13.6	14.0	15.7	18.3	17.4	15.6	13.9	13.1	12.5

Historical Net Interchange

The net interchange is the sum of the inflows and outflows of the ISO Control Area and includes dynamic schedules. The imports and exports do not include energy that passes through the ISO Control Area from one control area to another. The import and export data shown in Figure VII-B is developed using raw data prior to small adjustments for control area balancing. Although energy delivered by generators in the ISO Control Area has declined over the last year, Net Imports have increased.

[15] The all time high of 20.73 MW is adjusted to remove SMUD. SMUD had generated 1.02 billion kWh at that time.

Figure VII-B
Monthly Net Import Comparison from 1999 through 2002
(Does not include wheeled energy[16] or adjustments for control area settlements.)



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1999												
Imports	5.92	5.19	5.52	5.33	4.93	5.07	6.24	6.16	6.22	5.42	5.87	6.57
Exports	(0.73)	(0.69)	(0.62)	(0.42)	(0.81)	(0.90)	(1.33)	(1.32)	(1.08)	(0.95)	(0.92)	(0.75)
Net	5.19	4.51	4.90	4.91	4.12	4.17	4.91	4.84	5.14	4.47	4.95	5.82
2000												
Imports	6.64	5.44	4.67	5.08	5.11	5.02	5.41	5.54	5.31	5.36	5.34	5.43
Exports	(0.81)	(0.83)	(0.81)	(0.61)	(1.34)	(2.20)	(2.73)	(3.38)	(2.42)	(1.36)	(1.82)	(2.41)
Net	5.82	4.61	3.86	4.47	3.77	2.82	2.68	2.16	2.89	4.00	3.52	3.02
2001												
Imports	4.99	5.36	5.20	4.83	5.29	4.12	3.87	4.19	3.87	4.14	4.85	4.90
Exports	(1.91)	(2.15)	(1.92)	(1.72)	(1.43)	(1.49)	(1.97)	(1.93)	(1.10)	(0.80)	(0.88)	(0.73)
Net	3.08	3.21	3.28	3.11	3.86	2.63	1.90	2.26	2.77	3.34	3.96	4.17
2002												
Imports	5.37	4.99	4.13	5.34	6.14	5.78	5.60	5.45	5.67	5.35	6.05	5.39
Exports	(0.69)	(0.61)	(0.51)	(0.48)	(0.64)	(1.36)	(1.97)	(1.53)	(1.07)	(0.81)	(0.94)	(1.13)
Net	4.69	4.38	3.61	4.85	5.50	4.41	3.63	3.92	4.60	4.55	5.12	4.26
						Includes Net Exports to SMUD beginning 6/19/02						

[16] Wheeled Energy - Energy that passes through the ISO Control Area from one control area to another and does not serve any load in the ISO Control Area.

Glossary of Terms and Acronyms

Term/Acronym	Definition
APCD	Air Pollution Control District
APS	Arizona Public Service
AQMD	Air Quality Management District
BACT	Best Available Control Technology
CA-MX	California-Mexico
CARB	California Air Resources Board
CEC	California Energy Commission
CFE	Comision Federal de Electricidad
CO	Carbon Monoxide
COI	California-Oregon Intertie
Control Area	A geographic area that regulates its generation in order to balance load and maintain planned interchange schedules with other control areas and assists in controlling the frequency of the interconnected system in accordance with the WECC and NERC criteria.
CPUC	California Public Utility Commission
DWR	California Department of Water Resources
EMS	ISO Energy Management System
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IID	Imperial Irrigation District
IOU	Investor Owned Utility – a utility entity whose assets are owned by investors
ISO	California Independent System Operator
LDWP	Los Angeles Department of Water and Power
MID	Modesto Irrigation District
MSA	Metered Subsystem Agreement
MUNI	Municipal Utility
NCPA	Northern California Power Authority
NDC	Net Dependable Capacity – defined as the power level that a Generator Unit can sustain, on average, measured at or compensated to the Point of Delivery to the electric grid by both telemetry and ISO revenue metering systems if there are no equipment, operating or regulatory restrictions. It is mathematically equal to Gross Dependable Capacity minus any capacity utilized for the unit's Auxiliary Load, On-Site Load if applicable, and Step-Up Transformer and Project Transmission Losses. If the Generating Unit provides Ancillary Services, the Net Dependable Capacity must be tested and certified by the ISO.
NERC	North American Electric Reliability Council
NEVP	Nevada Power Company

Term/Acronym	Description
NOx	Oxides of Nitrogen
OTC	Operating Transfer Capability
PAC	PacifiCorp
PDCI	Pacific DC Intertie
PG&E	Pacific Gas and Electric Company
PGA	Participating Generator Agreement
QF	Qualifying Facilities
RBRP	Rolling Blackout Reduction Programs
RMR	Reliable Must Run Contract
SCE	Southern California Edison
SCIT	Southern California Import Transmission
SCR	Selective Catalyst Technology
SDG&E	San Diego Gas and Electric Company
SLIC	Scheduling and Logging for the ISO and California database
SMUD	Sacramento Municipal Utility District
SOX	Oxides of Sulfur
SPP	Sierra Pacific Power
SRP	Salt River Project
SVP	Silicon Valley Power
SWPL	South West Power Link
TID	Turlock Irrigation District
Time of Daily Peak	Is defined as the time that the ISO Control Area Coincidental Peak Load occurred each day.
UDC	Utility Distribution Company
VOC	Volatile Organic Compounds
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
Wheeled Energy	Energy that passes through the ISO Control Area from one control area to another and does not serve any load in the ISO Control Area.
WOR	West of River