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Decision 93323 JUL 22 1981 ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

An Investigation before the Public Utilities Commission and the California Energy Commission into electric utility system reliability.	OII 89 (Filed April 21, 1981)

ORDER MODIFYING INVESTIGATION

By OII 89, dated April 21, 1981, the California Public Utilities Commission (CPUC) initiated a joint investigation with the California Energy Commission (CEC) into electric utility system reliability for the period 1982-1985. All electric utilities within the jurisdiction of the CPUC were made respondents to this proceeding. By this order the respondents will be limited to all electric utilities with generating capacity within California. These include Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company. We will not include CP National, Sierra Pacific Power Company, and Pacific Power & Light Company as respondents, but encourage their participation in our proceeding.

On June 22, 1981 the staffs of the CPUC and the CEC held a workshop with the electric utilities (including publicly owned utilities) and interested parties, in order to focus more precisely on the data request contained in the original OII. Subsequently, the two staffs sent out a revised data request to all parties for their comment and review.

Review of the revised data request convinces us to modify the original data request of April 21, 1981. The revised data request is contained in Appendix A.

IT IS ORDERED that:

1. Pacific Power & Light Company, Sierra Pacific Power Company, and CP National are deleted as respondents in OII 89.

2. The respondent utilities are ordered to submit to the Docket Office by August 21, 1981, an original and 12 copies of the data requested in Appendix A, attached. This data request supersedes that of April 21, 1981.

This order is effective today.

Dated JUL 22 1981, at San Francisco, California.

President

Commissioners

APPENDIX A

Data Request For

Adequacy of Utility System Reliability 1982-1985

I. Reliability of the Utility System Generation

A. Update of Generating System Capability 1982 through 1985.

1. Expected generating capability of the utility system each month from August 1, 1981 through December 31, 1985.

DATA REQUIRED: The generating capacity of the utility system including purchases and after deducting scheduled maintenance, each month from August 1981 through December 1985. The current California Power Pool Loads and Resources Report, April 1981 (CPPLRR) will be sufficient for this data requirement except that scheduled maintenance should be itemized by units. If SMUD is included in PG&E's system, separate data need not be submitted. At the June 22 workshop, the LADWP representative indicated LADWP data equivalent to the CPPLRR was available.

2. New generating resources, including contract purchases but excluding emergency purchases, expected to come on-line between August 1, 1981 and July 31, 1985.

DATA REQUIRED: The latest resource plan filed with the CEC will be used if no changes have occurred. If a new resource is not expected to operate at its installed capacity, then show the capacity expected to be available at the time of the system peak. Include status toward operation for each unit, including percent completed and major milestones leading to commercial operation.

3. Effect of forced outages on system generation capability.

   a. Forced outage rate of each thermal generating technology by type and unit size, (e.g., 50-99 MW, 100-199 MW, 200-299 MW, 300-399 MW, 400-599 MW, 600-799 MW, 800 MW and above) and comparison with industry averages.

DATA REQUIRED: Based on the last five years (1976-1980) of operating experience, provide the equivalent forced outage rate for each unit class shown in 3.a. above. This data is required for each thermal generating technology. Outage definitions should conform to the definitions used by the National Electric Reliability Council/Edison Electric Institute.

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b. Megawatts of each generating technology expected to be forced out on peak.

DATA REQUIRED: Number of megawatts statistically expected to be forced out during the system peak each year from 1982 through 1985 and derivation of the numbers.

c. Forced outage rates assumed for immature units.

DATA REQUIRED: The forced outage rate statistically expected during the first three years of operation and the expected mature forced outage rate. Provide assumptions for each.

d. Load curtailment due to loss of generation of the system.

DATA REQUIRED: List for the last five years (1976-1980) the number of generation outages resulting in loss of load, as result of a Stage III Alert, and indicate number of customers curtailed due to the outage, the cause and duration thereof.

B. Short-Term Demand Forecast.

1. Most recent forecast of monthly energy sales and peak demand for 1982 through 1985 used for supply planning.

DATA REQUIRED: Provide on a monthly basis the most recent forecast of energy sales and peak demand for 1982 through 1985. The current CPPLRR will satisfy this data requirement. Contractual sales or exports and interruptible loads should be shown separately. If SMUD is included in PG&E's load forecast, separate data need not be submitted. At the June 22 workshop, the LADWP representative indicated that data for LADWP equivalent to that contained in the CPPLRR was available.

2. Forecast assumptions on conservation.

DATA REQUIRED: Provide an itemization of all conservation measures or programs included in the demand forecast and their expected effect on peak demand.

C. Reserve Margins each Year from 1982 through 1985.

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1. a. Reserve margins before and/or after forced outages but including scheduled outages and known or expected restrictions.

   b. Utility estimate of reserve margin requirements before and/or after forced outages. Discussion of criteria upon which requirements are based.

DATA REQUIRED: The utility estimate of the required reserve margin before and/or after forced outages for each year 1982 through 1985. If a Loss of Load Expectation (LOLE) model is used in determining reserve margins, provide a general description of the model and assumptions relating to the level of reliability required, utility interconnections, forced outage rates, and any operating limitations, such as NO_x requirements.

If reserve margin requirements are based on other criteria, provide the basic assumptions and rationale upon which this judgment is based.

D. Transmission Capability.

1. Historical limitations on bulk power transfer among California utilities and between the California utilities and the PSW and PNW.

DATA REQUIRED: For the months of June, July, August and September for the last five years, list the number of power transfers between the California utilities and PSW and PNW that were limited due to inadequate transmission capabilities, loop flows or low voltage problems on your system.

2. Transmission capability that will be available, the firm contracts that will utilize this capability, and the estimated loss of capability due to loop flow or other restrictions each summer for 1982 through 1985 between:

   a. California and the Pacific Northwest (PNW).

   b. Southern California and the Hoover area.

   c. California and Arizona/New Mexico.

   d. Geysers area.

DATA REQUIRED: Based on previous utility data submittals and other sources of information the CEC expects the transmission capability between the areas indicated in a. through d. above to be shown in Tables 1-5 for the years 1982 through 1985. If the utilities expect the actual transfer capability to differ from the amounts shown in Tables 1-5, as the result of new transmission lines or changes in existing lines, low voltage problems, loop flow problems, changes in contract delivery amounts or any other factors, the utility is to provide their estimate of the transfer capability and the reason why it is different from the CEC's estimate.

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II. Transmission and Distribution System Reliability

A. Outages Resulting in Interruptions to Electrical Customers.

1. The duration of transmission and distribution interruptions to electrical customers.

2. The frequency of transmission and distribution interruptions to electrical customers.

DATA REQUIRED: For transmission and distribution outages resulting in interruptions to electrical customers, provide the average duration of the outage per customer for the last five years and for the twelve-month period ending December 31, 1980. Also provide the average frequency of interruptions per customer for the last five years and for the twelve-month period ending December 31, 1980.

III. Reliability Needs of End-Users

A. Summary of the Record in CPUC Case 9884.

B. Data Obtained from End-Users in Addition to that Provided in Case 9884.

IV. Potential Actions for Increasing Reserve Margins for Period 1982 through 1985

A. Reduce Forced Outage Rates on Generation Systems.

1. Analysis of forced outage rates to identify problem areas.

2. Relationship of maintenance practice and procedures to reduce forced outage rates of thermal generating units.

DATA REQUIRED: Describe current preventive maintenance programs for thermal generating units. This should include rationale for determining the length of time between scheduled maintenance and inspection of major generating system components, criteria for scheduling of overhauls, description of lubrication and inspection programs, vibration monitoring programs, non-destructive testing procedures, and chemical and metallurgical analysis. Also describe storeroom or spare parts inventory procedures, including the general criteria for determining what component spares are kept in inventory, extent to which historical maintenance records are maintained and a description of maintenance personnel training programs. Data submitted should be at least as detailed as that submitted by SDG&E in Case 9884, Exhibit 225, describing their preventive maintenance programs, which will satisfy this data requirement. Also describe the level of maintenance coordination with other utilities both in-state and out-of-state.

3. Incentives to improve forced outage rates.

a. Changes in CPUC maintenance expense allowance.

b. Revenues linked to plant reliability.

DATA REQUIRED: Describe the drawbacks or limitations of the present maintenance procedures. Describe methods to improve present maintenance procedures. Municipal utilities are to provide their annual maintenance expense for generation for the years 1976 through 1980.

B. Demand Reducing Measures.

1. Load management programs.

a. Assess the effect the current load management programs will have on peak demand during the 1982 through 1985 time period.

DATA REQUIRED: For each conservation measure identified in I.B.2., specify, in megawatts, the expected reduction in peak demand during the 1982 through 1985 time period.

b. Identify new cost-effective load management programs and estimate their potential for peak demand reduction.

DATA REQUIRED: Identify load management programs not included in the forecast but still being considered for the 1982 to 1985 time period and the effect of each program on peak demand.

2. Load shifting by large power users, such as DWR and MWD.

a. Megawatt potential for load shifting.

DATA REQUIRED: For each of the past five years (1976-1980), how much capacity has DWR, MWD or other large power users made available to each utility as the result of load shifting or load dropping.

b. Agreements, compensation and implementation procedures required to make use of load shifting potential.

DATA REQUIRED: What written contracts or agreements would be required prior to the use of load shifting to specify compensation to be provided by the utilities, cost of any capacity and energy needed by DWR/MWD or others, needed to recover from effects of load shifting? These are to be considered short-term contracts for the period 1982 through 1985 and not emergency or long-term contracts.

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3. Other demand reducing measures.

<u>DATA REQUIRED:</u> What other demand reducing measures to you believe would be effective in the 1982 through 1985 time periods? What are the barriers to their implementation?

C. Supply Augmentation Measures.

1. Assess planned retirement schedules.

<u>DATA REQUIRED:</u> Any changes to retirement schedules contained in the most recent resource plan filed with the CEC.

2. Additional firm purchases in Pacific Northwest (PNW) and Pacific Southwest (PSW).

<u>DATA REQUIRED:</u> Indicate availability of potential firm purchases in PNW and PSW for the period 1982 through 1985.

3. Use of customer-owned auxiliary power systems.

a. Use of auxiliary power systems by utility to increase generating capability.

b. Number of owners switching to auxiliary power system during emergencies at request of the utilities.

c. Incentives required to allow utility use of auxiliary systems.

<u>DATA REQUIRED:</u> Identify number of customers who will have auxiliary power generation 1982 through 1985. Provide data, including size of the generation, under utility control or customer control, and indicate if there is a contractual arrangement with the customer. Identify what incentives are required to promote use of auxiliary power generation during shortage of capacity.

Some of the required information was acquired as part of the CEC's contingency planning effort. Where data has already been provided, only data or information on programs or measures under consideration, adopted or implemented subsequent to previous submittals need be provided. The dates of data previously received are as follows:

PG&E -- Data based on 1978 survey and presented as part of CPUC OII-26.

LADWP-- Response to "Energy Shortage Contingency Plan Questions," January 5, 1981.

SMUD -- "Fifty-four (54) customers who have some form of auxiliary power have been identified." No other data has been provided.

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SCE -- No written information provided.

SDG&E -- No information provided.

BGP -- Response to "Energy Shortage Contingency Plan Questions," (no date indicated).

4. Accelerated development of cogeneration.

DATA REQUIRED: Discussion of potential options for accelerating development. (For SCE, PG&E and SDG&E, the "Cogeneration--Quarterly Report to the CPUC," will satisfy this data requirement if the total cogeneration resources shown in the Quarterly Report are consistent with the cogeneration resources shown in the resource plan submitted in Item I.A.)

D. Expanded Statewide Coordination.

1. Include municipalities to share reserves with private utilities (Staged Alert Program).

2. Statewide hydroelectric dispatch.

3. Coordinated unit commitment procedure.

DATA REQUIRED: Describe the level of existing coordination among all utilities, both during normal and emergency periods. Describe planned level of coordination among all utilities for the years 1982 through 1985. Include a discussion of and results from any studies of coordinated operating or maintenance procedures. For municipal utilities, provide any updates to the information submitted in response to the CEC's November 25, 1980 "Energy Shortage Contingency Plan Questions."

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Table 1

PACIFIC NORTHWEST ENTITLEMENT AND CONTRACTS
(MW)

Northwest	Capacity Entitlements of Interconnection 1/	Current Contract Amounts 1982	1983	1984	1985
PG&E	1392.5				
Portland		400	400	400	400
BPA		600	600	600	600
SCE	1197.5				
Portland		94	94	94	94
Wash. W&P		56	56	56	56
BPA		517	517	517	517
LADWP	560				
BPA		525	525	525	525
SDG&E	195				
Wash. W&P		112	112	112	112
BGP	140				
BPA		122	122	122	122
USBR	400				
State of CA.	15				
TOTAL	3900 MW	2426	2426	2426	2426
Entitlements not loaded		1474	1474	1474	1474
Estimated Loop Flow		500	500	500	500
Net Not Loaded		974	975	974	974
D.C. Line Upgrade					450
Net Not Loaded					1424

1/ Two 500 kV AC lines between California and PNW and one 800 kV DC line.

Table 2

Bulk Power Transfer Capability
(Megawatts)

Between Los Angeles Area and Hoover Area			
1982	1983	1984	1985
6,000	6,000	6,000	6,000

Between Southern California--Southern Nevada and New Mexico--Arizona			
1982	1983	1984	1985
2,700	*	*	4,500

* Dependent on current estimate of completion dates of new transmission lines.

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Table 3

Projected Summer Capacity from the Geysers Area

	Without Castle Rock to Lakeville Transmission Line	With Castle Rock to Lakeville Transmission Line	
1982 Existing	665 MW	Existing	665 MW
NCPA 2	106 MW	NCPA 2	106 MW
1983 Existing	771 MW	Existing	771 MW
Geysers 17	110 MW	Geysers 17	110 MW
		Geysers 18	110 MW
1984 Existing	881 MW	Existing	991 MW
		SMUDGEO 1	65 MW
		SMUDGEO 2	55 MW
		Wild Well	5 MW
		Bottle Rock	55 MW
1985 Existing	881 MW	Existing	1171 MW
		Geysers 16	110 MW

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Table 4

Out-of-State Capacity
from the Southwest Ownership & Purchase

Ownership	1982	1983	1984	1985
<u>SCE</u>				
Mojave	885	885	885	885
Four Corners	761	761	749	749
Palo Verde	0	187	374	374
<u>LADWP</u>				
Mojave	316	316	316	316
Navajo	550	550	550	508
Coronado	210	140	70	70
Palo Verde	0	70	140	140
Palo Verde (SCAPPA)		75	150	150
Total	2722	2984	3230	3192
Purchase Total	1667	1669	1910	2062
Grand Total	4389	4653	5144	5254

Table 5

Out-of-State Capacity
Purchases in the Southwest
(Megawatts)

	1982	1983	1984	1985
SCE				
Hoover	617	617	617	617
Navajo	278	253	233	0
Cholla 4	0	0	115	330
Mexico	0	0	35	70
SDG&E				
Tuscon	100	100	100	165
PS New Mexico	127	154	210	185
Mexico	0	0	55	150
LADWP				
Hoover	511	511	511	511
BGP				
Hoover	34	34	34	34
Total	1667	1669	1916	2062

(END OF APPENDIX A)