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JUN 12 1997

Decision 97-06-063 June 11, 1997

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

| | |
|---|---|
| Application of Pacific Gas and Electric Company for Authority to Adjust Its Electric Rates Effective January 1, 1997, and for Commission Order Finding That Electric and Gas Operations During the Reasonableness Review Period from January 1, 1995 to December 31, 1995 Were Prudent. | Application 96-04-001 (Filed April 1, 1996) |

ORIGINAL

ORDER MODIFYING DECISION 96-12-080

On December 20, 1996, the Commission issued interim Decision (D.) 96-12-080 in the first phase (forecast phase) of Pacific Gas & Electric Company's (PG&E) Application (A.) 96-04-001.

On January 28, 1997, PG&E filed a petition to modify D.96-12-080 pointing out certain errors in the calculation of PG&E's revenue requirement for 1997 contained in Appendix B to the decision. PG&E also pointed out that pages 1 and 2 of Appendix C were omitted from D.96-12-080.

Specifically, PG&E points out that the tables contained in Appendix B include an incorrect revenue requirement of $22.7 million for the annual earnings assessment proceeding (AEAP). According to PG&E, the correct AEAP revenue requirement is $27.4 million. PG&E also points out that the calculations for payments to the qualifying facilities (QFs) contained in the decision were in error. PG&E states that if the correct amount of payment to QFs is used, PG&E's Eenrgy Cost Adjustment Clause (ECAC) revenue requirement would be reduced by $718.8 million instead of the $720.4 million ECAC revenue reduction adopted in the decision. Based on the above, PG&E believes that its consolidated revenue requirement reduction should be $554.3 million instead of the adopted consolidated revenue requirement reduction of $560.5 million.

We have reviewed D.96-12-080 and found PG&E's claims to be valid. Accordingly, we have corrected Appendix B. Correction to Appendix B results in changes to the text on pages 1, 2, 12, 22, 23 and 24 of the decision. The modified decision is included as Attachment A to this order. The modified decision includes the omitted pages from Appendix C.

Finding of Fact

D.96-12-080 contained certain calculational errors and omissions, as pointed out in PG&E's petition to modify D.96-12-080.

Conclusions of Law

1. D.96-12-080 should be modified to correct certain errors.
2. PG&E's petition to modify D.96-12-080 should be granted.

IT IS ORDERED that:

1. Pacific Gas and Electric Company's (PG&E) petition to modify Decision (D.) 96-12-080, filed January 28, 1997, is granted.
2. D.96-12-080 is modified in accordance with Attachment A to this order.
3. The modifications to D.96-12-080 are effective December 20, 1996, nunc pro tunc.
4. Application 96-04-001 remains open to address the reasonableness of PG&E's Electric and Gas Operations.

This order is effective today.

Dated June 11, 1997, at San Francisco, California.

P. GREGORY CONLON
President
JESSIE J. KNIGHT, JR.
HENRY M. DUQUE
JOSIAH L. NEEPER
RICHARD A. BILAS
Commissioners

# APPENDIX B

## PACIFIC GAS AND ELECTRIC COMPANY

Electric Department

Forecast Year 1997

SUMMARY OF REVENUE REQUIREMENT CHANGES

CONSOLIDATED IN THIS PROCEEDING

| Line No. | Revenue Items | ADOPTED BEGINNING 1-1-97 REVENUE CHANGE (000) | Line No. |
|---|---|---|---|
| 1 | ECAC | ($563,407) | 1 |
| 2 | AER * | $0 | 2 |
| 3 | ERAM in A.96-04-001 without Cost of Capital | ($152,850) | 3 |
| 4 | CARE | ($2,555) | 4 |
| 5 | Total Change in A.96-04-001 | ($718,812) | 5 |
| 6 | ERAM in other proceedings consolidated in A.96-04-001 | $160,635 | 6 |
| 7 | Cost of Capital | ($5,306) | 7 |
| 8 | Annual Earnings Assessment Proceeding (AEAP) | $9,169 | 8 |
| 9 | Total Change in Consolidated Revenue Requirement | ($554,314) | 9 |

* AER costs are included in ECAC costs.

# APPENDIX B

## PACIFIC GAS AND ELECTRIC COMPANY
## Electric Department
## Forecast Year 1997
## SUMMARY OF ADOPTED REVENUE REQUIREMENTS IN THIS PROCEEDING, A.96-04-001

| LINE NO. | REVENUE ELEMENT | PRESENT RATE REVENUE (000) (a) | REVENUE CHANGE (000) (b) | ADOPTED REVENUE REQUIREMENT (000) (c) | LINE NO. |
|---|---|---|---|---|---|
| 1 | Energy Cost Adjustment Clause (ECAC) | $4,113,792 | ($563,407) | $3,550,385 | 1 |
| 2 | Annual Energy Rate (AER) ** | $0 | $0 | $0 | 2 |
| 3 | Base Energy Rate (ERAM) in A.96-04-001 | $3,413,887 | ($152,850) | $3,261,037 | 3 |
| 4 | California Alternate Rates for Energy (CARE) | $32,852 | ($2,555) | $30,297 | 4 |
| 5 | Total Change in A.96-04-001 | $7,560,531 | ($718,812) | $6,841,719 | 5 |
| 6 | Base Energy Rate (ERAM) in other proceedings | $0 | $160,635 | $160,635 | 6 |
| 7 | Annual Earnings Assessment Proceeding (AEAP) | $18,221 | $9,169 | $27,390 | 7 |
| 8 | Cost of Capital | $0 | ($5,306) | ($5,306) | 8 |
| 9 | Conservation Financing Adjustment (CFA) | $1,518 | $0 | $1,518 | 9 |
| 10 | CPUC Fees | $9,111 | $0 | $9,111 | 10 |
| 11 | Subtotal | $28,850 | $164,498 | $193,348 | 11 |
| 12 | Total Retail Revenues | $7,589,381 | ($554,314) | $7,035,067 | 12 |
| 13 | Other Operating Revenues | $47,377 | $0 | $47,377 | 13 |
| 14 | Total Revenues | $7,636,758 | ($554,314) | $7,082,444 | 14 |

* Changes to CEE revenues and expenses reflect values for 1996 as requested in PG&E's AEAP filing (A.96-05-002). See PG&E Rebuttal dated July 29, 1996.

** AER costs are included in ECAC costs.

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APPENDIX B

PACIFIC GAS AND ELECTRIC COMPANY

Electric Department

Forecast Year 1997

ADOPTED ENERGY EXPENSES

Forecast Period: January 1 through December 31

| Line No. | Revenue Element | Quantity GWh (a) | | MDth (b) | Average Cost (c) | | Total Costs ($000) (d) | Line No. |
|---|---|---|---|---|---|---|---|---|
| | **Fossil Fuel** | | | | | | | |
| 1 | Commodity | 203,741 | Dth | | 1.42705 | $/Dth | $290,748 | 1 |
| 2 | Transportation & Storage | | | | | | $123,667 | 2 |
| 3 | *Subtotal Gas* | 203,741 | Dth | | 2.03403 | $/Dth | $414,415 | 3 |
| 4 | Residual Oil | 0 | Dth | | | $/Dth | $0 | 4 |
| 5 | Distillate Oil | 23 | Dth | | 4.19982 | $/Dth | $95 | 5 |
| 6 | *Subtotal Fossil Fuel* | 203,763 | Dth | | 2.03427 | $/Dth | $414,510 | 6 |
| 7 | Geothermal Steam | 4,673 | Gwh | | 0.01477 | $/Kwh | $69,028 | 7 |
| | **Purchased Power** | | | | | | | |
| 8 | Irrigation Districts | 5,432 | Gwh | | 0.00127 | $/Kwh | $6,878 | 8 |
| 9 | CVP | (2,460) | Gwh | | 0.00807 | $/Kwh | ($19,863) | 9 |
| 10 | Variably Priced QF Energy | 12,573 | Gwh | | | | $258,506 | 10 |
| 11 | Other QF Including Capacity Payments | 9,013 | Gwh | | | | $1,301,884 | 11 |
| 12 | *Total QF* | 21,586 | Gwh | | 0.07229 | $/Kwh | $1,560,390 | 12 |
| 13 | Northwest | 2,491 | Gwh | | 0.01537 | $/Kwh | $38,285 | 13 |
| 14 | Southwest (Including Sales) | (426) | Gwh | | 0.02216 | $/Kwh | ($9,440) | 14 |
| 15 | CDWR | 0 | Gwh | | | | $0 | 15 |
| 16 | Other | 4 | Gwh | | 0.09222 | $/Kwh | $332 | 16 |
| 17 | *Subtotal Purchased Power* | 26,626 | Gwh | | 0.05921 | $/Kwh | $1,576,582 | 17 |
| 18 | Water for Power | 13,865 | Gwh | | 0.00006 | $/Kwh | $823 | 18 |
| 19 | Oil Inventory Carrying Cost | | | | | | $1,426 | 19 |
| 20 | Gas Storage Carrying Cost | | | | | | $0 | 20 |
| 21 | Variable Wheeling | | | | | | $147 | 21 |
| 22 | Losses(Gains) on Fuel Oil Sales | | | | | | $0 | 22 |
| 23 | *Subtotal Energy Expense* | | | | | | $2,062,516 | 23 |
| 24 | Less 9% of Energy Expense (AER) | | | | | | $0 | 24 |
| 25 | *Subtotal* | | | | | | $2,062,516 | 25 |
| 26 | Diablo Canyon (DC) Settlement Revenues * | 16,883 | Gwh | | 0.09904 | $/Kwh | $1,672,044 | 26 |
| 27 | Excess Oil Inventory Carrying Cost | | | | | | $3 | 27 |
| 28 | Humboldt Nuclear D & D Cost | | | | | | $198 | 28 |
| 29 | *Subtotal* | | | | | | $3,734,761 | 29 |
| 30 | Allocation to CPUC Jurisdictional @ | 0.99950942 | | | | | $3,732,929 | 30 |
| 31 | Less: DC Basic Revenue Requirement | | | | | | $159,227 | 31 |
| 32 | *Subtotal* | | | | | | $3,573,702 | 32 |

* The average Diablo Canyon rate for variable fuels, excluding the basic revenue requirement and F&U expense and including the Safety Committee Fee is 0.08964

APPENDIX B

PACIFIC GAS AND ELECTRIC COMPANY

Electric Department

Forecast Year 1997

ADOPTED ENERGY EXPENSES

| Line No. | Revision Date: January 1, 1997<br>Forecast Period: Twelve Months Beginning January 1, 1997 | | ($000) | Line No. |
|---|---|---|---|---|
| | | | (a) | |
| | *ECAC REVENUE REQUIREMENT (cont.)* | | | |
| 32 | *Subtotal (from page 1)* | | $3,573,702 | 32 |
| 33 | Estimated ECAA Balance on January 1 | | ($49,700) | 33 |
| 34 | DC Safety Committee Fee | | $641 | 34 |
| 35 | Less: Designated Sales Revenue (excl. FF&U) | | $13,484 | 35 |
| 36 | Plus: SRAC Estimated Adjustment | | $5,000 | 36 |
| 37 | *Subtotal* | | $3,516,159 | 37 |
| 38 | Franchise Fees & Uncollectible Accounts Expense @ | 0.009734 | $34,226 | 38 |
| 39 | TOTAL ECAC REVENUE REQUIREMENT | | $3,550,385 | 39 |
| 40 | Less: ECAC Revenue at Present Rates of January 1 | | $4,113,792 | 40 |
| 41 | CHANGE IN ECAC REVENUE REQUIREMENT | | ($563,407) | 41 |
| 42 | *AER REVENUE REQUIREMENT* | | | 42 |
| 43 | 9% of Energy Expense (Line 23) | | $0 | 43 |
| 44 | Allocation to CPUC Jurisdiction @ | 0.99950942 | $0 | 44 |
| 45 | Less: Designated Sales Revenue (excl. FF&U) | | $0 | 45 |
| 46 | *Subtotal* | | $0 | 46 |
| 47 | Franchise Fees & Uncollectible Accounts Expense @ | 0.009734 | $0 | 47 |
| 48 | TOTAL AER REVENUE REQUIREMENT | | $0 | 48 |
| 49 | Less: AER Revenue at Present Rates of January 1 | | $0 | 49 |
| 50 | CHANGE IN AER REVENUE REQUIREMENT | | $0 | 50 |
| 51 | *ERAM REVENUE REQUIREMENT* | | | 51 |
| 52 | Base Revenue Amount | | $3,368,512 | 52 |
| 53 | | Less: 1996 DCBRR | $166,458 | 53 |
| 54 | | Plus: 1997 DCBRR | $160,777 | 54 |
| 55 | Estimated ERAM Balance on January 1 | | ($54,986) | 55 |
| 56 | Hazardous Substance Mechanism Transfer | | $102 | 56 |
| 57 | Less: CARE Shortfall | | $30,997 | 57 |
| 58 | Less: Designated Sales Revenues | | $15,903 | 58 |
| 59 | TOTAL ERAM REVENUE REQUIREMENT | | $3,261,037 | 59 |
| 60 | Less: ERAM Revenue at Present Rates of January 1 | | $3,413,887 | 60 |
| 61 | CHANGE IN ERAM REVENUE REQUIREMENT | | ($152,850) | 61 |
| 62 | *CARE REVENUE REQUIREMENT* | | | 62 |
| 63 | CARE Shortfall | | $30,997 | 63 |
| 64 | Estimated CAREA Balance on January 1 | | ($700) | 64 |
| 65 | TOTAL CARE REVENUE REQUIREMENT | | $30,297 | 65 |
| 66 | Less: CARE Revenue at Present Rates of January 1 | | $32,852 | 66 |
| 67 | CHANGE IN CARE REVENUE REQUIREMENT | | ($2,555) | 67 |
| 68 | | | | 68 |
| 69 | Total Change | | ($718,812) | 69 |

*** AER costs are included in ECAC costs.

APPENDIX B

# PACIFIC GAS AND ELECTRIC COMPANY

Electric Department
Forecast Year 1997
REVENUE CONSOLIDATION
RELATIVE TO REVENUE AT PRESENT RATES

| Line No. | Revenue Element | | Revenues at Present Rates ($000) | 1997 Pending Revenue Change ($000) | 1997 Pending Revenue Requirement ($000) | 1997 Addressed in A.96-04-001 and other proceedings as of 11-20-96 Revenue Change ($000) | 1997 Addressed in A.96-04-001 and other proceedings as of 11-20-96 Revenue Requirement ($000) | Source | Line No. |
|---|---|---|---|---|---|---|---|---|---|
| | | | (a) | (b) = (c - a) | (c) | (d) = (e - a) | (e) | (f) | |
| 1 | **Energy Cost Adjustment Clause (ECAC)** | | | | | | | | 1 |
| 2 | ECAC Costs | | | | 3,573,702 | | 3,573,702 | A.96-04-001 | 2 |
| 3 | DCPP Settlement Revenues: | 1,672,044 | | | | | | A.96-04-001 | 3 |
| 4 | Adjust for FERC | (820) | | | | | | | 4 |
| 5 | Adjust for 1997 DCBRR | (159,227) | | | | | | | 5 |
| 6 | Less: Net 1997 DCPP ECAC Expense: | 1,511,997 | | 1,511,997 | 1,511,997 | | 0 | A.96-03-054 | 6 |
| 7 | Plus: DCPP ICIP Revenues | | | 608,486 | 608,486 | | 0 | A.96-03-054 | 7 |
| 8 | Less: DCPP ICIP FF&U | | | 5,866 | 5,866 | | 0 | A.96-03-054 | 8 |
| 9 | Net ECAC costs for 1997 | | | (909,377) | 2,664,325 | | 3,573,702 | | 9 |
| 10 | ECAC Balance on January 1, 1997 * | | | | (49,700) | | (49,700) | A.96-04-001 | 10 |
| 11 | DCPP Safety Committee Fee | | | | 641 | | 641 | A.96-04-001 | 11 |
| 12 | Less: Resale Sales | | | | 13,484 | | 13,484 | A.96-04-001 | 12 |
| 13 | Plus: SRAC Estimated Adjustment | | | | 5,000 | | 5,000 | D.96-12-028 | 13 |
| 14 | Subtotal | | | | 2,606,763 | | 3,516,159 | | 14 |
| 15 | FF&U Expense @ 0.009734 | | | | 25,374 | | 34,226 | A.96-04-001 | 15 |
| 16 | Total ECAC Revenue Requirement | | 4,113,792 | (1,481,635) | 2,632,157 | (563,407) | 3,550,385 | | 16 |
| 17 | | | | | | | | | 17 |
| 18 | **Annual Energy Rate (AER)** | | | | | | | | 18 |
| 19 | AER Costs *** | | | | 0 | | 0 | A.96-04-001 | 19 |
| 20 | Less: Resale Sales | | | | 0 | | 0 | A.96-04-001 | 20 |
| 21 | Subtotal | | | | 0 | | 0 | | 21 |
| 22 | FF&U Expense @ 0.009734 | | | | 0 | | 0 | A.96-04-001 | 22 |
| 23 | Total AER Revenue Requirement | | 0 | 0 | 0 | 0 | 0 | | 23 |
| 24 | | | | | | | | | 24 |
| 25 | **1997 Base Energy Revenue Requirement** | | | | | | | | 25 |
| 26 | 1996 Base Revenue Amount | | | | 3,368,512 | | 3,368,512 | A.96-04-001 | 26 |
| 27 | Less: 1996 DCBRR | | | | 166,468 | | 166,468 | A.96-04-001 | 27 |
| 28 | Plus: 1997 DCBRR | | | | 160,777 | | 160,777 | A.96-04-001 | 28 |
| 29 | Hazardous Substance Mechanism Transfer | | | | 102 | | 102 | A.96-04-001 | 29 |
| 30 | Less: CARE Shortfall | | | | 30,997 | | 30,997 | A.96-04-001 | 30 |
| 31 | Less: Discounted Sales Revenues | | | | 15,903 | | 15,903 | A.96-04-001 | 31 |
| 32 | Estimated ERAM Balance on January 1, 1997 | | | | (54,966) | | (54,986) | A.96-04-001 | 32 |
| 33 | Subtotal in A.96-04-001 | | 3,413,887 | | 3,261,037 | (152,850) | 3,261,037 | | 33 |
| 34 | | | | | | | | | 34 |
| 35 | Cost of Capital Increase | | 0 | | (5,306) | (5,306) | (5,306) | A.96-05-022 | 35 |
| 36 | | | | | | | | | 36 |
| 37 | Diablo Canyon Sunk Costs | | | 1,479,669 | 1,479,669 | | 0 | A.96-03-054 | 37 |
| 38 | Less: 1997 DCBRR | | | 160,777 | 160,777 | | 0 | A.96-03-054 | 38 |
| 39 | Angels/Utica Annual Amortization (1997 portion) | | | | 376 | | 376 | D.96-06-061 | 39 |
| 40 | Less: Angels/Utica Sales Credit | | | | 231 | | 231 | D.96-06-061 | 40 |
| 41 | Less: Angels/Utica Revenue Requirement | | | | 2,625 | | 2,625 | D.96-06-061 | 41 |
| 42 | Helms Adjustment Account Amortization | | | | 2,000 | | 2,000 | D.96-09-037 | 42 |
| 43 | Less: DCPP Decommissioning/IRS Ruling | | | | 3,116 | | 3,116 | Advice 1614-E | 43 |
| 44 | Base Revenue Filing | | | | 164,231 | | 164,231 | Advice 1612-EA | 44 |
| 45 | Subtotal in other proceedings | | 0 | | 1,479,527 | 160,635 | 160,635 | | 45 |
| 46 | | | | | | | | | 46 |
| 47 | Total ERAM Revenue Requirement | | 3,413,887 | 1,321,371 | 4,735,258 | 2,479 | 3,416,366 | | 47 |
| 48 | | | | | | | | | 48 |
| 49 | **California Alternative Rates for Energy (CARE)** | | | | | | | | 49 |
| 50 | CARE Shortfall | | | | 30,997 | | 30,997 | A.96-04-001 | 50 |
| 51 | Estimated CARE Account Balance on January 1 | | | | (700) | | (700) | A.96-04-001 | 51 |
| 52 | | | 32,852 | (2,555) | 30,297 | (2,555) | 30,297 | | 52 |
| 53 | | | | | | | | | 53 |
| 54 | **Annual Earning Assessment Proceeding (AEAP)** | | | | | | | | 54 |
| 55 | AEAP | | 18,221 ** | 9,169 | 27,390 | 9,169 | 27,390 | A.96-05-002 | 55 |
| 56 | | | | | | | | | 56 |
| 57 | **Other Revenue Requirements** | | | | | | | | 57 |
| 58 | Conservation Financing Adjustment (CFA) | | 1,518 | | 1,518 | | 1,518 | A.96-04-001 | 58 |
| 59 | California Public Utilities Commission Fees | | 9,111 | | 9,111 | | 9,111 | D.91-11-056 | 59 |
| 60 | Revenue for Transition Cost Recovery | | 0 | 153,650 | 153,650 | 0 | 0 | A.96-08-001, et al. | 60 |
| 61 | Total Retail Revenues | | 7,589,381 | | 7,589,381 | | 7,035,067 | | 61 |
| 62 | Other Operating Revenues | | 47,377 | | 47,377 | | 47,377 | D.95-12-055 | 62 |
| 63 | Total Revenues | | 7,636,758 | 0 | 7,636,758 | (554,314) | 7,082,444 | | 63 |

* January 1 ECAC balance does not reflect Advice Letters 1973-G and 1599-E related to UEG refunds.
** The adopted decision in the AEAP proceeding is anticipated to be issued concurrently with the ECAC.
*** AER costs are included in ECAC costs.

# APPENDIX B

## PACIFIC GAS AND ELECTRIC COMPANY
## Electric Department
## Forecast Year 1997
## REVENUE CONSOLIDATION
## RELATIVE TO 1996 ADOPTED REVENUE REQUIREMENTS

| Line No. | Revenue Element | | 1996 Adopted Revenue Requirement ($000) | Revenue Change ($000) | 1997 Illustrative Revenue Requirement ($000) | Source for 1996 Adopted Revenue Requirement | Line No. |
|---|---|---|---|---|---|---|---|
| | | | (a) | (b) | (c) | (d) | |
| 1 | **Energy Cost Adjustment Clause (ECAC)** | | | | | | 1 |
| 2 | ECAC Costs | | 3,563,645 | 10,057 | 3,573,702 | A. 95-04-002 | 2 |
| 3 | DCPP Settlement Revenues. | 1,672,044 | | | | | 3 |
| 4 | Adjust for FERC | (820) | | | | | 4 |
| 5 | Adjust for 1997 DCBRR | (160,777) | | | | | 5 |
| 6 | Less: Net 1997 DCPP ECAC Expense. | 1,510,447 | | | | | 6 |
| 7 | Plus: DCPP ICIP Revenues | | | | | | 7 |
| 8 | Less: DCPP ICIP F&U | | | | | | 8 |
| 9 | Net ECAC costs for 1997 | | | | | | 9 |
| 10 | ECAC Balance on January 1 | | 270,866 | (320,566) | (49,700) | A. 95-04-002 | 10 |
| 11 | Less: Deferral | | 0 | | 0 | | 11 |
| 12 | DCPP Safety Committee Fee | | 673 | (32) | 641 | A. 95-04-002 | 12 |
| 13 | Less: SO2 Allowances | | 173 | (173) | 0 | A. 95-04-002 | 13 |
| 14 | Less: Resale Sales | | 21,337 | (7,853) | 13,484 | A. 95-04-002 | 14 |
| 15 | Plus: SRAC Estimated Adjustment | | 0 | 5,000 | 5,000 | A 96-05-002 | 15 |
| 16 | Subtotal | | 3,813,674 | (297,515) | 3,516,159 | A. 95-04-002 | 16 |
| 17 | FF&U Expense @ 0.009734 | | 37,122 | (2,896) | 34,226 | A. 95-04-002 | 17 |
| 18 | Less: FF&U Expense Associated with Deferral | | 0 | | 0 | | 18 |
| 19 | Total ECAC Revenue Requirement | | 3,850,796 | (300,411) | 3,550,355 | | 19 |
| 20 | | | | | | | 20 |
| 21 | **Annual Energy Rate (AER)** | | | | | | 21 |
| 22 | AER Costs | | 196,391 | (196,391) | 0 | A. 95-04-002 | 22 |
| 23 | Less: Designated Sales Transactions to Resale Customers | | 2,119 | (2,119) | 0 | A. 95-04-002 | 23 |
| 24 | Subtotal | | 194,272 | (194,272) | 0 | A. 95-04-002 | 24 |
| 25 | FF&U Expense @ 0.009734 | | 1,891 | (1,891) | 0 | A. 95-04-002 | 25 |
| 26 | Total AER Revenue Requirement | | 196,163 | (196,163) | 0 | | 26 |
| 27 | | | | | | | 27 |
| 28 | **1997 Base Energy Revenue Requirement:** | | | | | | 28 |
| 29 | 1996 Base Revenue Amount | | 3,248,634 | 119,878 | 3,368,512 | A. 94-12-005/A.95-05-016 | 29 |
| 30 | Plus: TEFRA Amortization | | 2,537 | (2,537) | | | 30 |
| 31 | Less: Geysers 15 Offset Recovery | | 1,750 | (1,750) | | | 31 |
| 32 | Net GRC Revenue Requirement | | 3,249,421 | (3,249,421) | | | 32 |
| 33 | Less: Other Operating Revenues | | 47,377 | (47,377) | | | 33 |
| 34 | Net GRC Impact on Retail Rates | | 3,202,044 | (3,202,044) | | | 34 |
| 35 | | | | | | | 35 |
| 36 | Diablo Canyon Basic Revenue Requirement (DCBRR) | | | | | | 36 |
| 37 | 1996 DCBRR | | 156,458 | 0 | 166,458 | A. 94-12-005 | 37 |
| 38 | Plus: 1997 DCBRR | | | | 160,777 | A. 94-12-005 | 38 |
| 39 | Less: 1997 DCBRR | | | | 0 | | 39 |
| 40 | Less: DCPP Decommissioning/IRS Ruling | | | | 3,116 | A. 94-12-005 | 40 |
| 41 | Angels/Utica Annual Amortization (1997 portion) | | 0 | | 376 | A. 94-12-005 | 41 |
| 42 | Base Revenue Filing | | | | 164,231 | A. 95-04-002 | 42 |
| 43 | Cost of Capital | | 0 | | (5,306) | A.95-04-002/A.95-05-016 | 43 |
| 44 | Diablo Canyon Sunk Costs | | | | 0 | | 44 |
| 45 | 1996 Base Revenue Amount | | 3,368,512 | 483,430 | 3,851,942 | | 45 |

(continued on the next page)

*** AER costs are included in ECAC costs

# APPENDIX B

## PACIFIC GAS AND ELECTRIC COMPANY
## Electric Department
## Forecast Year 1997
## REVENUE CONSOLIDATION
## RELATIVE TO 1996 ADOPTED REVENUE REQUIREMENTS

(continued from the previous page)

| Line No. | Revenue Element | 1996 Adopted Revenue Requirement ($000) (a) | Revenue Change ($000) (b) | 1997 Illustrative Revenue Requirement ($000) (c) | Source for 1996 Adopted Revenue Requirement (d) | Line No. |
|---|---|---|---|---|---|---|
| 46 | | | | | | 46 |
| 47 | Estimated ERAM Balance on January 1 | 104,526 | (159,512) | (54,986) | A. 95-04-002 | 47 |
| 48 | | | | | | 48 |
| 49 | Hazardous Substance Mechanism Transfer | 5,435 | (5,333) | 102 | | 49 |
| 50 | Helms Adjustment Account Amortization | 0 | | 2,000 | | 50 |
| 51 | Low Emission Vehicle (LEV) | 614 | (614) | 0 | | 51 |
| 52 | Less: Angels/Utica Revenue Requirement | 0 | | 2,625 | | 52 |
| 53 | Less: Angels/Utica Sales Credit | 0 | | 231 | | 53 |
| 54 | Less: CARE Shortfall | 31,211 | (214) | 30,997 | | 54 |
| 55 | Less: Conservation Financing Account (CFA) Transfer | 50 | (50) | 0 | | 55 |
| 56 | Less: Demand Side Management (DSM) Refund | 11,378 | (11,378) | 0 | | 56 |
| 57 | Less: Designated Sales Revenue | 70,607 | (54,704) | 15,903 | A. 95-04-002 | 57 |
| 58 | Total ERAM Revenue Requirement | 3,365,841 | 50,525 | 3,416,366 | | 58 |
| 59 | | | | | | 59 |
| 60 | **California Alternative Rates for Energy (CARE):** | | | | | 60 |
| 61 | CARE Shortfall | 31,211 | (214) | 30,997 | A. 95-04-002 | 61 |
| 62 | Estimated CARE Account Balance on January 1 | 2,543 | (3,243) | (700) | A. 95-04-002 | 62 |
| 63 | Total CARE | 33,754 | (3,457) | 30,297 | | 63 |
| 64 | | | | | | 64 |
| 65 | **Annual Earning Assessment Proceeding (AEAP)** | | | | | 65 |
| 66 | Energy Efficiency Incentive Payments | 17,835 | 9,555 | 27,390 | A. 95-04-041 | 66 |
| 67 | | | | | | 67 |
| 68 | **Other Revenue Requirements:** | | | | | 68 |
| 69 | Conservation Financing Adjustment (CFA) | 1,494 | 24 | 1,518 | A. 95-04-002 | 69 |
| 70 | California Public Utilities Commission Fees | 8,968 | 143 | 9,111 | D 91-11-056 | 70 |
| 71 | Revenue for Transition Cost Recovery | 0 | | 0 | | 71 |
| 72 | Total Retail Revenues | 7,474,852 | (439,785) | 7,035,067 | | 72 |
| 73 | Other Operating Revenues | 47,377 | 0 | 47,377 | | 73 |
| | Total Revenues | 7,522,229 | (439,785) | 7,082,444 | A.94-12-005 | |

# Appendix B

## PACIFIC GAS AND ELECTRIC COMPANY

### Electric Department -- Forecast Year 1997

### FORECAST BY REVENUE ACCOUNT
(THOUSANDS OF KWH)

| Line No. | REVENUE ACCOUNT: | TOTAL | Line No. |
|---|---|---|---|
| 1 | RESIDENTIAL | 25,456,504 | 1 |
| 2 | | | 2 |
| 3 | LIGHT AND POWER: | | 3 |
| 4 | SMALL | 7,028,618 | 4 |
| 5 | MEDIUM | 20,815,146 | 5 |
| 6 | TOTAL | 27,843,764 | 6 |
| 7 | | | 7 |
| 8 | LARGE LIGHT AND POWER: | | 8 |
| 9 | CCSF INDUSTRIAL | 1,025,717 | 9 |
| 10 | OTHER ACCOUNT 359 | 16,652,338 | 10 |
| 11 | TOTAL | 17,678,056 | 11 |
| 12 | | | 12 |
| 13 | PUBLIC AUTHORITY | 353,000 | 13 |
| 14 | RAILWAY | 300,000 | 14 |
| 15 | AGRICULTURE | 3,757,964 | 15 |
| 16 | STREET LIGHTING | 442,044 | 16 |
| 17 | | | 17 |
| 18 | NONCPUC: | | 18 |
| 19 | INCREMENTAL SALES(1) | 536,600 | 19 |
| 20 | OTHER RESALE(1) | 285,115 | 20 |
| 21 | | | 21 |
| 22 | INTERDEPARTMENTAL | 153,670 | 22 |
| 23 | | | 23 |
| 24 | TOTAL PG&E SALES | 76,806,712 | 24 |
| 25 | | | 25 |
| 26 | LUAF | 6,856,804 | 26 |
| 27 | ELECTRIC DEPT USES | 29,708 | 27 |
| 28 | | | 28 |
| 29 | TOTAL PG&E SALES AND LOADS | 83,693,224 | 29 |
| 30 | | | 30 |
| 31 | LOAD SUPPLIED BY OTHERS: | | 31 |
| 32 | | | 32 |
| 33 | SMUD | 8,933,800 | 33 |
| 34 | OTHER AREA LOAD | 14,308,581 | 34 |
| 35 | | | 35 |
| 36 | TOTAL AREA LOAD(2) | 106,935,620 | 36 |
| 37 | | | 37 |
| 38 | SALES OUTSIDE AREA | 530,300 | 38 |
| 39 | | | 39 |
| 40 | TOTAL PLANNING LOAD | 107,465,910 | 40 |

*PARTS MAY NOT SUM TO TOTALS DUE TO ROUNDING.
(1) LINE 12 REFERS TO DESIGNATED TRANSACTIONS TO RESALE CUSTOMERS INCLUDED IN THE CPUC JURISDICTION FOR RATEMAKING PURPOSES.
LINE 13 REFERS TO OTHER FERC JURISDICTIONAL SALES FORECASTS IN REVENUE ACCOUNT 358.
(2) TOTAL AREA LOAD DOES NOT INCLUDE OUT-OF-AREA PG&E SALES.

Source: PG&E Application 96-04-001 Forecast of Electric Operations, page 3-8.

# APPENDIX B

## PACIFIC GAS AND ELECTRIC COMPANY

## Electric Department

## Forecast Year 1997

### Northwest Economy Energy Prices

Mills/kWh

| Line No. | Month | On-Peak | Off-Peak | Line No. |
|---|---|---|---|---|
| 1 | January 1997 | 18.8 | 18.5 | 1 |
| 2 | February 1997 | 18.6 | 18.2 | 2 |
| 3 | March 1997 | 17.4 | 16.9 | 3 |
| 4 | April 1997 | 18.2 | 17.6 | 4 |
| 5 | May 1997 | 15.7 | 15.1 | 5 |
| 6 | June 1997 | 14.9 | 14.5 | 6 |
| 7 | July 1997 | 14.5 | 14.5 | 7 |
| 8 | August 1997 | 17.1 | 16.9 | 8 |
| 9 | September 1997 | 18.7 | 18.2 | 9 |
| 10 | October 1997 | 18.3 | 18.0 | 10 |
| 11 | November 1997 | 18.9 | 18.7 | 11 |
| 12 | December 1997 | 19.8 | 19.6 | 12 |

# APPENDIX B

## PACIFIC GAS AND ELECTRIC COMPANY

### Electric Department

### Forecast Year 1997

### 1997 AVERAGE DISPATCH GAS COSTS

| Line No. | Month | Price ($/Dth) | Line No. |
|---|---|---|---|
| 1 | January 1997 | 1.97 | 1 |
| 2 | February 1997 | 1.96 | 2 |
| 3 | March 1997 | 2.01 | 3 |
| 4 | April 1997 | 2.02 | 4 |
| 5 | May 1997 | 1.94 | 5 |
| 6 | June 1997 | 1.82 | 6 |
| 7 | July 1997 | 1.74 | 7 |
| 8 | August 1997 | 1.78 | 8 |
| 9 | September 1997 | 1.82 | 9 |
| 10 | October 1997 | 1.79 | 10 |
| 11 | November 1997 | 1.94 | 11 |
| 12 | December 1997 | 2.15 | 12 |
| 13 | Simple Average | 1.912 | 13 |

## APPENDIX B

### PACIFIC GAS AND ELECTRIC COMPANY

**Electric Department**

**Forecast Year 1997**

### 1997 SAN JUAN, PERMIAN AND ALBERTA MAINLINE GAS PRICES

| Line No. | Month | San Juan Mainline ($/Dth) | Permian Mainline ($/Dth) | Alberta Mainline ($/Dth) | Line No. |
|---|---|---|---|---|---|
| 1 | January 1997 | 1.49 | 1.74 | 1.15 | 1 |
| 2 | February 1997 | 1.44 | 1.73 | 1.15 | 2 |
| 3 | March 1997 | 1.39 | 1.78 | 1.23 | 3 |
| 4 | April 1997 | 1.38 | 1.79 | 1.24 | 4 |
| 5 | May 1997 | 1.31 | 1.71 | 1.10 | 5 |
| 6 | June 1997 | 1.24 | 1.60 | 1.02 | 6 |
| 7 | July 1997 | 1.17 | 1.52 | 0.88 | 7 |
| 8 | August 1997 | 1.27 | 1.55 | 0.83 | 8 |
| 9 | September 1997 | 1.35 | 1.57 | 0.87 | 9 |
| 10 | October 1997 | 1.34 | 1.55 | 0.94 | 10 |
| 11 | November 1997 | 1.42 | 1.66 | 1.06 | 11 |
| 12 | December 1997 | 1.50 | 1.85 | 1.20 | 12 |
| 13 | Average | 1.36 | 1.67 | 1.06 | 13 |

# APPENDIX B

## PACIFIC GAS AND ELECTRIC COMPANY

### Electric Department

### Forecast Year 1997

### AVERAGE COSTS OF POWER PLANT GAS[(a)]
### ($/DTH AT THE BURNERTIP)

| Line No. | Month | Total Gas Cost ($000) | UEG Gas Requirement (MDth) | Average Rate ($/Dth) | Line No. |
|---|---|---|---|---|---|
| 1 | January 1997 | 38,136.83 | 17,187.70 | 2.22 | 1 |
| 2 | February 1997 | 34,366.52 | 16,252.50 | 2.11 | 2 |
| 3 | March 1997 | 26,191.70 | 12,015.30 | 2.18 | 3 |
| 4 | April 1997 | 34,723.95 | 16,599.00 | 2.09 | 4 |
| 5 | May 1997 | 25,339.12 | 13,303.00 | 1.90 | 5 |
| 6 | June 1997 | 26,440.44 | 14,180.10 | 1.86 | 6 |
| 7 | July 1997 | 30,749.53 | 17,202.20 | 1.79 | 7 |
| 8 | August 1997 | 49,064.51 | 25,500.40 | 1.92 | 8 |
| 9 | September 1997 | 46,796.62 | 22,832.00 | 2.05 | 9 |
| 10 | October 1997 | 40,984.11 | 20,525.30 | 2.00 | 10 |
| 11 | November 1997 | 31,178.80 | 14,523.30 | 2.15 | 11 |
| 12 | December 1997 | 30,441.33 | 13,619.80 | 2.24 | 12 |
| 13 | Average | 414,413.50 | 203,740.70 | 2.034 | 13 |

(a) The monthly average cost of gas is calculated by dividing the total cost of gas by the forecasted monthly throughput.

APPENDIX C

PACIFIC GAS AND ELECTRIC COMPANY
1997 ECAC/1995 REASONABLENESS CASE
A. 96-04-001
SUMMARY OF UNCONTESTED ISSUES

A. UNCONTESTED RESOURCE ASSUMPTIONS

1. Area Load Forecast (exlcuding deliveries out of area) - June forecast
ECAC test year Jan. 1997 - Dec. 1997 106,935.3 GWh

2. Hydroelectric Generation - May snow survey

| | | |
|---|---|---|
| a. | PG&E owned Hydro w/o Helms | 13,773.1 GWh |
| b. | Irrigation Districts | 5,431.7 GWh |
| c. | USBR (WAPA) Hydro | 4,647.8 GWh |
| d. | NCPA | 566.0 GWh |
| e. | SMUD | 1,694.8 GWh |
| f. | CCSF | 1,964.8 GWh |
| g. | MID/TID | 525.0 GWh |

3. Helms Pumped Storage
Three units with a combined generating capacity of 1212 MW and pumping capacity of 966 MW. Inflows and water management operations modeled through PROMOD EXCH records.

4. Southwest Firm Purchases - 23.1 GWh
Firm energy and purchase from the 24 MW Etiwanda hydro unit. Purchase amount based on contract estimate.

5. WSPP Out-of-Area Sales - 530.3 GWh
Non-firm off-peak sales based on 1990-1995 recorded data and employs the approach adopted in ECAC Decision 95-12-051.

6. Southwest Miscellaneous purchases by PG&E - 324.0 GWh
Fixed off-peak purchases based on historical quantities.

7. California Power Pool Purchases[1]
Economic energy purchases assumed at an incremental heat rate of 11,000 Btu/kWh.

8. Sierra Pacific Purchases - 3.6 GWh
Around the clock deliveries to serve PG&E customers in the Echo Summit Area.

9. CCPA Geothermal - 689.9 GWh
One 62 MW unit available based on actual operations. Energy split 50% to SMUD, 40% to MID/TID, and 10% to CSC based on ownership.

10. NCPA Resources
a. NCPA Geothermal - 1,261.6 GWh
Unit with cycling operations - 238 MW on-peak, 120 MW off-peak.
b. NCPA COO - 33.8 GWh
Fixed firm unscheduled transaction based on historical quantities.
c. NCPA CT - 7.0 GWh
Fixed non-firm peaking transaction based on historical quantities.

APPENDIX C

PACIFIC GAS AND ELECTRIC COMPANY
1997 ECAC/1995 REASONABLENESS CASE
A. 96-04-001
SUMMARY OF UNCONTESTED ISSUES

A. UNCONTESTED RESOURCE ASSUMPTIONS - Continued

11. QF Generation [1]

a. Firm capacity contracts modeled at their firm capacity ratings. Remaining QFs modeled with average megawatts.
b. Gilroy is scheduled to be curtailed in agreement with provisions of the fourth amendment of the contract dated June 6, 1991. 100% variable.
c. BAF is scheduled to be curtailed in agreement with provisions of the second amendment to the contract dated June 6, 1991. 20% fixed and 80% variable.
d. Crockett cogen is dispatched pursuant to the first amendment of the PPA.
e. 162 hours of Option B curtailments are forecast during 1997, consistent with ECAC Decision 95-12-051. Option B QFs assumed to continue delivering power during curtailment hours and receive the alternate price. Non-standard curtailment provisions not tied to minimum load conditions are forecast.
f. Hydro capacity factor for 1996 is adjusted to reflect May hydro conditions.

12. SMUD Resources

a. SMUD Geothermal - 551.2 GWh
Unit availability based on two year average historical outage statistics.
b. SMUD PV, SMUD CT - 7.8 GWh
Fixed peaking transaction based on historical quantities.
c. SCE sales to SMUD - 188.0 GWh
SMUD elected 300 MW contract capacity. Amount of energy purchased based on SMUD's own forecast of expected purchases.
d. SMUD COGEN - 964.7 GWh
Takes based on SMUD's own forecast of expected generation.
e. SMUD imports - 3,099.9 GWh
Imports from both the Northwest and Southwest in amounts needed to balance their loads and available resources (both owned and operated by them or purchased by them). Firm imports reflect existing contractual agreements and additional amounts to meet spinning requirements. Economy energy imports scheduled around the clock with more energy taken during the peak hours.

13. MID/TID in area resources.

a. MID/TID CT - 7.0 GWh
Fixed peaking transaction based on historical quantities.
b. MID/TID Combined cycle - 684.7 Gwh
Takes based on the MUNI's expected operation of the units

14. MUNI Imports - 1,657.4 GWh

a. 100 MW firm peaking contract, increasing to 150 MW between BPA and MSR with 592 GWh of energy takes during the forecast period.
b. 50 MW firm contract between NCPA and WWP, 100 MW firm contract between MSR and San Juan reflected. Takes based on contractual agreement and needs.

---

[1] PG&E forecasts 21,615.3 Gwh of QF generation (including hydro QFs). DRA forecasts 21,852.0 Gwh of QF generation (including hydro QFs). Differences are due to the dispatchable Crockett cogen project.

APPENDIX C

PACIFIC GAS AND ELECTRIC COMPANY
1997 ECAC/1995 REASONABLENESS CASE
A. 96-04-001
SUMMARY OF UNCONTESTED ISSUES

A. UNCONTESTED RESOURCE ASSUMPTIONS - Continued

14. MUNI Imports - continued

c. Additional non-firm purchases in amounts needed to balance their loads and available resources (both owned and operated by them or purchased in the area). One-half of the purchases scheduled around the clock, with the remaining scheduled during the daytime.

15. Northwest for WAPA - 3,517.6 GWh

Forecast based on WAPA's estimate of firm purchases under their existing long-term contracts. WAPA's remaining intertie allocation is assumed filled up with non-firm purchases during on-peak hours.

16. Northwest for PG&E*

a. Energy availability up to the line entitlement on the AC line and the DC lines, 6.6% forced outage rate on the DC line to account for forced outages, and AC loop flow causing 10% line limitations from April through June.

b. Layoffs and AC/DC line capacity swaps between participants in the COT project and PG&E reflected.

c. Transmission losses are 6% on the AC line and 7.5 % on the DC line.

d. Existing firm exchange contract with Puget Sound Power and Light reflected.

e. Initial seed runs for determining economy energy prices based on methodology adopted in D. 88-11-052.

17. Diablo Canyon - 16,883.5 GWh

95% operating capacity factor based on sum-of-the-years digits for the last four completed cycles. One 45 day refueling outage starting in April 1997 is reflected. One week ramp-up is assumed following the refueling outage.

18. Geysers Units*

Unit availability based on average historical forced outage statistics. Steam supply limitations modeled as capacity derations. Forecast reflects the Steam Sales Agreement with UNOCAL which supplies steam to 12 of the 14 units.

19. Conventional Thermal Plants*

Unit availability based on five years' average historical forced outage statistics. Heat rate data based on latest IHR curves. Heat rate performance factor as follows:

| Fossil Units | Percent | Fossil Units | Percent |
|---|---|---|---|
| Pittsburg 7 | 1.25 | Morro Bay 1,2 | 1.21 |
| Moss Landing 6,7 | 1.65 | Pittsburg 1,2,3,4 | 3.46 |
| Contra Costa 6,7 | 1.80 | Hunters Point 4 | 2.24 |
| Morro Bay 3,4 | 1.88 | Hunters Point 2,3 | 1.74 |
| Pittsburg 5,6 | 3.33 | Humboldt Bay | 1.72 |
| Potrero 3 | 1.73 | | |

20. Combustion Turbine Units*

Unit availability based on five year average historical forced outage statistics.

* Generation forecasts differs between PG&E and DRA's production simulation runs due to the different assumptions in the dispatch price of gas.

# APPENDIX C

## PACIFIC GAS AND ELECTRIC COMPANY
## 1997 ECAC /1995 REASONABLENESS CASE
## A. 96-04-001
## SUMMARY OF UNCONTESTED ISSUES

### B. UNCONTESTED MODELING CONVENTIONS

1. Dispatchers Risk Aversion Feature
   100% of weekends, zero weeknights and weekdays.

2. Minimum Thermal Generation
   Use in PROMOD the minimum fuel burn feature to assure at least 379 GWh / month generation from the conventional thermal generating plants.

3. Must Run Units
   Combination of designating units as must run or use of PROMOD's area protection feature. At least seven units are maintained on line, with additional units during the summer peak period as described in Appendix F of PG&E's Forecast of Electric Operations Report filed in Application 95-04-002.

4. Minimum Load Conditions
   Backdown order according to economic and contractual rules as shown on pages 4-23 and 4-24 of PG&E's Forecast Report. In PROMOD, FRPL records are used to mimic the backdown order.

5. Minimum Downtime
   72 hours for 750 MW, 48 hours for the other classes of units.

6. Spinning Reserve Requirement
   7% weekdays, with 404 MW adjustment for Helms. 7% weeknights, 7% weekends.

APPENDIX C

PACIFIC GAS AND ELECTRIC COMPANY
1997 ECAC/ 1995 REASONABLENESS CASE
A. 96-04-001
SUMMARY OF UNCONTESTED ISSUES

## C. OTHER UNCONTESTED ISSUES

1. Incremental Energy Rate (QFIER)
   9,603 Btu/kWh, pursuant to Decision 95-12-051 which adopted a 2-year QF Settlement Agreement.

2. QF O&M Adder*
   1.2 mills/kWh, pursuant to Decision 95-12-051 which adopted a 2-year QF Settlement Agreement.

3. Energy Reliability Index (ERI)
   The ERI equals 1.0. The ERI is used to calculate the capacity payments to QFs under as-available offers and is subject to change, once the final decision is issued in Phase 2 of PG&E's 1996 GRC Application 94-12-005.

4. Distillate Fuel Oil Inventory
   Annual average inventory level of 92,000 barrels.

5. Variable Wheeling Expense
   The $147,000 estimate of variable wheeling expense is based on 1995 recorded wheeling expense. Variable wheeling expenses do not include transmission capacity for Southern San Joaquin Power Authority.

6. Dispatch Cost of Gas
   a. The Permian basin or the San Juan basin is the incremental source for UEG fuel supplies, depending on the forecast of UEG demand.
   b. The components of the dispatch cost of gas are the commodity cost of gas, brokered/discounted interstate demand charges, interstate volumetric charges, interstate shrinkage charges, intrastate shrinkage charges, and a credit for reducing future ITCS charge.

7. Compliance Reports
   - Franchise Fees and Uncollectible (FF&U) Factor study -- Pursuant to Decision 95-12-051, PG&E performed a study of the FF&U factor as a function of FF&U rates rather than dollor amounts adopted in GRC. PG&E recommends that its current methodology be retained for calculating the FF&U factor.
   - Northwest Economy Energy Price Study -- Pursuant to Decision 95-12-051, PG&E performed a study of the variables that influence Northwest economy energy prices. PG&E recommends using its current methodology in which the price of economy energy purchases from the Northwest are based on a percent of the thermal incremental costs. DRA recommends using one of the regression formulas from the Northwest economy energy price study to develop the price of economy energy purchases from the Northwest.

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* As stated in the second PHC, dated June 19, 1996, the second phase of this proceeding will address O&M double recovery, if necessary, (Pursuant to Decision 95-12-051, PG&E performed a study on the double recovery of fixed O&M costs through capacity payments and standby and retired plant components of the O&M adder). Hearings in the second phase will be held in the spring of 1997.

APPENDIX C

PACIFIC GAS AND ELECTRIC COMPANY
1997 ECAC/ 1995 REASONABLENESS CASE
A. 96-04-001
SUMMARY OF UNCONTESTED ISSUES

C. OTHER UNCONTESTED ISSUES - Continued

7. Compliance Reports - continued

- Typical Week and Weekly Dispatch Option in PROMOD -- Pursuant to Decision 95-12-051, PG&E performed a study which compared PROMOD typical week and weekly dispatch options. PG&E recommends using the current typical week option. DRA also used the typical week option.

The 1997 ECAC decision incorporates an estimated adjustment of $5 million to accomodate the formula changes adopted for PG&E in the Short Run Avoided Cost (SRAC) decision issued 12/9/96, D.96-12-028 for 1997 only, due to the significant cost estimate provided by PG&E and also due to the last minute calculations requested. The text below provides the data request response to the Energy Division of the CPUC.

"Including the revised SRAC pricing methodology contained in [D.96-12-028]....results in a net increase in the 1997 ECAC/AER/ERAM/CARE Revenue Requirement of $35.4 million ($35.1 million without F&U). Approximately $30 million of the net revenue requirement change is due to the increase in QF SRAC expenses that reflect higher gas prices experienced in October/November/December 1996. The remainder is due to the impact of the new SRAC pricing formula on 1997 forecast expenses. Neither forecast gas quantities nor QF generation were changed for either 1996 or 1997 from those contained in PG&E's October Update.

As noted above, PG&E's estimated actual gas prices for October/November/December were used to determine the revised QF expenses for 1996. These are shown on Attachment 1.

For 1997, monthly gas prices were developed based on the ALJ's September 23, 1996 resource mix ruling which directed that an average of ORA and DRI forecasts be used. Attachment No. 1 shows the prices forecast at Topock and at Malin for 1997. The Topock border price consists of the forecast basin prices for the San Juan and Permian basins, weighted by the forecast UEG gas volumes for each basin respectively, and includes the 1997 ECAC forecast Transportation cost to Topock on both the El Paso and Transwestern pipelines. The Malin border price consists of the forecast basin price for the Alberta basin plus the forecast transportation cost to Malin on ANG and PGT. These prices are based on border volumes, which are inclusive of the 1.75% needed for intrastate shrinkage and do not include intrastate transportation costs.

For both 1996 and 1997, the change in QF costs also has a small effect on Balancing Account interest and Irrigation District expenses. These have been included in the dollars above. Attachment 1 shows the gas prices used for October/November/December 1996 and for 1997. It also shows the application of the new SRAC pricing formula. Attachments 2 and 3 show the increase in Variable Priced QF energy expenses for 1996 and 1997 ............"

The SRAC pricing methodology adopted 12/9/96 in D.96-12-028 for PG&E is also attached.

# APPENDIX C
(CONTINUED)

## CALCULATIONS FOR SRAC PAYMENTS

## BASED ON D.96-12-028

AH 1

## SRAC Payment Calculation Based on SRAC Transition Formula Approved by CPUC on 12/3/1996

Pn = (Po+Po*((GPn-GPo)/GPo)*Factor)*TOU

| | Po | GPo | Factor |
|---|---|---|---|
| Winter | 2.3973 | 1.6394 | 0.7875 |
| ~~Summer~~ | ~~1.8748~~ | ~~1.4457~~ | ~~0.6270~~ |

TOU = Time-of-Use factor, calculated as follows:

| Summer | | Winter | |
|---|---|---|---|
| Peak | 1.066 | | |
| Partial-Peak | 1.022 | Partial-Peak | 1.032 |
| Off-Peak | Varies by month* | Off-Peak | Varies by month* |
| Super Off-Peak | 0.946 | Super Off-Peak | 0.950 |

California Border Gas Prices:

| ($/MMBtu) | Oct-96 | Nov-96 | Dec-96 | Jan-97 | Feb-97 | Mar-97 | Apr-97 | May-97 | Jun-97 | Jul-97 | Aug-97 | Sep-97 | Oct-97 | Nov-97 | Dec-97 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Topock | 1.73 | 2.61 | 3.69 | 1.79 | 1.72 | 1.59 | 1.63 | 1.50 | 1.42 | 1.40 | 1.62 | 1.70 | 1.67 | 1.64 | 1.09 |
| Malin | 1.35 | 2.35 | 3.57 | 1.55 | 1.55 | 1.63 | 1.64 | 1.49 | 1.41 | 1.27 | 1.21 | 1.25 | 1.33 | 1.45 | 1.60 |
| Average | 1.54 | 2.48 | 3.63 | 1.67 | 1.635 | 1.61 | 1.635 | 1.495 | 1.415 | 1.335 | 1.415 | 1.475 | 1.5 | 1.545 | 1.645 |
| | | | | | | | | | | | | | | | |
| Pn (TOU = 1) (Cents/kwh) | 1.951 | 3.365 | 4.690 | 2.433 | 2.392 | 2.363 | 2.392 | 1.915 | 1.850 | 1.785 | 1.850 | 1.899 | 1.919 | 2.289 | 2.404 |

| Time of Use H | Oct-96 | Nov-96 | Dec-96 | Jan-97 | Feb-97 | Mar-97 | Apr-97 | May-97 | Jun-97 | Jul-97 | Aug-97 | Sep-97 | Oct-97 | Nov-97 | Dec-97 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Peak | 138 | 0 | 0 | 0 | 0 | 0 | 0 | 126 | 128 | 132 | 126 | 126 | 138 | 0 | 0 |
| Partial-Peak | 161 | 247 | 273 | 288 | 247 | 273 | 288 | 147 | 147 | 154 | 147 | 147 | 161 | 234 | 288 |
| Off-Peak | 321 | 353 | 347 | 334 | 313 | 347 | 314 | 347 | 327 | 334 | 347 | 327 | 321 | 366 | 334 |
| Super-Off Peak | 125 | 120 | 124 | 124 | 112 | 124 | 119 | 124 | 120 | 124 | 124 | 120 | 125 | 120 | 124 |
| Total | 745 | 720 | 744 | 744 | 672 | 744 | 719 | 744 | 720 | 744 | 744 | 720 | 745 | 720 | 744 |
| | | | | | | | | | | | | | | | |
| Off-Peak T-O-U Factor | 0.982 | 0.995 | 0.993 | 0.991 | 0.993 | 0.993 | 0.990 | 0.986 | 0.985 | 0.984 | 0.986 | 0.985 | 0.982 | 0.986 | 0.991 |

Note:
Pn (TOU = 1) estimated for October, November, and December of 1996. Actual QF energy postings based on the SRAC transition formula not yet available.

WWN 12/17/96

PG&E
1997 ECAC/1995 REASONABLENESS CASE
QF REVENUE REQUIREMENT
(DOLLARS)
Based on June Update 6/1/1996
SRAC Energy Payments Revised 12/16/1996

Run: 12/16/96

APPENDIX C

Att. 2 p.2/11

| | OCTOBER 1996 | NOVEMBER 1996 | DECEMBER 1996 | Total 1996 |
|---|---|---|---|---|
| As-Del Capacity | 6,892,160 | 575,184 | 551,312 | 67,990,852 |
| Firm Capacity | 64,948,909 | 14,442,514 | 14,442,514 | 462,352,978 |
| Fixed Energy (Before C | 61,290,498 | 57,400,438 | 58,805,078 | 785,160,154 |
| Curt Benefit-Fixed Ener | 0 | 0 | 0 | -6,795,020 |
| Net Fixed Energy | 61,290,498 | 57,400,438 | 58,805,078 | 778,365,134 |
| Variable Energy (Before | 19,333,155 | 31,659,289 | 45,073,414 | 257,705,179 |
| Curt Benefit-SRAC Ene | 0 | 0 | 0 | -7,099 |
| Net Variable Energy | 19,333,155 | 31,659,289 | 45,073,414 | 257,698,080 |
| Contract Amendment & Pay-for-Curtailment | 855,729 | 1,113,022 | 8,415,729 | 121,049,428 |

Note:
1. No changes in capacity expenses, fixed energy expenses, and contract amendment & Pay-for-Curtalment expe
2. The variable energy payments for October, November, and December of 1996 have been revised from the June
The SRAC prices for these 3 months were updated to reflect our current estimate of the variable energy prices
Commission's December 9 Decision on SRAC Transition Formula. However, the actual QF energy price postin
based on the SRAC transition formula are not yet available.

WWN 12/17/96

Attachment 2

## SRAC Transition Formula and Coefficients for PG&E

PG&E's SRAC Formula uses two seta of coefficients: one set for winter months (November through April) and one set for summer months (May through October). The formula and seasonal coefficients are as follows:

$$P_n = \{P_O + P_O * [(GP_n - GP_O)/GP_O] * \text{Factor}\} * \text{TOU}$$

where:

| | | |
|---|---|---|
| $P_n$ | = | SRAC price for posting period n, |
| $P_O$ | = | Starting energy price, based on 12-month averages of recent, pre-January 1, 1996 SRAC energy prices paid by each public utility electrical corporation to non-utility power generators, |
| $GP_n$ | = | Gas price for period $_n$ at the California border, |
| $GP_O$ | = | Starting gas index price based on an average of California border index gas prices for the same annual periods as the starting energy price; |
| Factor | = | Gas factor, and |
| TOU | = | Time-of-Use factor, calculated as follows: |

<u>Summer</u>

| | |
|---|---|
| Peak | 1.065 |
| Partial-Peak | 1.022 |
| Off-Peak | [No. of hours in Month n - (1/065 * No. of Summer Peak hours in Month n)- (1.022 * No. of Summer Partial-Peak hours in Month n) - (.0946* No. of Summer Super Off-Peak hours in Month n)]/No. of Summer Off-Peak hours in Month n |
| Super Off-Peak | 0.946 |

<u>Winter</u>

| | |
|---|---|
| Partial-Peak | 1.032 |
| Off-Peak | [No. of hours in Month n - (1.032 * No. of Winter Partial-Peak hours in Month n) - (0.950 * No. of Winter Super Off-Peak hours in Month n)]/ No. of Winter Off-Peak hours in Month n |
| Super Off-Peak | 0.950 |

Attachment 2 (cont'd.)

| | PG&E SRAC Formula Seasonal Coefficients | | |
|---|---|---|---|
| **Season** | **$P_o$** (¢/kWh) | **$GP_o$** ($/MMBtu) | **Factor** |
| Winter | 2.3973 | 1.6394 | 0.7875 |
| Summer | 1.8748 | 1.4457 | 0.6270 |

(END OF ATTACHMENT 2)

APPENDIX D

# PACIFIC GAS AND ELECTRIC COMPANY

## COMPARISON OF

## CONTESTED ISSUES

August 29, 1996

APPENDIX D

# PACIFIC GAS AND ELECTRIC COMPANY
# 1997 ECAC / 1995 REASONABLENESS CASE
# A. 96-04-001

## *COMPARISON OF CONTESTED ISSUES*

| ISSUES | PG&E | DRA | TURN |
|---|---|---|---|
| **A. RESOURCE ASSUMPTIONS** | | | |
| Northwest Energy Pricing | PG&E proposes that Northwest economy energy prices are based on a percent of the thermal incremental cost. | DRA uses one of the regression formulas from the Northwest Economy Energy Price Study to develop the price of economy energy purchases from the Northwest. | No position stated. |
| **B. COST OF GAS** | | | |
| Total Cost of Gas | PG&E forecasts a total cost of gas for UEG of $419 million. | DRA forecasts a total cost of gas for UEG of $427 million. | No position stated. |
| Average Rate | $2.19/Dth | $1.90/Dth | No position stated. |
| Mainline Average Gas Price Forecast Methodology | PG&E uses the basin gas price forecast from DRI/McGraw-Hill's May 1996 issue of <u>Monthly Natural Gas Price Outlook</u>. | DRA developed its own model using a time series method to forecast basin gas prices. | No position stated. |
| Mainline Average Gas Price Forecast - Permian Basin | $1.80/Dth | $1.54/Dth | No position stated. |
| Mainline Average Gas Price Forecast - San Juan Basin | $1.48/Dth | $1.23/Dth | No position stated. |
| Mainline Average Gas Price Forecast - Alberta Basin | $1.15/Dth | $0.95/Dth | No position stated. |

APPENDIX D

# PACIFIC GAS AND ELECTRIC COMPANY
# 1997 ECAC / 1995 REASONABLENESS CASE
# A. 96-04-001

## COMPARISON OF CONTESTED ISSUES

| ISSUES | PG&E | DRA | TURN |
|---|---|---|---|
| **B. COST OF GAS** | | | |
| Annual Average Gas Dispatch Price(*) | $1.94/Dth | $1.70/Dth | No position stated. |
| Transwestern Demand Charges | PG&E includes Transwestern demand charges. UEG holds 50,000 Dth/day of firm transport capacity on Transwestern's San Juan lateral and mainline pipeline. | No position stated. (DRA appears to use the methodology adopted in Decision 95-12-051 which uses the El Paso transportation rates as a proxy for Transwestern demand charges). | No position stated. |
| UEG Gas Supply | Total throughput is 191,737 MDth, composed of approximately 46,000 MDth of Canadian supplies, 13,000 MDth of U.S. Southwest supplies via Transwestern and, 133,000 MDth Southwest via EPNG. | Total throughput is 225,517 MDth. | No position stated. |
| **C. FUEL OIL INVENTORY** | | | |
| Fuel Oil Inventory Level | Heavy Oil Inventory = 1.7 million barrels which allows for approximately 3 weeks of operation at PG&E's oil-capable plants. | Heavy Oil Inventory = 1.2 million barrels which allows for 2 weeks of operation at PG&E's oil-capable plants. | No position stated. |
| Fuel Oil Carrying Costs | $1,369,000 | $1,008,000 | No position stated. |

Note:

(*) The difference in PG&E's and DRA's gas dispatch price are solely caused by the basin gas price assumptions. The differences in the dispatch prices and Northwest prices are reflected in PG&E's and DRA's PROMOD runs, which then produces different generation resource mix results (i.e., conventional thermal, geothermal, Crockett cogeneration, and economy energy purchases). Attachment 1 compares the different resource mix results and the impact on the production expenses.

APPENDIX D

# PACIFIC GAS AND ELECTRIC COMPANY
# 1997 ECAC / 1995 REASONABLENESS CASE
# A. 96-04-001

## *COMPARISON OF CONTESTED ISSUES*

| ISSUES | PG&E | DRA | TURN |
|---|---|---|---|
| **D. REVENUE REQUIREMENT & RESULTS OF OPERATIONS** | | | |
| ECAC/AER/ERAM/ CARE Revenue Requirement Change | PG&E proposes an ECAC/AER/ERAM/ CARE revenue requirement decrease of $572 million. | DRA proposes an ECAC/AER/ERAM/ CARE revenue requirement decrease of $684 million. | No position stated. |
| Consolidation of Proceedings | PG&E proposes to consolidate its ECAC/AER/ERAM/ CARE revenue requirement decrease with the electric revenue requirement outcomes from the following proceedings: Diablo Canyon, 1997 Base Revenue, 1996 AEAP, and 1997 COC. | DRA believes PG&E's request to implement the Diablo, Base Revenue, AEAP, and COC applications is premature, inconsistent, and inappropriate with positions PG&E has taken in this proceeding. | No position stated. |
| Double Counting of the End-of-Year 1996 ECAC Overcollection | PG&E maintains that DRA errs in its calculation of the additional rate reduction of $684 million because that number includes the one-time refund of $88 million. Consequently, DRA's recommendations result in double counting the $88 million 1996 ECAC end-of-year balance. Removal of the $88 million results in a corrected number of $596 million. | DRA recommends: (1) a one-time refund to ratepayers of their projected $88 million end-of-year 1996 ECAC overcollection and, (2) an additional rate reduction of $684 million in 1997 (**). | No position stated. |

Note:

(**) During PG&E's cross of DRA's witness Charvez, Charvez stated that there was double counting in the $684 million reduction. The $684 million should be reduced by $88 million resulting in an additional rate reduction of $596 million.

APPENDIX D

# PACIFIC GAS AND ELECTRIC COMPANY
# 1997 ECAC / 1995 REASONABLENESS CASE
# A. 96-04-001

## COMPARISON OF CONTESTED ISSUES

| ISSUES | PG&E | DRA | TURN |
|---|---|---|---|
| **E. RATE FREEZE PROPOSAL AND RATE REFUNDS** | | | |
| Rate Freeze Proposal and Rate Refunds | In PG&E's Motion, filed August 9, 1996, PG&E proposes that the CPUC adopt an interim electric rate freeze beginning 1/1/97 and lasting until the CPUC issues a decision on the Diablo Canyon/Rate Freeze Proposal. PG&E proposes to refund with interest the difference between the interim rate freeze and the rates that would have been in effect beginning on 1/1/97, in the event that the Diablo Canyon/Rate Freeze Proposal is not adopted. If the Commission adopts PG&E's Diablo Canyon/Rate Freeze Proposal, all balancing account overcollections would be used to accelerate recovery of Diablo Canyon transition costs through 2001, as well as, accelerate recovery of its other utility generation transition costs, including associated regulatory assets. | DRA's response to PG&E's August 9 Motion is due September 6, 1996. However, in DRA's direct filing, DRA proposes that (1) the ECAC balancing account overcollection as of 12/31/96, which DRA estimates at $88 million (***), be returned to ratepayers through a one-time refund; (2) the CPUC suspend implementation of further ECAC rate reductions related to 1997 operations until 3/31/97, on the assumption that this will allow the CPUC to complete its analysis of PG&E's Diablo Canyon/Rate Freeze Proposal; and (3) all ECAC revenues accrued from 1/1/97, until the CPUC issues a decision in the Diablo Canyon/Rate Freeze Application, be refunded to ratepayers. | TURN agrees with DRA's position on the treatment of the ECAC balancing account overcollection as of 12/31/96 and is silent on the implementation of further ECAC rate reductions related to 1997 operations. |

Note:

(***) PG&E's forecast 1996 end-of-year ECAC calculation is $64 million. The difference in PG&E's and DRA's forecast end-of-year balance is due to different gas and production expenses forecasts for May through December of the 1996 lead year.

APPENDIX D

# PACIFIC GAS AND ELECTRIC COMPANY
# 1997 ECAC / 1995 REASONABLENESS CASE
# A. 96-04-001

## COMPARISON OF CONTESTED ISSUES

| ISSUES | PG&E | DRA | TURN |
|---|---|---|---|
| **E. RATE FREEZE PROPOSAL AND RATE REFUNDS** | | | |
| **AER Mechanism** | PG&E supports DRA's recommendation to temporarily suspend the AER during the interim rate freeze period pending a decision in the Diablo Canyon Application. | DRA recommends either (1) temporarily suspending the AER or (2) crediting the ECAC balancing account with the portion of the AER which would be collecting revenues above the ECAC forecast expenses during 1997 pending a decision in the Diablo Canyon Application. | TURN proposes reducing the AER rate to reflect the lower forecast of PG&E's fuel and purchased power costs for 1997 and increasing the ECAC rate by an equal and offsetting amount. |

A.?? 04 001 ALJ/AYG/?mn

COMPUTILS
DRA's 2nd Errata vs June Up

# APPENDIX

## PACIFIC GAS AND ELECTRIC COMPANY
## 1997 ECAC/AER/ERAM/CARE
## DRA's 2nd Errata vs 1997 Test Year Forecast (June Update)



Date: January 1, 1997
Period: Twelve Months Beginning January 1, 1997

| | Quantity | | | Price | | | Total Costs ** | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | DRA Errata Filing MDth or GWh | June 11 Update MDth or GWh | Difference MDth or GWh | DRA Errata Filing $/Dth or Kwh | June 11 Update $/Dth or Kwh | Difference $/Dth or Kwh | DRA Errata Filing (000) | June 11 Update (000) | Difference (000) | Line No. |
| Fossil Fuel | | | | | | | | | | |
| Commodity | 225,517 | 191,737 | (33,780) | 1.31852 | 1.53747 | 0.21895 | $297,350 | $294,791 | (2,559) | 1 |
| Transportation & Storage | | 0 | | | | | $130,028 | $124,252 | (5,776) | 2 |
| Subtotal Gas | 225,517 | 191,737 | (33,780) | 1.89510 | 2.18551 | 0.29041 | $427,378 | $419,043 | (8,335) | 3 |
| Residual Oil | 0 | 0 | 0 | | | | $0 | $0 | 0 | 4 |
| Distillate Oil | 20 | 23 | 3 | 4.67980 | 4.09483 | -0.58497 | $95 | $95 | 0 | 5 |
| *Subtotal Fossil Fuel* | 225,538 | 191,760 | (33,778) | 1.89535 | 2.18574 | 0.29039 | $427,473 | $419,138 | (8,335) | 6 |
| Geothermal Steam | 3,880 | 4,703 | 1,123 | 0.01434 | 0.01481 | 0.00047 | $52,493 | $70,818 | 18,325 | 7 |
| Purchased Power | | 0 | | | | | | | | |
| Irrigation Districts | 5,432 | 5,432 | (0) | 0.00125 | 0.00132 | 0.00007 | $6,772 | $7,187 | 415 | 8 |
| CVP | (2,460) | (2,460) | (0) | 0.00807 | 0.00807 | 0.00000 | ($19,863) | ($19,863) | 0 | 9 |
| Variably Priced QF Energy | 12,573 | 12,573 | 0 | | | | $242,733 | $277,302 | 34,569 | 10 |
| Other QF Including Capacity Payments | 9,279 | 9,042 | (237) | | | | $1,299,933 | $1,306,850 | 6,917 | 11 |
| Total QF | 21,852 | 21,615 | (237) | 0.07060 | 0.07329 | 0.00269 | $1,542,666 | $1,584,152 | 41,486 | 12 |
| Northwest | 827 | 3,663 | 2,836 | 0.01439 | 0.01330 | -0.00109 | $11,894 | $48,711 | 36,817 | 13 |
| Southwest (Including Sales) | (421) | (426) | (5) | 0.01791 | 0.02260 | 0.00469 | ($7,539) | ($9,634) | (2,095) | 14 |
| CDWR | 0 | 0 | 0 | | | | $0 | $0 | 0 | 15 |
| Other | 4 | 4 | (0) | 0.09222 | 0.09222 | 0.00000 | $332 | $332 | 0 | 16 |
| *Subtotal Purchased Power* | 25,233 | 27,826 | 2,593 | 0.06080 | 0.05789 | -0.00291 | $1,534,282 | $1,610,885 | 76,623 | 17 |
| Water for Power | 13,883 | 13,882 | (1) | 0.00008 | 0.00008 | 0.00000 | $812 | $836 | 24 | 18 |
| Oil Inventory Carrying Cost | | | | | | | $1,008 | $1,369 | 361 | 19 |
| Gas Storage Carrying Cost | | | | | | | $0 | $0 | 0 | 20 |
| Variable Wheeling | | | | | | | $147 | $147 | 0 | 21 |
| Losses(Gains) on Fuel Oil Sales | | | | | | | $0 | $0 | 0 | 22 |
| Subtotal Energy Expense | | | | | | | $2,016,195 | $2,103,194 | 86,999 | 23 |
| Less 9% of Energy Expense | | | | | | | $181,458 | $189,287 | 7,829 | 24 |
| Subtotal | | | | | | | $1,834,737 | $1,913,907 | 79,170 | 25 |
| QF Settlement Revenues * | 16,883 | 16,883 | 0 | 0.09904 | 0.09904 | 0.00000 | $1,672,044 | $1,672,044 | 0 | 26 |
| Excess Oil Inventory Carrying Cost | | | | | | | $3 | $3 | 0 | 27 |
| Nuclear O & D Cost | | | | | | | $198 | $198 | 0 | 28 |
| Subtotal | | | | | | | $3,506,982 | $3,586,152 | 79,170 | 29 |
| Allocation to CPUC Jurisdictional @ | 0.99950942 | 0.99950942 | | | | | $3,505,281 | $3,584,392 | 79,131 | 30 |
| Less DC Basic Revenue Requirement | | | | | | | $159,685 | $159,685 | 0 | 31 |
| Subtotal | | | | | | | $3,345,576 | $3,424,707 | 79,131 | 32 |
| | | | | | | | | | | 33 |

* Average rate excludes the basic revenue requirement and F&U expense and includes the Safety Committee Fee

** Requested to be recovered in rates

8/15/98

CLM/ETALS
DRA's 2nd Errata vs June Up

# APPENDIX D

## PACIFIC GAS AND ELECTRIC COMPANY
## 1997 ECAC/AER/ERAM/CARE
## DRA's 2nd Errata vs 1997 Test Year Forecast (June Update)



Revision Date: January 1, 1997
Forecast Period: Twelve Months Beginning January 1, 1997

| Line No | | DRA Errata Filing (000) | June 11 Update (000) | Difference (000) | Line No |
|---|---|---|---|---|---|
| | ECAC REVENUE REQUIREMENT (cont.) | | | | |
| 32 | Subtotal (from page 1) | $3,345,576 | $3,424,707 | $79,131 | 32 |
| 33 | Estimated ECAA Balance on January 1 | ($68,167) | ($64,070) | $24,097 | 33 |
| 34 | DC Safety Committee Fee | $641 | $641 | $0 | 34 |
| 35 | Less: Discounted Sales Revenue (excl. F.) | $2,271 | $2,271 | 0 | 35 |
| 36 | Subtotal | $3,245,779 | $3,349,007 | $103,228 | 36 |
| 37 | Franchise Fees & Uncollectible Accounts Expense @ | $31,594 | $32,599 | $1,005 | 37 |
| 38 | TOTAL ECAC REVENUE REQUIREMENT | $3,277,373 | $3,381,606 | $104,233 | 38 |
| 39 | Less: ECAC Revenue at Present Rates of January 1 | $3,914,353 | $3,914,353 | $0 | 39 |
| 40 | CHANGE IN ECAC REVENUE REQUIREMENT | ($636,980) | ($532,747) | $104,233 | 40 |
| | AER REVENUE REQUIREMENT | | | | |
| 41 | 9% Of Energy Expense (Line 33) | $101,458 | $109,287 | $7,829 | 41 |
| 42 | Allocation to CPUC Jurisdiction @ | $101,369 | $109,194 | $7,825 | 42 |
| 43 | Less: Discounted Sales Revenue (excl. F.) | $1,214 | $1,214 | $0 | 43 |
| 44 | Subtotal | $100,155 | $107,980 | $7,825 | 44 |
| 45 | Franchise Fees & Uncollectible Accounts Expense @ | $1,754 | $1,830 | $76 | 45 |
| 46 | TOTAL AER REVENUE REQUIREMENT | $101,909 | $109,810 | $7,901 | 46 |
| 47 | Less: AER Revenue at Present Rates of January 1 | $119,440 | $119,440 | $0 | 47 |
| 48 | CHANGE IN AER REVENUE REQUIREMENT | ($17,531) | ($9,630) | $7,901 | 48 |
| | ERAM REVENUE REQUIREMENT | | | | |
| 49 | Base Revenue Amount | $3,368,512 | $3,368,512 | $0 | 49 |
| 50 | Estimated ERAM Balance on January 1 | $82,508 | $82,508 | $0 | 50 |
| 51 | Research, Development & Demonstration Unspent Funds | ($17,751) | ($17,751) | $0 | 51 |
| 52 | Hazardous Substance Mechanism Transfer | $100 | $100 | ($0) | 52 |
| 53 | Less: CARE Shortfall | $30,997 | $30,997 | $0 | 53 |
| 54 | Less: Discounted Sales Revenues | $15,903 | $15,903 | $0 | 54 |
| 55 | TOTAL ERAM REVENUE REQUIREMENT | $3,388,469 | $3,388,469 | ($0) | 55 |
| 56 | Less: ERAM Revenue at Present Rates of January 1 | $3,415,887 | $3,415,887 | $0 | 56 |
| 57 | CHANGE IN ERAM REVENUE REQUIREMENT | ($27,418) | ($27,418) | ($0) | 57 |
| | CARE REVENUE REQUIREMENT | | | | |
| 58 | CARE Shortfall | $30,997 | $30,997 | $0 | 58 |
| 59 | Estimated CAREA Balance on January 1 | ($7) | ($7) | $0 | 59 |
| 60 | TOTAL CARE REVENUE REQUIREMENT | $30,990 | $30,990 | $0 | 60 |
| 61 | Less: CARE Revenue at Present Rates of January 1 | $32,852 | $32,852 | $0 | 61 |
| 62 | CHANGE IN CARE REVENUE REQUIREMENT | ($1,862) | ($1,862) | $0 | 62 |
| | Total Change | ($683,781) | ($571,657) | $112,134 | |

(END OF APPENDIX D)

# Appendix E

## LIST OF ACRONYMS AND ABBREVIATIONS

| | |
|---|---|
| AC | alternating current |
| BAF | Basic American Foods |
| BPA | Bonneville Power Administation |
| Btu | British thermal unit |
| CCPA | Central California Power Agency |
| CCSF | City and County of San Francisco |
| COG | cogeneration |
| COGEN | cogeneration |
| COT | California-Oregon Transmission Project |
| CSC | City of Santa Clara |
| CT | combustion turbine |
| DC | direct current |
| DRA | Division of Ratepayer Advocates |
| ECAC | Energy Cost Adjustment Clause |
| ERI | Energy Reliability Index |
| EXCH | Exchange. Acronym used in PROMOD. |
| FRPL | Fuel Replacement. Acronym used in PROMOD. |
| GRC | General Rate Case |
| GWh | gigawatt-hour |
| IHR | Incremental Heat Rate |
| ITCS | Interstate Transistion Cost Surcharge |
| MID | Modesto Irrigation District |
| MSR | Modesto, Santa Clara, Redding |
| MUNI | municipal utilities |
| MW | megawatt |
| NCPA | Northern California Power Agency |
| O&M | operation and maintenance |
| PG&E | Pacific Gas and Electric Company |
| PPA | Purchased Power Agreement |
| PROMOD | Production forecasting model owned by Energy Management Associates (EMA). |
| PV | Photovoltaic |
| QFIER | Qualifying Facilities Incremenal Energy Rate |
| QFs | qualifying facilities |
| SCE | Southern California Edison Company |
| SMUD | Sacramento Municipal Utility District |
| TID | Turlock Irrigation District |
| UEG | Utility Electric Generation |
| UNOCAL | Union Oil Company of California |
| USBR | United States Bureau of Reclaimation |
| WAPA | Western Area Power Administration |
| WSPP | Western Systems Power Pool |
| WWP | Washington Water & Power |

(END OF APPENDIX E)

Mailed
DEC 26 1996

Decision 96-12-080 December 20, 1996

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

| | |
|---|---|
| Application of Pacific Gas and Electric Company for Authority to Adjust Its Electric Rates Effective January 1, 1997, and for Commission Order Finding That Electric and Gas Operations During the Reasonableness Review Period from January 1, 1995 to December 31, 1995 Were Prudent. | Application 96-04-001 (Filed April 1, 1996) |

(See Appendix A for Appearances.)

# MODIFIED INTERIM OPINION

## Summary

The Commission concludes that Pacific Gas and Electric Company's (PG&E) authorized fuel-related revenue requirement should be reduced by $718.8 million in this proceeding, effective January 1, 1997. The reduction in PG&E's fuel-related revenue requirement will be offset by an increase of $164.5 million in other proceedings. The four elements of decrease in this proceeding are: (1) a reduction in Energy Cost Adjustment Clause (ECAC) revenues, which cover 91% of PG&E's energy expenses and amortization of a forecasted overcollection in the ECAC balancing account; (2) a reduction in Annual Energy Rate (AER) revenues, which cover the remaining 9% of PG&E's energy expenses; (3) an increase in base rate revenues, to amortize a forecasted undercollection in PG&E's Electric Revenue Adjustment Mechanism (ERAM) balancing account; and (4) an increase in revenues for the California Alternate Rates for Energy (CARE) program, which supports energy rate discounts for low-income customers.

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Page 2

Table 1 below shows the authorized decrease,[1] relative to revenues at present rates:

TABLE 1

Summary of Revenue Requirement Decrease

| Rate Element | Revenue Change ($ millions) |
|---|---|
| ECAC | $(563.407) |
| AER (included with ECAC) | (0.0) |
| ERAM revenue requirement | (152.850) |
| CARE | 2.555) |
| Total in this proceeding | $(718.812) |
| Other Proceedings | |
| ERAM in Other Proceedings | $160.635 |
| Cost of Capital Proceeding | (5.306) |
| Annual Energy Assessment Proceeding | 9.169 |
| Subtotal Other Proceedings | $164.498 |
| Total Change in Consolidated Revenue Requirement | $(554.314) |

In a typical ECAC proceeding, PG&E's electric rates would have been reduced by approximately 10% to account for the $718.8 million decrease in authorized revenue requirement. However, as provided in the cost recovery plan PG&E filed in response to the

1 Details of revenue requirement changes are shown in Appendix B.

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Page 3

new Public Utilities (PU) Code § 368,[2] PG&E's overall electric rates will not be revised. Also, as provided in PG&E's cost recovery plan, the projected overcollections in PG&E's ECAC and ERAM balancing accounts as of December 31, 1996, will be used to offset PG&E's uneconomic generation-related costs. The ratemaking treatment of these overcollections and uneconomic costs is being dealt with in our decision on the cost recovery plans and in A.96-08-001 et al. (Transition Cost Proceeding).

In addition, this decision suspends PG&E's AER until further order by the Commission.

Procedural Background

On April 1, 1996, PG&E filed this application requesting authority to adjust its electric rates and for a reasonableness review of its electric and gas operations during 1995. Along with its application, PG&E also filed its testimony and related workpapers in accordance with the rate case plan adopted in Decision (D.) 89-01-040. As required by the rate case plan, on June 11, 1996, PG&E served its June Update and related workpapers, which updated PG&E's sales forecast, resource mix, gas costs, qualifying facilities (QFs) expenses, and recorded balancing account balances.

The Division of Ratepayer Advocates (DRA)evaluated of PG&E's filing. Based on its evaluation, DRA prepared its report, which was served on July 12, 1996. Since the hearings in this

2 Section 368 was added to the PU Code by Assembly Bill (AB) 1890. Section 368 requires electric utilities to file cost recovery plans that provide, among other things, that the electric rates that were in effect on June 10, 1996, remain in effect until January 1, 1998. PU Code § 368 also allows electric utilities to file plans to recover costs of uneconomic generation-related assets by applying certain overcollections towards recovery of the costs.

ATTACHMENT A
Page 4

proceeding, the Commission has transferred the functions of DRA to the Office of Ratepayer Advocates (ORA). DRA will be referred to as ORA in this order.

Toward Utility Rate Normalization (TURN), the only other active party in this proceeding, served its testimony on July 24, 1996. PG&E served its rebuttal testimony on August 9, 1996.

On May 15, 1996, the California Cogeneration Council, the Independent Energy Producers Association, and the Cogeneration Association of California filed a motion requesting that a separate phase and procedural schedule be established to address the issue of possible double recovery of fixed operations and maintenance (O&M) costs through the O&M adder[3] PG&E pays to QFs. PG&E and ORA filed responses to the motion.

On June 5, 1996, Administrative Law Judge (ALJ) Garde issued a ruling outlining the scope and timing of the issues that would be addressed in this proceeding. According to the ruling,

---

3 In PG&E's forecast year 1996 ECAC proceeding, the Commission, in response to a proposal by DRA, made a finding that there may be double recovery of fixed O&M costs through the O&M adder that PG&E pays to QFs.

Decision (D.) 95-12-051 adopted a fixed O&M adder for PG&E through 1997 pursuant to a settlement between PG&E and various parties. The settlement provides that PG&E's O&M adder value and incremental energy rate will remain fixed until the end of 1997 unless the Commission adopts a new methodology for determining short-run avoided cost (SRAC) payment to QFs in the Biennial Investigation (I.89-07-004). D.95-12-051 also directed PG&E to present testimony in this proceeding regarding the possibility that the current methodology for determining PG&E's O&M adder results in double recovery of fixed O&M related payments. According to D.95-12-051, the issue of double recovery is to be addressed in a separate phase of this proceeding.

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Page 5

the proceeding will be completed in three phases: (1) the first phase will deal with 1997 forecast issues except O&M adder double recovery and the incremental energy rate (IER) for 1997; (2) the second phase will address rate design issues and the O&M double recovery issue (if necessary); and (3) the third phase will address the reasonableness of PG&E's operations during 1995.

On August 9, 1996, PG&E filed a motion for an interim electric rate freeze pending a final decision in PG&E's Diablo Canyon/Rate Freeze Application, A.96-03-054 (Diablo Application). In the Diablo Application, PG&E seeks to modify the pricing structure for power generated at the Diablo Canyon Nuclear Power Plant. PG&E also seeks to freeze its electric rates at the January 1, 1996 level. PG&E filed its motion for a rate freeze in this proceeding subsequent to ALJ Barnett's ruling that a decision in the Diablo Application will not be rendered until 1997. PG&E's request for a rate freeze is discussed later in this order.

<u>Hearings</u>

ALJ Garde convened prehearing conferences (PHCs) on May 15 and June 19, 1996. The schedule for the forecast phase of the proceeding was adopted at the June 19 PHC. Evidentiary hearings in the forecast phase were held from August 26 through August 29, 1996. Other than the ORA and PG&E, only TURN participated in the evidentiary hearings.

During the evidentiary hearings, ORA and PG&E stated that they were able to resolve several issues. The remaining contested issues fall under two categories: (a) resource assumptions and (b) revenue requirement. They are as follows:

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A. Resource Assumption and Modelling Convention Issues

1. Mainline gas price forecast/Cost of gas

2. Northwest energy pricing

3. Transwestern demand charges

4. Fuel oil inventory level

B. Revenue Requirement and Results of Operations

5. ECAC/AER/ERAM/CARE revenue requirement change

6. Refunding of end-of-year 1996 ECAC overcollection

7. Rate freeze proposal

8. Temporary suspension of the AER mechanism

TURN did not oppose the agreed-upon resolution of the uncontested issues. TURN's participation was limited to Issues 7 and 8 listed above.

Evidence on the contested issues was taken during the hearing. PG&E and ORA provided testimony. The forecast phase of the proceeding was submitted upon receipt of concurrent reply briefs on September 23, 1996.

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Uncontested Issues

The agreed-upon resolution of resource assumptions, modelling conventions, and other uncontested issues is included in Exhibit 11 which is reproduced as Appendix C[4] to this decision. The agreed-upon resolution of issues included in Exhibit 11 is reasonable and will be adopted for this proceeding.

On September 23, 1996, the ALJ issued a ruling which set forth resource assumptions and modelling conventions in accordance with the rate case plan adopted in D.89-10-040. On September 26, 1996, the ALJ issued a supplemental ruling on resource assumptions and modelling conventions to correct an omission. ORA and PG&E advised the ALJ that the workshop on resource assumption and modelling conventions required by the rate case plan was not necessary for this proceeding. Accordingly, the workshop was not held.

On October 15, 1996, PG&E served exhibits which incorporate the adopted assumptions and conventions into pricing factors and test year revenue requirements. The revised pricing factors and revenue requirements are contained in Appendix B to this order.

We confirm the resource assumptions and modelling conventions adopted by the ALJ in his ruling.

Following is a discussion of the contested issues about resource assumptions and modelling conventions:

4 An explanation of acronyms and abbreviations used in Appendix C is contained in Appendix E.

<u>Mainline Price of Gas/Cost of Gas</u>

PG&E buys most of the natural gas for utility electric generation (UEG) from the United States Southwest and Canada and a small amount from California and other producers. The cost of the gas used by PG&E for UEG is reported to the Commission in annual reports. However, in an ECAC proceeding, the Commission, based on forecasts by the parties, adopts a price for gas that PG&E will most likely experience during the following calendar year. The price of gas forecasted in this proceeding is the average price PG&E is expected to pay in 1997.

PG&E expects to buy nearly all of its Southwest gas from the Permian and San Juan basins. PG&E procures its Canadian gas from the Alberta basin. Typically, PG&E procures less than 3% of its gas for UEG from California and other sources.

For this proceeding, PG&E adopted the gas price forecast made in the May 1996 issue of "Monthly Gas Price Outlook" by DRI/McGraw-Hill (DRI). DRI forecasts the Permian basin gas price to average $1.80/decatherm (Dth), the San Juan basin price to average $1.48/Dth and the Alberta basin gas price to average $1.15/Dth in 1997.

ORA's forecast of gas prices is developed by the use of time series analysis. ORA's forecast used computer software entitled "Times Series Processor, Version 4.2." ORA used recorded gas prices from various basins to project future gas prices. ORA projects the Permian gas price to average $1.54/Dth, the San Juan basin price to average $1.23/Dth, and the Alberta basin price to average $0.96/Dth.

Both PG&E and ORA claim their forecasting method is superior. The following are some of the points PG&E makes in support of its forecast:

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- In the past four years, DRI's forecast accuracy has been within $0.07/Dth for the Permian and San Juan basins and within $0.03/Dth for the Alberta basin. The accuracy of ORA's forecast is unknown.

- DRI's gas price model includes numerous variables that affect gas prices, whereas ORA's model only includes recorded past gas prices.

- Unlike ORA's model, DRI's gas price model was developed by using standard statistical and econometric model-building tools.

- The Commission has relied on DRI's gas price model in previous proceedings and even ORA recommended using DRI's forecasts in previous proceedings.

ORA contends that DRI consistently forecasts prices of gas that are higher than actual prices experienced. ORA believes that its method of forecasting is innovative and forward-looking. According to ORA, its independent analysis generates a more accurate forecast of gas prices because ORA used more recent data which more accurately reflect market conditions that are likely to occur in the future.

Discussion

It is not possible to forecast gas prices that are likely to occur during 1997 with absolute accuracy. While DRI's forecast is used widely in the gas industry, it has had significant forecast errors in the past. Forecast error is defined as the difference between the forecast made in a given month for 12 months later and the actual price observed for the month forecasted. By PG&E's own analysis in Exhibit 3 the average forecast errors for the basins under consideration range from $0.47/Dth to $0.63/Dth. ORA's forecast technique, however, is untried and does not have a record

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to test its accuracy. It is likely that gas prices in 1997 will be between the two forecasts and will be close to the average of the two forecasts. We will adopt the average of the gas prices forecast by PG&E and ORA for this proceeding. The adopted monthly and average gas prices are shown in Table 2 below:

TABLE 2
($/Dth)

| | Permian Mainline | San Juan Mainline | Canadian Mainline |
|---|---|---|---|
| January | 1.74 | 1.49 | 1.15 |
| February | 1.73 | 1.44 | 1.15 |
| March | 1.78 | 1.39 | 1.23 |
| April | 1.79 | 1.38 | 1.24 |
| May | 1.71 | 1.31 | 1.10 |
| June | 1.60 | 1.24 | 1.02 |
| July | 1.52 | 1.17 | 0.88 |
| August | 1.55 | 1.27 | 0.83 |
| September | 1.57 | 1.35 | 0.87 |
| October | 1.55 | 1.34 | 0.94 |
| November | 1.66 | 1.42 | 1.06 |
| December | 1.85 | 1.50 | 1.20 |
| 1997 Average | 1.67 | 1.36 | 1.06 |

Based on the adopted mainline price of gas, PG&E estimates that PG&E will use 203,741 MDth of gas at an average price of $1.42705/Dth for a total cost $290.748 million. These adopted values are shown in Appendix B on Page 3, line 1.

Northwest Economy Energy Pricing

Operation of electric system simulation models requires input assumptions about resource prices, including prices of economy energy purchased by PG&E from the Pacific Northwest (Northwest). PG&E assumes that the price of Northwest economy energy is a fixed fraction of PG&E's incremental thermal energy cost. That fraction or price ratio changes from month to month.

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ORA's methodology of computing the price ratio incorporates, along with PG&E's incremental thermal energy cost, an additional variable for rainfall in the Northwest and PG&E's service area. ORA's methodology is based on a regression formula from the Northwest Economy Energy Price Study[5] performed by PG&E.

During the evidentiary hearings, PG&E's witness conceded that ORA's methodology should be used to compute Northwest economy energy price. We will adopt ORA's methodology of computing Northwest economy energy price.

Fuel Oil Inventory Level

PG&E uses natural gas for electric generation. However, PG&E maintains fuel oil inventories for use in its oil-capable electric generating units when the supply of natural gas is inadequate to meet PG&E's generation requirements. This allows PG&E to maintain its electric system reliability. The Commission allows PG&E to recover the cost of maintaining its fuel oil inventory.

For 1997, PG&E plans to maintain a fuel oil inventory level of 1.7 million barrels which will allow approximately three weeks of operation at PG&E's oil-capable generating units. PG&E plans to maintain 1,860 megawatts (MW) of electric generating units with the capability to burn fuel oil.

ORA recommends that PG&E be allowed to maintain a fuel oil inventory level which will allow only two weeks of operation at PG&E's electric generation units. In support of its position, ORA

5 In PG&E's forecast year 1996 ECAC proceeding (A.95-04-002), the Commission ordered PG&E to conduct a study on Northwest economy energy price which would include rainfalls in the Northwest and PG&E's service area as variables. PG&E was required to include the study in its showing for this proceeding. PG&E has complied.

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states that Southern California Edison Company (Edison) is requesting only nine days of fuel oil inventory in its current ECAC proceeding.

PG&E disagrees with ORA's position. PG&E states that Edison has a capability of generating 7,076 MW from its oil-fired units for which Edison would need a fuel oil inventory of 4.5 million barrels for nine days of operations. PG&E contends that any volume of oil lasts for more days if only a limited number of units burn oil, which is what PG&E plans to do. Edison, on the other hand, plans to use most of its oil-burning units. Thus comparing PG&E's requested three-week oil inventory with Edison's nine-day oil inventory is wrong, because it does not indicate how much energy from oil-fired units each respective utility is projecting in case of gas shortage.

PG&E also states that ORA's proposal would result in higher total cost to customers, because it fails to take into consideration costs to customers of electrical outages.

We believe that because of its lower capacity to generate electricity using fuel oil, PG&E would need to maintain a level of fuel oil inventory which will allow it greater flexibility to meet its load requirements and to maintain system reliability. A fuel oil inventory level which will allow three weeks of operation or 1.7 million barrels would provide PG&E the needed flexibility. We will authorize PG&E to maintain a fuel oil inventory level of 1.7 million barrels for 1997.

<u>Transwestern Demand Charges</u>

On July 13, 1990, PG&E signed an agreement with Transwestern Pipeline Company (Transwestern) to enter into a 15-year contract for firm gas transportation capacity on Transwestern's mainline expansion and the San Juan Lateral. The

Commission, in D.95-12-046, found that PG&E's action in entering into its contract with Transwestern was unreasonable.

Although PG&E's entering into the contract was found unreasonable, PG&E, in calculating its total cost of gas, includes full demand charges for 50,000 Dth/day of transportation capacity on Transwestern's mainline and lateral pipelines.

While ORA has not stated its position on this issue, ORA's calculations appear to be based on the methodology adopted in D.95-12-051 which used the El Paso Natural Gas Company (El Paso) transportation rates as a proxy for Transwestern demand charges. D.95-12-051 adopted a proxy rate of 20% of the as-billed El Paso rates for Transwestern demand charges.

PG&E agreed to the treatment of Transwestern demand charges in the 1996 forecast year ECAC proceeding. However, PG&E is still attempting to recover charges which are the subject of reasonableness dispute.

We will deny PG&E's request and use the methodology adopted in D.95-12-051 for computing Transwestern demand charges.

<u>Revenue Requirements and Results of Operation</u>

As shown in Table 1, PG&E's revenue requirement will be lower than the currently authorized revenue requirement by $718.8 million. The adopted revenue requirements for PG&E for 1997 are shown in Appendix B on Page 1.

When the proceeding was submitted upon filing of concurrent reply briefs, PG&E and ORA proposed different treatment of the changes in PG&E's revenue requirements. Essentially, PG&E proposed that its rates not be revised and that any projected overcollections for 1997 be used to offset PG&E's transition costs. ORA disagreed with PG&E's rate freeze proposal and recommended that the projected overcollection be refunded to ratepayers. The

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positions of parties regarding revenue requirements and results of operation are contained in Exhibit 12 which is reproduced as Appendix D[6] to this order.

We believe that it is not necessary to discuss the positions of the parties on the issue of revenue requirements and results of operation because of the enactment of AB 1890 on September 23, 1996. AB 1890 adds or modifies several sections of the PU Code to advance the restructuring of the electric utility industry begun by the Commission in D.95-12-063. Enactment of AB 1890 will have a significant impact on revenue requirement and results of operation issues in this proceeding and may render certain issues moot.

The two new PU Code sections that will have a significant impact on this proceeding are §§ 368 and 390. However, the precise impact of §§ 368 and 390 on this proceeding is subject to interpretation. Accordingly, the ALJ issued a ruling dated October 3, 1996, asking PG&E to provide its assessment of the impact of AB 1890 on this proceeding. PG&E filed its report on the impact of AB 1890 on this proceeding on October 18, 1996. ORA and California Industrial Users (CIU) filed responses to PG&E's report.

<u>PG&E's Position</u>

PG&E believes that AB 1890 substantially resolves the following issues in this proceeding:

1. PG&E's August 9, 1996, Motion For An Interim Rate Freeze;

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6 An explanation of acronyms and abbreviations used in Appendix D is contained in Appendix E.

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2. The treatment of 1996 year-end ECAC and ERAM balancing account overcollections and one-time refund;

3. Revenue allocation and rate design issues scheduled for Phase II of ECAC hearings; and

4. SRAC energy payments to QFs.

1. Rate Freeze

Section 368(a) specifies how electric utility rates shall be set through the transition period. Specifically, § 368(a) provides, in relevant part:

> "The cost recovery plan shall set rates for each customer class, rate schedule, contract, or tariff option, at levels equal to the level as shown on electric rate schedules as of June 10, 1996, provided that rates for residential and small commercial customers shall be reduced so that these customers shall receive rate reductions of no less than 10 percent for 1998 through 2002. These rate levels for each customer class, rate schedule, contract, or tariff option shall remain in effect until the earlier of March 31, 2002, or the date on which the commission-authorized costs for utility generation-related assets and obligations have been fully recovered."

As stated earlier, on August 9, 1996, PG&E filed a motion in this proceeding for an interim electric rate freeze pending a final decision in the Diablo Application. In the Diablo Application, PG&E seeks to freeze its electric rates at January 1, 1996 level. PG&E contends that its interim rate freeze request is preempted by AB 1890. According to PG&E, its rates on June 10, 1996 were the same as those in effect on January 1, 1996. Consequently, PG&E believes that its proposed rate freeze in this ECAC proceeding is fully consistent with § 368(a).

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2. Treatment of Balancing Account Balances and Refunds

Section 368(a) requires electric utilities to propose a plan for recovery of the costs of uneconomic generation-related assets.[7] For the purpose of determining the extent to which the costs of uneconomic generation-related assets have been recovered, § 368(a) specifies that any overcollections in ECAC or ERAM balancing accounts as of December 31, 1996, are to be credited to the recovery of these costs.

PG&E states that this provision clearly rejects the proposal by ORA and TURN to refund the overcollections in ECAC/ERAM balancing accounts. According to PG&E, § 368(a) also obviates the ORA recommendation that PG&E be ordered to refund any monies accrued in its ECAC balancing account from January 1, 1997, until such time a decision in the Diablo Application is issued. PG&E contends that ORA's recommendation to refund monies would be in direct violation of AB 1890.

3. Revenue Allocation and Rate Design in ECAC Phase II

As stated earlier, a separate phase of this application was tentatively planned to address( 1) revenue allocation and rate design issues in the event the Diablo Application were to be rejected by the Commission and( 2) any rate design issues from a decision in Phase II of PG&E's 1996 General Rate Case proceeding (A.94-12-005). PG&E believes that § 368(a) removes the need for holding a separate phase in this proceeding on revenue allocation and rate design issues by setting electric "rates for each customer class, rate schedule, contract, or tariff option, at levels equal to the level shown on electric rate schedules as of June 10, 1996."

7 Recovery of cost of uneconomic generation-related costs are part of transition costs.

According to PG&E, its proposal in this proceeding is consistent with AB 1890 in that electric rate schedules will be maintained at the June 10, 1996 level, which is the same as the January 1, 1996 level, proposed by PG&E.

4. <u>Short-Run Avoided Costs</u>

PU Code § 390(b) specifies a formula for calculating SRAC payments paid to QFs:

> "[S]hort run avoided cost energy payments paid to nonutility power generators by an electrical corporation shall be based on a formula that reflects a starting energy price, adjusted monthly to reflect changes in a starting gas index price in relation to an average of current California natural gas border price indices. The starting energy price shall be based on 12-month averages of recent, pre-January 1, 1996, short-run avoided energy prices paid by each public utility electrical corporation to nonutility power generators. The starting gas index price shall be established as an average of index gas prices for the same annual periods."

PG&E states that this formula replaces the old method for determining SRAC payments to QFs, which required a calculation of the O&M Adder. With the replacement of that methodology, there is no need to hold hearings on the calculation of the O&M Adder.

PG&E points out that estimated QF payments described in its June Update were based on an uncontested Electric Reliability Index of 1.0 and the values for the 1996 and 1997 IER and O&M Adder adopted in PG&E's 1996 forecast year ECAC decision (D.95-12-051). The values and calculations necessary to make the formula specified in § 390(b) operational are yet to be agreed upon by the affected parties or approved by the Commission. Consequently, in PG&E's October 15 filing of updated testimony based on ALJ Garde's

Resource Mix Ruling, PG&E included an estimate of QF payments based on the uncontested QF generation and pricing components contained in Appendix C. PG&E recommends that if the Commission approves the specific methodology for using the formula specified in § 390(b) prior to the issuance of this ECAC decision, then the resulting SRAC payments should be reflected in this decision.

Responses of Other Parties to PG&E's Report

CIU agrees with PG&E's assessment of the impact of AB 1890 on this proceeding.

While ORA does not totally disagree with PG&E's assessment of the impact of AB 1890, ORA seeks clarification of two issues:

1. ORA contends that AB 1890 provides for a cumulative rate reduction of 20% for residential and commercial customers from the rates in effect on June 10, 1996.

2. ORA states that AB 1890 is not intended to guarantee 100% recovery of PG&E's uneconomic generation-related assets. According to ORA, AB 1890 grants an opportunity, not a right, to recover costs related to generation-related assets. In support of its position, ORA cites PU Code § 330(s) which provides in relevant part that:

> "It is proper to allow electrical corporations an opportunity to continue to recover, over a reasonable transition period, those costs and categories of costs for generation-related assets and obligations,... that the commission, prior to December 20, 1995, had authorized for collection in rates and that may not be recoverable in market prices in a competitive generation market,...."

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Discussion

We agree with PG&E that § 368 requires the cost recovery plans to provide that the rate levels as of June 10, 1996, should remain in effect until January 1, 1998, the end of forecast period in this proceeding. However, ORA is correct in pointing out that § 368 requires the plans to provide that the electric rates for residential and commercial customers will be reduced by no less than 10% effective January 1, 1998, and AB 1890 contemplates a further reduction of no less than 10% by April 1, 2002 (§ 330(a)).

While we do not propose to revise PG&E's electric rates in this proceeding to account for the projected overcollections in 1997, we are considering, in another proceeding, the refunding of certain amounts which are either the subject of reasonableness disputes or are part of the direct refund accounts as set forth in D.96-12-025.

We agree with ORA's contention that AB 1890 provides an opportunity, not a guarantee, for electric utilities to recover their generation-related assets. The issues relating to recovery of PG&E's uneconomic generation-related assets are being addressed in the Transition Costs Proceeding, and we will not discuss them further here.

As to the issue of rate design, we believe that because § 368(a) requires the cost recovery plans to set electric rates at June 10, 1996 level throughout the forecast year 1997, there will be no need to address revenue allocation in this proceeding, and the opportunities for rate design may be limited to adjustments of components of the June 10 rates. This issue will be considered in an appropriate proceeding.

Turning to the question of SRAC payments to QFs, we note that the SRAC payments in this proposed decision are based on PG&E's October 15 exhibit prepared in response to the ALJ's

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resource mix ruling. However, the Commission is considering, in a separate proceeding, application of the methodology of calculating SRAC payments to QFs specified in § 390(b). If the Commission adopts a new methodology for calculating SRAC payments to QFs before this decision is issued, we will revise this decision to reflect the new methodology.

Suspension of the AER Mechanism

The AER was established to provide incentives to utilities to minimize fuel expenditures. The AER exposes a utility to some of the risk and gives it some incentive to minimize fuel costs by allowing it to keep some of the gains or to suffer some of the losses related to its fuel cost management. In PG&E's case, 91% of the difference between estimated and actual revenues is subject to recovery through ECAC balancing account treatment and the remaining 9% is put into the AER and is not recoverable through the balancing account.

PG&E and TURN supported ORA's recommendation to temporarily suspend the AER until a final decision in the Diablo Application is issued. Under this proposal, the AER would be reinstated once a decision is issued in the Diablo Application. However, as discussed below, we will suspend PG&E's AER indefinitely. The AER mechanism functions only when PG&E's rates are revised to reflect the estimated fuel expenses for the forecast year. Since we are not adjusting PG&E's rates to account for estimated decrease in PG&E's fuel expenses in this proceeding, the AER mechanism will not provide its intended incentive. PG&E's success or failure in controlling fuel costs will affect only the pace of its collection of transition costs, and the effect on shareholders will be indirect and drawn out. Accordingly, we will

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suspend the AER mechanism for PG&E indefinitely. Our authorized ECAC revenues will cover 100% of PG&E's forecasted energy expense.

Comments on ALJ's Proposed Decision

ALJ's proposed decision was filed and mailed to the parties on November 19, 1996. PG&E, ORA, and the California City-County Street Light Association filed comments on the proposed decision. PG&E and ORA also filed reply comments.

PG&E, in its comments, points out certain minor errors which have no bearing on the outcome of the proceeding. We have corrected those errors. After considering other comments and reply comments, we are issuing the decision as proposed with the following modifications:

SRAC Payments to QFs

On the subject of SRAC payments to QFs, the proposed decision states that:

> "However, the Commission is considering, in a separate proceeding, application of the methodology of calculating SRAC payments to QFs specified in § 390(b). If the Commission adopts a new methodology for calculating SRAC payments to QFs before this decision is issued, we will revise this decision to reflect the new methodology."

On December 9, 1996, the Commission issued D.96-12-028 which adopted new methodology of calculating SRAC payments to QFs based on PU Code § 390(b). We have revised Table 1 and the tables in Appendix B to reflect the changes to 1997 QF expenses resulting from the new calculation of SRAC payments to QFs (See Appendix C).

Hearings in the Second Phase of the Proceeding

Hearings in the second phase of the proceeding were tentatively set to address any revenue allocation, rate design, and O&M adder double recovery issues. PU Code § 368 removes the need for a separate phase in this proceeding to address revenue allocation and rate design issues. With the adoption of a new methodology of calculating SRAC payments to QFs based on PU Code § 390(b), there is no need to hold hearings on the O&M adder double recovery issue. Hence, there is no need to hold hearings in the second phase of this proceeding.

In addition to the modifications described above, we have also included the changes to PG&E's revenue requirement authorized by the Commission since the proposed decision was served on the parties.

Findings of Fact

1. The forecast period for this PG&E ECAC proceeding is January 1 through December 31, 1997.

2. PG&E, ORA, and TURN are the only active parties in this proceeding.

3. PG&E and ORA were able to resolve several issues in this proceeding as shown in Appendix C.

4. TURN does not oppose the agreed-upon resolution of uncontested issues contained in Appendix C.

5. Approval of the agreed-upon resolution of the uncontested issues will not harm the ratepayers.

6. PG&E's mainline gas prices are based on DRI's forecast made in the May 1996 issue of "Monthly Gas Price Outlook."

7. ORA used recorded gas prices from various basins to project future gas prices using a time series program.

8. While DRI's forecast is used widely in the gas industry, it has had significant forecast errors in the past.

9. ORA's forecast technique is untried and does not have a record to test its accuracy.

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10. It is likely that gas prices in 1997 will fall between those forecasted by PG&E and ORA and will be close to the average of the two forecasts.

11. PG&E assumes that the price of Northwest economy energy is a fixed fraction of PG&E's incremental thermal energy cost; that fraction or price ratio varies from month to month.

12. ORA's methodology for computing the price for Northwest economy energy also relies on PG&E's incremental thermal energy cost; however, ORA, in its calculations, incorporates an additional variable for rainfall in the Northwest and PG&E's service area.

13. PG&E's witness conceded that ORA's methodology should be used to compute Northwest economy energy price.

14. PG&E plans to maintain a fuel oil inventory level of 1.7 million barrels, which would allow approximately three weeks of operation at PG&E's oil-capable generating units.

15. ORA recommends that PG&E be allowed to maintain a fuel oil inventory level which would allow only two weeks of operation at PG&E's oil-capable electric generation units.

16. PG&E needs to maintain a level of fuel oil inventory which will allow it flexibility to meet its load requirements and to maintain system reliability; a fuel oil inventory level of 1.7 million barrels would provide PG&E the needed flexibility.

17. In calculating its total cost of gas, PG&E includes full demand charges for 50,000 Dth/day of transportation capacity on Transwestern's mainline and lateral pipelines.

18. In D.95-12-051, the Commission disallowed a portion of the Transwestern demand charge by using a proxy rate of 20% of the as-billed El Paso rates for Transwestern demand charges.

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19. The disallowance of a portion of Transwestern demand charges was a result of a Commission conclusion in D.95-12-046 (Conclusion of Law 2) that PG&E's entering into its contract with Transwestern was unreasonable.

20. Although PG&E agreed to the treatment of Transwestern demand charges in its 1996 forecast year ECAC proceeding, PG&E is now attempting to recover charges which are the subject of reasonableness dispute.

21. The ALJ's rulings of September 23 and 26, 1996 on resource assumptions and modelling convention specified that:

a. The average of mainline gas prices forecasted by PG&E and ORA should be adopted.

b. ORA's methodology of computing Northwest economy energy price should be adopted.

c. PG&E should be allowed to mainline a fuel oil inventory of 1.7 million barrels.

d. A proxy rate of 20% of the as-billed El Paso rates for Transwestern demand charges should be used.

22. Based on the forecast in this proceeding, PG&E's revenue requirement for 1997 will be $718.8 million lower than the currently authorized revenue requirement.

23. On September 23, 1996, Governor Wilson signed into law AB 1890.

24. AB 1890 adds or modifies several sections of the PU Code to advance the restructuring of the electric utility industry.

25. PU Code § 368 requires electric utilities to submit cost recovery plans that provide that electric rates will be equal to the levels that were in effect on June 10 1996 until January 1, 1998.

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26. PU Code § 368 allows electric utilities to propose plans to recover costs of uneconomic generation-related assets by applying certain revenue overcollections towards recovery of these costs.

27. The Commission is addressing the recovery of uneconomic generation-related assets in connection with its review of the cost recovery plans and in A.96-08-001 et al.

28. PU Code § 368 removes the need for a separate phase in this proceeding for revenue allocation and rate design issues.

29. With the adoption of a new methodology for calculating SRAC payments to QFs, there is no need to hold hearings on the O&M adder double recovery issue.

30. There is no need to hold hearings in the second phase of this proceeding which were tentatively set to address revenue allocation, rate design, and O&M adder double recovery issues.

Conclusions of Law

1. The resource assumptions and modelling conventions specified in the ALJ's rulings of September 23 and 26, 1996, should be adopted.

2. PG&E's current rates are the same as the rates that were effective on June 10, 1996, and PG&E's rates should not be changed in this proceeding, pending the Commission's decision on PG&E's cost recovery plan.

3. The disposition of PG&E's projected overcollections should be in accordance with the Commission's directive in the decision on PG&E's cost recovery plan.

4. Pending commission action on the cost recovery plans, further consideration of revenue allocation and rate design issues in this proceeding is not necessary.

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MODIFIED ORDER

IT IS ORDERED that:

1. Pacific Gas and Electric Company's (PG&E) authorized fuel-related revenue requirement is reduced by $718.812 million in this proceeding. This reduction in fuel-related revenue requirement will be offset by revenue requirement increase of $164.498 million in other proceedings, resulting in a net reduction of $554.314 million in PG&E's authorized revenue requirement, effective January 1, 1997.

2. The revisions to PG&E's Energy Cost Adjustment Clause (ECAC), Annual Energy Rate (AER), Electric Revenue Adjustment Mechanism (ERAM), and California Alternate Rates for Energy (CARE) revenue requirements set forth in Appendix B (Page 4 of 12) to this decision are adopted, effective January 1, 1997.

3. The revisions to PG&E's total authorized revenue requirements set forth in Appendix B (Page 5 of 12) to this decision are adopted, effective January 1, 1997.

4. PG&E's AER mechanism is suspended until further order of the Commission.

5. This proceeding shall remain open to address the reasonableness of PG&E's electric and gas operation during 1995.

This order is effective today.

Dated December 20, 1996, at San Francisco, California.

P. GREGORY CONLON
President
DANIEL Wm. FESSLER
JESSIE J. KNIGHT, JR.
HENRY M. DUQUE
JOSIAH L. NEEPER
Commissioners

(END OF ATTACHMENT A)

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## List of Appearances

Applicants: William H. Edwards, Annette Beitel, and Deborah Walker, Attorneys at Law, for Pacific Gas and Electric Company; and James C. Scott Shotwell, by John P. Hughes, for Southern California Edison Company.

Interested Parties: Edson & Modisette, by Carolyn A. Baker, Attorney at Law, for various interested clients; Barbara Barkovich, for Barkovich & Yap; Morrison & Foerster, by Jerry Bloom, Attorney at Law, for California Cogeneration Council; Michael Boccadoro, for Agricultural Energy Consumers Association; Jackson, Tufts, Cole & Black, by William M. Booth, Attorney at Law, for California Large Energy Consumers Association; David Branchcomb, for Henwood Energy Services; Norman J. Furuta, Attorney at Law, for the Department of Defense; Steven a. Geringer, Attorney at Law, for self; Ater, Wynne, Hewitt, Dodson & Skerritt, by Michael Alcantar and Kirk Gibson, Attorneys at Law, for Cogeneration Association of California; Grueneich Resource Advocates, by Dian M. Grueneich, Attorney at Law, for the Department of General Services; Graham & James, by Peter W. Hanschen and Martin A. Mattes, Attorneys at Law, for Agricultural Energy Consumers Association; Ellison & Schneider, by Lynn Haug and Douglas K. Kerner, Attorneys at Law, for Independent Energy Producers Association; Aldyn Hoekstra, for Cambridge Energy Research Associates; Carolyn Kehrein, for various clients; Thomas Knobloch, for Brubaker & Associates; Ronald Liebert, Attorney at Law, for California Farm Bureau Federation; Sutherland, Asbill & Brennan, by Keith McCrea, Attorney at Law, for California Manufacturers Association; Bartle Wells Associates, by Reed V. Schmidt, for California City-County Street Light Association; Downey, Brand, Seymour & Rohwer, by Philip A. Stohr and Dan L. Carroll, Attorneys at Law, for California Industrial Users; and Robert Finkelstein, by Theresa Cook Mueller, Staff Attorney, for Toward Utility Rate Normalization.

Intervenor: McCracken, Byers & Bergeron, by David J. Byers, Attorney at Law, for California City-County Street Light Association and Marin Street Light Authority.

Office of Ratepayer Advocates: Joseph DeUlloa, Attorney at Law, and Raymond Charvez.

(END OF APPENDIX A)