2. New Generation and Long-Term Contracts

2.1 New Generation

In 2002, approximately 2,764 MW of new generation capacity was constructed and began operation within the ISO control area. Over 2,090 MW of this new generation were combined-cycle generation plants, and 499 MW were combustion turbine engines, both fueled by natural gas. Most new generation was sited in Northern California. Specifically, 2,263 MW was sited in NP-15 with 71 MW sited in ZP-26. 430 MW was located in SP-15. The following table shows new generation projects beginning operation during the past year.

Table 2.1. 2002 Completed New Generation in Commercial Operation

Generation Project	*Developer*	*Net Dependable Capacity (MW)*	*Commercial Operation Date*	*Actual Parallel Date*	*Construction Status*
Gates	Wellhead Energy	49.9	27-Dec-01	8-Jan-02	Complete
King City Energy Center	Calpine	48.7	14-Jan-02	14-Jan-02	Complete
Gilroy Energy Center unit 3	Calpine	48.7	28-Feb-02	12-Feb-02	Complete
Midsun Generation Facility	Energy Transfer-Hanover Ventures LP	21.3	15-Apr-02	23-Jan-02	Complete
Olinda Landfill II	Ridgewood Power Management	2.5	01-May-02	14-Mar-02	Complete
El Cajon	Cal Peak	55.0	29-May-02	06-May-02	Complete
Springs Generation Project	City of Riverside	44.0	13-Jun-02	25-May-02	Complete
Delta Energy Center	Calpine	845.2	17-Jun-02	19-Feb-02	Complete
Vaca-Dixon	Cal Peak	55.0	21-Jun-02	13-May-02	Complete
Moss Landing Generating Project, Unit 1	Duke Energy	510.0	01-Jul-02	09-Apr-02	Complete
Yuba City Energy Center	Calpine	48.7	01-Jul-02	10-Jun-02	Complete
Henrietta Peaking Project - Unit 1	GWF Energy	50.0	01-Jul-02	17-Jun-02	Complete
Henrietta Peaking Project - Unit 2	GWF Energy	50.0	01-Jul-02	19-Jun-02	Complete
Moss Landing Generating Project, Unit 2	Duke Energy	510.0	11-Jul-02	26-May-02	Complete
Huntington Beach Unit 3	AES	225.0	31-Jul-02	16-Jan-02	Complete
Cabazon Wind Generation	Cabazon Wind Partners	41.0	31-Aug-02	30-Aug-02	Complete
Whitewater Hill Wind Project	Whitewater Energy Corporation	64.5	31-Aug-02	31-Aug-02	Complete
Marina-LFG	Monterey Regional Waste Management Dist.	1.0	12-Sep-02	15-Aug-02	Complete
Valero Cogeneration Unit 1 (Self Generation)	Valero Refining Company -- California	44.7	18-Oct-02	16-Sep-02	Complete

Generation Project	Developer	Net Dependable Capacity (MW)	Commercial Operation Date	Actual Parallel Date	Construction Status
Feather River Energy Center	Calpine	48.7	23-Dec-02	20-Dec-02	Complete
Total Commercial for 2002		2,763.9			

Additionally, 1,474 MW of new generation was completed and connected to the ISO-controlled grid but did not begin commercial operations during 2002.

Table 2.2. Completed New Generation Not in Commercial Operation by December 31, 2002

Generation Project	Developer	Net Dependable Capacity (MW)	Commercial Operation Date	Actual Parallel Date	Construction Status
La Paloma Generating Project, unit 1	PG&E NEG	255.0	10-Jan-03	25-Apr-02	Complete
La Paloma Generating Project, unit 2	PG&E NEG	255.0		08-Jun-02	Complete
La Paloma Generating Project, unit 3	PG&E NEG	255.0	13-Jan-03	25-Jul-02	Complete
La Paloma Generating Project, unit 4	PG&E NEG	255.0		18-Sep-02	Complete
Central La Rosita II, Phase 1	Intergen	160.0		13-Dec-02	Complete
Goosehaven Energy Center	Calpine	48.7	06-Jan-03	20-Dec-02	Complete
Creed Energy Center	Calpine	48.7	06-Jan-03	20-Dec-02	Complete
THUMS Generation (Self Generation)	THUMS Long Beach Company	47.0		20-Dec-02	Complete
Lambie Energy Center	Calpine	48.7	06-Jan-03	21-Dec-02	Complete
Los Esteros Critical Energy Facility	Calpine	195.0		28-Dec-02	Complete
Spartech Plastics (Self Generation)	Spartech Plastics	3.8	No Data		Complete
Additional Connected for 2002		1,474.4	(Note: This includes 2 of the 4 Los Esteros Units or 195 MW/2)		

The ISO projected that 6,490 MW of new generation would be developed in its 2001/02 Winter Assessment (p. 7). It revised that estimate to 6,083 MW in its 2002 Summer Assessment (p. 15), albeit with the caveat that it expected only 5,093 of that capacity to connect to the system due to the progress of construction of some of the planned projects.

Energy firms' financial difficulties, restrictive permitting requirements, and additional costs, such as upgrading transmission for interconnection, have contributed to the cancellation or delay of 2,205 MW of planned generation, excluding generation that had connected to the grid, but had not gone commercial.

2.1.1 Retirements

Approximately 1,409 MW of generation capacity was removed from service in 2002. All but 8 MW of that capacity was located within the SP-15 congestion zone. Below is a list of units that were retired.

Table 2.3. Generation Retirements in 2002

Generating Units	*Capacity (MW)*
High Grove Units 1-4	148
Huntington Beach 5	128
Naval Station 1	22
Naval Training Center	15
North Island 1	21
North Island 2	21
San Bernardino Units 1 & 2	126
San Gorgonio Hydro	2
Georgia Pacific Lumber	8
Etiwanda 1 & 2	264
Broadway 1 & 2	93
El Segundo 1 & 2	339
South Bay Unit 4	222
Total Retirements for 2002	1,409

Generation within the ISO Control Area changed by the following net amounts:

Table 2.4. Net Generation Capacity Change in 2002

Congestion Zone	*Generation Additions (MW)*	*Generation Reductions (MW)*	*Net Generation Change (MW)*
NP-15	2,263	-8	2,255
ZP-26	71	0	71
SP-15	430	-1,401	-971
ISO Control Area	2,764	-1,409	1,355

2.1.2 Transmission Issues Associated with New Generation

The amount of new generation being developed in the ISO control area is placing a strain on the existing transmission resources under ISO control. Existing measures to mitigate intra-zonal transmission congestion are suboptimal in their handling of potential increases in congestion. The upcoming ISO 2003 Summer Assessment will examine this issue in more detail.

During 2002, the Pittsburg substation was one of the areas where local transmission limitations impeded output from generation units and the only area impacted by new generation beginning operation during 2001 and 2002. As a result of this new generation interconnecting with the Pittsburg substation, the ISO dispatched significant amounts of energy using both Reliability-Must-Run (RMR) contracts and out-of-sequence units to mitigate intra-zonal congestion at significant cost to load.

(See section 7.3 for further details.) The new Los Esteros Critical Energy Facility is expected to further exacerbate this situation.

In 2003, once the 600 MW Termoelectrica De Mexicali facility and a combined 470 MW from Intergen projects become commercial, there will be severe limitations on imports from Mexico and these generation projects (imports and generation will be limited to 800 MW). Further, only 200 MW of additional imports from Arizona on the Southwest Power Link will be allowed.

The ISO expects that retirement of generation in SP-15 will exacerbate risks of South of Lugo path overloads.

2.2 CERS Long-term Power Purchase Agreements

The California Energy Resource Scheduling (CERS) division of the California Department of Water Resources devoted significant amounts of time and effort to renegotiating many of the long-term power purchase agreements that were signed in 2001. By the end of 2002, CERS had successfully renegotiated agreements with the following suppliers:

- Calpine Energy Services
- Calpeak Power LLC
- Capitol Power
- Clearwood Electric LLC
- Colton Power LP
- Constellation Power Source (including High Desert Power Project, LLP)
- GWF Energy
- PG&E Energy Trading
- County of Santa Cruz
- Soledad Energy
- Sunrise Power LLC
- Wellhead Power LLC
- Whitewater Energy Corporation
- Williams Energy Marketing and Trading

During the 2002 calendar year, the renegotiations did not significantly change the quantity of energy procured under long-term contract. They did, however, shift much of the non-firm[1] or unit-contingent energy to a firm but dispatchable[2] contract

[1] "Non-firm" energy can be unit-contingent or system-contingent energy, whose level of provision is dependent on physical operating constraints of the generating unit or transmission system; or as-available energy from a renewable resource.

[2] "Dispatchable" contracts allowed CERS to submit to the suppliers a dispatch schedule indicating the quantity CERS wanted to procure from the unit without penalty.

structure to provide greater dependability and greater dispatch flexibility under differing operating conditions. The initial 2001 contract provisions resulted in between two-thirds and three quarters of the total hourly contract capacities being provided as non-firm power during summer 2002. After renegotiations of contract terms completed prior to and during the summer of 2002, non-firm power was reduced to approximately one-half of the total hourly contract capacities. The following charts compare the average contract capacities after renegotiation to the average actual residual net short.[3] The capacities are shown for summer and non-summer and weekend and weekday periods.

3 The Residual Net Short is the amount of the three major Investor-Owned Utilities' loads that remain uncovered after subtracting load served by retained generation resources.

Figure 2.1. 2002 Summer Weekday Capacities

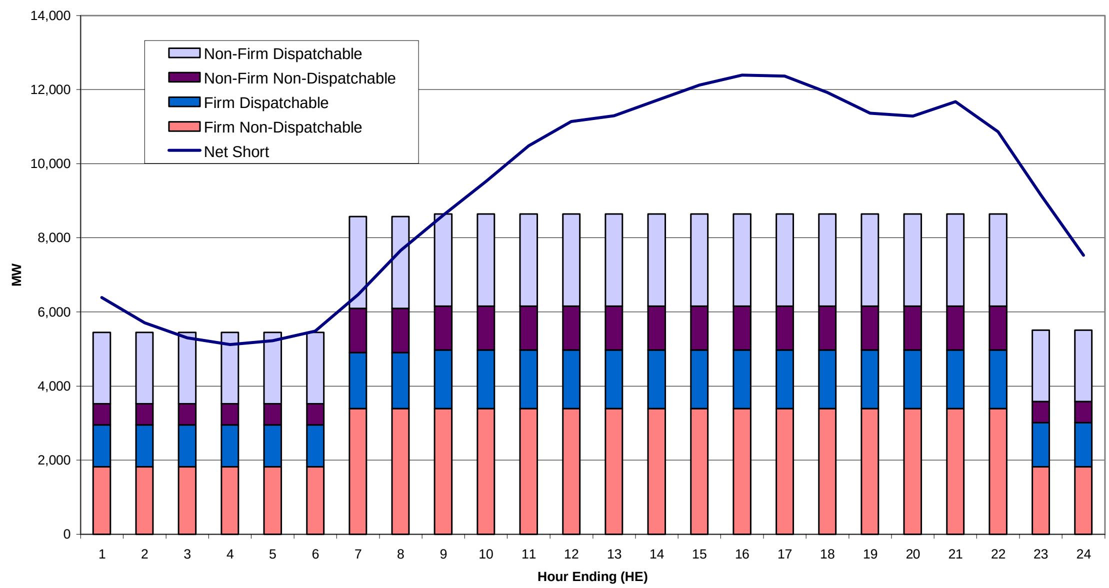


Figure 2.2. 2002 Summer Weekend Capacities

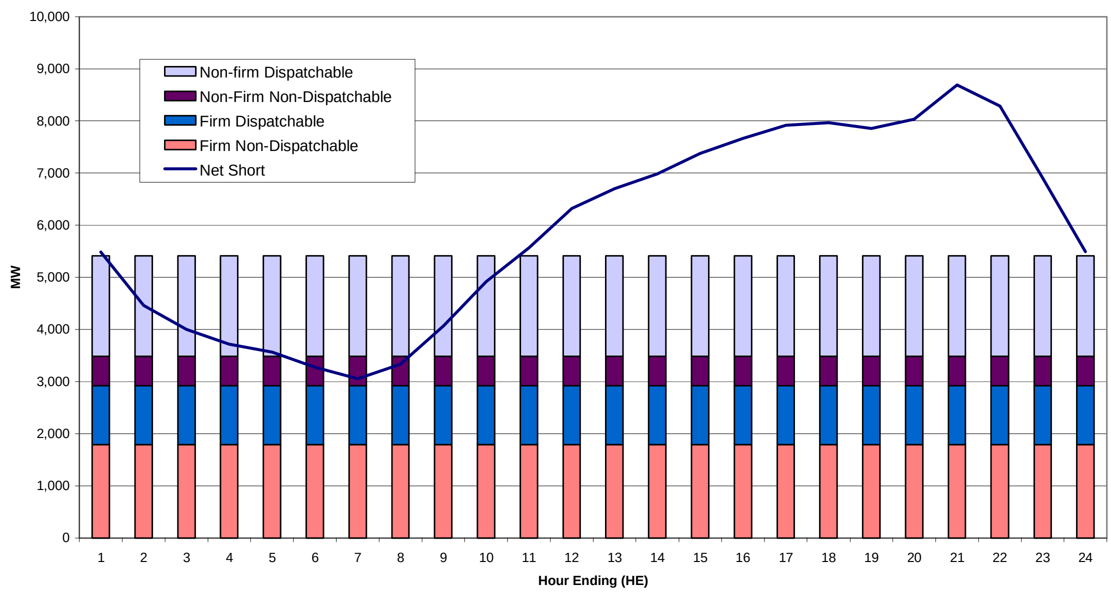


Figure 2.3. 2002 Non-Summer Weekday Capacities

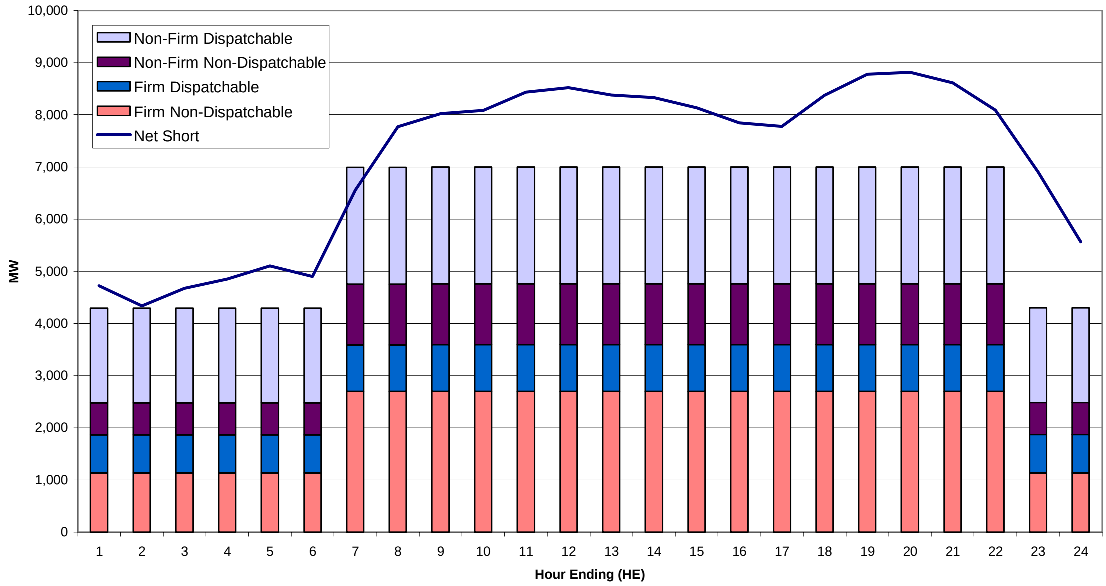
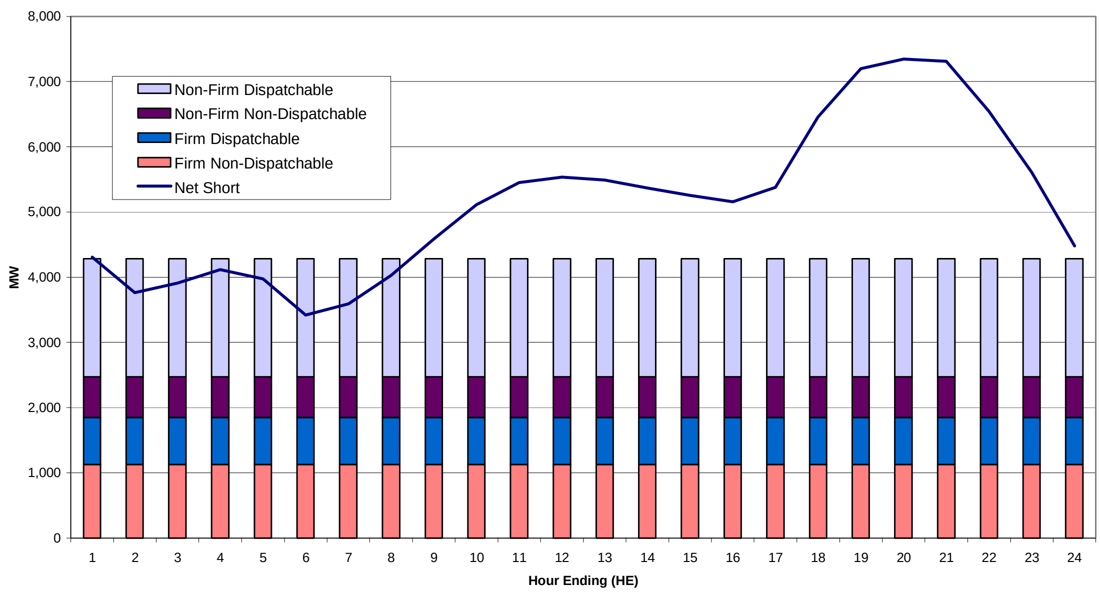
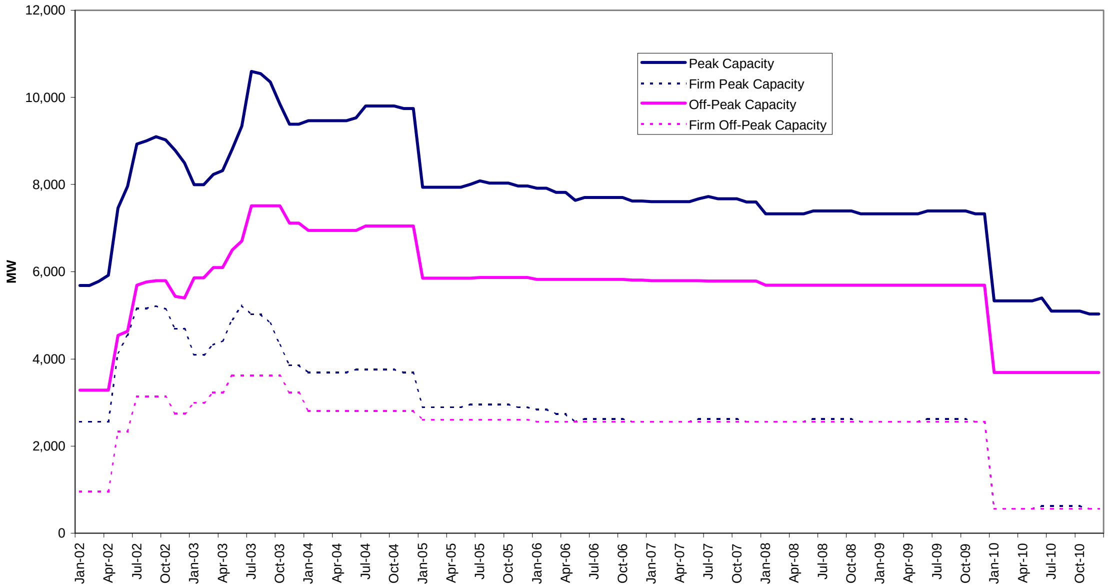


Figure 2.4. 2002 Non-Summer Weekend Capacities



Beyond 2002, the contract renegotiations have resulted in greater contracted energy quantities becoming available earlier in the contract term, along with a shortening of the lengths of the contracts, on average. The median term of the contract portfolio is now eight to nine years, versus 10 years before renegotiation. The following chart depicts the average monthly capacities from 2002 to 2010.

Figure 2.5. Monthly Capacities, January 2002 to December 2010



2.2.1 Contract Disputes

The California Electricity Oversight Board (EOB) and California Public Utilities Commission (CPUC) filed a complaint with FERC on February 25, 2002, in docket EL02-62-000. Within the complaint, the EOB and CPUC argued that the rates negotiated within the original power purchase agreements were unjust and unreasonable, and requested that FERC either make the agreement voidable at the State's option; abrogate the contracts in their entirety; or, adjust the terms of the contracts to reflect just and reasonable rates. The EOB and CPUC also requested that FERC establish a refund-effective date. The respondent suppliers argued that a Mobile-Sierra "public interest" burden of proof standard should be applied in determining whether the contracts should be altered, versus a "just and reasonable" standard.

On April 25, 2002, FERC issued an order specifying that, for contracts whose terms specifically require a "public interest" burden of proof standard, the "public interest" burden of proof shall be applied. For other contracts without that specific requirement, FERC set the issue for hearing. At the same time, FERC encouraged all parties to actively engage in negotiated settlements to avoid litigation. The proceeding is ongoing at this time.

2.2.2 Contract Terminations

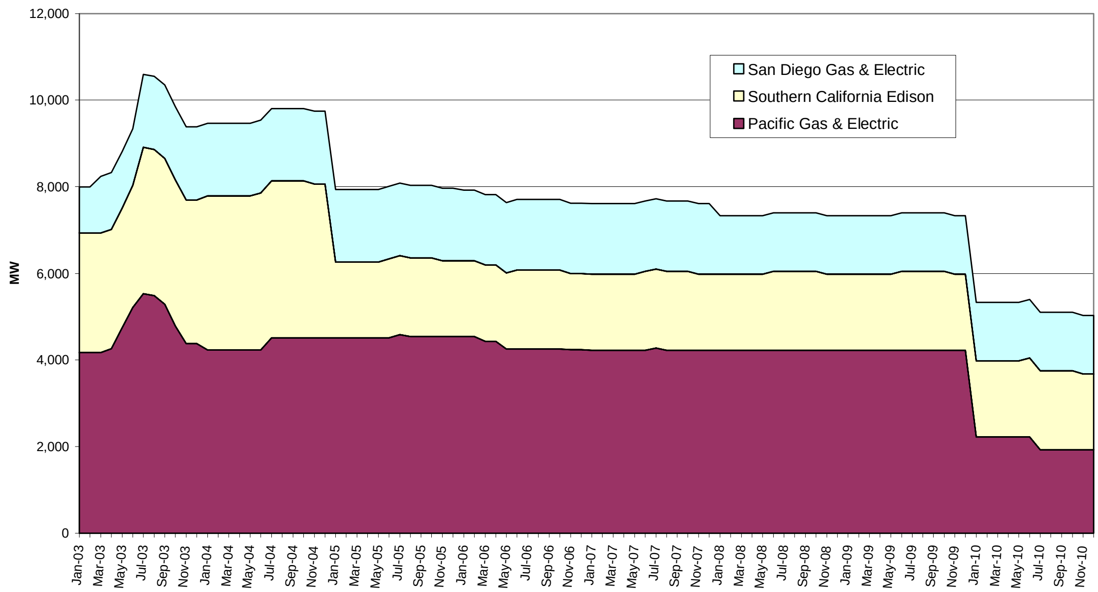
The State terminated the Soledad Energy contract in April 2002, but subsequently renegotiated the terms of the contract in June 2002. The Capitol Power contract was renegotiated in March 2002, but was terminated on December 24, 2002.

The State has alleged that Sempra Energy is in breach of contract for failing to bring a planned generation plant to the required phase of development by April 2002. Sempra Energy disputes this claim, and the contract has not been renegotiated.

2.2.3 Contract Allocations among the Investor-Owned Utilities and Procurement Decisions in R.01-10-024

The California Public Utilities Commission issued a decision on September 23, 2002 on how contract allocations were to be made.[4] The portfolio was divided so that, averaged between 2003 and 2009, 43% of capacity was allocated to Pacific Gas and Electric, 38% was allocated to Southern California Edison, and 19% was allocated to San Diego Gas and Electric. Below is a chart of monthly average peak capacities, divided by utility; note that the capacity percentages will not exactly correspond to the divisions cited in the CPUC decision, due to methodological differences.

Figure 2.6. Monthly Average Peak Capacities, by Investor-Owned Utility



The CPUC also ordered the utilities to assume operational, dispatch, and administrative functions associated with these contracts effective January 1, 2003. Consequently, CERS was no longer an active scheduling coordinator after December 31, 2002.

In a separate order on August 22, 2002, the CPUC also authorized the utilities to enter into multi-year capacity contracts of up to five years to cover portions of the residual net short using the credit of the Department of Water Resources.[5] The order specified a 30-day timeframe for the CPUC's Energy Division to approve the contract.

4 See D.02-09-053.
5 See D.02-08-071