California Electricity Price Spikes: An Update on the Facts

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Executive Summary

When prices for a product like electricity spike to previously unknown levels, people want to know why. However, in the rush to find a reason it is easy to make mistakes and jump to conclusions before all of the facts are known. A balanced understanding of the causes of high electricity prices in California and the West[1] starting in the summer of 2000, and continuing until the beginning of the summer of 2001 requires a systematic look at the facts. This requires time, and the information that is now available contradicts many early conclusions regarding the causes of the high prices.

When electricity prices rose in California and the West during the period from May 2000 to June 2001, some analysts blamed the rise on the exercise of market power. For example, Robert McCullough concluded in an article that appeared in *Public Utilities Fortnightly* that the high prices in the summer of 2000 could not be explained by changes in the fundamental factors that affect electricity prices, such as load levels, the availability of hydroelectric generation, fuel prices, or the demand/supply balance.[2] McCullough argued that certain non-utility generating plants in California were not producing their full output during the crisis, seemingly providing support for his contention that it was the exercise of market power, and not market fundamentals, that was largely responsible for the high prices.[3]

A more complete examination of the data challenges these conclusions, providing a picture more like that of a perfect storm, in which a number of unfavorable demand/supply events improbably coincided, leading to increases in electricity prices that are understandable in hindsight.

- Electricity prices were high in the West during 2000 and 2001 at least in part because of a shift in the demand/supply balance, leading to a supply shortage more extreme than in any year in recent history, including the drought year of 1994.

- In all but two months between January 2000 and June 2001 electricity consumption was higher than in the same month of any prior year (1993-1999).

- Decreased hydroelectric generation was a significant factor in the supply shortage. The data clearly show that this decline began in June 2000, when hydro generation was almost 20 percent lower than in prior years (1995-1999).

- There was a large decline in the output of nuclear plants, particularly in the period from January 2001 through May 2001 when the 1,080 MW San Onofre Nuclear Generating Station Unit 3 was out of service.

- The overall supply shortage was dramatic and sustained. From May 2000 to June 2001, the electricity demand that had to be met month after month by generating resources other than hydro, coal and nuclear plants was typically 3,000 GWh more than in prior years (1993-1999) and rose to a high of 8,784 GWh (60 percent) in May 2001. This sustained shortfall in hydro, coal and nuclear electricity supply was predominantly met by running existing gas-fired generators at *much* higher levels than in the past. In May 2001 alone, the 8,784 GWh shortfall in hydro, nuclear and coal output amounted to a need to operate the equivalent of 48 more 250 MW gas-fired units (at full capacity) than would have been required to meet electricity demand in previous years.

- The data confirm that the electricity output and hours on-line of gas and oil-fired generators, including those owned by non-utility generators, were significantly higher from May 2000 to June 2001 than they had been in any previous year (1994-1999). From January 2001 through May 2001, for example, the output of non-utility generating units was 57 percent higher than during January-May of the drought year of 1994.

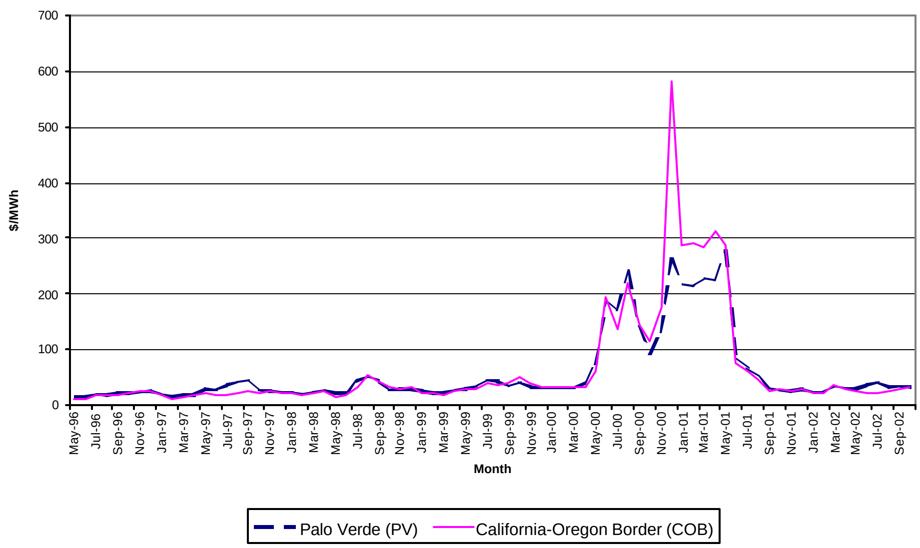
- As the supply shortage led to dramatically increased demand for gas-fired generation, electricity prices rose through a combination of dramatically higher gas prices, higher prices for NOx emission allowances (required for some gas-fired generation) and the inevitable use of less efficient gas-fired generating plants.

The discussion that follows provides the building blocks for an improved understanding of the causes of high electricity prices in California and the West during the period from May 2000 to June 2001. The analyses presented here can be replicated based on publicly available information. Since assembly of the supporting data takes time and resources, to simplify the task for others the numerical data for each figure and table and additional discussion of data sources are available on the lecg.com website.[4]

Reviewing the Facts

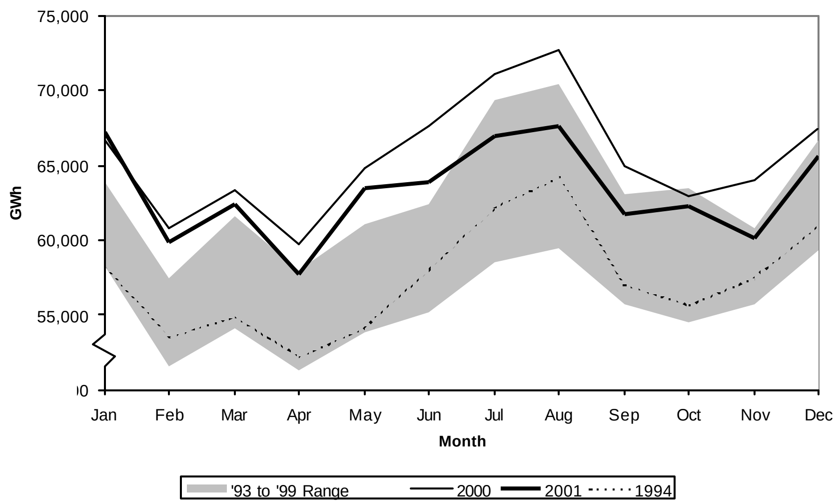
High Prices. Figure 1 shows the record of wholesale electricity prices in California and the West that many are still trying to understand. The figure reports average monthly on-peak spot electricity prices at two major trading centers – Palo Verde and the California-Oregon Border – as reported by *Megawatt Daily.* It shows that the average monthly on-peak spot prices at these trading centers ranged from under $12 per MWh to over $580 per MWh from May 1996 to September 2002. Monthly average prices became very high in the spring of 2000 and did not fall below $50/MWh again until the summer of 2001. The analysis that follows will discuss how this run-up in prices is connected to the underlying demand/supply balance for electricity.

Figure 1
Monthly Electricity Price Averages in the West



Increased Electricity Consumption. Electricity consumption during 2000 and 2001 was generally higher than that during prior years. Figure 2 shows the total monthly electricity consumption for the West by month, with separate lines representing the years 1994, 2000 and 2001, and a shaded range representing the minimum and maximum of the years 1993 through 1999.[5] In 2000, for example, electricity consumption ranged from a low of 59,766 GWh in April, to a high of 72,640 GWh in August. In all but two months between January 2000 and June 2001 electricity consumption was higher than in the same month of any prior year (1993-1999). Electricity consumption did not significantly decline in relation to prior years until the summer of 2001. (In this figure and in many of those that follow, 1994 is graphed separately since it is a year in which there was a drought in the West. Therefore, it is used throughout as a benchmark for illustrating the severity of the electricity supply shortage from May 2000 to June 2001 relative to prior drought conditions. Note that the vertical scale changes among the figures in the paper in order to make them more legible in a small print format.)

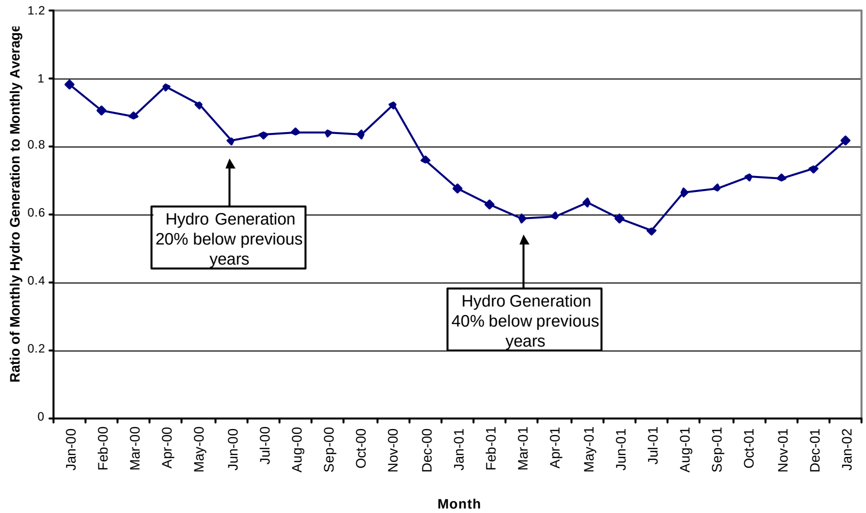
Figure 2
Monthly Electricity Consumption in WSCC*



*The WSCC is the Western Systems Coordinating Council, which covers the westen U.S. and portions of Canada and Mexico.

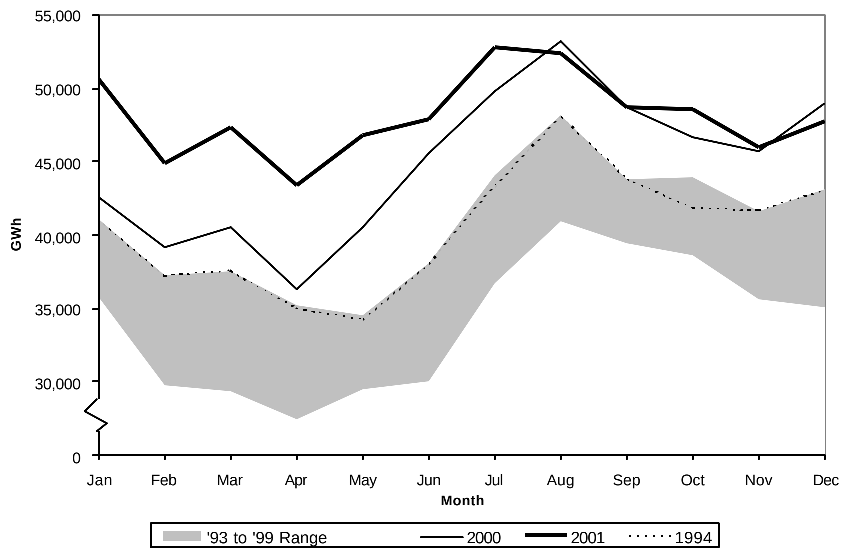
Decreased Hydroelectric Generation. While electricity consumption was high in the West during the period of high prices, there was also a substantial reduction in several important sources of electricity supply. [6] Figure 3 shows that during the period from January 2000 to January 2002, western hydroelectric generation was below the average level in previous years (1995-1999). A substantial reduction in hydroelectric generation began in the May/June 2000 timeframe, when electricity prices first increased sharply. Robert McCullough incorrectly concluded, based on data on Columbia River flows, that a decline in hydroelectric generation did not occur until 2001, when the drought started. Although the reduction in hydroelectric generation in the West became more severe in 2001, the data clearly show that hydroelectric generation fell significantly below the levels in previous years for the second half of 2000.

Figure 3
WSCC: Ratio of Actual Monthly Hydro Generation (2000-2002) to Monthly Average Hydro Generation (1995-1999)



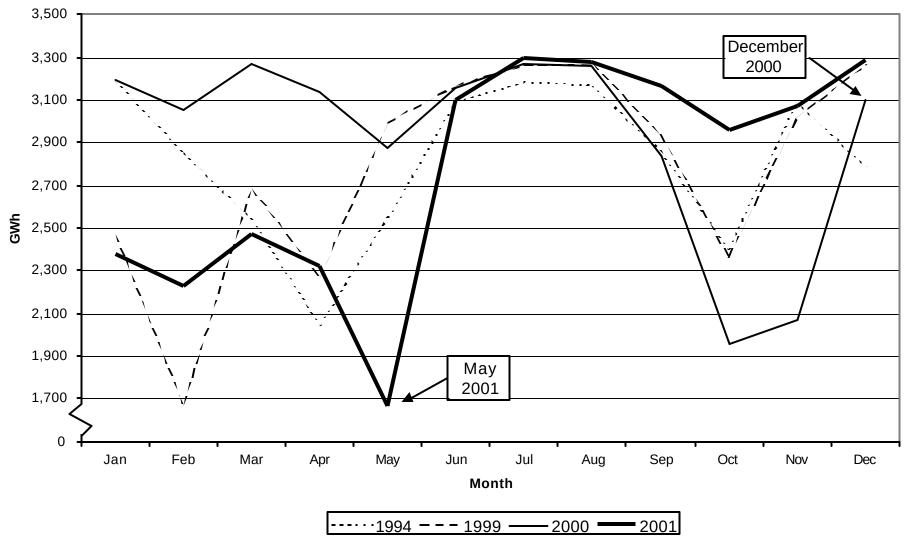
As a result, substantially more electricity consumption had to be met by non-hydro generation. Figure 4 shows monthly electricity consumption in the West minus U.S. and Canadian hydroelectric generation.[7] The lines representing 2000 and 2001 lie above the shaded region for all years going back to 1993, indicating that significantly higher amounts of electricity consumption had to be met by non-hydro sources in 2000 and 2001 than had been required in either the drought year of 1994 or in any other year back to 1993. The vertical gap between the graphs for May 2001 and May 1994, for example, means that 12,597 more GWh of electricity needed to be generated from non-hydro sources during May 2001 than during May 1994 (27% of total May 2001 electricity demand). Decreased hydroelectric generation was a significant cause of the shortfall of electricity supply and generating capacity that led to increases in electricity prices in the West beginning in June 2000.

Figure 4
WSCC: Monthly Electricity Consumption less Hydro Generation



Decreased Nuclear Generation. Outages at nuclear plants also contributed to the electricity supply shortage and high prices in the West. Nuclear generation in California was depressed during the first half of 2001 at the same time that hydro generation fell well below historical levels. The two solid lines in Figure 5 show that nuclear output fell from 3,104 GWh in December 2000 to 1,668 GWh in May 2001.[8] The cumulative impact of this decline was substantial. The total output of nuclear units in California over the period from January through May was lower in 2001 than in any year except 1997. Nuclear output from January to May 2001 was nearly 4,500 GWh lower than during the same period in 2000 and more than 2,000 GWh lower than during the same period in the drought year of 1994.

Figure 5
Monthly Output of California Nuclear Units



The substantial decline in nuclear output during the first half of 2001 reflects the large impact of the shutdown of Unit 3 of the San Onofre Nuclear Generating Station (SONGS) from January 3, 2001 to June 1, 2001. The extended outage of Unit 3, which has a nameplate capacity of 1,080 MW, was one cause of the rolling blackouts that occurred in California during February 2001.[9] Unit 3 was originally shut down for a refueling outage at the beginning of 2001. When engineers attempted to re-start the unit on February 3, 2001, a circuit breaker fault caused a fire and related damage to plant equipment. The supply shortage caused by the Unit 3 outage was compounded by the refueling outage of Diablo Canyon Nuclear Unit 2 from the end of April 2001 to June 1-2, 2001. This refueling outage was originally intended to be non-coincident with the outage of SONGS Unit 3. The figure above clearly shows the increase in electricity supply that occurred when both nuclear units came back on-line at the same point at the beginning of June 2001.

Unprecedented Need for Gas-Fired Generation. Decreases in nuclear and hydro generation and high levels of electricity consumption increased the need for gas-fired generation in the West from May 2000 to June 2001 far above levels required in previous years. Figure 6 shows monthly electricity consumption in the West less Western hydro generation and less the output of Western U.S. nuclear and coal plants.[10] The vertical gap between the graphs for May 2001 and May 1994, for example, means that 8,784 more GWh of electricity needed to be generated from sources other than hydro, nuclear or coal during May 2001 than during May 1994. (The performance of Western coal plants was relatively normal during the May 2000 to June 2001 period, although the usual process of taking coal-fired generation off-line for maintenance in the fall and spring further increased the need for gas-fired generation. Coal-fired generation is subtracted here to show more clearly the level of electricity demand that had to be met primarily by gas-fired generation.)

Figure 6
Monthly WSCC Electricity Consumption less WSCC Hydro, U.S. Nuclear and U.S. Coal Generation

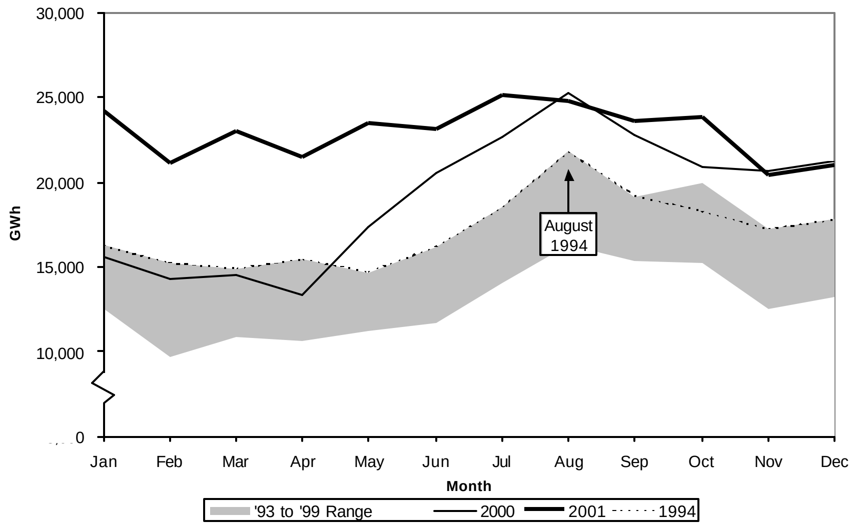
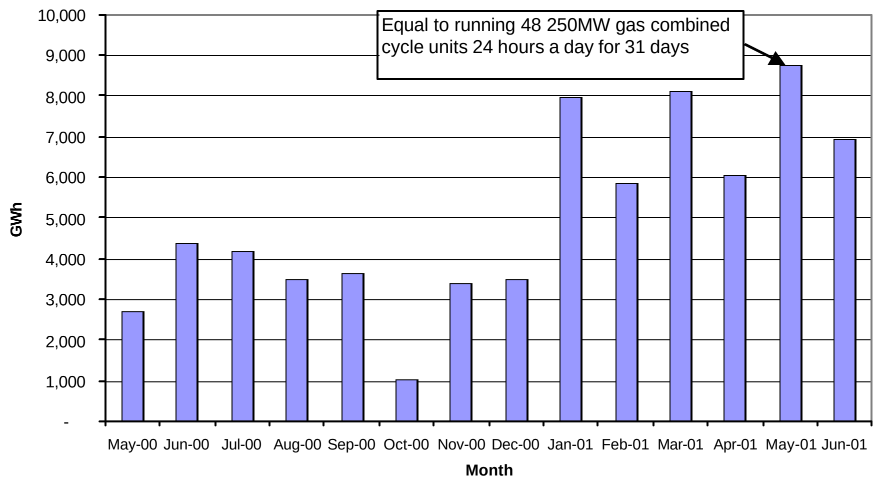


Figure 6 shows that from May 2000 through the end of 2001 the electricity consumption met by generating resources other than hydro, coal and nuclear plants was higher in every month than it ever had been previously, including the months of the drought year of 1994. The increased demand on other generating resources, which were primarily gas-fired, was both dramatic and sustained. For many months running, the demand on generating resources other than hydro, coal and nuclear units approximately equaled or exceeded that during August 1994, which was the worst summer-month in these terms of any prior year. Thus, the continuous demand requirement was analogous to having to serve the August 1994 peak load month after month by relying more heavily on primarily gas-fired generation. Yet despite the sustained demand during this period, gas-fired generation needed to be taken off-line for routine annual maintenance and environmental upgrades.

Figure 7 provides a second perspective on the data in Figure 6. It shows, for instance, that in June 2000 the electricity demand met by generating resources other than hydro, coal and nuclear plants was 4,390 GWh more than the maximum demand met by these resources in June of any prior year (1993-1999). Looking across the period from May

2000 to June 2001, the electricity demand that had to be met month after month by generating resources other than hydro, coal and nuclear plants was typically 3,000 GWh more than in prior years (1993-1999) and rose to a high of 8,784 GWh (60 percent) in May 2001.[11] This sustained shortfall in hydro, coal and nuclear electricity supply was predominantly met by running existing gas-fired generators at much higher levels than in the past. Over this time period, the monthly increase in output from these primarily gas-fired resources ranged from 5 to 60 percent of the prior same-month maximum, averaging 31 percent over the whole period. In May 2001 alone, the 8,784 GWh shortfall in hydro, nuclear and coal output amounted to a need to operate the equivalent of 48 more 250 MW gas-fired units or six SONGS nuclear generating plants (at full capacity in all hours of the month) than would have been required to meet electricity demand in previous years.

Figure 7
Additional Generation (GWh) Required May 2000 - June 2001 minus Prior Monthly Maximum (1993 - 1999)



Decreased Output from Qualifying Facilities (QFs).[12] The last step in analyzing the increase in the electricity consumption that had to be met primarily by gas-fired generation from the summer 2000 to the summer 2001 would be to subtract from the data in Figure 6 the output of California QFs, such as wind power generators and steam cogenerators. Owners of QFs sell electricity to the California utilities under long-term contracts, with a price set by a formula rate. Two issues occurred during 2000-2001 that reduced QF output. The first issue was that during 2001 the price paid for QF generation, based on the formula rate, was at times too low to cover the cost of natural gas, which made it unprofitable for some QFs to operate. Second, Southern California Edison (SCE) and Pacific Gas & Electric (PG&E) could not adjust the retail prices that they charged their customers to recover the cost of the wholesale electricity they purchased during the period of high electricity prices. As a result, SCE and PG&E were unable to pay their bills, and among the entities that were not paid were the QFs supplying them with wholesale electricity. Thus, QF output likely fell because many gas-fired QFs could not afford to pay extremely high gas prices in order to generate electricity for which they might not be adequately paid, might be paid only after a long delay, or might not be paid at all.

Unfortunately a complete public data set of QF output cannot be assembled from EIA data because many QFs did not report their output to the EIA. Table 1 presents an approximate measure of QF output, based on reports prepared by the CAISO, which shows a decline in average hourly output from QFs in California for several months during the first half of 2001.[13] During April 2001, average hourly QF output fell by 1,105 MWh from April 2000, which is a 19% decline. In addition to this limited data, there is also anecdotal evidence that the supply shortage situation shown in Figure 6 was aggravated by reduced output from QFs, particularly during the spring of 2001.[14]

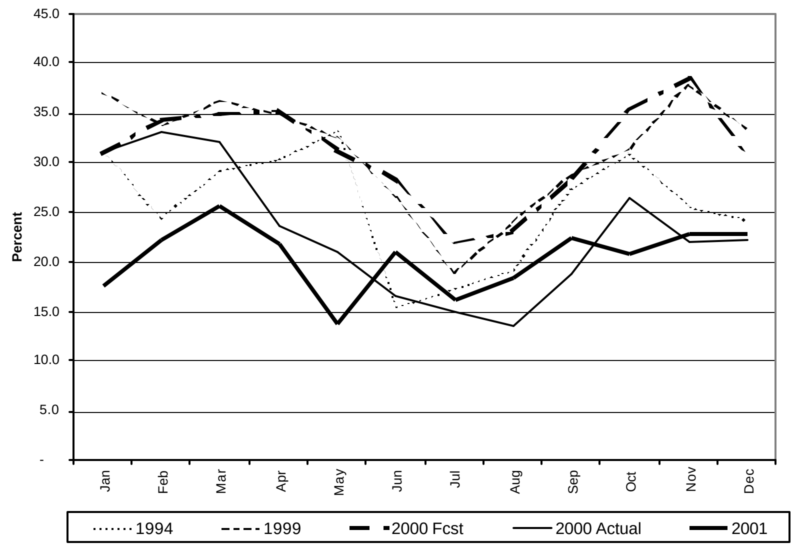
Table 1
Average Hourly California QF Output (MWh)

	2000	2001	Change
January	5,835	5,651	(184)
February	5,318	5,221	(98)
April	5,748	4,643	(1,105)
May	6,328	5,615	(713)

Low Reserve Margins. The discussion up to this point has portrayed the tight demand/supply balance for electric energy in the West by evaluating the relationship between monthly electricity consumption and electricity supply, both measured in gigawatt-hours. Another way to evaluate the demand/supply balance in the West is to analyze if there was an adequate stock of electric generating capacity, or “steel in the ground,” measured in terms of megawatts. This analysis is reported in terms of reserve margins, which are a measure of the electric generating capacity in a region that is in excess of peak electricity demand, expressed as a percentage of the peak demand.

Based on WSCC reported reserve margins,[15] Robert McCullough has argued that 2000 was not an unusual year in terms of the demand/supply balance for electricity. Unfortunately – since his conclusions are often repeated – his analysis apparently erroneously relied on forecast reserve margins for 2000 and actual reserve margins for other years.[16] Figure 8 shows the actual reserve margins for 1994, 1999, 2000 and 2001 as reported by the WSCC, as well as the forecast 2000 reserve margin.[17] The reserve margins fluctuate predictably with the seasons, falling during the summer months. While the forecast margins for 2000 were in line with prior year levels, the actual reserve margins for 2000 reported by the WSCC were very low by historical standards and, starting in July 2000, were even below the drought year of 1994. The reported actual reserve margin for 2000 was less than 20 percent for each month from June 2000 through September 2000, and the margins for July through September 2000 were the lowest reported reserve margins for those months over the entire period from 1980 through 2001. The reserve margins continued to be very low throughout 2001, falling far below 1994 levels during the January 2001 to May 2001 period.

Figure 8
WSCC Actual Reserve Margins



Increase in Gas-Fired Generation. The predictable result of the tight demand/supply balance shown in Figures 6, 7 and 8 is that gas and oil-fired plants in California operated at far higher levels from May 2000 to June 2001 than they ever had before, even in the prior drought year of 1994. Table 2 below shows that a constant-capacity sample (the largest that could be assembled based on publicly available data) of California gas and oil-fired units, owned by both utilities and non-utility generators (NUGs), started generating electricity far above previous levels in the summer of 2000.[18] For example, the NUG output was 5,618 GWh in June 2000, a 49 percent increase from the 3,779 GWh that the same plants produced during June 1994. This increased generation by California gas and oil-fired units continued into the first half of 2001.

Table 2
Monthly Output (GWh) of California Regulated Utility and NUG Units: 1994-2001
(Sample of Generators Held Constant in Each Year)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Jan-Dec	Total Jan-May	Total Jun-Dec
						Regulated Utility Units									
1994	840	589	623	822	550	677	737	994	693	744	851	745	8,863	3,423	5,440
1995	683	512	576	585	427	453	649	974	718	534	374	250	6,736	2,782	3,953
1996	246	206	207	228	244	285	506	745	447	315	208	171	3,808	1,131	2,678
1997	162	144	156	238	406	274	434	633	592	402	189	170	3,799	1,105	2,694
1998	180	141	151	189	265	240	834	1,298	881	520	353	342	5,394	925	4,469
1999	238	468	386	481	442	746	901	953	738	1,170	495	459	7,476	2,015	5,461
2000	459	420	541	390	821	1,019	1,182	1,362	1,099	847	687	786	9,613	2,631	**6,982**
2001	1,017	868	845	941	853	745	759	934	774	695	435	369	9,234	**4,523**	4,710
						Non-Utility (NUG) Units									
1994	4,175	3,678	3,871	4,089	3,117	3,779	4,813	6,721	5,639	5,004	4,681	4,914	54,483	18,930	35,553
1995	3,243	2,303	2,592	1,976	1,304	1,262	3,263	4,898	4,275	2,910	2,654	2,034	32,715	11,419	21,297
1996	2,324	1,332	1,043	1,496	1,475	1,888	3,567	4,542	3,039	2,898	2,064	1,591	27,259	7,670	19,589
1997	1,383	1,172	2,085	2,246	3,156	2,178	3,831	4,011	4,800	2,947	1,894	2,264	31,968	10,042	21,926
1998	2,310	1,521	2,025			(NM: Data not available, see footnote.)									
1999	2,124	1,666	1,769	2,045	1,574	2,372	3,658	4,369	4,265	5,645	3,372	2,838	35,699	9,179	26,520
2000	3,130	2,766	2,039	1,928	3,754	5,618	6,283	7,879	6,642	5,833	4,979	4,903	55,754	13,616	**42,137**
2001	6,087	5,503	6,405	5,864	5,905	5,542	6,663	6,800	5,695	4,819	3,473	3,748	66,503	**29,764**	36,740

Total Regulated Utility Summer Capacity: **5,711 MW in all years**
Total Non-Utility Summer Capacity: **17,048 MW in all years**

The data in Table 2 challenge blanket assertions of economic or physical withholding by the NUGs as a group. The NUG units reported in this table, which were owned and operated by Duke, Dynegy/NRG, Mirant, Reliant, AES/Williams, and Thermo Ecotek , are those that have been criticized for having low capacity factors during the period from May 2000 to June 2001. The data, however, show that during this period, the output of units owned by the NUGs was well above their output in any prior year, including the drought year of 1994. From June-December 2000, the output of the NUG units was 19 percent higher than during June-December 1994. In August 2000, electricity generation by NUG units increased by 80 percent over August of the previous year. The output stayed significantly above previous levels throughout the fall of 2000, when maintenance outages typically occur. Then, in January-May 2001, the NUGs reported an output that was 57 percent above that during January-May 1994. Since Table 2 reports the output of a constant capacity sample of generating units , it is clear that the capacity utilization of the sample was also above the level in previous years. Any claim that NUGs as a whole had below-normal utilization from May 2000 to June 2001 is not accurate.

Table 3 provides a second perspective on the increased level of operation of gas and oil-fired generators in California during the second half of 2000 and first half of 2001. The table shows the number of hours in which a constant sample of gas and oil-fired generators (the largest for which data were available) reported electricity output in each month.[19] The data clearly show a large increase in the number of hours in which these units were operating in June-December 2000 and in January-May 2001, relative to the same periods for previous years. For example, in June 2000 the NUG units were on-line for 29,484 hours, a 64 percent increase from the 17,956 hours reported for June of the previous year.

Table 3
Monthly Hours Generating - Selected CA Units 1997-2001
(Constant Sample of 37 Regulated Utility Units, 60 Non-Utility (NUG) Units)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Jan-Dec	Total Jan-May	Total Jun-Dec
	Regulated Utility Units														
1997	-	-	-	-	-	-	-	-	-	7,746	4,527	4,218	-	-	-
1998	4,443	4,232	4,598	4,644	5,600	6,051	12,083	15,498	12,750	8,681	7,126	6,691	92,397	23,517	68,880
1999	5,427	5,425	7,098	6,289	7,930	11,277	13,362	13,397	10,302	14,804	8,836	8,564	112,711	32,169	80,542
2000	10,725	8,719	8,857	8,014	12,690	14,885	17,311	18,727	14,709	12,184	9,968	10,803	147,592	49,005	**98,587**
2001	11,480	9,899	10,719	8,940	12,200	12,729	14,528	15,421	13,304	11,888	8,433	8,246	137,787	**53,238**	84,549
	Non-Utility (NUG) Units														
1997	-	-	-	-	-	-	-	-	-	16,806	12,322	13,883	-	-	-
1998	15,451	12,266	13,746	12,132	11,175	13,590	23,236	28,805	23,636	19,149	15,176	15,766	204,128	64,770	139,358
1999	17,110	14,852	14,363	16,853	15,043	17,956	25,110	25,458	21,675	29,667	18,043	17,618	233,748	78,221	155,527
2000	19,529	17,772	15,619	15,015	22,125	29,484	32,093	36,083	31,757	29,310	22,750	26,375	297,912	90,060	**207,852**
2001	30,300	25,658	28,731	26,977	25,890	27,009	33,005	34,396	27,762	23,013	20,566	22,324	325,631	**137,556**	188,075

Table 3 provides a reasonably comprehensive view of the overall availability of utility and non-utility gas and oil-fired generators during 2000 and 2001. Robert McCullough has argued that NUG plants had unusually high outage rates during this period of time, relative to similar plants,[20] but Table 3 shows that both utility and NUG gas and oil-fired generators were actually on-line for far more hours from May 2000 to June 2001 than in prior years. The units were on-line for fewer hours in the fall, winter and spring months than during the summer peak, but this is consistent with performing maintenance and environmental upgrades during these seasons. It does not appear from the data in Table 3 that the high prices in California were caused by a lower overall level of gas and oil-fired unit availability than in previous years.

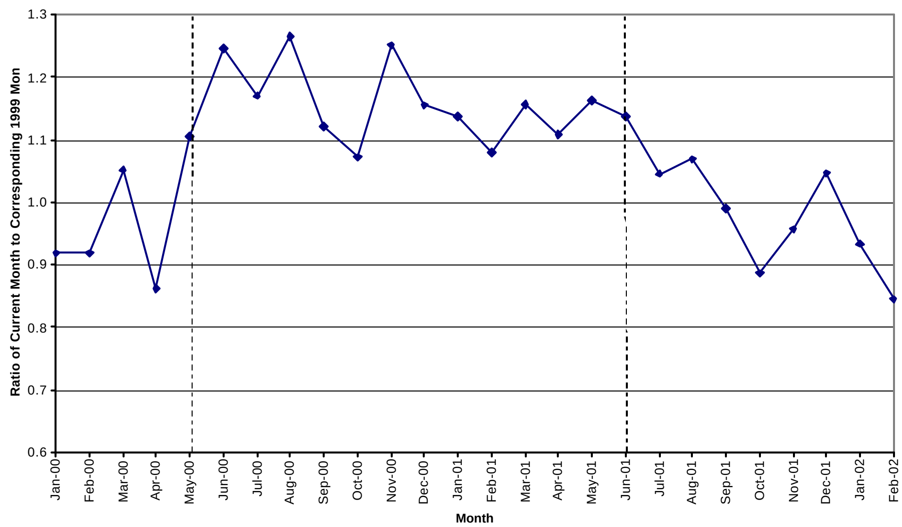
The between-year comparison of the output and hours on-line of NUG generation challenges the argument that the operation of these units at only 50.3 percent of their capacity, on average, over the May 2000 to June 2001 period proves that their output was too low.[21] To the contrary, it is clear that the average utilization rate was unusually high for these NUG units. The economics of gas-fired generators typically means that they are not run all of the time. Gas-fired generators are often used to respond to increases in energy consumption during the peak hours of each day, when output from cheaper generating units cannot be increased rapidly enough. These "load-following" units operate at minimum levels during many other hours of the day and night and may be taken off-line when demand is low. Likewise, some gas-fired generators, with low capital costs but high running costs, are operated only during periods of peak electricity demand, such as the hot days of the summer. Peaking units normally have capacity factors much less than 20 percent. Thus, in comparison with the typical operation of gas-fired units, the increased operation of the NUG gas and oil-fired generators, leading to an average capacity factor of 50.3 percent, during the summer 2000 to summer 2001 period was extraordinary. It should be noted again that this increase in gas and oil-fired generation occurred during a period when many of the gas and oil-fired units needed to be taken off-line for routine annual maintenance and environmental upgrades.

It is also worth noting that the increase in gas and oil-fired electricity generation occurred despite environmental regulations that limited the operation of some generators in California during the relevant period. Dynegy's Cabrillo II unit[22] and Mirant's Potrero 4, 5 and 6 units[23] were subject to annual run time limits of 876 and 877 hours, respectively.

Similarly, Reliant Energy's Mandalay Unit 3 was subject to charges in the range of $4,000 to $6,000 per hour for exceeding a rolling annual throughput limit.[24] During 2000 and 2001, the sustained reduction in hydro and nuclear generation caused output limitations at these units to be much more restrictive than was likely anticipated. In addition, some gas and oil-fired generators were subject to water outlet temperature restrictions. An example of the most significant of these restrictions, which reduced output during the late May to early July period, was at Mirant's Pittsburg 1-6 and Contra Costa 6 and 7 generating units in northern California. Although some of the run-time limitations were eventually modified so as to better reflect the environmental costs of high levels of operation, without imposing absolute operational limits, delays in implementing these changes probably reduced the supply of energy from the affected generating units during the latter part of 2000 and early 2001.

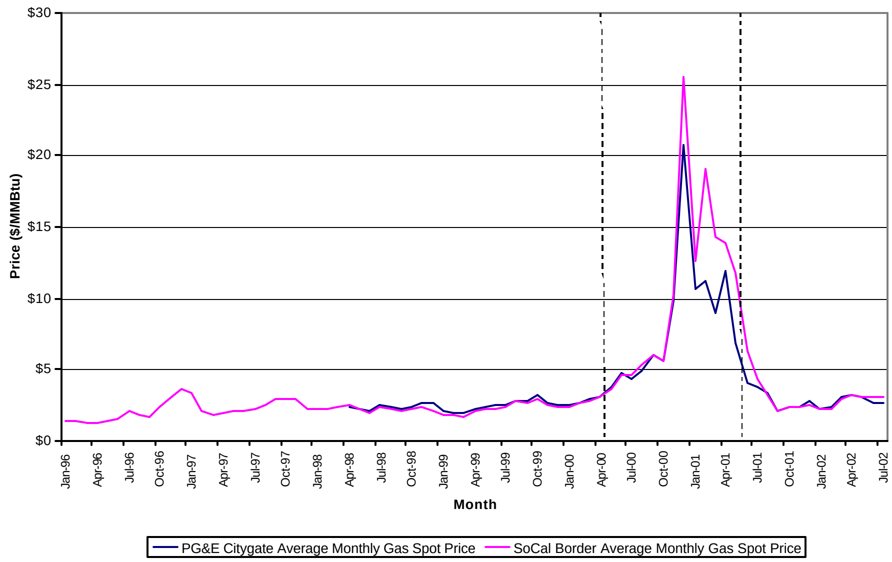
Increase in Gas Consumption. The unprecedented level of generation by gas and oil-fired units shown in Tables 2 and 3 accompanied a dramatic rise in natural gas consumption in California from May 2000 to June 2001. Figure 9 shows the ratio of monthly natural gas consumption in California from January 2000 to February 2002, relative to consumption during the same month in 1999.[25] In May 2000, this ratio exceeded 110 percent, and rose to over 125 percent in August 2000. Usage during each month from May 2000 to June 2001 greatly exceeded usage during the same month in 1999, as well as usage during the same month of each year back to 1989, when data were first reported.[26] The period of high electricity prices during 2000 and 2001 matches almost perfectly with the period from May 2000 to June 2001 in which monthly gas consumption in California was 10 percent or more above the 1999 level.

Figure 9
Ratio of Current Month Natural Gas Consumption to 1999 Month, California



High Gas Prices. The link between the increase in demand for gas-fired generation and increased electricity prices can be explained in large part by the pattern of gas prices. Figure 10 shows the monthly average spot gas price for two important trading locations – the PG&E Citygate and the Southern California Border.[27] Gas prices started to rise in the summer of 2000, and spiked at high levels during the winter of 2000 and spring of 2001, before falling again. Increasing gas prices pushed up the cost of supply from gas-fired generating units, which directly translated into higher market prices for electricity.

Figure 10
Average Monthly Gas Prices



High Cost of NOx Emission Allowances. Gas prices were not the only source of upward pressure on the supply cost of gas-fired generating units. At the same time that the demand for gas-fired generation in the West reached unprecedented levels, many gas-fired units were required to comply with a variety of environmental constraints. The most widely discussed of these constraints are the air emission limits for NOx, enforced by the South Coast Air Quality Management District (SCAQMD). Its RECLAIM program allows emission sources such as generating units to comply with emissions reduction targets by either reducing emissions or purchasing emission allowances from other emission sources.

The increased reliance on gas-fired generation caused a dramatic rise in SCAQMD emission allowance prices during the period from mid-2000 to mid-2001.[28] Table 4 shows the increase in electricity generation by units in the SCAQMD region that lead to a large increase in demand for SCAQMD allowances and drove up allowance prices.[29] For example, from January to May 2001, the output of these units was 13,439 GWh, an 83 percent increase from 7,337 GWh in January to May 1994.

Table 4
Monthly Output (GWh) of SCAQMD NUG Units: 1993-2001

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Jan-Dec	Total Jan-May	Total Jun-Dec
1993	1,495	1,452	1,547	1,333	783	1,307	1,371	1,953	1,670	1,746	1,912	1,655	18,222	6,610	11,612
1994	1,678	1,336	1,346	1,693	1,283	1,789	2,060	2,987	2,055	1,890	1,785	1,555	21,458	7,337	14,121
1995	1,585	1,242	1,446	1,174	817	803	1,764	2,939	2,353	1,348	1,031	693	17,194	6,263	10,930
1996	622	493	437	581	616	795	1,582	2,117	1,357	1,165	599	610	10,973	2,748	8,225
1997	557	418	719	635	1.170	904	1.470	1.711	1.961	1.225	653	658	12.081	3.500	8.582
1998	646	641	803			(NM: Data not available, see footnote)									
1999	429	434	553	807	645	1.158	1.768	2.196	1.843	2.603	1.273	774	14.484	2.868	11.616
2000	994	746	752	865	1,738	2,662	3,195	3,784	2,851	2,502	1,832	1,813	23,733	5,094	18,638
2001	3,030	2,657	2,759	2,443	2,550	2,265	2,765	3,031	2,508	1,972	1,518	1,452	28,950	13,439	15,512

Data available from three public entities on actual NOx emission allowance acquisition costs for this period range from $12 to $51.44 per pound, with a large number of purchases in the $45 to $50 range.[30] Emissions allowances costing $10 to $50/lb could translate into an increased electricity supply cost of $40 to $200/MWh for gas-fired generating units. For example, the Los Angeles Department of Water and Power (LADWP) was paying prices in the range of $47-$48/lb for SCAQMD emission allowances during January 2001. For a gas-fired steam generation unit with an emissions rate in the range of 1-1.5/lbs per MWh, this would have translated into a cost increase ranging from $47 to $70/MWh, just for the cost of the allowances. These allowance costs could translate into additional supply costs of $200/MWh or more for gas turbines that could have emissions rates up to 4 or 5 lbs/MWh.

Triple Impact. The unusually tight demand/supply balance in the West during the second half of 2000 and the first half of 2001 increased the demand for gas-fired electricity generation far above historical levels, leading to dramatically increased electricity prices for three reasons.

- The period of high demand for gas-fired generation occurred during a period when the cost of gas was far above usual levels.
- High demand pushed up the cost of the emission allowances needed for some gas-fired generation.
- Increased demand for gas-fired generation led to the operation, on margin, of relatively inefficient gas-fired generators, or of generators with high NOx emission rates. Operation of less efficient and high emission generating units thus magnified the impact of increasing gas and emission allowance prices on the cost of supply from gas-fired generating units.

Table 5
Gas-Fired Generation Cost Comparisons

Cost Components	**Before**	**After**
Gas Prices ($/mmbtu)	$3	$13
Heat Rate (btu/KWh)	10,000	15,000
NOx Price ($/lb)	$1	$45
Emissions Rate (lbs/MWh)	0.5	3
Gas-Fired Supply Costs	**Before**	**After**
Gas Costs ($/MWh) = ($/mmbtu/1000) * btu/KWh	$30	$195
Emissions Costs ($/MWh) = $/lb * lbs/MWh	$0.50	$135
Gas-Fired Supply Cost ($/MWh)	**$30.50**	**$330**

Table 5 provides an illustrative example of the increase in the cost of gas-fired generation, resulting from the need to operate less efficient generating units and to pay more for gas and emission allowances. Since in a market setting, the offer price of the last activated unit of supply sets the overall market clearing price, the increased cost of supply from gas-fired units led directly to higher market prices for electricity.

Conclusions

There is a clear and simple economic explanation for most or all of the large increase in electricity prices in California and the West from May 2000 to June 2001. Prices in the electricity market increased like those in any competitive market when there is a shortage because increasingly less efficient sources of electricity supply needed to be used and some inputs became more expensive.

Electricity prices were high in the West during 2000 and 2001 at least in part because of a shift in the demand/supply balance, leading to a situation more extreme than in any year in recent history, including the drought year of 1994. Demand for energy in the West was generally higher in 2000 and the first half of 2001 than it was in previous years. At the same time, supply was lower due to a number of factors; the most important was a reduction in hydroelectric generation in the Pacific Northwest and Canada beginning in the May/June 2000 time frame. The reduction in hydro generation was compounded at times by reduced output from nuclear generating plants in California, maintenance outages at coal plants and reductions in the electricity supplied by QFs, which occurred because of a failure to pay adequately for their output. Moreover, environmental restrictions on gas-fired units in California limited their ability to meet the increased demand (or substantially increased their supply cost).

The extraordinarily tight demand/supply balance led to increased demand for gas-fired electricity generation during the second half of 2000 and the first half of 2001. This increased electricity prices for a number of reasons. The increased reliance on gas-fired generation occurred during a period of very high overall demand for gas in California, when gas prices were peaking far above their usual levels. High demand also pushed up the cost of the emission allowances needed for some gas-fired generation. Finally, to make matters worse, the impact of increasing gas and emission allowance prices was magnified by the need to operate less efficient and high emission gas-fired generating units during the supply shortage, which further raised electricity supply costs.[31] Thus, contrary to some early accounts, the data show a clear economic explanation for most, if not all, of the run-up in electricity prices in California and the West in 2000-2001.

The data also challenge the conclusion that the output and availability of NUG units was reduced in order to raise prices during the period of high electricity prices in the West. During the second half of 2000 and first half of 2001 both the electricity output and hours on-line of NUG facilities were much higher than in any year in recent history. Whether particular generation was withheld from the market on specific days by specific units will continue to be the subject of investigation. What is clear is that a case for economic or physical withholding of non-utility generation bears a strong burden to show that output could have been increased even further above the extraordinary levels observed, while remaining profitable on the margin at lower market prices.

In assessing the impact of a shortage in electricity generating capacity or electric energy, increasing prices should not be assumed, in the absence of specific supporting facts, to indicate withholding. Electricity supply prices can rise sharply as the demand/supply balance becomes tight for a number of legitimate reasons. This can occur because of a shortage of energy, as discussed above, as well as for a more subtle reason that is particular to electricity markets. In the operation of the electric system, generating capacity is used not only to generate electric energy, but also to provide regulation and operating reserves, which are products that reduce the likelihood of widespread, uncontrolled blackouts. Some generating capacity can be shifted from supplying operating reserves to supplying energy in a shortage situation. This avoids blackouts, but the reserve shortage reduces reliability and system operators are required to restore their operating reserves. Thus, during a shortage period, prices reach the price cap because there is not enough electric generating capacity available at any price. The California ISO operated in such a reserve shortage situation for 38 days during the winter and spring of 2001, contributing to noticeable price spikes.

About the Author

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The analyses reported in this paper draw on a variety of analyses performed at LECG, LLC on behalf of Allegheny Energy Supply Company, LLC, Mirant Americas Energy Marketing, L.P., Morgan Stanley Capital Group Inc., Reliant Energy Services, Inc., Sempra Energy Resources, and Williams Energy Marketing & Trading Company. The conclusions in this paper are those of the author and do not necessarily reflect the views of other members of the firm of LECG, LLC. Mirant Corporation, an energy merchant company that owns generation assets in the United States, including California, provided funding for this paper.

[1] In this paper, "West" is synonymous with the Western Systems Coordinating Council (WSCC), which covers the states of Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming, the provinces of Alberta and British Columbia in Canada and a small portion of Mexico. Many of the analyses presented rely on data publicly reported for the WSCC. The Western Electric Coordinating Council was formed in April 2002 and includes the WSCC.

[2] See Robert McCullough, "Price Spike Tsunami: How Market Power Soaked California," *Public Utilities Fortnightly*, January 1, 2001, pp. 22 - 32.

[3] *Ibid*. See also, Robert McCullough, "Revisiting California: Market Power after Two Years," *Public Utilities Fortnightly*, April 1, 2002, pp. 28 - 37.

[4] See http://www.lecg.com. Links: Practices; Electric Power, Oil and Gas; Research Papers & Testimony; California Electricity Markets

[5] Source of data is WSCC 10-Year Coordinated Plan Summaries (1994-2002).

[6] Sources of data are: EIA Electric Power Monthly, Table 11 (April 1994 - May 2002) and Statistics Canada, Data Sets D372041 (British Columbia) and D372011 (Alberta).

[7] Sources of data are: WSCC 10-Year Coordinated Plan Summaries (1994-2002); EIA Electric Power Monthly, Table 11 (April 1994 - May 2002); and Statistics Canada Data Sets D372041 (British Columbia) and D372011 (Alberta). This figure does not reflect U.S. non-utility hydro generation because this output (which is relatively small) was not reported prior to 1999.

[8] Sources of data are: EIA Form-759 (1993-2000) and Form-900 (2001).

[9] See http://www.laweekly.com/ink/01/18/news-bradley.php.

[10] Sources of data are: Demand -- WSCC 10-Year Coordinated Plan Summaries (1994-2002); US Hydro data - -- EIA Electric Power Monthly, Table 11 (April 1994 - May 2002); Canadian Hydro data -- Statistics Canada, Data Sets D372041 (British Columbia) and D372011 (Alberta); Nuclear data -- EIA Form-759 (1993-2000) and EIA Form-906 (2001); Coal data -- EIA Electric Power Monthly, April 1994 - July 2002, Tables 8 and 62.

[11] Sources of data are: Demand -- WSCC 10-Year Coordinated Plan Summaries (1994-2002); US Hydro data - EIA Electric Power Monthly, Table 11 (April 1994 - May 2002); Canadian Hydro data --- Statistics Canada, Data Sets D372041 (British Columbia) and D372011 (Alberta); Nuclear data -- EIA Form-759 (1993-2000) and EIA Form-906 (2001); Coal data -- EIA Electric Power Monthly, April 1994 - July 2002, Tables 8 and 62.

[12] Qualifying Facilities are a category of electricity generating plants that meet ownership, operating and efficiency criteria established by the Federal Energy Regulatory Commission.

[13] The data reported in Table 1 are must-take generation output as reported by the CAISO, minus nuclear output as reported to the EIA. Sources of data are: CAISO Market Analysis Report, Anjali Sheffrin, March 30, 2001; CAISO Market Analysis Report, Eric Hildebrandt, June 20, 2001; EIA Form-759 (2000) and EIA Form-906 (2001).

[14] See *Megawatt Daily*, April 5, 2001 (p. 1), April 19, 2001 (p. 8), April 20, 2001 (pp. 1 and 9), and May 3, 2001 (p. 2).

[15] The actual hour by hour reserve margins for the WSCC are not compiled or reported. The "actual reserve margin" reported by the WSCC appears to be calculated on a non-simultaneous basis and apparently does not account for all outages or transactions that might have occurred at a single point in time. It therefore does not measure the absolute level of reserves at a single point in time, but provides a measure that can be used to compare reserve levels in one year to the reserve levels in the same month of other years.

[16] See Robert McCullough, "Revisiting California: Market Power after Two Years," *Public Utilities Fortnightly*, April 1, 2002, p. 31.

[17] Source of data is WSCC Load and Resources Reports.

[18] Notes to Table: The data include units that reported output for each year from 1994 -1997 and 1999 - 2001. Those that did not file in one or more years, or those that retired before 2001 or were activated after 1994 were not included. Because no Form-900 existed in 1998, the new owners of divested assets did not file reports for the plants in the second part of the year. The plants resumed reporting in 1999 with the introduction of Form-900. Output for those months in 1998 designated NM in the table have been excluded because data comparable to the other years cannot be compiled. Sources of data are: EIA Form-759 (1994-2000), EIA Form-900 (1999-2000), EIA Form-906 (2001) and EIA Form-860A.

[19] Notes to Table: This table reports the number of hours in a given month that California non-utility generators and regulated utility units reported generation to the EPA's Continuous Emissions Monitoring System (CEMS). Gas turbines (GTs) do not report to CEMS. Note that CEMS and EIA databases do not contain identical sets of generators. Source of data is http://www.epa.gov/airmarkets/emissions/raw/index.html.

[20] See Robert McCullough, "Revisiting California: Market Power after Two Years," *Public Utilities Fortnightly*, April 1, 2002, p. 33.

[21] *Ibid*.

[22] The Cabrillo unit in the San Diego region had an annual run time limit of 876 hours that was binding in 2001. Prepared Direct (Phase II) Testimony of J. Kent Williams, Dockets EL00-95-045 and EL00-98-042, July 3, 2002, pp. 6, 21.

[23] See "Emergency Motion for Clarification of Mirant and Request for Waiver of Answer Period," Docket No. EL00-95-031, June 26, 2001; and "Order Granting Emergency Motion for Clarification," Docket No. EL00-950-39.

[24] Prepared Direct Testimony of Joey Lell, July 3, 2002, Dockets No. EL00-95-045 and EL00-98-042, pp. 6-7.

[25] Source of data is http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/natural_gas_monthly/ngm.html.

[26] It was not possible to assemble a consistent data set on natural gas consumption specifically by generating plants. EIA reports data on the consumption of natural gas by electric utilities in the *Natural Gas Monthly* publication. As units were sold to NUGs, however, these consumption data were transferred from the utility category to the industrial category, where it is not possible to separate out the NUG consumption of natural gas from other industrial consumption.

[27] Source of data is *Gas Daily*.

[28] See, for example, SCAQMD's *Review of Reclaim Findings*, Chapter 6, October 20, 2000 located at http://www.aqmd.gov/hb/001040a.html; SCAQMD's *White Paper on Stabilization of NOx RTC Prices*, January 11, 2001, located at http://www.aqmd.gov/hb/010123a.html.

[29] Notes to Table: Only includes those units in Table 2 that required emissions allowances. Output for those months in 1998 designated NM in the table have been excluded because data comparable to the other years cannot be compiled. Sources of data are: EIA Form-759 (1993-2000), EIA Form-900 (1999-2000) and EIA Form-906 (2001).

[30] Source of data for the City of Burbank is "Burbank Refund Hearing6-30-02.xls"; for the Los Angeles Department of Water and Power is "VANDOC_111456_1.xls"; for the City of Pasadena is "Responsive Testimony of Eric R. Klinkner, in BLF0776.doc", undated.

[31] Beginning in late June 2000 and continuing through the summer of 2000, extremely high electricity prices also occurred in some hours due to capacity shortages. In these hours, prices were high because the price of capacity needed for reserves reached the $750/MWh bid cap, rather than because of the impact of high gas and emissions allowance prices.