California Energy Resources Scheduling

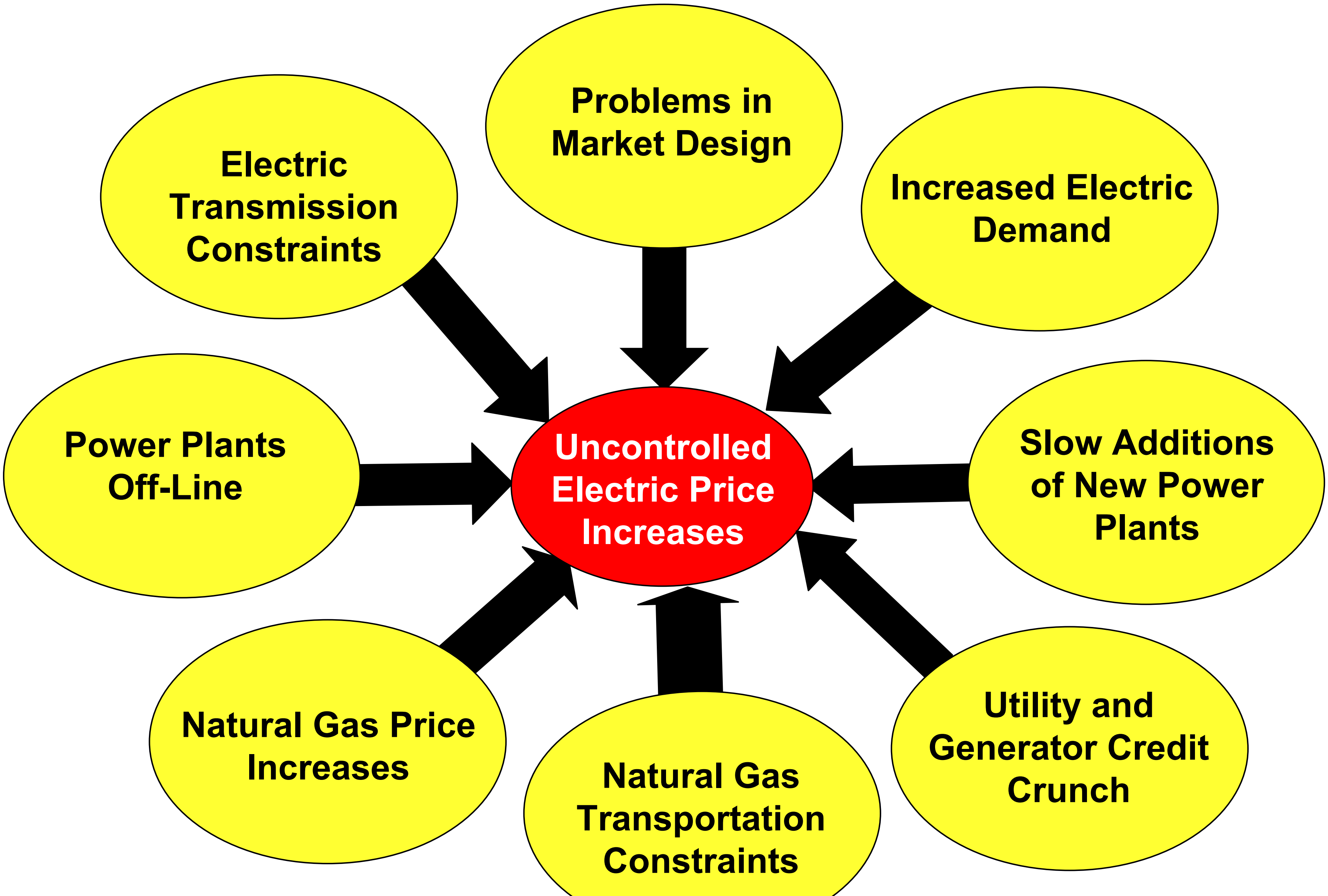
a Division of
California Department of Water Resources

Annual Report for Calendar Year 2001

(Provides Data as Required by AB 1X)

Index

Evolution of the Crisis



Changes in the Rules Create Foundation for Future Prices

- The path to the 2001 crisis began with implementing the restructuring of the electric utility and power market in California in 1996-98
- Pacific Gas and Electric, Southern California Edison and San Diego Gas and Electric (the investor-owned utilities or “IOUs”) sold most of their power generation assets (except for nuclear, hydroelectric, and a few selected fossil fuel generators) to non-regulated power producers, at multiples of book value
- A rate cap was put in place on retail electric rates
- All short-term energy sales were directed through the new California Power Exchange -- which cleared prices at the highest marginal cost (concept that works when you have excess supply)

Customer Demands Rise, Supplies Don’t Keep Pace

- Electric demand continued to increase – approximately 6,800 MW of additional peak demand between 1996 and 2000 (adding the equivalent of more than the entire electric load of the City of Los Angeles)
- Only 1200 MW of new power plants were added in that same period (combination of slow response by market and permitting challenges)
- The existing generating plants sold by the IOUs were largely aged - and getting older
- Plants 40+ years old used only in the highest peak hours in prior recent years were being called upon for greater use
- Pollutant emission limitations reduced the run time for the older plants, further limiting supply

Energy Transportation Systems Constrain Supply

- Electric transmission capability between southern and northern California is constrained and no timely action taken to relieve the constraint
- In peak periods, at present, natural gas demand typically requires over 95 percent of the available interstate gas pipeline capacity to deliver gas into California
- The El Paso natural gas pipeline serving southern California explodes in August 2000, cutting a major transportation path to provide fuel to electric generators and to enable completion of typical summer injection of gas into storage
- Result: not enough gas can get into California, and electric transmission constraints preclude routing enough excess electric energy from other regions from northern to southern California or south to north

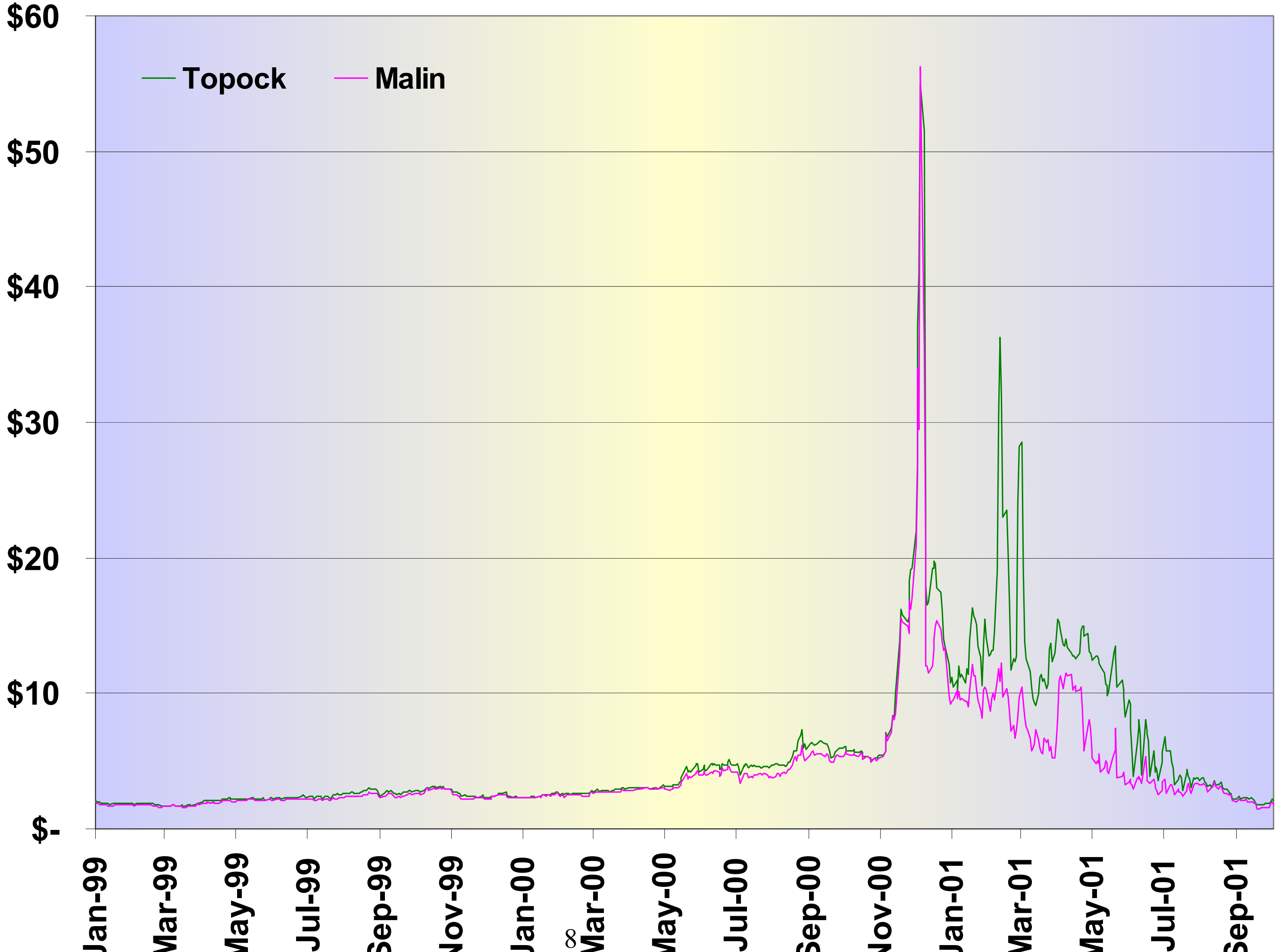
Major Outages of Available Power Plants Reduced Supply

- Unusually dry weather resulted in limited output from hydro facilities
- Nearly 30 percent of generation in California is hydroelectric
- By early 2001, California hydro production was projected to be 70 percent of normal*
- Pacific Northwest had second driest winter on record
- Extraordinary outages last winter shocked the system -- up to 13,000 MW of total generating capacity was off-line (1/3 of winter peak demand)
  - causes included weather, pollution control installation, advanced plant age, stalled payments, and possible manipulation

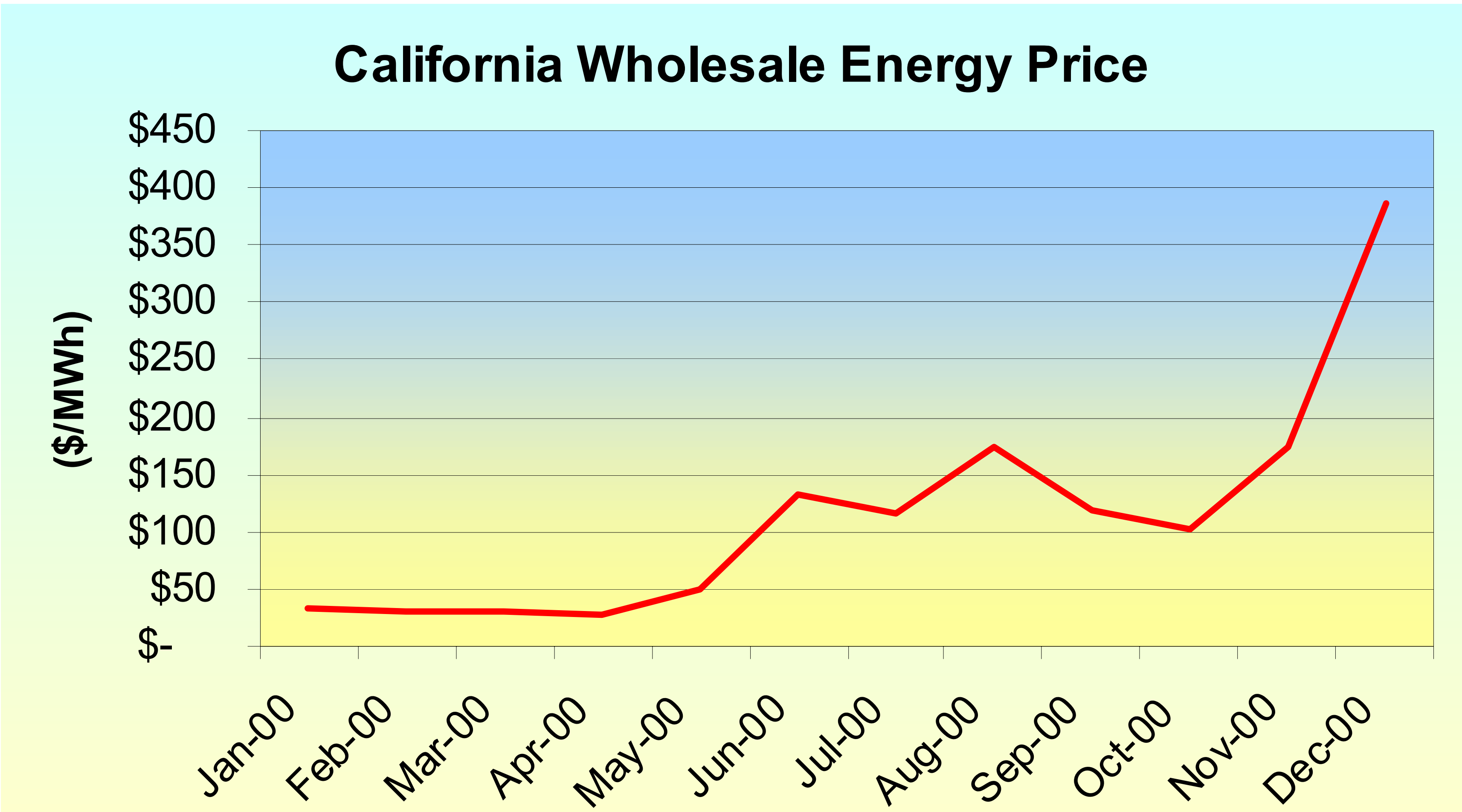
*Source: California Energy Commission, California Department of Water Resources, and the Climate Diagnostic Center

Natural Gas Price Spikes Took Heavy Toll

- Heightened by the El Paso gas pipeline explosion on August 19, 2000



By Late Summer 2000, Energy Prices were at Historic High Levels - and Increased Further by Year-End



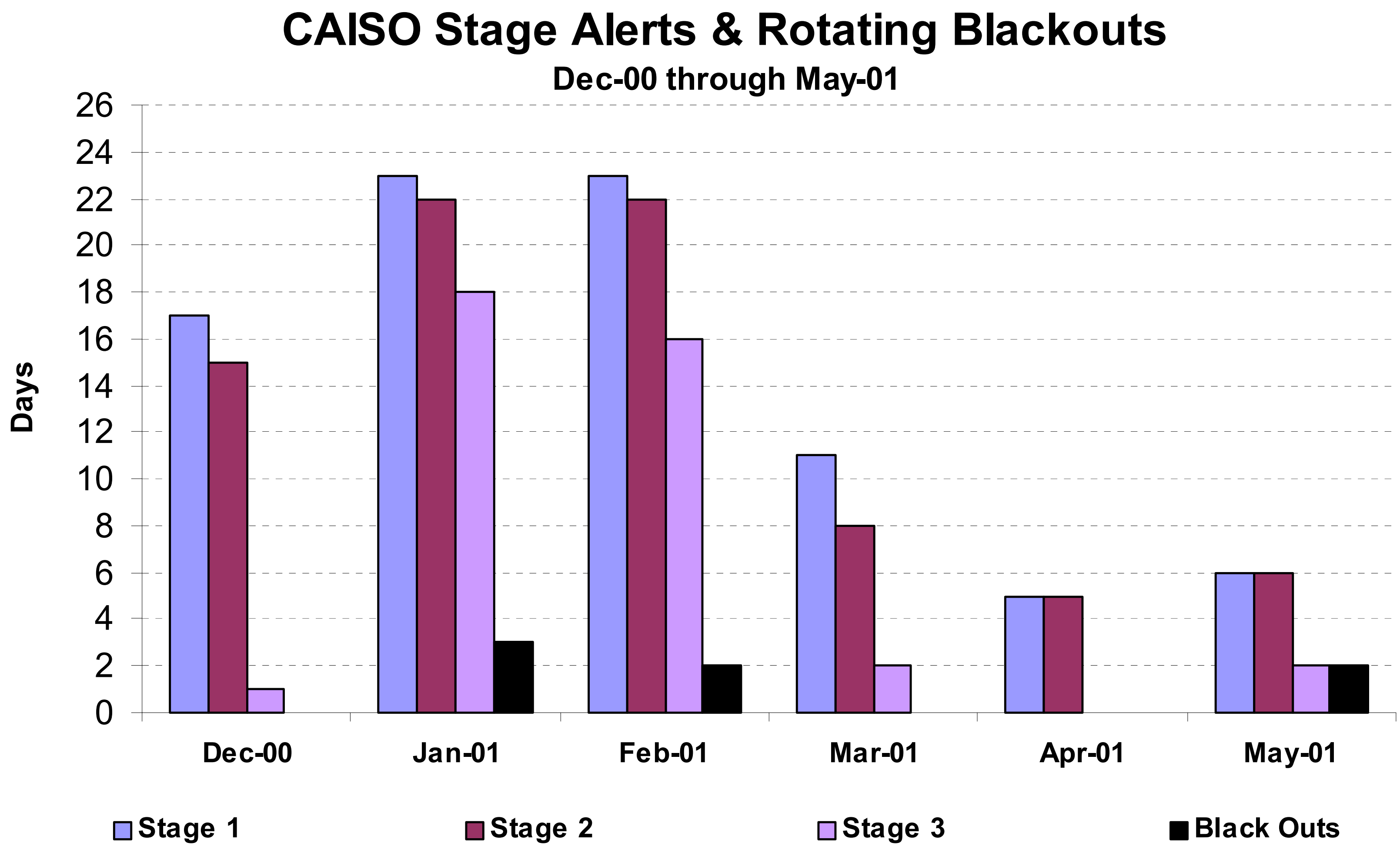
First Quarter 2001 Sees Average Hourly Prices

- In January 2001, average daily cost of spot market energy was over $400 per megawatt hour (MWh) (or 40 cents per kilowatthour)
- The power supply cost component in IOUs’ retail rates was about $65/MWh to $73/MWh
- Spot energy prices were five to six times the amount utilities could recover in rates
- Over 1/3 of total requirements of PG&E, SCE and SDG&E customers was being bought in the spot market

Staggering Daily Costs of Energy Was Unsupportable

- Total daily cost of energy in January 2001 ranged from $50 million to $90 million, from $2 million to nearly $4 million **per hour** for energy
- On January 30, 2001, the California Power Exchange ceased trading and sought creditor protection
- Between the last week of January and the first week of February, both PG&E and Southern California Edison defaulted on debt payments, quickly falling below investment grade credit
- The California Independent System Operator, not receiving payments for energy it purchased, became uncreditworthy
- Many power suppliers quit selling in California altogether, creating more price pressure
- Without intervention, monthly net short energy costs could have exceeded $1.5 billion to $2 billion
- PG&E later (April 6, 2001) filed for bankruptcy protection

The State Went on Alert and Rotating Blackouts Began



The State Acted in January 2001 to Keep the Lights On

- California Department of Water Resources (DWR) was given authority to purchase the "net short" energy that the IOUs cannot supply to customers from their own sources

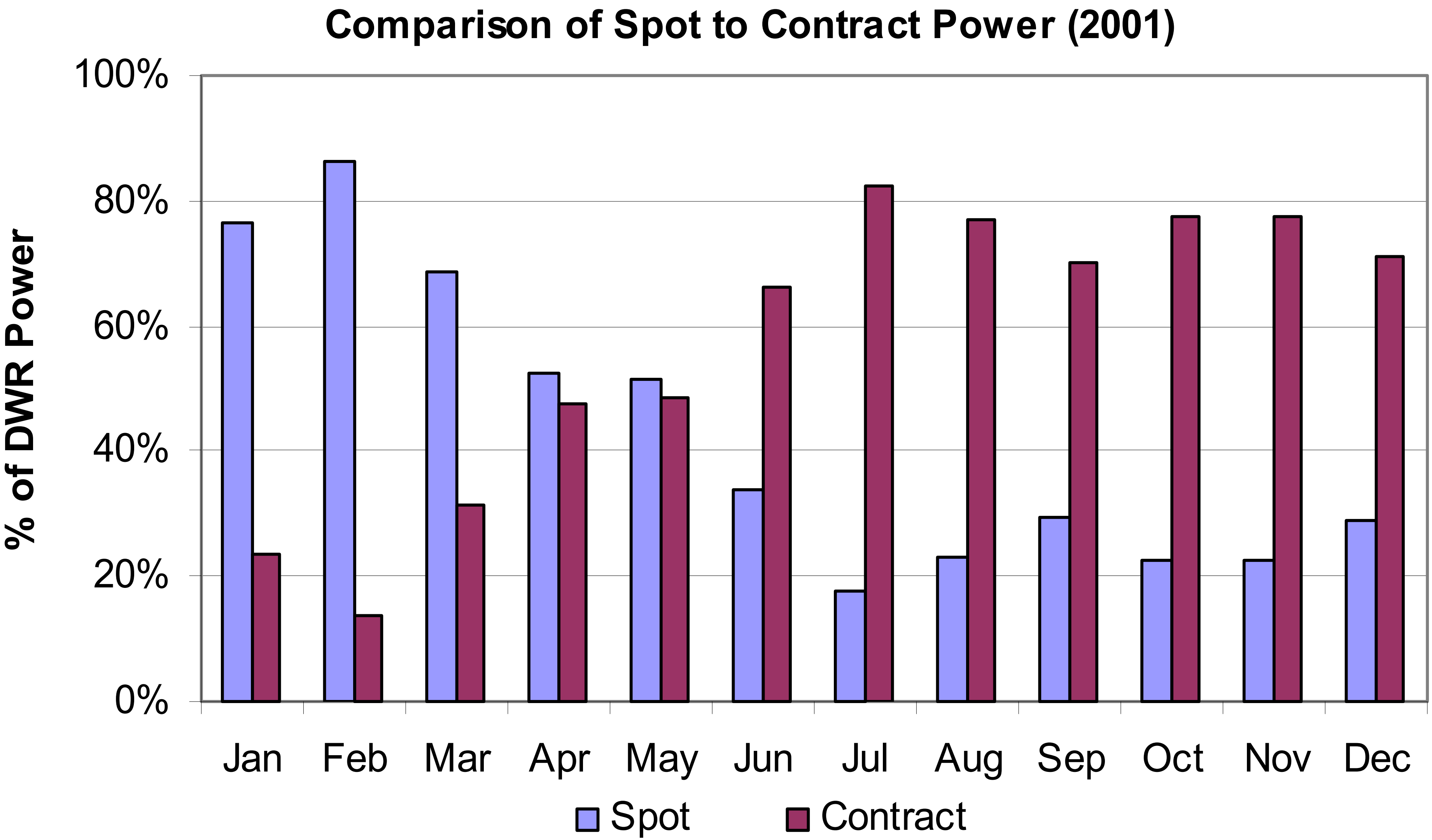
- Legislation Enacted (Senate Bill 7X, Assembly Bill 1X and Senate Bill 31X)
  - provided for DWR's role in purchasing and reselling power to retail customers
  - established temporary funding from the General Fund
  - authorized issuance of bonds
  - required recovery of costs through rate increases

- Created a self-supporting and creditworthy structure based on revenues for DWR
  - enables DWR to smooth out costs of power over term of financing
  - allows DWR to use financing to compensate for volatility in energy markets

The State's Strategy Aimed to Stabilize the Market and Bring Prices Down

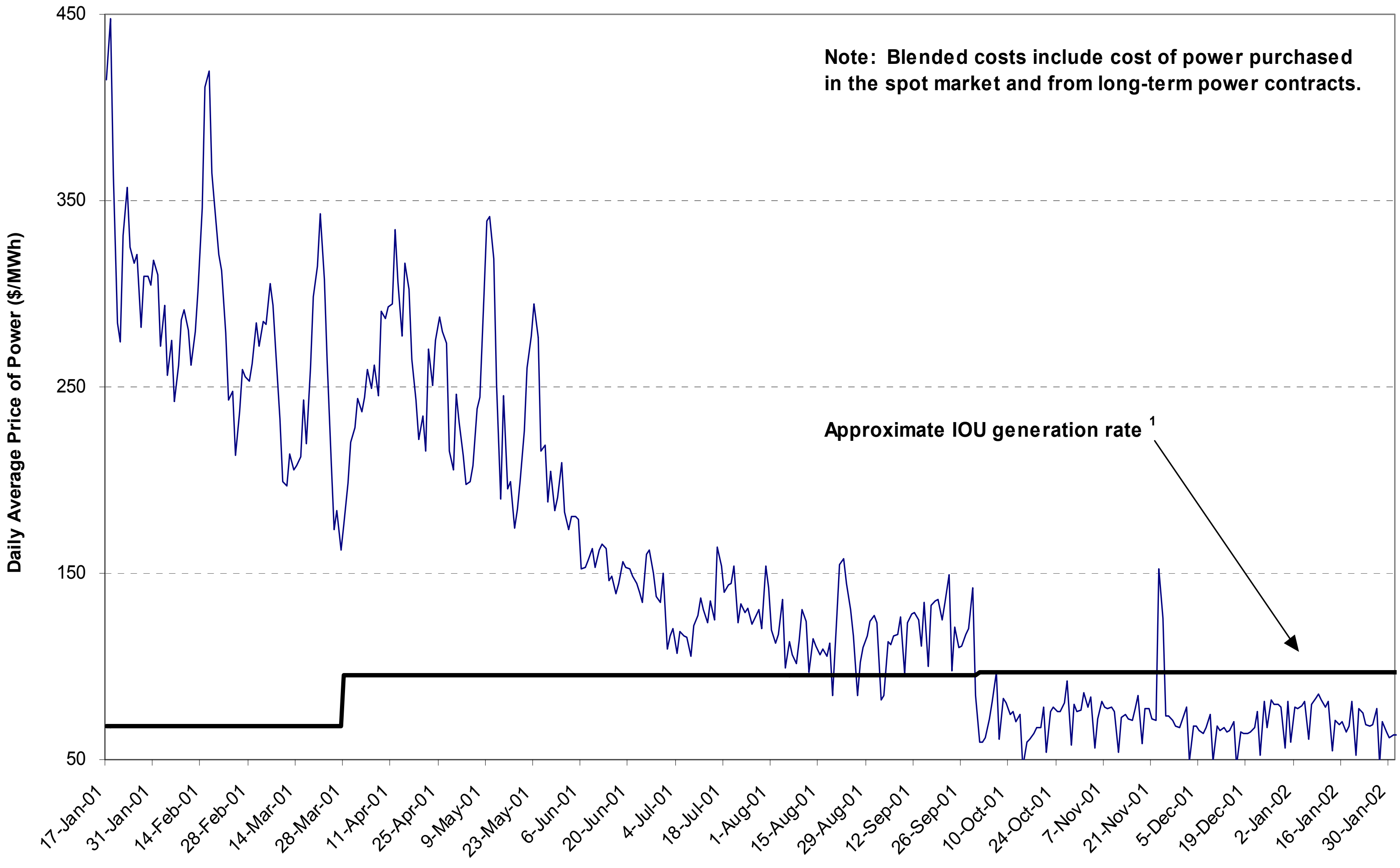
- Increase power supply in State by streamlining power plant siting process
- Return existing power plants to service to restore existing capacity
- Alleviate dependence on spot market purchases through new power contracts
- Prioritize contracts tied to new generation capacity in the State
- Promote conservation and demand reduction

California's Spot Market Exposure has Declined



[1] Spot includes only day ahead, hour ahead, real time, and OOM net of off-system sale

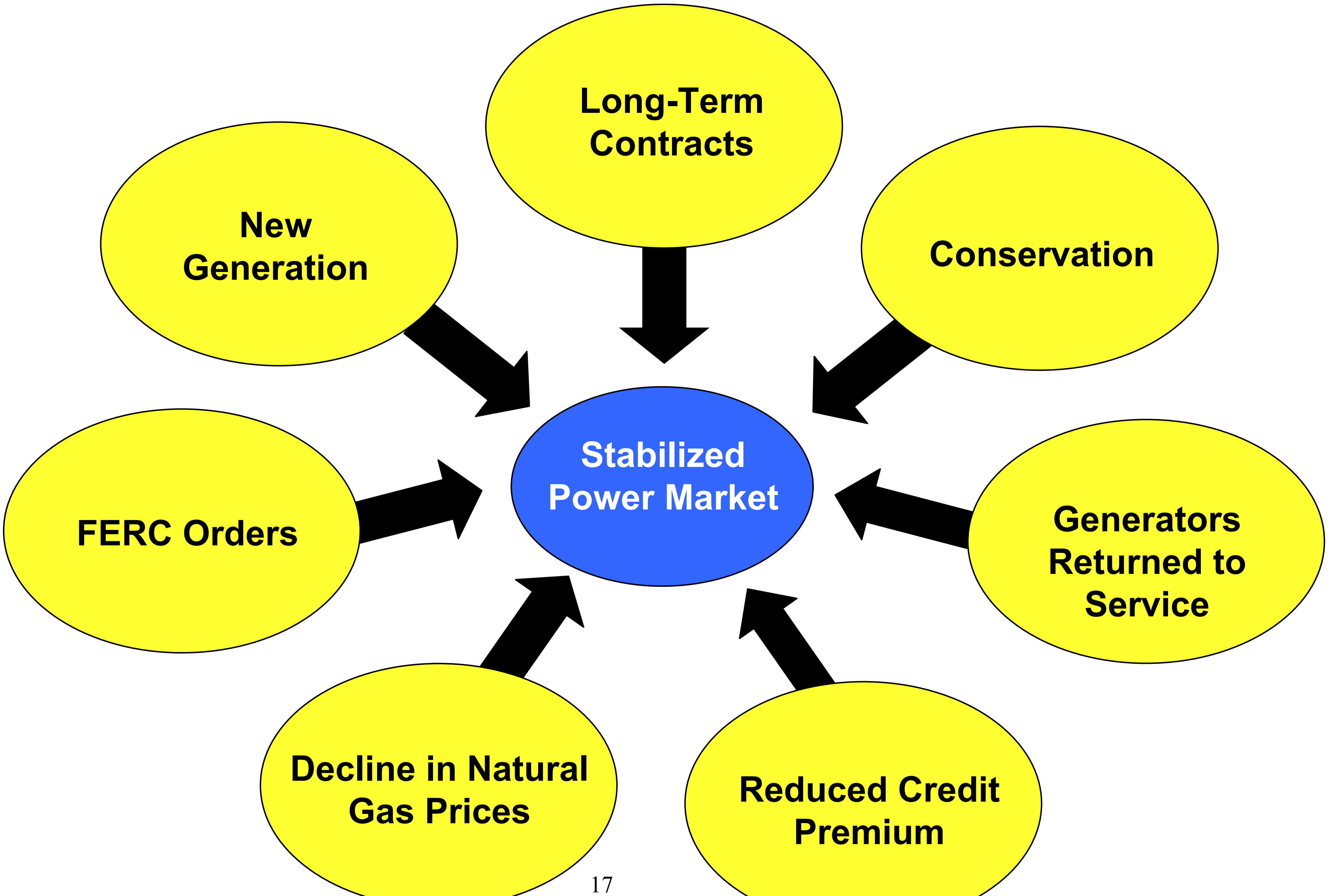
Prices Return to Near-Normal



[1] Rate is weighted average of total IOU sales. Includes $30/MWh increase to PG&E and SCE generation rates on 3/29/01 and a $14.60/MWh increase to SDG&E generation rates on 10/1/01.

Source: California Department of Water Resources

Factors Contributing to a Stable California Power Market



Protecting Consumers from Crisis Costs

- $6 billion advanced from State General Fund January through June 26, 2001
- $500 million block advances provided to Department of Water Resources to purchase energy for utilities' customers (in Jan-Feb, $500 million every 7 to 12 days)
- $4.3 billion "bridge loan" obtained June 26, 2001 - stopped need for General Fund advances
- Rates increased for PG&E and Southern California Edison in March 2001
- Rates increased for San Diego Gas & Electric in September 2001
- February 21, 2002—California Public Utilities Commission adopts DWR revenue requirement and a rate agreement assuring recovery of net short energy purchase costs of DWR

Resulting CPUC Adopted DWR—Supplied Energy Rate

Energy Rate Comparison for 2001-2002

$/MWh

	PG&E	**SCE**	**SDG&E**
DWR Rate[1]	92.95	97.44	72.85
Gen Rate [2]	64.71	72.77	65.00
Weighted Average Rate[3]	73.46	79.43	69.16

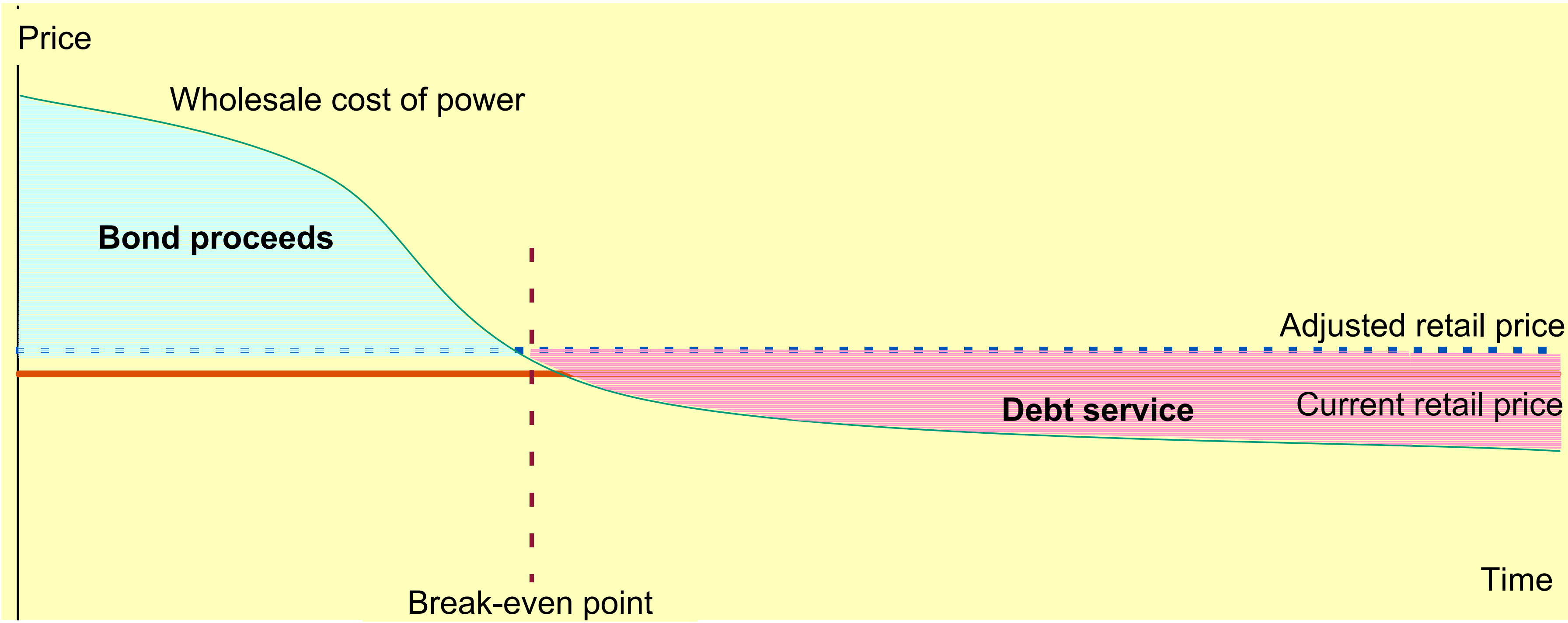
[1] Applied to DWR—Supplied Energy

[2] Existing IOU generation rate in retail rates, prior to anticipated adjustments from pending CPUC URG case

[3] Reflects following share of DWR--Supplied Power:

PG&E	31%
SCE	27%
SDG&E	53%

Bonds Used to Smooth Out the Cost of Power



- Until the break-even point, bond proceeds will be used to pay the cost of power and debt service, together with revenues received from customers
- After the break-even point, customer revenue will be sufficient to pay debt service and cost of power as purchased power costs fall below rates

Note: Figure not drawn to scale

Financial Reports
For Year and Quarter Ended December 31, 2001

Preface

Pursuant to the reporting requirement in AB 1X, the following information reflects energy acquisition activities and expenditures incurred by the California Energy Resources Scheduling Division (CERS) of the Department of Water Resources for the calendar year 2001. Included are all costs related to initial setup, administration, and energy acquisition.

CERS was created by AB 1X to purchase electricity on behalf of customers of Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric and, subsequently, the California Independent System Operator.

In 2001, CERS purchased 62.1 million megawatt hours of electricity at a cost of $11.6 billion. Most of that cost – nearly $8.8 billion - was incurred during the first six months of the year. Total monthly costs peaked in May 2001 at $1.8 billion. Monthly costs fell dramatically to a low of $278 million in November 2001.

Average monthly spot market prices peaked at $355 per megawatt hour in January 2001 but declined every month to a low of $28 per megawatt hour in October 2001.

CERS' daily expenditures for electricity declined by more than 600 percent over the course of 2001. In the early months of the year, daily expenses for energy typically ranged from $40 million to $60 million with several days in May reaching $100 million. By October, daily expenditures for energy averaged $10 million and decreased to $9 million per day in November and December.

Despite dire predictions that the summer of 2001 would be plagued by several hundred hours of electrical blackouts, there were none. In total, California had 23 hours of blackouts over seven days. The last blackout day occurred on May 8, 2001.

The major factors contributing to the dramatic decrease in electricity prices and increase in electricity market stability include the injection of reliable power through long-term contracts, increased supplies of, and lower prices for, natural gas, lower consumer demand through voluntary conservation and the addition of new generation capacity. The combined effect of these factors resulted in lower spot market prices and the declining cost of electricity purchased by CERS over the last six months of 2001.

Financial Reports
Statement of Cash Flows and Available Funding (in millions)

	Quarter Ended December 31, 2001	January 17, 2001 - December 31, 2001
Cash Receipts		
Advances from General Fund		$ 6,210
Proceeds from June 26, 2001 Interim Loan		4,300
Revenue from Ratepayers of IOUs	$ 1,124	3,444
Receipts from California ISO		148
Total Cash Receipts	1,124	14,102
Cash Expenditures		
Power (net of power sales)	1,741	11,190
Repayment to General Fund		116
Interest on Interim Loan	69	69
Administration and costs incurred in anticipation of sale of long-term bonds	9	46
Total Cash Expenditures	1,819	11,421
Change in Cash	(695)	2,681
Cash Balance at October 1, 2001	3,376	
Cash Balance at December 31, 2001	2,681	2,681
Accruals		
Accounts payable for Power delivered through December 31, 2001	717	717
Funding Available at December 31, 2001	$ 1,964	$ 1,964

Financial Reports
Summary of Appropriations (in millions)

Source	Effective Date	Amount
Appropriations to DWR	01/17/01	$302
Appropriations under SBX1 7	01/19/01	400
Appropriations under ABX1 1		
Original Appropriation	02/01/01	500
First Deficiency	02/15/01	500
Second Deficiency	02/23/01	500
Third Deficiency	03/04/01	500
Fourth Deficiency	03/12/01	500
Fifth Deficiency	03/19/01	500
Sixth Deficiency	03/29/01	500
Seventh Deficiency	04/07/01	500
Eighth Deficiency	04/22/01	500
Ninth Deficiency	04/29/01	500
Tenth Deficiency	05/07/01	500
Additional Appropriation for Administrative Expenditures	06/18/01	8
Total General Fund Appropriations		**$6,210**

Notes:

DWR reimbursed the General Fund for $116,300,000, the cash remaining in the DWR Electric Fund, when the funding from the Bridge Loan became available on June 26, 2001.

Four additional deficiency notices totaling $2 billion were appropriated; however, there were no expenditures from those notices. As required by ABX1 1, deficiency notices were requested 10 days before it was anticipated they would be needed for additional commitments. However, funds were transferred to the DWR Electric Power Fund only as they were needed to make payments on the commitments.

Financial Reports
Receipts from Ratepayers of IOUs

	Pacific Gas & Electric	San Diego Gas & Electric	Southern California Edison	Total
February		$33		$33
March	$76	77	$55	208
April	143	16	93	252
May	159	18	99	276
June	213	36	118	367
July	268	31	138	437
August	223	27	151	401
September	192	14	140	346
October	184	13	184	381
November	157	34	171	362
December	202	37	142	381
Totals	$1,817	$336	$1,291	$3,444

San Diego Gas & Electric began payments to DWR on February 7, 2001 under the terms of a Letter Agreement between SDG&E and DWR entered into on February 7, 2001.

Pacific Gas & Electric and Southern California Edison began making payments to DWR on March 29, 2001 under the terms of a PUC Order issued March 27, 2001.

Financial Reports
Summary of Monthly Energy Commitments

	Spot Market			Contracts			ISO Related Costs	Total		
Date	Mwh (millions)	Cost (millions)	Avg. Price	Mwh (millions)	Cost (millions)	Avg. Price	Cost (millions)	Mwh (millions)	Cost (millions)	Avg. Price
January 2001	1.037	368	355	0.387	118	306	159	1.425	645	453
February 2001	3.863	1,193	309	0.761	127	168	405	4.624	1,726	373
March 2001	4.092	1,157	283	2.727	500	183	138	6.819	1,794	263
April 2001	3.274	1,114	340	3.246	584	180	59	6.520	1,758	270
May 2001	3.770	1,060	281	3.772	746	198	20	7.542	1,826	242
June 2001	1.859	203	109	3.906	663	170	137	5.765	1,003	174
July 2001	1.273	91	72	4.825	634	131	36	6.098	761	125
August 2001	1.577	80	51	4.379	557	127	20	5.955	656	110
September 2001	1.486	47	31	3.359	467	139	17	4.845	531	110
October 2001	1.116	32	28	3.505	278	79	15	4.621	324	70
November 2001	0.968	30	31	2.786	233	84	15	3.754	278	74
December 2001	1.298	40	31	2.854	238	83	17	4.152	294	71
Total	**25.614**	**5,415**	**211**	**36.507**	**5,145**	**141**	**1,038**	**62.121**	**11,597**	**187**

Spot Market includes: Day-ahead, hour-ahead, and real-time power purchase costs for bilateral purchases made by CERS.
Contracts include: Long-term and short-term, balance of month, quarterly, and block forward purchases.
ISO Costs include: Real time energy, ancilliary services, transmission and dispatch costs incurred in the ISO market plus costs incurred by CERS as the credit worthy backer of the investor owned utilities. Costs per month agree to amounts billed to CERS by ISO as a result of November 6, 2001 FERC order.

Actual Energy Expenditures vs. Forecast - 2001

	FORECAST[1]			ACTUAL			DIFFERENCE FROM FORECAST	
	MWh (millions)	Cost (millions)	Price $/MWh	MWh (millions)	Cost (millions)	Price $/MWh	MWh (millions)	Cost (millions)
January	--	--	--	1.425	$645	453	--	--
February	--	--	--	4.624	$1,726	373	--	--
March	--	--	--	6.819	$1,794	263	--	--
April	5.976	$1,781	298	6.520	$1,758	270	0.544	<$23>
May	6.113	$1,756	287	7.542	$1,826	242	1.429	$70
June	5.399	$1,123	208	5.765	$1,003	174	0.366	<$120>
July	4.447	$1,123	252	6.098	$ 761	125	1.651	<$362>
August	5.149	$ 933	181	5.955	$ 656	110	0.806	<$277>
September	5.433	$ 955	175	4.845	$ 531	110	<0.588>	<$424>
October	5.419	$ 724	133	4.622	$ 324	70	<0.797>	<$400>
November	4.321	$ 661	153	3.755	$ 278	74	<0.566>	<$383>
December	4.409	$ 716	162	4.152	$ 294	71	<0.257>	<$422>

1 Forecast for April – June based on Navigant Consulting, Inc. model used to generate May 2, 2001 Revenue Requirement filing. Forecast for July thru September based on revised Revenue Requirement filed with the Public Utilities Commission on August 7, 2001.

Financial Reports

Power Purchase Commitments October 2001

Mo./	Spot Market			Contracts			ISO Cost	Total		
Day	MWh	Dollars	$/MWh	MWh	Dollars	$/MWh	Dollars	MWh	Dollars	$/MWh
10/1	114,278	3,660,731	32	108,802	9,314,344	86	1,664,979	223,080	14,640,054	66
10/2	104,755	3,029,103	29	113,642	9,427,807	83	561,924	218,397	13,018,834	60
10/3	80,269	2,127,135	27	113,630	9,440,653	83	532,042	193,899	12,099,830	62
10/4	60,580	1,618,059	27	111,626	9,400,332	84	198,937	172,206	11,217,328	65
10/5	24,630	610,827	25	112,203	9,440,071	84	131,969	136,833	10,182,867	74
10/6	3,362	78,851	23	111,531	9,396,711	84	148,394	114,893	9,623,956	84
10/7	25,897	641,307	25	69,032	4,450,632	64	295,476	94,929	5,387,415	57
10/8	15,017	383,897	26	111,247	9,380,097	84	306,151	126,264	10,070,145	80
10/9	12,289	301,673	25	115,744	9,480,254	82	374,445	128,033	10,156,372	79
10/10	28,785	701,108	24	116,462	9,493,066	82	572,627	145,247	10,766,801	74
10/11	24,899	598,776	24	117,180	9,546,278	81	255,147	142,079	10,400,201	73
10/12	32,676	856,709	26	114,003	9,469,005	83	908,026	146,679	11,233,740	77
10/13	25,887	638,338	25	111,323	9,394,575	84	178,206	137,210	10,211,119	74
10/14	82,466	2,212,421	27	74,856	4,636,668	62	278,728	157,322	7,127,817	45
10/15	92,722	2,673,726	29	115,080	9,504,560	83	566,108	207,802	12,744,394	61
10/16	75,416	2,015,154	27	116,594	9,540,166	82	449,112	192,010	12,004,432	63
10/17	47,226	1,241,955	26	130,069	9,932,752	76	365,948	177,295	11,540,655	65
10/18	40,695	1,165,247	29	130,006	9,936,986	76	732,499	170,701	11,834,732	69
10/19	33,619	935,167	28	130,865	9,930,579	76	363,766	164,484	11,229,512	68
10/20	18,194	466,970	26	112,933	9,445,976	84	146,283	131,127	10,059,229	77
10/21	30,729	788,085	26	81,941	4,836,456	59	138,599	112,670	5,763,140	51
10/22	16,624	444,229	27	123,445	9,724,328	79	286,575	140,069	10,455,132	75
10/23	10,894	319,741	29	123,179	9,724,735	79	698,936	134,073	10,743,412	80
10/24	17,570	551,539	31	123,388	9,745,786	79	941,572	140,958	11,238,897	80
10/25	17,561	558,273	32	123,649	9,744,616	79	762,846	141,210	11,065,735	78
10/26	3,095	111,178	36	123,578	9,752,430	79	750,622	126,673	10,614,230	84
10/27	1,731	58,007	34	112,540	9,440,496	84	438,879	114,271	9,937,382	87
10/28	22,727	781,883	34	84,139	4,972,011	59	241,986	106,866	5,995,880	56
10/29	11,326	526,408	46	124,013	9,768,926	79	718,898	135,339	11,014,232	81
10/30	15,756	692,361	44	123,926	9,771,368	79	469,877	139,682	10,933,606	78
10/31	25,006	934,516	37	124,263	9,791,083	79	102,995	149,269	10,828,594	78
	1,116,681	31,723,374	28	3,504,889	277,833,747	79	14,582,555	4,621,570	324,139,676	70

Spot Market includes: Day-ahead, hour-ahead, and real-time pow er purchase costs for bilateral purchases made by CERS.
Contracts include: Long-term and short-term, balance of month, quarterly, and block forw ard purchases.
ISO Costs include: Real time energy, ancilliary services, transmission and dispatch costs incurred in the ISO market plus costs incurred by CERS as the credit backer of the investor ow ned utilities. Costs per month agree to amounts billed to CERS by ISO as a result of November 6, 2001 FERC order.
Amounts show n above may be revised in Settlement processes.

Financial Reports

Power Purchase Commitments November 2001

Mo./	Spot Market			Contracts			ISO Cost	Total		
Day	MWh	Dollars	$/MWh	MWh	Dollars	$/MWh	Dollars	MWh	Dollars	$/MWh
11/1	43,049	1,546,304	36	85,477	8,092,656	95	562,137	128,526	10,201,097	79
11/2	33,284	1,152,822	35	85,298	8,076,201	95	782,551	118,582	10,011,574	84
11/3	22,320	685,038	31	85,029	8,048,496	95	677,742	107,349	9,411,276	88
11/4	49,555	1,467,963	30	50,106	3,946,601	79	124,315	99,661	5,538,879	56
11/5	53,178	1,725,024	32	85,521	8,077,278	94	262,747	138,699	10,065,049	73
11/6	49,905	1,558,369	31	85,414	8,075,067	95	165,624	135,319	9,799,060	72
11/7	43,178	1,396,651	32	100,638	8,519,045	85	366,181	143,816	10,281,877	71
11/8	44,086	1,442,731	33	102,148	8,563,908	84	139,127	146,234	10,145,766	69
11/9	32,326	1,059,215	33	102,443	8,577,294	84	420,014	134,769	10,056,523	75
11/10	38,703	1,187,241	31	96,408	8,360,192	87	725,390	135,111	10,272,823	76
11/11	41,525	1,227,756	30	74,532	4,678,221	63	647,468	116,057	6,553,445	56
11/12	39,201	1,283,963	33	103,120	8,610,914	84	958,053	142,321	10,852,930	76
11/13	30,261	982,977	32	103,441	8,623,708	83	1,119,028	133,702	10,725,713	80
11/14	26,373	692,351	26	102,598	8,570,521	84	832,542	128,971	10,095,414	78
11/15	23,446	559,770	24	102,575	8,569,176	84	803,147	126,021	9,932,093	79
11/16	29,180	749,953	26	102,492	8,554,288	83	171,825	131,672	9,476,066	72
11/17	18,947	512,422	27	96,832	8,341,348	86	126,578	115,779	8,980,348	78
11/18	21,659	510,218	24	73,789	4,595,156	62	122,369	95,448	5,227,743	55
11/19	21,871	544,331	25	102,172	8,515,856	83	140,838	124,043	9,201,025	74
11/20	12,490	253,372	20	102,479	8,555,639	83	694,208	114,969	9,503,219	83
11/21	30,149	784,771	26	103,001	8,613,808	84	1,051,315	133,150	10,449,894	78
11/22	36,985	1,081,013	29	59,650	4,126,194	69	107,091	96,635	5,314,298	55
11/23	18,230	493,490	27	99,141	8,389,862	85	133,940	117,371	9,017,292	77
11/24	936	18,606	20	93,692	8,209,946	88	178,797	94,603	8,407,099	89
11/25	7,185	171,045	24	74,589	4,646,907	62	168,981	81,774	4,986,933	61
11/26	22,237	717,724	32	102,486	8,539,864	83	544,721	124,723	9,802,309	79
11/27	29,814	964,601	32	102,594	8,572,223	84	889,440	132,408	10,426,264	79
11/28	50,423	1,870,042	37	102,430	8,571,134	84	1,100,384	152,853	11,541,560	76
11/29	55,137	2,065,329	37	102,250	8,569,874	84	354,692	157,387	10,989,895	70
11/30	42,502	1,410,511	33	104,474	8,681,534	83	273,261	146,976	10,365,306	71
	968,135	30,115,603	31	2,786,819	232,872,911	84	14,644,509	3,754,954	277,633,023	74

Spot Market includes: Day-ahead, hour-ahead, and real-time pow er purchase costs for bilateral purchases made by CERS.
Contracts include: Long-term and short-term, balance of month, quarterly, and block forw ard purchases.
ISO Costs include: Real time energy, ancilliary services, transmission and dispatch costs incurred in the ISO market plus costs incurred by CERS as the credit w orthy backer of the investor ow ned utilities. Costs per month agree to amounts billed to CERS by ISO as a result of November 6, 2001 FERC order.
Amounts show n above may be revised in Settlement processes.

Financial Reports

Power Purchase Commitments December 2001

Mo./	Spot Market			Contracts			ISO Cost	Total		
Day	MWh	Dollars	$/MWh	MWh	Dollars	$/MWh	Dollars	MWh	Dollars	$/MWh
12/1	38,904	1,030,959	26.50	87,418	8,102,909	93	165,397	126,322	9,299,265	74
12/2	60,293	1,667,008	27.65	66,056	4,450,936	67	107,856	126,349	6,225,800	49
12/3	51,666	1,572,794	30.44	94,419	8,404,821	89	109,865	146,085	10,087,480	69
12/4	50,307	1,498,821	29.79	93,761	8,337,825	89	482,478	144,068	10,319,124	72
12/5	53,690	1,611,603	30.02	98,591	8,479,134	86	701,788	152,281	10,792,525	71
12/6	61,002	1,777,045	29.13	99,545	8,467,215	85	116,382	160,547	10,360,642	65
12/7	49,140	1,438,003	29.26	99,096	8,442,346	85	169,641	148,236	10,049,990	68
12/8	31,705	844,655	26.64	98,294	8,402,635	85	105,590	129,999	9,352,880	72
12/9	58,203	1,634,593	28.08	67,879	4,486,348	66	132,800	126,082	6,253,741	50
12/10	43,811	1,283,201	29.29	99,089	8,437,743	85	811,544	142,900	10,532,488	74
12/11	55,418	1,683,894	30.39	98,699	8,420,912	85	723,956	154,117	10,828,762	70
12/12	57,994	2,120,381	36.56	98,756	8,430,054	85	712,856	156,750	11,263,291	72
12/13	61,419	2,129,635	34.67	98,653	8,424,028	85	700,750	160,072	11,254,413	70
12/14	52,539	1,607,448	30.60	99,128	8,451,816	85	723,965	151,667	10,783,229	71
12/15	46,169	1,476,374	31.98	98,922	8,437,828	85	466,552	145,091	10,380,754	72
12/16	74,925	2,401,356	32.05	67,982	4,502,230	66	410,575	142,907	7,314,161	51
12/17	62,970	2,052,384	32.59	99,555	8,477,511	85	451,017	162,525	10,980,912	68
12/18	64,959	2,081,371	32.04	99,629	8,489,321	85	525,238	164,588	11,095,930	67
12/19	64,089	1,998,810	31.19	99,065	8,449,002	85	1,214,618	163,154	11,662,430	71
12/20	59,856	1,937,524	32.37	100,170	8,515,141	85	910,731	160,026	11,363,396	71
12/21	51,778	1,558,559	30.10	100,378	8,525,217	85	477,861	152,156	10,561,637	69
12/22	23,823	639,733	26.85	99,985	8,506,098	85	1,206,481	123,808	10,352,312	84
12/23	39,270	1,188,720	30.27	68,848	4,558,974	66	213,276	108,118	5,960,970	55
12/24	3,165	94,900	29.98	99,918	8,502,179	85	434,864	103,083	9,031,943	88
12/25	13,493	314,131	23.28	52,798	4,020,049	76	623,901	66,291	4,958,081	75
12/26	5,201	161,033	30.96	99,894	8,500,619	85	658,611	105,095	9,320,263	89
12/27	9,022	296,052	32.81	99,618	8,485,089	85	775,432	108,640	9,556,573	88
12/28	10,330	314,603	30.46	99,822	8,492,691	85	992,596	110,152	9,799,890	89
12/29	12,905	345,811	26.80	99,561	8,473,374	85	508,632	112,466	9,327,817	83
12/30	25,128	713,803	28.41	68,821	4,549,474	66	401,053	93,949	5,664,330	60
12/31	5,042	139,390	27.65	99,892	8,492,738	85	484,941	104,934	9,117,069	87
	1,298,216	$39,614,594	$30.51	2,854,242	237,716,257	83	16,521,247	4,152,458	293,852,098	71

Spot Market includes: Day-ahead, hour-ahead, and real-time power purchase costs for bilateral purchases made by CERS.
Contracts include: Long-term and short-term, balance of month, quarterly, and block forward purchases.
ISO Costs include: Real time energy, ancilliary services, transmission and dispatch costs incurred in the ISO market plus costs incurred by CERS as the credit worthy backer of the investor owned utilities. Costs per month agree to amounts billed to CERS by ISO as a result of November 6, 2001 FERC order.
Amounts shown above may be revised in Settlement processes.

Power Purchases for Quarter Ending December 2001 by Counterparty

COMPANY	OCTOBER			NOVEMBER			DECEMBER			TOTAL		
	MWh	Dollars	Avg. Price	MWh	Dollars	Avg. Price	MWh	Dollars	Avg. Price	MWh	Dollars	Avg. Pric
American Electric Power Services	-	-	-	150	4,800	32	200	4,600	23	350	9,400	27
New Energy, Inc.	1,358	45,576	34	918	21,431	23	710	14,640	21	2,986	81,647	27
Allegheny Energy Trading Services	638,434	34,489,699	54	473,200	29,364,940	62	394,900	27,853,950	71	1,506,534	91,708,589	61
City of Anaheim	2,115	44,940	21	-	-	-	645	15,872	25	2,760	60,812	22
Avista Energy Inc.	16,376	541,438	33	25,379	766,308	30	115,217	3,490,362	30	156,972	4,798,108	31
Bonneville Power Administration	47,257	1,868,931	40	29,592	850,742	29	54,247	1,711,758	32	131,096	4,431,431	34
BP Energy Company	25	644	26	397	12,379	31	3,835	114,652	30	4,257	127,675	30
City of Burbank	30	1,380	46	335	9,235	28	-	-	-	365	10,615	29
Calpine	567,701	34,922,578	62	352,039	28,315,872	80	354,385	28,889,940	82	1,274,125	92,128,390	72
California Department of Water Resources	16,993	391,391	23	26,707	796,759	30	108,001	2,671,133	25	151,701	3,859,283	25
Commonwealth Energy Corp	2,341	66,820	29	13,836	388,696	28	-	-	-	16,177	455,516	28
CDWR - State Water Project	96	2,688	28	-	-	-	-	-	-	96	2,688	28
Alliance Colton	-	-	-	-	-	-	624	31,200	50	624	31,200	50
Constellation Power Source	143,028	14,992,711	105	117,624	13,516,845	115	115,783	13,419,979	116	376,435	41,929,535	111
Coral Power, L.L.C	97,898	21,871,079	223	53,267	5,039,399	95	54,845	5,023,219	92	206,010	31,933,697	155
Duke Energy Trading & Marketing, L.L.C.	179,926	9,499,233	53	173,063	8,988,495	52	182,656	9,287,453	51	535,645	27,775,181	52
Dinumba Biomass	-	-	-	-	-	-	3,600	234,000	65	3,600	234,000	65
East Bay Municipal Utility District	-	-	-	-	-	-	616	17,224	28	616	17,224	28
Dynegy Power Marketing Inc.	571,290	59,259,906	104	539,235	54,110,859	100	558,400	55,317,404	99	1,668,925	168,688,169	101
El Paso Merchant Energy	54,183	5,541,609	102	76,945	5,986,930	78	116,827	7,423,425	64	247,955	18,951,964	76
Enron Power Marketing, Inc.	31,180	1,179,049	38	27,717	1,074,713	39	1,600	67,200	42	60,497	2,320,962	38
Eugene Water & Electric Board	280	10,190	36	250	6,000	24	1,875	60,950	33	2,405	77,140	32
Fresno Cogen	-	-	-	-	-	-	105	5,250	50	105	5,250	50
Grant County PUD	25	950	38	6,728	231,485	34	1,365	44,530	33	8,118	276,965	34
GWF Power	1,598	44,744	28	-	-	-	-	-	-	1,598	44,744	28
Imperial Valley Resource Recovery	11,920	1,192,000	100	11,520	1,152,000	100	11,904	1,190,400	100	35,344	3,534,400	100
Los Angeles Department of Water & Power	11,048	439,431	40	5,422	231,011	43	1,625	80,400	49	18,095	750,842	41
Madera Biomass	-	-	-	-	-	-	6,336	411,840	65	6,336	411,840	65
Mirant	417,152	39,951,785	96	482,798	40,264,179	83	638,530	45,551,645	71	1,538,480	125,767,609	82
Modesto Irrigation District	60	1,820	30	-	-	-	890	29,110	33	950	30,930	33
Mieco, Inc.	356,100	12,926,075	36	456,600	16,542,400	36	316,200	12,679,300	40	1,128,900	42,147,775	37
Morgan Stanley Capital Group	64,250	4,227,725	66	37,400	3,483,200	93	49,400	3,902,100	79	151,050	11,613,025	77
Northern California Power Agency	17,380	517,277	30	7,306	201,258	28	2,879	71,718	25	27,565	790,253	29

Note: Purchases reflect bilateral transactions including long-term, short-term, block forward and spot transactions entered into by CERS and does not include ISO real-time energy or ancillary service costs purchased or guaranteed by CERS.

Power Purchases for Quarter Ending December 2001 by Counterparty (Con't.)

COMPANY	OCTOBER			NOVEMBER			DECEMBER			TOTAL		
	MWh	Dollars	Avg. Price	MWh	Dollars	Avg. Price	MWh	Dollars	Avg. Price	MWh	Dollars	Avg. Price
Reliant Energy Service	135,150	3,490,775	26	38,810	1,314,641	34	17,505	554,479	32	191,465	5,359,895	28
PacifiCorp Power Marketing, Inc.	117,374	7,965,133	68	113,511	7,706,809	68	114,871	7,912,475	69	345,756	23,584,417	68
PG&E Energy Trading - Power, L.P.	28,142	1,856,903	66	26,341	1,735,944	66	20,615	1,400,978	68	75,098	4,993,825	66
Public Service of New Mexico	25,124	678,031	27	7,814	212,360	27	34,065	860,958	25	67,003	1,751,349	26
Pinnacle West	3,195	95,730	30	310	8,435	27	1,400	41,600	30	4,905	145,765	30
Powerex	166,703	4,810,503	29	69,597	2,547,489	37	106,527	3,356,710	32	342,827	10,714,702	31
City of Seattle, City Light Dept.	200	5,450	27	662	18,278	28	5,335	150,365	28	6,197	174,093	28
San Diego Gas & Electric	200	4,250	21	-	-	-	-	-	-	200	4,250	21
Sempra Energy Trading (AIG)	12,899	336,847	26	10,825	282,088	26	18,187	505,472	28	41,911	1,124,407	27
Sacramento Municipal Utility Dist	17,145	1,454,852	85	14,635	1,339,169	92	41,463	2,209,309	53	73,243	5,003,330	68
Silicon Valley Power (Santa Clara)	150	450	3	-	-	-	-	-	-	150	450	3
Snohomish	349	11,239	32	380	10,430	27	-	-	-	729	21,669	30
Soledad Energy LLC	1,660	132,800	80	5,530	442,400	80	5,952	476,160	80	13,142	1,051,360	80
Sierra Power Corp	-	-	-	-	-	-	2,520	163,800	65	2,520	163,800	65
Sierra Pacific Industries	-	-	-	912	21,888	24	-	-	-	912	21,888	24
Salt River Project	35,626	923,345	26	26,263	733,702	28	39,079	968,965	25	100,968	2,626,012	26
Sunrise Power Company	41,820	1,080,790	26	2,170	108,500	50	8,114	405,700	50	52,104	1,594,990	31
TransAlta Energy Marketing U.S.	25,690	785,276	31	34,385	1,055,605	31	28,977	824,151	28	89,052	2,665,032	30
Tucson Electric Power	1,265	31,970	25	735	22,625	31	375	12,625	34	2,375	67,220	28
Tacoma Power	927	27,205	29	1,577	50,708	32	604	17,808	29	3,108	95,721	31
City of Vernon	-	-	-	58	1,726	30	95	3,040	32	153	4,766	31
Western Area Power Administrator	65	1,300	20	180	4,320	24	-	-	-	245	5,620	23
Williams Energy M and T	757,842	41,832,603	55	481,531	34,011,461	71	608,224	37,851,002	62	1,847,597	113,695,066	62
TOTAL	4,621,570	$ 309,557,121	$ 67	3,754,954	$ 262,988,514	$ 70	4,152,458	$ 277,330,851	$ 67	12,528,982	$ 849,876,486	$ 68

Note: Data shown reflects bilateral transactions including long-term,short-term, block forward contracts and spot transactions entered into by CERS and does not include ISO real time energy or ancillary service costs purchased or guaranteed by CERS.

Power Sales for Quarter Ending December 2001 by Market

OCTOBER 2001			
Sale Type	**MWh**	**Total Cost $**	**Avg $/MWh**
OOM	150,956	$ 2,272,135	$ 15
DA	48,235	$ 1,416,422	$ 29
HA	10,596	$ 234,325	$ 22
TOTAL	**209,787**	**$ 3,922,882**	**$ 19**
SALES AS PERCENTAGE OF TOTAL ESTIMATED LOAD	**1.19%**		

NOVEMBER 2001			
Sale Type	**MWh**	**Total Cost $**	**Avg $/MWh**
OOM	141,472	$ 1,391,986	$ 10
DA	48,700	$ 1,013,463	$ 21
HA	70,866	$ 787,674	$ 11
TOTAL	**261,038**	**$ 3,193,123**	**$ 12**
SALES AS PERCENTAGE OF TOTAL ESTIMATED LOAD	**2.16%**		

DECEMBER 2001			
Sale Type	**MWh**	**Total Cost $**	**Avg $/MWh**
OOM	2,950	$ 40,500	$ 14
DA	110,999	$ 2,628,207	$ 24
HA	74,747	$ 1,415,218	$ 19
TOTAL	**188,696**	**$ 4,083,925**	**$ 22**
SALES AS PERCENTAGE OF TOTAL ESTIMATED LOAD	**1.52%**		

QUARTER ENDED DECEMBER 2001			
Sale Type	**MWh**	**Total Cost $**	**Avg $/MWh**
OOM	295,378	3,704,621	$ 13
DA	207,934	5,058,092	$ 24
HA	156,209	2,437,217	$ 16
TOTAL	**659,521**	**11,199,930**	**$ 17**
SALES AS PERCENTAGE OF TOTAL ESTIMATED LOAD	**1.57%**		

Note: Out of Market (OOM) sales are sales transacted in real-time at the direction of the CISO. Day Ahead (DA) and Hour Ahead (HA) sales are transacted to reconcile CERS purchases with the IOU net short positions.

Financial Reports

Power Sales for Quarter Ending December 2001 by Counterparty

COMPANY NAME	OCTOBER			NOVEMBER			DECEMBER			TOTAL		
	MWh	Dollars	Avg. Price	MWh	Dollars	Avg. Price	MWh	Dollars	Avg. Price	MWh	Dollars	Avg. Price
Avista Energy	350	5,700	16	3,045	33,580	11	9,550	114,655	12	12,945	153,935	12
American Electric Pow er Services	-	-	-	750	20,500	27	52,800	1,378,000	26	53,550	1,398,500	26
Allegheny Energy Trading Services	-	-	-	-	-	-	17,600	478,000	27	17,600	478,000	27
City of Anaheim	348	6,264	18	-	-	-	-	-	-	348	6,264	18
Arizona Public Service	1,000	13,550	14	1,250	13,950	11	-	-	-	2,250	27,500	12
Bonneville Pow er Administration	15,487	228,915	15	22,002	197,433	9	4,000	66,100	17	41,489	492,448	12
BP Energy Company	-	-	-	-	-	-	445	11,580	26	445	11,580	26
City of Burbank	190	4,140	22	165	2,640	16	200	4,000	20	555	10,780	19
Calpine	903	24,190	27	3,048	61,329	20	4,506	95,267	21	8,457	180,785	21
California Dept of Water Resources	-	-	-	640	17,280	27	-	-	-	640	17,280	27
Commission de Federale Electricidad	630	16,875	27	-	-	-	-	-	-	630	16,875	27
Constellation Pow er Source	32,448	540,183	17	9,934	142,153	14	7,285	128,590	18	49,667	810,926	16
Coral Pow er, L.L.C	840	14,655	17	4,113	51,889	13	1,657	36,418	22	6,610	102,961	16
Duke Energy Trading & Marketing, L.L	800	24,000	30	800	17,600	22	2,475	51,263	21	4,075	92,863	23
Dynegy Pow er Marketing Inc.	350	8,750	25	2,500	33,000	13	7,450	137,725	18	10,300	179,475	17
El Paso Merchant Energy	560	12,840	23	3,777	57,557	15	3,652	80,686	22	7,989	151,083	19
Enron Pow er Marketing, Inc.	5,998	168,046	28	-	-	-	-	-	-	5,998	168,046	28
Grant County PUD	45	585	13	-	-	-	-	-	-	45	585	13
Los Angeles Dept of Water & Pow er	47,052	657,689	14	42,550	430,940	10	10,932	190,805	17	100,534	1,279,434	13
Mirant	24,215	755,300	31	4,180	61,980	15	30,671	631,438	21	59,066	1,448,718	25
Mieco, Inc.	3,200	116,000	36	37,600	781,600	21	-	-	-	40,800	897,600	22
New Energy Inc.	-	-	-	787	11,913	15	100	1,740	17	887	13,653	15
Reliant Energy Service	7,774	195,887	25	550	15,263	28	2,925	78,725	27	11,249	289,874	26
PacifiCorp Pow er Marketing, Inc.	965	14,475	15	-	-	-	-	-	-	965	14,475	15
PG & E Energy Trading	-	-	-	-	-	-	24	552	23	24	552	23
Public Service of New Mexico	7,363	163,266	22	6,548	82,830	13	1,600	25,100	16	15,511	271,196	17
Portland General Electric Company	7,703	141,916	18	8,061	87,794	11	5,672	93,524	16	21,436	323,233	15
Pow erex	18,598	237,628	13	60,783	571,416	9	3,850	43,100	11	83,231	852,144	10
City of Seattle, City Light Department	490	10,810	22	1,008	8,558	8	-	-	-	1,498	19,368	13
Sempra Energy Trading (AIG)	1,200	26,075	22	1,345	14,600	11	4,682	94,414	20	7,227	135,089	19
Sacramento Municipal Utility District	-	-	-	-	-	-	750	16,050	21	750	16,050	21
Snohomish	-	-	-	710	7,190	10	-	-	-	710	7,190	10
Soledad Energy, LLC	48	3,840	80	-	-	-	-	-	-	48	3,840	80
Salt River Project	22,163	331,272	15	26,002	262,024	10	6,775	110,800	16	54,940	704,096	13
TransAlta Energy Marketing U.S.	6,492	128,097	20	14,915	120,783	8	2,395	44,195	18	23,802	293,075	12
Tucson Electric Pow er	185	3,780	20	-	-	-	-	-	-	185	3,780	20
Tacoma Pow er	65	1,180	18	40	840	21	-	-	-	105	2,020	19
City of Vernon	-	-	-	30	360	12	-	-	-	30	360	12
Williams Energy Marketing and Tradin	2,325	66,975	29	3,905	86,123	22	6,700	171,200	26	12,930	324,298	25
Total	209,787	$ 3,922,882	$ 19	261,038	$ 3,193,123	$ 12	188,696	$ 4,083,925	$ 22	659,521	$ 11,199,929	$ 17

Note: Data show n only reflects bilateral transactions entered into by CERS

20/20 Rebate Program

Utility	Amount of Rebate Credit	Percentage of Customer Participation
Pacific Gas & Electric	$122,999,682	27%
San Diego Gas and Electric	$27,554,250	39%
Southern California Edison	$134,674,378	28%
Total	$285,228,310	

Financial Reports
Administrative Costs - Fiscal Year 2001-2002

	Annual Budget (thousands)	Actual July 1, 2001 thru December 31, 2001 (thousands)
Total Salaries and Benefits	$6,409	$1,887
Distributed Administration	4,048	2,024
Operating Expenses and Equipment		
Consulting and Professional	7,958	11,275
Information Systems	2,000	5,872
Other Items of Expense	1,820	349
TOTAL ADMINISTRATIVE COSTS	$22,235	$21,407

During the quarter ended December 31, 2001, DWR filed a Deficiency Notice with the Department of Finance that would increase CERS appropriated budget for the 2001-2002 fiscal year by $39.8 million to $62 million.

Financial Reports
Administrative Costs - Fiscal Year 2000-2001

	Budget (thousands)	Actual (thousands)
Letters of Credit[1]	$ 1,200	$ 600
Consultant Contracts	7,375	6,194
Labor	847	1,872
Rent, Tenant Improvements	60	Included in Operating Expenses
Office and IT Equipment	883	2,797
Operating Expenses	518	1,554
IT: Energy Scheduling and Settlements System	2,500	Included in IT Equipment
TOTAL ADMINISTRATIVE COSTS	$ 13,383	$13,017

[1] Letters of credit to address CERS start-up credit issues only in place in January/February, prior to long-term contracts.

The total reported covers the period January 17, 2001 through June 30, 2001.

Energy Cost Categories

The Department of Water Resources (DWR) energy costs are presented in three major categories as follows:

Spot Price/Purchases:

- Includes day-ahead purchases, hour-ahead purchases and ISO real-time purchases.

Contract Purchases:

- Includes long-term contracts (over one fiscal quarter in duration), and short-term contracts entered into by the CERS trading desk (balance of month, monthly, and quarterly purchases).

- The inclusion of current short-term contracts, which have a higher unit cost than long-term contracts, increases the average cost/MWh compared to forecasts released by DWR depicting only longer-term contracts.

ISO, Ancillary Service, Transmission and Dispatch Costs:

- Due to the ISO's settlements process, actual audited costs are not available. The values shown in this report are estimated.

- An audit may determine that some ISO costs included in this estimate are not DWR's responsibility. Conversely, some ISO costs not now charged to DWR may become DWR's responsibility.