Decision 88 12 040 DEC 9 1988

ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Mailed

DEC 1 2 1988

Application of PACIFIC GAS AND ELECTRIC COMPANY for Commission order finding that PG&E's gas and electric operations during the reasonableness review period from February 1, 1987 to January 31, 1988, were prudent.	Application 88-04-020 (Filed April 7, 1988)
Application of PACIFIC GAS AND ELECTRIC COMPANY for authority to adjust its electric rates effective August 1, 1988.	Application 88-04-057 (Filed April 21, 1988)

(See Decision 88-11-052 for appearances.)

OPINION ON REVENUE REQUIREMENT AND INCREMENTAL ENERGY RATE

In Decision (D.) 88-11-052, we resolved issues concerning the load forecast, resource forecast, modeling conventions, and calculation of the incremental energy rate (IER) for the August 1, 1988 through July 31, 1989 forecast year for Pacific Gas and Electric Company (PG&E). The earlier opinion decided all disputed issues that needed to be resolved before the parties' production cost models could be run to determine the revenue requirement for PG&E's Energy Cost Adjustment Clause (ECAC) expenses and the IER for the forecast period.

Because the specific mix of resource assumptions we adopted in D.88-11-052 had not previously been run through the parties' models, we did not have before us a precise revenue requirement or IER that corresponded to the details of our decision. We instructed the administrative law judge (ALJ) assigned to this proceeding to coordinate the development and reporting of the results of the final runs of the parties' models with our adopted resource assumptions.

The ALJ convened a workshop on November 28, 1988, to resolve any lingering uncertainties or misunderstandings about the details of our decision. The parties then ran their models and reported the results in letters submitted to the ALJ on December 5, 1988. Results were submitted by PG&E; the Commission's Division of Ratepayer Advocates (DRA); Santa Fe Geothermal, Inc., Unocal Corporation, and Freeport-McMoRan Resource Partners (Santa Fe); and the California Cogeneration Council, Independent Energy Producers, and Midset Cogeneration Company (CCC).

Several specific results were requested. The net change in revenue requirement included the changes resulting from the ECAC, the Annual Energy Rate (AER), the Energy Revenue Adjustment Mechanism (ERAM), the Diablo Canyon Adjustment Clause (DCAC), and the Conservation Financing Adjustment (CFA). At this stage of the proceeding, no dispute remains about the ERAM,[1] DCAC, and CFA changes, but both the ECAC and AER revenue requirements vary with the specific resource assumptions that go into the models. For purposes of comparison, we refer primarily to the net change in revenue requirement resulting from all component changes in this proceeding. The Commission Advisory and Compliance Division calculated the revenue requirement resulting from Santa Fe's and CCC's runs based on information submitted by those parties.

---

1 The ERAM revenue decrease referred to throughout the hearings ($201,586,000) was based on an erroneous reading of the tariffs that underlie the calculation of the authorized base revenue amount. In addition, present rate revenues have changed slightly to reflect changes in revenues associated with a residential load management program. The two parties filing complete revenue requirement calculations, PG&E and DRA, have used the corrected ERAM decrease of $198,084,000.

IERs were to be differentiated by season and time of day and reported as an annual average IER. In D.88-11-052, we ordered the calculation of variable operating and maintenance (O&M) costs to be removed from the calculation of the IER and to be paid to qualifying facilities (QFs) as a separate and discrete payment. The models calculated the amount of this O&M adder and the parties reported this result and calculated the IER that would have resulted if the O&M adder had been retained in the calculations. This equivalent IER also takes into account the cash working capital adder, another discrete component of the payments to QFs.

In addition, parties had the option of reporting the IERs that result from their simulations when the Rancho Seco nuclear power plant is removed from the resource mix. Because of Rancho Seco's past operating problems and because a recently passed initiative calls for the plant to be shut down if it does not operate well, we allowed for the possibility of changing the IER if Rancho Seco is shut down during the forecast period.

Finally, the price of geothermal power for 1989 depends on the cost of fossil fueled generation in 1988. The costs for part of 1988 result from the model, so parties have also reported the 1989 geothermal power price associated with the results of their model runs.

PG&E filed the results of three PROMOD runs. In addition to a run without Rancho Seco, PG&E filed the results of two runs that included Rancho Seco. One case was identified as PG&E's preferred case, which continued to use PG&E's must-run list to meet the minimum generation requirement, except for the months of March through May 1989, when only four units were designated as must-run. The second case restricted the use of must-run units to only the four units in March through May 1989, as agreed to in the workshop of November 28. On pages 48 and 48a of D.88-11-052, we clarified that use of the must-run list was to minimized. We conclude that

PG&E's alternative case best meets the intent of our decision, and we will concentrate on the results of that case.

The revenue requirement increase for PG&E's alternative case is $78,992,000. The annual average IER is 8,935 Btu/kWh, and the variable O&M adder is 1.06 mills/kWh. The resulting equivalent IER is 9,551 Btu/kWh. Without Rancho Seco, the IER becomes 9,649 Btu/kWh, and the variable O&M adder increases to 1.10 mills/kWh. The equivalent IER is 10,306. PG&E's reported geothermal steam cost for 1989 is 16.01 mills/kWh.

CCC also used PROMOD. The final runs result in a net revenue requirement increase of $78,286,000. The annual average IER is 8,989 Btu/kWh. The variable O&M adder is 1.09 mills/kWh, and the equivalent IER is 9,411 Btu/kWh. The 1989 geothermal price is forecasted to be 15.532 mills/kWh. With Rancho Seco removed, the IER increases to 9,519 Btu/kWh, and the O&M adder changes to 1.06 mills/kWh. The equivalent IER is 9,849 Btu/kWh.

DRA used ELFIN, which, like PROMOD, is a load duration curve model. DRA's runs result in a revenue requirement of $64,095,000. DRA's annual average IER is 8,440 Btu/kWh. The price of geothermal generation in 1989 is 16.05 mills/kWh. DRA did not report its O&M adder or the equivalent IER.

Santa Fe used PROSYM, a chronological model. The final simulations resulted in a net revenue requirement of $98,545,000 and an annual average IER of 9,040 Btu/kWh. The variable O&M adder amounted to 0.934 mills/kWh, resulting in an equivalent IER of 9,415 Btu/kWh. The forecasted price of geothermal power for 1989 is 15.548 mills/kWh. When Rancho Seco is removed from the simulation, the resulting average annual IER is 9,798 Btu/kWh, the variable O&M adder is 1.024 mills/kWh, and the equivalent IER is 10,220 Btu/kWh.

The parties' results are summarized in Table 1.

TABLE 1

Party	Average IER	O&M Adder	Equivalent IER	Net Revenue Increase
PG&E				
Rancho Seco In	8,935	1.06	9,551	$78,992,000
Rancho Seco Out	9,649	1.10	10,306	
DRA				
Rancho Seco In	8,440			$64,095,000
Santa Fe				
Rancho Seco In	9,040	0.934	9,415	$98,545,000
Rancho Seco Out	9,798	1.024	10,220	
CCC				
Rancho Seco In	8,989	1.09	9,411	$78,286,000
Rancho Seco Out	9,519	1.06	9,849	

At this point in the proceeding, we are disturbed that the models do not show more convergence than they do. The ELFIN results, in particular, vary considerably from the results of the other models. At this point, there is no opportunity to explore why ELFIN diverges from the other models; the current differences are larger than those that resulted when the models were clearly operating under different assumptions. It is also unexplained why Santa Fe's revenue requirement exceed the other parties' results by a substantial amount.

Although considerable effort has been put into clarifying the assumptions and modeling conventions, some apparent differences still remain. PG&E has included the geothermal adder in its calculation of the equivalent IER; CCC and Santa Fe have not. The result, as may be expected, is that PG&E's equivalent IER is higher than Santa Fe's and CCC's, although its unadjusted average IER is lower.

Despite these concerns, we believe that the models converge sufficiently to allow us some degree of confidence in adopting a set of results. In particular, the two PROMOD runs show substantial agreement, and the differences between the PROMOD results and Santa Fe's PROSYM results for the IER appear to reflect the differences between a chronological model and a load duration curve model.

We will adopt the results presented by PG&E. PG&E's alternative case has run the model under the assumptions we desired, and its calculations of the equivalent IER include all adders paid to QFs. We are not faulting the other parties for not including the geothermal adder, since it was not clear up to now how the equivalent IER calculation should be performed. Although PG&E notes in its letter accompanying its filing that some illogical operational effects result from the specific assumptions adopted in D.88-11-052, those effects were not noted on the record and our decision was properly made on the basis of the information presented in the hearings. We will tolerate these operational anomalies because we find that the overall results are reasonable.

The revenue requirement increases we adopt in this decision will be combined with revenue changes in other pending PG&E cases. The resulting rates will be reflected in a decision in this proceeding later this year. The revenue allocation and rate design leading to the revised rates will reflect revised marginal energy costs that are consistent with the IER and revenue requirement adopted in this decision. The marginal energy cost associated with the QF-in run will be used in developing rates. In addition, as we noted on page 70 of D.88-11-052, when the rate changes are put into effect, the suspension of the AER we ordered in D.88-09-036 will terminate.

Findings of Fact

1. The specific mix of resources assumptions adopted in D.88-11-052 had not been run through the production cost models sponsored by the parties at the time of that decision.

2. The parties ran the assumptions adopted in D.88-11-052 through the models and reported the results to the ALJ on December 5, 1988.

3. PG&E filed an alternative case that reflected the assumptions of D.88-11-052 and included all adders paid to QFs in the calculation of the equivalent IER.

4. CCC's overall results were very close to PG&E's and Santa Fe's IER results were close to PG&E's in light of the different approaches of their models.

Conclusions of Law

1. PG&E's results should be adopted in this case.

2. A reasonable IER for the forecast period is 8,935 Btu/kWh.

3. A reasonable O&M adder for the forecast period is 1.06 mills/kWh.

4. A reasonable net revenue requirement increase for the forecast period is $78,992,000, as shown in Appendices A and B.

5. If Rancho Seco is removed from the resource assumptions, a reasonable IER is 9,649 Btu/kWh and a reasonable O&M adder is 1.10 mills/kWh.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E) is authorized to increase it Energy Cost Adjustment Clause (ECAC) revenue

requirement by $281,420,000; to increase its Annual Energy Rate revenue requirement by $19,312,000; to decrease its Electric Revenue Adjustment Mechanism revenue requirement by $198,084,000; to decrease its Diablo Canyon Adjustment Clause revenue requirement by $14,089,000; and to decrease its Conservation Financing Account revenue requirement by $9,567,000.

2. On or before December 28, 1988, and in conjunction with other rate changes to be ordered by the Commission in A.88-07-037, A.84-06-014, A.85-08-025, and Advice Letter No. 1226-E, PG&E shall file revised tariff schedules for electric rates reflecting the revenue increase authorized by this decision. The revised tariff schedules shall become effective on January 1, 1989, and shall comply with General Order 96-A.

3. Effective with the next scheduled change in prices paid to qualifying facilities (QFs) on February 1, 1989, PG&E shall base its payments to variably priced QFs on an annual incremental energy rate (IER) of 8,935 Btu/kWh, with appropriate seasonal and time differentiation as shown in Appendix C. Avoided variable operating and maintenance costs shall be reflected in a separate component of the payment, or adder, that is set at 1.06 mills/kWh.

This order is effective today.

Dated DEC 9 1988, at San Francisco, California.

STANLEY W. HULETT
President
DONALD VIAL
FREDERICK R. DUDA
G. MITCHELL WILK
JOHN B. OHANIAN
Commissioners

I CERTIFY THAT THIS DECISION WAS APPROVED BY THE ABOVE COMMISSIONERS TODAY.

Victor Weisser, Executive Director

AB

APPENDIX A

PACIFIC GAS & ELECTRIC COMPANY
Electric Department - Total Company
ADOPTED ENERGY COSTS
ECAC Forecast Period August 1, 1988 to July 31, 1989

	Type of energy	Purchases/ Generation (Gwh)	%	Average cost (cents/Kwh)	Total costs (000's of $)	ECAC costs (000's of $)	AER costs (000's of $)
		(a)	(b)	(c)	(d)	(e)	(f)
	Steam Plants						
1	Gas - UEG	18,541.7	25.2%	3.04	$563,624.0	$512,897.8	$50,726.2 1/
2	Oil - Residual	309.1	0.4	2.89	8,938.0	8,133.6	804.4 2/
3	Oil - Distillate	41.7	0.1	5.25	2,188.0	1,991.1	196.9 3/
4	Subtotal Steam Plants	18,892.5	25.7	3.04	574,750.0	523,022.5	51,727.5
5	Geothermal Steam Plants	9,734.0	13.2	1.53	148,802.0	135,409.8	13,392.2
6	Nuclear Steam Plants	13,094.0	17.8	0.76	99,791.0	90,809.8	8,981.2
	Purchased Power						
7	Irrigation Dist.	3,740.0	5.1	1.26	47,065.0	42,829.2	4,235.8
8	CVP (Capacity & Energy)	(3,408.0)	(4.6)	0.81	(27,714.0)	(25,219.7)	(2,494.3)
9	SMUD	1,104.0	1.5	2.81	31,019.0	28,227.3	2,791.7
	Cogeneration & other QFs						
10	Variably priced QF energy payments	6,991.3	9.5	2.74	191,560.0	174,319.6	17,240.4
11	Other	4,783.7	6.5	11.16	533,646.0	485,617.9	48,028.1
12	Pacific Northwest	6,320.0	8.6	2.07	130,679.0	118,917.9	11,761.1
13	Southwest, incl. power pool sales	385.0	0.5	2.04	7,860.0	7,152.6	707.4
14	Others - CDWR	630.0	0.9	1.73	10,885.0	9,905.4	979.6
15	- Other	6.0	0.0	6.82	409.0	372.2	36.8
16	Subtotal Purchased Power	20,552.0	27.9	4.50	925,409.0	842,122.2	83,286.8
[illegible]	Water for Power	11,300.0	15.4	0.03	3,767.0	3,428.0	339.0
[illegible]	Oil Inventory Carrying Cost				6,223.0	5,662.9	560.1
19	Standby Charges				912.0	829.9	82.1
20	Variable Wheeling				930.0	846.3	83.7
21	Subtotal	73,572.5	100.0%	2.39	$1,760,584.0	$1,602,131.4	$158,452.6
22	Allocation to California Jurisdiction	71,909.8			1,720,794.8	1,565,923.3	154,871.5 4/
23	Write-down of Fuel Oil Inventory				26,027.0	23,684.6	2,342.4 5/
24	Interest on unamortized write-down				377.0	343.1	33.9
25	Excess oil inventory carrying cost				1,024.0	1,024.0	0.0
26	TOTALS	71,909.8			$1,748,222.8	$1,590,974.9	$157,247.9

Note: ECAC costs are 91% of Total costs and AER costs are 9% of Total costs, unless otherwise specified.
1/ = Equivalent to 196,382 billion BTU at an average heat rate of 10,591 BTU/Kwh.
2/ = Equivalent to 3,324 billion BTU at an average heat rate of 10,754 BTU/Kwh.
3/ = Equivalent to 620 billion BTU at an average heat rate of 14,868 BTU/Kwh.
4/ = Jurisdictionalized at 97.74%
5/ = Jurisdictionalized at 98.36%

APPENDIX A

PACIFIC GAS & ELECTRIC COMPANY
Electric Department - California Jurisdiction
CHANGES IN ECAC, AER, ERAM, CFA & DCAC REVENUES
ECAC Forecast Period August 1, 1988 to July 31, 1989

		Revenues (000's of $)	Adopted average rate at forecasted sales (cents/Kwh)
		(a)	(b)
	ECAC REVENUES		
1	Adopted ECAC costs	$1,590,974.9	
2	Less: Recorded ECAC undercollection as of 7/31/88	43,272.0	
3	ECAC costs amortized over the forecast period	1,634,246.9	
4	Uncollectibles & Franchise Fee Factor	1.007740	
5	Adopted ECAC rev. reqr. for the forcast period	1,646,896.0	2.503
6	Less: Present rate ECAC revenues at rates effective 5/17/88	1,365,476.0	
7	Change in ECAC revenues	$281,420.0	0.428
	AER REVENUES		
8	Adopted AER costs	$157,247.9	
9	Uncollectibles & Franchise Fee Factor	1.007740	
10	Adopted AER rev. reqr. for the forcast period	158,465.0	0.241
11	Less: Present rate AER revenues at rates effective 5/17/88	139,153.0	
12	Change in AER revenues	$19,312.0	0.029
	ERAM REVENUES		
13	Authorized Base Revenue Amount effective 5/17/88	$3,089,602.0	
14	Add: ERAM undercollection as of 7/31/88	26,133.0	
15	Add: CFA overcollection as of 7/31/88	(9,713)	
16		3,106,022.0	4.720
17	Less: Present rate ERAM revenues at rates effective 5/17/88	3,304,106.0	
18	Change in ERAM revenues	(198,084.0)	(0.301)
	CFA REVENUES		
19	Authorized CFA revenues	$1,500.0	0.002
20	Less: Present rate CFA revenues at rates effective 5/17/88	11,067.0	
21	Change in CFA revenues	($9,567.0)	(0.015)
	DCAC REVENUES		
22	Authorized DCAC revenues	$472,856.0	0.719
23	Less: Present rate DCAC revenues at rates effective 5/17/88	486,945.0	
24	Change in DCAC revenues	($14,089.0)	(0.021)
25	TOTAL CHANGE IN ECAC, AER & ERAM REVENUE	78,992.0	0.120

(END APPENDIX A)

APPENDIX B

PACIFIC GAS & ELECTRIC COMPANY
Electric Department - CPUC Jurisdiction
SUMMARY OF REVENUE CHANGES
ECAC Forecast Period August 1, 1988 to July 31, 1989

Line	Rate Element	Change in Revenue Requirement ($000)
1	ECAC	281,420
2	AER	19,312
3	ERAM	(198,084)
4	DCAC	(14,089)
5	CFA	(9,567)
6	Total	$78,992

(END APPENDIX B)

A.88-04-020, A.88-04-057 ALJ/BTC
CACD/llg/2

APPENDIX C
PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED AVOIDED ENERGY COSTS
ECAC Forecast Period -- August 1, 1988-July 31, 1989

	DESCRIPTION	SUMMER					WINTER				ANNUAL AVERAGE
		PEAK	PARTIAL PEAK	OFF PEAK	SUPER OFF-PK	SEAS AVG	PARTIAL PEAK	OFF PEAK	SUPER OFF-PK	SEAS AVG	
1	INCREMENTAL ENERGY RATE (IER) (BTU/KWH) -- WITHOUT ADDERS	9068	9003	8642	8319	8741	9570	9186	7981	9133	8935
2	G-UEG RATE ($/MMBTU)	2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92
3	AVOIDED COST OF ENERGY (CENTS/KWH) (L1 * L2)/(10 EXP 6)	0.02648	0.02629	0.02523	0.02429	0.02552	0.02794	0.02682	0.02330	0.02667	0.02609
4	ENERGY WITH O&M ADDER OF 1.06 mill PER KWH (L3 + .00106)	0.02754	0.02735	0.02629	0.02535	0.02658	0.02900	0.02788	0.02436	0.02773	0.02715
5	REV REQ ASSOCIATED WITH CASH WKING CAPITAL (L4 *(21.7% of 2.21%))	0.00013	0.00013	0.00013	0.00012	0.00013	0.00014	0.00013	0.00012	0.00013	0.00013
6	GEOTHERMAL ADDER (.0005866)	0.00059	0.00059	0.00059	0.00059	0.00059	0.00059	0.00059	0.00059	0.00059	0.00059
7	AVOIDED COST OF ENERGY (CENTS/KWH) WITH ADDERS (LINES 4-6)	0.02826	0.02807	0.02701	0.02606	0.02730	0.02973	0.02860	0.02507	0.02845	0.02787
	TRANSMISSION										
8	ENERGY LOSS FACTOR	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
9	AVOIDED ENERGY COST + LOSSES CENTS/KWH (L7 * L8)	0.02826	0.02807	0.02701	0.02606	0.02730	0.02973	0.02860	0.02507	0.02845	0.02787
	PRIMARY										
10	ENERGY LOSS FACTOR	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
11	AVOIDED ENERGY COST + LOSSES CENTS/KWH (L7 * L10)	0.02826	0.02807	0.02701	0.02606	0.02730	0.02973	0.02860	0.02507	0.02845	0.02787
	SECONDARY										
12	ENERGY LOSS FACTOR	1.0148	1.0131	1.0093	1.0093		1.0119	1.0087	1.0087		
13	AVOIDED ENERGY COST + LOSSES CENTS/KWH (L7 * L12)	0.0287	0.0284	0.0273	0.0263		0.0301	0.0289	0.0253		

(END OF APPENDIX C)

Now that we are in the midst of reviewing AT&T-C's A.87-10-039 for pricing flexibility, it is important that we focus our attention on implementing a decision in that proceeding before addressing a brief period of high earnings based on past rates.

More specifically, we have recently struggled with the question of AT&T-C's status as a dominant carrier in a competitive market. The record in this proceeding is replete with situations where AT&T-C's business judgments are necessarily conditioned by competitive pressures; however, we have conducted this rate case in the traditional manner usually applied to a monopoly utility.

We addressed these concerns directly in D.87-07-017, where we laid out a regulatory framework under which AT&T-C could apply for pricing flexibility. In A.87-10-039, we are considering AT&T-C's application in which AT&T-C proposes pricing bands under the observation approach, which was one option offered to it in D.87-07-017.

The observation approach is intended as a substitute for traditional rate-base regulation for AT&T-C. Through careful monitoring of the results, we intend to determine whether pricing flexibility should be curtailed, maintained, or further extended for AT&T-C. D.87-07-017 contained a detailed discussion of the relative efficacy of various measures of market power and customer benefits or costs.

If AT&T-C is granted pricing flexibility in A.87-10-039, then we will expect parties, including DRA, to participate actively in the monitoring program. We will also expect to receive periodic reviews by DRA and AT&T-C of the benefits that customers are receiving due to pricing flexibility and the greater competitiveness we hope to foster. In addition to the factors that will be explicitly considered in the monitoring program, DRA will be free to observe any other indicators of market behavior that it believes relevant.

is out of order under Rules 43 and 85 of the Commission's Rules of Practice and Procedure.

AT&T-C further asserts that DRA's action in filing the Motion is a blatant disregard of the Commission's effort in Investigation (I.) 85-11-013 to find a viable alternate to traditional cost-of-service regulation for AT&T-C. Specifically I.85-11-013 and A.87-10-039 were designed to determine the extent to which the Commission's regulation of AT&T-C should be relaxed. Therefore, AT&T-C pleads that DRA's Motion is fundamentally inconsistent with the Commission's observation approach under the market flexibility concept, and should be rejected.

As to the merits of DRA's Motion based on the high first quarter 1988 rate of return, AT&T-C contends that further analysis shows extreme volatility of earnings for other recent periods which must also be considered. As examples AT&T-C points to its 1985 monthly earnings which fluctuated from -24.25% to +27.86%; for 1986 the range was -24.13% to +33.22%; and for 1987 the low was -62.86% to a high of +60.96%. In addition, AT&T-C claims that for two of the three years, AT&T-C's intrastate earnings were substantially below its authorized rate of return.

Therefore, high earnings for a single quarter cannot possibly be relevant for rate making purposes, and do not provide an indication of actual annual earnings, according to AT&T-C.

<u>Discussion</u>

We recognize the concern AT&T-C has expressed over the exclusive use of the traditional return on rate base for its California intrastate operations. These concerns were also voiced in the concurring opinion of Commissioners Victor Calvo and Donald Vial in D.86-11-079. After commenting on AT&T-C's small California intrastate rate base as compared to its overall expense level these Commissioners opined that: "In the next year (1987), the Commission will be re-examining its proper role in the regulation of the interLATA market generally and of AT&T specifically."