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Decision 91-05-054 May 22, 1991

BEORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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| In the Matter of the Application of the Southern California Edison Company (U 338-E) for: (1) Authority to Increase Its Energy Cost Adjustment Billing Factor, Increase Its Annual Energy Rate, and Increase Its Electric Revenue Adjustment Billing Factor Effective June 1, 1988; (2) Authority to Implement Modifications to Its Energy Cost Adjustment Clause as More Specifically Set Forth in this Application; (3) Authority to Revise the Incremental Energy Rate, the Energy Reliability Index, and Avoided Cost Pricing; (4) Review of the Reasonableness of Edison's Operations During the Period from December 1, 1986, through November 30, 1987; and (5) Review of the Reasonableness of Edison Payments to Qualifying Facilities Under Nonstandard Contracts During the Period from December 1, 1984, through November 30, 1987. | Application 88-02-016<br>(Filed February 11, 1988) |

(See Appendix A for appearances.)

# INDEX

# O P I N I O N

## Background

This application, filed by the Southern California Edison Company (Edison) on February 11, 1988, included three requests: (1) an increase in Edison's electric rates based on increases in revenue requirements related to Edison's Energy Cost Adjustment Clause (ECAC); (2) approval of the reasonableness of Edison's operations for the 1987 reasonableness review period; and (3) approval of the reasonableness of its nonstandard contracts with qualifying facilities (QF) for a three-year period beginning December 1, 1984. Review of Edison's application was divided into two phases: a forecast phase to address Edison's rate increase request, and a reasonableness phase to consider "traditional" ECAC reasonableness issues for the record period 1987 and reasonableness issues centered on QF nonstandard contracts for the period between December 1, 1984 and November 30, 1987. The reasonableness phase itself was split into two phases: the first phase consisting of a review of the Kern River Cogeneration Company (KRCC) contract and other traditional ECAC issues, and the second phase consisting of a review of nonstandard QF contracts.

A decision on the forecast phase was issued September 22, 1988 (Decision (D.) 88-09-031) and a decision on the KRCC contract was issued on September 25, 1990 (D.90-09-088). Rehearing of D.90-09-088 was granted December 27, 1990 (D.90-12-125) limited to the issue of the appropriate amount of disallowance for entering into an imprudent contract. That hearing is pending. This opinion represents the third decision in this application and covers the other traditional ECAC reasonableness issues. A fourth decision will be issued covering the rehearing and our review of the nonstandard QF contracts for the period December 1, 1984 through November 30, 1987 after hearings are completed.

**The Reasonableness of the Long-Term Power Sales Agreement (LTPSA) between Edison and Pacific Power and Light Company (PP&L)**

1. Edison's Evidence

Edison's witnesses testified as follows:

In November 1984 Edison's resource plan update identified a need to supply 1,250 megawatts (MW) of additional on-peak capacity and energy purchases to meet the company's load requirements for the next 20 years. This need was also projected in Edison's 1985 resource plan. A major portion of this additional capacity was included to replace 710 MW of existing peaking power purchase contracts that were expiring by the end of 1990. The need for additional capacity was anticipated to begin in 1987 and continue to the end of the 20-year planning period. In addition, Edison desired to maximize the use of the company's Pacific Intertie facilities in obtaining Pacific Northwest (PNW) economy energy and to pursue cost effective firm power transactions with PNW entities. To achieve these goals Edison solicited bids in late 1984 from 21 potential sellers in the western United States. Of those solicited, 16 responded and after review PP&L was considered one of the most probable suppliers and negotiations were initiated. PP&L's response to Edison's request indicated that it would likely offer the lowest price for the required capacity and energy.

As a result of those negotiations, on December 31, 1985 Edison and PP&L entered into a "long-term power sales memorandum of agreement" (MOA) which provided that PP&L would supply Edison with 225 MW of firm capacity between August 1, 1987 through September 30, 1988 and 200 MW of firm capacity between October 1, 1988 through September 30, 2006. The price was fixed for the period August 1, 1987 through December 31, 1987 at $38 per megawatt-hour (MWh); January 1, 1988 through December 31, 1988 at $41 per MWh; and January 1, 1989 through December 31, 1989 at $43 per MWh. The price for the additional years was based on a formula set forth in the agreement.

The MOA provided by its terms that it shall be effective as of the date of execution by both parties and shall terminate upon the earlier of the effective date of (1) the agreement pursuant to Section 2.2 (the LTPSA) or (2) September 30, 2006. The agreement was to be an LTPSA based on the terms and conditions contained in the MOA. The MOA provided in the event that the LTPSA had not been executed by both parties by June 1, 1987 and the MOA had not been terminated earlier, that PP&L shall file the MOA with the Federal Energy Regulatory Commission (FERC) and that the parties shall be bound by the terms of the MOA unless the FERC imposes conditions upon the parties' performance under the MOA which are unacceptable to either party.

At the time of entering into the MOA, Edison estimated that its savings under the MOA were projected to be $129 million in 1987 dollars. Additionally, the MOA had benefits beyond the $129 million savings which included: (a) the power made available was not tied to the availability of specific generating units; (b) transactions under the MOA were not subject to Bonneville Power Administration restrictions; (c) the power was to be delivered to Edison's system at times when the power had the greatest value, thus enhancing scheduling flexibility; (d) the ability to schedule emergency service at contract prices from the PP&L system; and (e) a reduction of fossil fuel generation on the Edison system which helps improve air quality in the Los Angeles Basin.

The LTPSA contemplated by the MOA was executed in June 1987. However, the price of gas and oil had fallen dramatically between the time of the execution of the MOA and the execution of the LTPSA. Because of that event, Edison sought to renegotiate the price component prior to signing the LTPSA. At the time Edison had three alternatives: (1) continue to accept the terms of the MOA;

(2) negotiate a termination agreement; or (3) negotiate an improvement to the MOA's terms. Edison decided not to walk away from the MOA because to do so might cost as much as $73 million in termination damages plus giving it the reputation of a company that does not live up to its agreements. If it did nothing, it expected PP&L to file the MOA with FERC according to its terms. Therefore, Edison decided to attempt to renegotiate the terms of the MOA. That renegotiation resulted in the LTPSA. Between August 1986 and June 1987, Edison and PP&L clarified language in the MOA associated with items such as billing procedures and audit rights, and especially negotiated a new pricing provision which Edison believes is more favorable than that of the MOA. The new pricing was expected to save Edison's ratepayers approximately $16 million in 1987 dollars when compared to the MOA. The 1987 price was reduced by $5.40 per MWh; the 1988 price was reduced by $5.40 per MWh; and the 1989 price was reduced by $5.90 per MWh. In addition, a price cap in the MOA was reduced by $5 per MWh beginning in 1990 thereby limiting Edison's financial exposure.

The LTPSA provides Edison with a 20-year firm, reliable source of peaking/intermediate capacity and associated energy for the period August 1, 1987 through September 30, 2006. The LTPSA is a reliable resource because the purchase is backed by the entire PP&L system. Delivery is not contingent upon the availability of one generating facility or a small set of generating facilities. With this assurance of reliability, the value of the capacity and associated energy is enhanced. Edison estimated that the savings of the LTPSA over its term would be approximately $197 million in 1987 dollars.

### 2. The Division of Ratepayer Advocates' (DRA) Evidence

DRA's witness testified as follows:

DRA believes that Edison should suffer a $3 million disallowance because Edison was imprudent in entering into the MOA and the LTPSA. DRA's position is that only fully executed contracts are considered firm commitments and therefore belong in a utility's resource plan because only fully executed contracts can provide assurance of actual prices, terms, and conditions and also because allowing nonfully executed contracts in the utility's resource plan may invite "gaming" by the utility, squeezing QFs out of the competitive process. DRA believes that the MOA was not a fully executed contract.

Edison was imprudent in executing the LTPSA because the assumptions that Edison made were, for the most part, unreasonable. Edison determined that the LTPSA had a net present value (npv) benefit of between $198 to $289 million on the following assumptions:

- o Purchase costs based on the contract prices for 1987-1989, and PP&L's forecast of contract prices for 1990-2006, dated June 19, 1987.
- o Alternative energy costs: Fuel costs from an Edison forecast of average gas prices, dated April 13, 1987; Incremental Energy Rates (IER) from an Edison forecast, dated January 20, 1987.
- o Alternative capacity costs: Combustion turbine costs from Edison's General Rate Case (GRC) filing; an Energy Reliability Index (ERI) with Edison's valuation of the LTPSA capacity; a performance adder of 18%.
- o The California Oregon Transmission Project (COT Project) is on line by 1991, which will permit exchanges.
- o A cost of capital of 12.65%.

DRA did not agree with many of Edison's assumptions and based its evaluation on the following changes to Edison's assumptions:

- Do not consider the $289 million npv because it is based on the 1985 S.O. 2 capacity price which does not warrant consideration as a 1987 assumption.
- Assume the COT Project does not come on line during the life of the contract. (This scenario was presented in Edison's June 23, 1987 spreadsheet resulting in a $174 million npv.)
- Alternative capacity costs: Remove the 18% performance adder; calculate ERIs using the GRC Resource Plan, valuing LTPSA capacity.
- Alternative energy costs: Use DRA's forecast of Edison's incremental gas costs, dated March 11, 1987.

Under these assumptions DRA projects a -$32 (negative) million npv for the contract life. Furthermore, the yearly npv does not turn positive until the tenth year of the purchase, and is less than $3 million npv benefit per year through the contract term. Based on the evidence, Edison was imprudent to execute the LTPSA.

Other evidence of the noncost effectiveness of the LTPSA are:

1. In November 1987 the Commission determined that no Standard Offer (S.O.) 4 contracts be made available and continued the suspension of S.O. 2 contracts.
2. Edison's fall 1986 resource plan shows that Edison has no identifiable need for the PP&L contract or other resources until 1996.
3. In July 1987 Edison stated that "even under the most optimistic scenarios, the oversupply situation may not diminish until well into the 1990s."
4. In the short run it is expected to be cheaper to run oil and gas units rather than purchase under the PP&L contract.

5. For the forecast period the PP&L purchase is expected to be $2 to $11 million above the cost of running Edison's oil and gas units.

6. For the four months during the record period for which the LTPSA was in effect, the PP&L purchase was an estimated $5 million above Edison's incremental costs.

To determine the disallowance DRA compared the PP&L purchases with the market price for alternative firm capacity and associated energy. DRA, to be conservative, used a $23.5 MWh price as the basis for the disallowance calculation. The price was based on a PP&L contract with Portland General Electric (PGE) for 200 MW of firm capacity with associated firm energy, take or pay for a minimum 25,000 MWh, effective August 24 through September 25, 1987. The difference in price between what Edison paid PP&L and what they would have paid PGE for the same energy through the periods August, September, October, and November of 1987 was $3,268,800.

DRA is of the opinion that Edison's entering into the MOA was unreasonable because:

1. Edison's capacity needs were significantly different by the time they signed the MOA (December 31, 1985) compared to when they made the determination of need (late 1984). In fact, the capacity situation had changed by May of 1985. An Edison memo from that period states:

> "In the November 27, 1984, Resource Plan Update, Electric System Planning identified a need to supply 1,250 MW of additional 'on-peak' capacity and energy purchases...Since the time in which the above purchase requirement and purchase schedule was formulated, Edison's base loaded resource picture has changed dramatically due to the unprecedented amount of QF contract executions. This activity in the QF area has placed Edison in a position of negotiating flexibility (emphasis added) which Edison can use to

achieve the best purchase agreements at the lowest possible price."

2. In May of 1985, Edison stated in the Order Instituting Rulemaking (OIR) 2 proceeding that "Adequate resources are currently committed or under contract to meet Edison's needs until the mid-1990s."

3. The recommended strategy and the awareness of the other options outlined in the Edison memo were a reasonable approach to take at that juncture. The important feature of the strategy was to maintain "negotiating flexibility." Since the need for capacity was diminishing, if not eliminated until the mid-1990s, Edison was in a position to bargain for cost effective purchases, if any commitments were to be made at all.

4. Edison's capacity surplus continued to become evident. In April of 1986, in its recommendation to continue the suspension of S.O. 2, Edison stated:

> "Edison has sufficient resources to meet its capacity needs to the mid-1990's.
>
> "The existing S.O. 2 capacity payment table does not reflect Edison's current capacity need and, thus, overvalues new QF capacity.
>
> "The existing S.O. 2 capacity payment table prices, if adjusted to reflect need, would be reduced 15 to 90 percent.
>
> "Continued availability of S.O. 2 would expose the ratepayer to capacity overpayments."

5. In that same recommendation, Edison explained how the capacity value adopted in December of 1984 was out of date by April of 1985, during which time approximately 1,100 MW of QF capacity was contracted. As of April 1986, Edison expected a capacity surplus of approximately 700 MW during mid-1987 to 1991, and an approximately 500 MW surplus during 1991 to 1993. The surplus diminishes around 1995.

6. Between the suspension of Interim S.O. 4 on April 18, 1985, and the execution of the MOA (December 31, 1985), Edison executed 333 MW of QF contracts, giving it a total of approximately 1,433 MW of QF capacity under fixed capacity arrangements. Clearly, Edison's need for capacity had diminished. The prudent course for Edison to take was to either use these changed conditions in further bargaining with PP&L, or not pursue an interutility contract.

DRA asserts that Edison's $593 million (nominal) cost effectiveness analysis of the MOA is flawed. Edison's key assumptions were:

- o Alternative capacity costs based on S.O. 2 capacity payments, effective January 1, 1985, plus an 18% performance adder.
- o Alternative energy costs using heat rates and average gas costs which are undocumented.
- o The COT Project is on line by 1991, providing exchange benefits.

DRA's criticism is based on:

The S.O. 2 capacity payments are not the proper alternative to compare to this purchase. First, S.O. 4 was suspended at the time of the MOA, and Edison's capacity payments for S.O. 2 and S.O. 4 are the same. Second, Edison's April 1986 testimony demonstrates that by April of 1985, any additional S.O. 2 capacity payments would result in excess costs to ratepayers. And finally, the most realistic peaking capacity alternative was, and still is, refurbishment of Edison's oil/gas units.

With the evident uncertainty of Edison's capacity needs, it would have only been prudent to execute the MOA with a nonbinding escape clause. A clause that is in the MOA, as amended by Amendment No. 1, May 7, 1986, states:

> "2.3 Near-Term Sales. In the event that the Agreement is not executed by both parties by June 1, 1986, Edison may terminate the Power Sales Contract between Pacific and Edison of even date herewith by giving thirty (30) days' written notice to Pacific. In no event may Edison terminate such contract before July 1, 1986. In the event of such termination by Edison, Pacific may terminate this memorandum at any time prior to June 1, 1987, by giving written notice thereof to Edison."

The escape mechanism would only allow Edison to cancel the short-term Power Sales Contract (PSC). There was no guarantee that PP&L would then cancel the MOA. In fact, if conditions were such that it made economic sense for Edison to cancel the relatively low-priced ($25.7/MWh) PSC, it would likely not make economic sense for PP&L to cancel the MOA. Without any out for Edison, PP&L was assured of a firm sale in a surplus market with dropping fuel prices. DRA believes that the MOA contained no reasonable escape clause for Edison.

DRA concludes that Edison's decision to execute the MOA was imprudent because:

- Edison's own forecasts said that they were expecting to be in a capacity surplus situation until the mid-1990s. Edison should have been certain that any capacity purchases it made during the MOA time frame were clearly cost effective.

- The MOA did not contain an adequate escape, if Edison would be economically harmed due to changed fuel or regulatory conditions.

- Edison's decision to enter the MOA was not unanimous among Edison management. A document from Edison's files states:

  > "The Law Department was informed that Mr. Allen and Management Committee directed System Development to obtain an 'escape clause' providing for termination in the event changed fuel or regulatory conditions would cause either

party to be economically harmed. The MOA does not provide any of the protections requested by Mr. Allen and the Management Committee."

As executed, the MOA was too risky. Edison was imprudent in executing it.

The witness testified that Edison was imprudent to sign the LTPSA and the MOA. Executing the LTPSA was imprudent because Edison should not have expected it to be cost effective over its lifetime or pass a first year cost effectiveness test until the mid-1990s. Executing the MOA was imprudent because Edison committed itself (no escape) when there was no clear need for capacity. DRA recommends a disallowance of $3 million for the record period.

## Discussion

### 1. The Standard of Review

We have frequently articulated the standard to judge utilities when reviewing activities such as are at issue in this proceeding. In Re San Diego Gas & Electric D.89-02-074 in Application (A.) 84-12-015, we set forth the standard as:

> "The term, 'reasonable and prudent,' means that at a particular time a utility's practices, methods, and acts followed the exercise of reasonable judgment in light of facts known or which should have been known at the time the decision was made. It means that the utility reasonably expected the act or decision to accomplish the desired result at the lowest reasonable cost consistent with good utility practices. Good utility practices are based upon cost-effectiveness, reliability, safety, and expedition.
>
> "A decision may be found to be reasonable and prudent if the utility shows that its decision making process was sound, that its managers considered a range of possible options in light of information that was or should have been available to them, and that its managers decided on a course of

> action that fell within the bounds of reasonableness, even if it turns out not to have led to the best possible outcome."

(See also D.89-02-074, pp. 6-11; Re Southern California Edison Co. D.90-09-088, pp. 14-16; D.87-06-021, pp. 19-20.)

2. The Memorandum of Agreement

DRA's position on the MOA is not clear. At the hearing it took the contradictory position that Edison should have executed the MOA only if it contained an escape clause, but then contended that the MOA was not a fully executed contract and therefore should not have been included in Edison's resource plan. In its brief DRA apparently has dropped the argument that the MOA was not a fully executed contract when it states "Because Edison was tied into an unreasonable MOA, the best it could hope for was to mitigate the harm to ratepayers by negotiating a more favorable LTPSA." (DRA Brief, p. 7.)

In our opinion the MOA was a legally binding agreement that contained all the terms necessary to constitute a long-term power purchase agreement. The provision in the MOA regarding a further long-term power purchase agreement was a condition subsequent to the execution of the MOA. It did not make the MOA illusory. The two issues before us regarding the reasonableness or unreasonableness of the MOA are (1) should it have been executed at all and, if so, (2) should it have contained a termination provision. We must determine these two issues on the facts as of December 1985.

DRA asserts that it was unreasonable for Edison to execute the MOA in December 1985 without including an escape clause to protect the ratepayers from economic harm due to changed fuel or regulatory conditions in the interim between the date of execution and the start of purchases under the LTPSA, August 1, 1987.

Edison replies that a termination provision in the MOA was not needed because Edison wanted a long-term firm resource and a termination provision would have had to have been reciprocal thereby increasing the risk that PP&L might have withdrawn. Rather than a firm contract, Edison would have had an as-available contract which could not be used for long-term planning.

We agree with Edison. A termination provision, as described by DRA, appears to be nothing more than an option to purchase power. There is no reason to believe that PP&L would have agreed to it - it, too, must plan; and if it had agreed, it would have either extracted a premium for the option or required a reciprocal provision. The fact that the contract was executed 18 months before power was to be delivered was prudent. We expect long-term planning by utilities.

A more important question is the need for firm peaking power in mid-1987, because that is what the MOA delivered, as determined in December 1985. DRA contends that during the period between November 1984, when Edison identified a need for on-peak capacity and energy, and December 1985, Edison was aware of a reduction in capacity need. DRA refers to Edison's May 1985 position in OIR 2 that it had adequate resources to meet its need until the mid-1990s, and that Edison had contracted for 1,100 MW of QF capacity between December 1984 and April 1985.

Edison argues that its November 1984 and November 1985 resource plans identified a need to supply 1,250 MW of additional on-peak capacity and energy purchases to meet its load requirements for the next 20 years, beginning in 1987. The MOA met a portion of that need. Edison admits that prior to executing the MOA, it was aware of changes in baseload capacity need caused by the execution of substantial quantities of QF contracts and informed the Commission of a potential QF capacity surplus in November 1984. And, Edison states, because of the QF capacity surplus Edison was able to negotiate the MOA contract on favorable terms. Edison declares that DRA's contention of an oversupply is misleading because Edison's comments applied to long-term baseload

QF resources, not to an intermediate and peaking resource such as the MOA.

In our opinion Edison acted reasonably in relying on its 1985 resource plan which showed a need for 1,250 MW of additional on-peak capacity. When executing the MOA, Edison knew of its recent QF additions (and also knew that as little as 30% of that capacity might actually come on line) but still anticipated a need for on-peak resources. It knew, for instance, that 710 MW of existing peaking power purchase contracts would expire in 1990. DRA's witness testified that it was unreasonable for Edison to rely solely on its 1985 resource plan for needs commencing in 1987. He testified "it was more reasonable to expect that PNW purchases may have been needed in the 1987 time frame, but to make a commitment at the time the MOA was executed was not a reasonable approach to take." (Tr. 1040.) He then testified that neither DRA nor he had reviewed Edison's 1985 resource plan.

DRA's failure to review Edison's 1985 resource plan leaves it with only one changed circumstance on which to base a conclusion that Edison was unreasonable in entering the MOA. And that circumstance was the increase in QF contracts in 1985. But the evidence shows that those contracts, to the extent they came on line, were to provide baseload power not on-peak. So we cannot find that Edison was unreasonable for that reason. DRA's other reason to criticize Edison was that Edison should not have committed to the MOA in December 1985 for delivery in August 1987; Edison should have waited. DRA's reasoning is not persuasive. If firm power is known to be needed, arrangements should be promptly made to acquire the power. To delay is to gamble with the ratepayers' money. An 18-month lead time is certainly reasonable for the quantity of power needed.

DRA argues that the LTPSA is unreasonably costly to ratepayers. We need not discuss the arguments pro and con on whether that is true. DRA concedes that the LTPSA was more favorable for the ratepayers than the MOA. Had Edison not entered into the LTPSA it is reasonable to assume that PP&L would have insisted on its rights under the MOA. Given that probability, Edison was prudent in negotiating an agreement more favorable than the MOA. DRA has presented no evidence that Edison could have made a better deal.

Although we believe that DRA's insistence on a termination clause was misplaced, it did, inferentially, raise the question of the reasonableness of long-term fixed price contracts. Over the past 20 years fuel prices have fluctuated in unpredictable ways, a lesson relearned over the past six months. It certainly would not be imprudent to tie the contract price for a commodity to factors not controllable by the parties such as current fuel prices or an appropriate price index. Edison recognized this problem at the time it signed the MOA and discussed with PP&L its concern over extreme changes in fuel costs. PP&L shared this concern and on January 10, 1986 wrote to Edison agreeing to negotiate terms in the contemplated LTPSA that "could mitigate the impact on either party of these extreme changes." (Exhibit 188.) That negotiation took place and the result was incorporated in the LTPSA.

**The Reasonableness of Losses Incurred on the Sale of Fuel Oil Inventory**

1. Edison's Evidence

In early 1987, Edison analyzed its short-term fuel oil requirements and concluded that about 1 million barrels of its 6.3-million barrel oil inventory would not be required during the summer months to maintain the necessary reliability of operations. Based on an analysis conducted in March 1987, Edison concluded that it would be beneficial to its ratepayers to sell the oil since the carrying cost savings realized from the lower inventory level would more than offset the expected losses on the sale. This is known as inventory cycling[1] and allows Edison to maintain a lower overall average inventory level while maintaining the necessary system reliability. Edison reduced its fuel oil inventory by approximately 1 million barrels in two sales transactions that were recorded in April and May 1987. DRA recommends disallowance of $301,000 on the fuel oil sale loss for April and $1.256 million on the fuel oil sale loss for May, contending that Edison's decision to sell was imprudent.

Edison states that the difference between Edison's estimate and DRA's estimate is primarily because DRA applied an inappropriate short-term carrying cost interest rate in calculating the projected costs of holding additional inventory. Edison used its weighted average cost of capital since that interest rate represents the true cost to the company of carrying oil in inventory.

Edison compared its analysis and DRA's analysis with actual sales prices as follows:

| Description | MBls. | Break-Even Sale Prices: Edison | Break-Even Sale Prices: DRA | Actual Sale Prices |
|---|---|---|---|---|
| April 1987 Sale | 500 | $13.84 | $15.57 | $15.93 |
| May 1987 Sale | 443 | 14.20 | 15.61 | 15.34 |
| Weighted Average | 943 | $14.00 | $15.59 | $15.66 |

1 Inventory cycling is the term used to describe the actions taken to adjust fuel oil inventory levels seasonally in order to maintain a relatively constant level of system reliability throughout the year. Fuel oil inventory cycling was authorized by the Commission in D.87-11-013, p. 40.

Edison contends that DRA's evaluation, including its adjustments, shows that in the aggregate the sale of the oil was economically justified.

Edison's witness testified that true costs must be used for economic evaluation of inventory management decisions. If inventory carrying costs allowable for ECAC ratemaking purposes are used as the basis for inventory management decisions, then those management decisions can be distorted because they do not reflect the utility's true cost. It is essential that any economic analysis take into consideration all of the costs and consequences of inventory management decisions. This can only be accomplished by using Edison's long-run cost of capital in the analysis.

An analysis based solely on short-term interest rates fails to take into consideration the cost associated with carrying additional short-term debt. For example, increasing the level of permanent short-term debt to finance fuel oil inventory will lead to increased long-term debt, thereby raising costs to the company's ratepayers. In addition, higher debt levels will affect shareholders' perceptions of risk, increasing equity costs. These costs should be reflected in any analysis of fuel oil cycling.

2. <u>DRA's Evidence</u>

DRA's witness testified that the loss for the April fuel oil sales was $4,132,000 of which, in DRA's opinion, $3,831,000 was reasonable, but $301,000 was unreasonable. For the May sale, DRA calculates the unreasonable portion of the loss to be $1,256,000. The witness testified that based on DRA's economic analysis, Edison used incorrect assumptions in its economic analysis and, if it had used the correct assumptions, its analysis would have shown that it was more expensive to ratepayers for Edison to sell the oil rather than to hold it.

The primary problem with Edison's analysis, in DRA's opinion, is that in calculating the carrying costs for the low sulfur fuel oil (LSFO) inventory Edison used an annual carrying cost rate of 21% per year, which is based on Edison's cost of capital. This is over three times larger than the short-term interest rate which the Commission has authorized Edison to use in calculating the fuel oil carrying costs booked into Edison's ECAC balancing account for the months of March and April 1987. Edison has been using a short-term interest rate in the calculation of its fuel oil carrying costs since January 1, 1986. Edison's cost for short-term debt during the record period was about 7%. Therefore, it was inappropriate for Edison to use a 21% carrying cost rate in its analysis of the costs of a fuel oil sale when it should have used the short-term interest rate which it uses in calculating its ECAC fuel oil carrying costs.

The amount of carrying costs is important because if a higher interest rate or cost of capital is assumed the resulting economic study will show a higher cost of holding oil in inventory, and the break-even price for an oil sale would be lower. Further, Edison's analysis suffers from other flaws, in DRA's opinion. Edison applied an incorrect inventory cost for inventory previously written down, and used an incorrect discount factor. If Edison had done the analysis correctly, the analysis would have shown that the April sale appeared only marginally beneficial to Edison's ratepayers. The problem with sales near the break-even point (whether to sell or to hold) is that by selling its LSFO inventory Edison shifted the risk associated with the inventory to its ratepayers, as the ratepayers would be responsible for any additional cost in reacquiring the fuel at a later time.

Discussion

DRA's argument is correct. Edison's use of an annual carrying cost rate of 21% per year in its economic analysis was improper. Edison should have used the short-term interest rate (about 7%) which it uses in calculating its ECAC fuel oil carrying costs. In D.85-12-107 this Commission set rates for fuel oil carrying costs using short-term interest rates. Edison has presented no facts which would show that D.85-12-107 was in error then or is in error now.

Edison's argument that "true costs" must be used for economic evaluation of inventory management decisions is a generalization that is not very helpful. The meaningful question is what are the "true costs"? DRA says that the true cost is short-term debt; Edison says it is Edison's weighted cost of capital. When making a decision on whether to sell inventory or carry it, the cost of carrying the inventory is a major concern. If Edison were nonregulated only its shareholders would be interested in the formula to determine whether to sell or hold; only the shareholders would profit or lose by the decision. But as a regulated company Edison is seeking to have the ratepayers stand surety for its decision. In that circumstance Edison must first consider the ratepayers' interest; and for fuel oil this Commission has measured that interest as the cost of short-term debt.

Edison argues that an analysis based solely on short-term interest rates fails to take into consideration the costs associated with carrying additional short-term debt, such as increased long-term debt and equity costs, and the perception of risk by shareholders. Edison points out that the Commission recognized that the use of short-term debt could have impacts on Edison's capital structure and rate of return (D.86-05-095) and that in a Commission-adopted settlement agreement (D.86-08-025 in A.83-12-53) Edison was granted a change in capital structure specifically to adjust for the impact of using short-term debt to finance fuel oil inventory. (Edison Opening Brief, p. 41.) The capital structure change adopted by the Commission was the result of a settlement agreement that contained no statements regarding adjustments for fuel oil inventory risk. The Commission did not explicitly adopt an adjustment in capital structure specific to the increased risk Edison associates with fuel oil inventory. Taking Edison's Opening Brief argument on its face, we contend that Edison cannot have it both ways. Edison states that it received an allowance in rate of return because it used short-term debt financing of fuel oil inventory; now it wants the ratepayers to pay that return plus an additional sum for the weighted cost of capital to finance fuel oil inventory. We will not countenance a double recovery.

Edison has raised some concerns with respect to the appropriateness of our current policy for funding fuel oil in inventory, and for the accompanying economic evaluation of inventory management decisions that we wish to consider further. We believe it appropriate to evaluate the adequacy of our current policy in a forum that provides for input from the energy utilities on a generic basis. Workshops should be held to identify other parties' concerns, if any, with the current policy and to afford informal discussion of the adequacy of our current policy in assessing the true costs. Depending on the results of these workshops, the Commission may decide to pursue the matter further within the context of an attrition proceeding or other appropriate procedure. We direct CACD to conduct such a workshop the timing of which will allow for hearing of any contentious issues or matters of policy in the test year 1993 energy utility rate proceedings. CACD shall report to the Commission on the results of the workshops.

Edison's argument that we should consider that in the aggregate the sales were justified is no more than hindsight and the improper consolidation of separate activities.

Debris Outage Prevention Measures

Edison operates 22 relatively small generating units at 10 hydro plants located in the San Bernardino/Big Bear Lake area in what Edison designates as its Southern Division. The rated capacity of these units ranges from 0.30 MW to 1.73 MW. The recorded energy production in the Southern Division was 492,000 MWh in the 1987 record period compared to 575,000 MWh expected for an average water year. DRA was not convinced that the dry water year experienced in 1987 was the major cause of the Southern Division's low capacity factor and contends that significant energy could be lost due to debris outage.

DRA recommends that, with respect to the Southern Division, the Commission should direct Edison to: (1) implement methods to prevent debris from causing a significant number of outage hours; (2) submit a report in the next ECAC reasonableness review, indicating outage prevention measures developed and taken, including budgeted and recorded costs; and (3) submit an economic study, if Edison had not taken steps to eliminate these outages.

The plants in the Southern Division are normally unmanned. During storm conditions, operating personnel monitor the sand and gravel in the plant's intake and, based on established criteria, bypass the generating facilities before sand and gravel in the water could cause damage to the turbine. In order to keep each plant operating as long as possible, the intake structure drain gate is periodically opened manually to flush out the accumulated debris. During periods when the water bypasses the turbine, the water condition is monitored until it is acceptable to return the generating facility to service. These operating practices minimize loss of production as well as protect the generating equipment.

Edison contends that the maximum amount of energy that potentially could have been lost during the 1987 record period, assuming that all debris outages were preventable, would have been only 2,000 MWh. This represents only a 0.2% increase in the Southern Division's annual capacity factor. For an average water year, the estimated energy loss, assuming the same forced outage rate, would only be 2,400 MWh which is approximately equal to $57,000 during the record period. This potential savings of approximately $2,600 per unit is far less than the additional cost of installing and operating additional debris removal equipment. Debris outage prevention measures are not cost-effective at this time.

DRA did not present evidence on the cost-effectiveness of its recommendation and did not brief this issue. We are persuaded that Edison's current practices of minimizing debris outages are adequate and that to expand its efforts would not be cost-effective.

Heat Rate Efficiency

A unit's efficiency is measured by a value known as heat rate, which is the amount of fuel (in Btu) required to produce a kilowatt-hour of generation. The lower the heat rate, the more efficient the power plant.

The Efficiency Deviation Method (EDM) was developed at the request of the Commission (D.86-04-059) (and adopted in D.88-07-021) to evaluate the heat rate performance of Edison's oil- and gas-fired units. The objective of the Commission, in reviewing heat rate performance, is to encourage the electric utilities to improve the efficiency of their generating units and thus reduce the consumption of fuel, thereby resulting in reduced cost to the ratepayer.

DRA recommends several improvements to Edison's EDM.

a. The comparison of recorded data with theoretical should be provided both on an "adjusted-to-baseline" basis and unadjusted basis.

b. The input/output (I/O) curves should be updated for all the units, in order to provide a more meaningful basis for measuring heat rate deviation as well as a more accurate heat rate estimate for the forecast period.

c. Edison should determine the effect on the accuracy of its data by different factors including minimum load operation, measurement errors, and use of oil and gas heat rates without converting to 100% gas.

d. Edison should provide the exact amount of the adjustments made to the theoretical I/O curves for (1) telemetering and computer malfunctions (i.e. measurement error), and (2) startup fuel.

Edison accepts DRA's recommendations that Edison update I/O heat curves following unit overhauls and that Edison provide a study regarding the accuracy of the data. However, Edison believes that comparing recorded data with theoretical data on both an adjusted-to-baseline and unadjusted basis would require additional time and money with no demonstrated benefit. DRA's witness testified that he had made no estimate of the cost to provide the studies requested by DRA.

We must be assured that DRA is provided with all the information it needs to perform a thorough analysis of Edison's operations and so we urge cooperation between the parties. As measuring techniques improve, information should be provided to DRA without the need for an order. We do not believe we have adequate evidence in the record to decide this issue. We will, therefore, put the matter over to be decided in A.90-06-001, a later reasonableness review proceeding.

Nuclear Unit Incentive Procedure

Edison recommended making the following revisions to the existing Target Capacity Factor (TCF) procedure:

- Revise the TCF deadband range for San Onofre Nuclear Generating Station (SONGS) Units 2 and 3 and Palo Verde Nuclear Generating Station (Palo Verde) Units 1, 2, and 3 to 55-75% from the existing 55-80%;
- Apply a three-fuel-cycle average to all nuclear units;
- Permit economic modifiers to be used to provide rewards; and
- Permit economic modifiers for NRC-mandated outages that are not the result of imprudent actions by Edison.

DRA opposed the proposed revisions to the deadband range, the three-fuel-cycle average, and the economic modifier for NRC-mandated outages.

The TCF procedure is intended to encourage superior performance and discourage poor performance by equitably allocating the risks, costs, and the benefits of nuclear plant operation between the utility and its ratepayers. Edison argues that its recommended revision to the deadband range is consistent with this intent because it more accurately reflects the expected performance of nuclear plants today, and because in a decision regarding Diablo Canyon (D.87-10-041, p. 17), we adopt a deadband rage of 55-75%. Edison presented testimony which evaluated the performance of 44 large nuclear plants. This data showed that with a 55-80% deadband range only 9% of the fuel cycles would have resulted in rewards, but approximately 21% would have resulted in penalties. If the 55-75% range had been in effect, there would have been rewards in 22% of the fuel cycles.

DRA argues that the Commission should reject Edison's recommendation. It says the Commission set the upper end of the deadband at 80% because this was the level of performance Edison used to justify the plant at the time it sought certification from the Commission. In setting the upper limit, the Commission explained:

> "...the focus of risk allocation and performance is on markedly superior or inferior performance...We cannot reasonably pass along supranormal returns to the utility for plant performance below that which the company utilized to gain certification of the plant." (D.83-09-007, pp. 58-59, emphasis added.)

DRA contends there is no evidence that the capacity potential of those units has changed since the TCF bands were established.

We agree with DRA. Granting a reward for exceptional service is itself an exceptional concept. We expect a utility to use its best efforts to operate efficiently and to strive to improve performance. It should not expect a reward for being slightly above average. Our rationale used to set the criteria for reward in D.83-09-007 was appropriate then, and we have been presented with no persuasive evidence that the criteria should be modified.

Edison recommends that the Commission should authorize a three-fuel-cycle average instead of a one-fuel-cycle period for the TCF procedure; and this should be done whether or not the Commission adopts Edison's proposed 55-75% deadband range. Edison cites D.87-10-041 where the Commission held that "...the three-fuel-cycle period is a better measurement of performance and a better incentive factor than one cycle." (At pp. 17-18.) DRA opposes the recommendation on the ground that a three-cycle period distorts the purpose of the TCF program, which is to focus risk allocation and performance incentives on "markedly superior or inferior performance." For the reasons stated in D.87-10-041, the three-fuel-cycle average should be applied to SONGS and Palo Verde.

Economic modifiers are adjustments made to the calculated fuel cycle capacity factor to compensate for conditions which cause a reduction in the recorded capacity factor because Edison reduces output or changes a scheduled refueling outage when to do so is beneficial to ratepayers. The existing TCF procedure allows for use of economic modifiers to mitigate a penalty for performance below 55% but does not allow economic modifiers to be used for the purpose of earning a reward when an award would have been earned but for the modifying event. Edison's proposed tariff modification is as follows:

> "The application of Economic Modifiers may remove or reduce a Nuclear Unit Incentive Procedure penalty, or cause or increase a Nuclear Unit Incentive Procedure reward."

Edison requests that NRC-mandated outages be included in Edison's tariffs as an economic modifier. This economic modifier would not apply if an NRC-required shutdown were ordered due to Edison's imprudence. A determination of whether the outage was the result of imprudence would be conducted on a case-by-case basis in an ECAC proceeding.

Edison believes that putting specific language in the tariff would resolve any question regarding whether it has the right to request a reward based upon an economic modifier. As with an economic modifier used to mitigate a penalty, Edison would submit a report to the Commission (for review in an ECAC proceeding) justifying the requested economic modifier and demonstrating what unit performance would have been but for the event that triggered the request for the economic modifier.

DRA opposes Edison's request as it believes more experience and data are required before an informed judgment can be made on this issue. DRA suggests that using economic modifiers to generate rewards may conflict with the purpose of the TCF.

The Commission addressed this issue in D.87-10-041, in which we stated:

> "... it should work either way; that is, the modifiers, when invoked, <u>should work to produce a reward as well as eliminate a penalty</u>. ...

> It seems clearly fair that if the utility is not responsible for the downtime or incurs downtime to benefit ratepayers, it should not be penalized if an award were otherwise due." (p. 18, emphasis added.)

We will follow D.87-10-041 with the caveat that modifiers which produce rewards should be considered carefully, on a case-by-case basis. It is one thing to say that we will not penalize a company for poor performance if it is shut down for reasons beyond its control; it is quite a different proposition to say that we will reward a company for good performance when it does not perform because of shutdown for reasons beyond its control. It may not have reached the reward plateau had it continued to operate. There is nothing automatic about the reward modifier; it is an opportunity, not a certainty.

<u>Coal Generation Reward</u>

DRA agreed that Edison's expenses for coal and gas burned at the Mohave Generation Station and at the Four Corners Generation Station were reasonable. DRA and Edison agree that the calculated reward for the Coal Plant Incentive Procedure for the record period should be $7,061,230.

<u>Nuclear Generation Reward</u>

DRA found the amount of nuclear energy generated during the record period to be reasonable. DRA and Edison agree on the calculated reward of $1,294,755 for San Onofre Nuclear Generating Station Unit No. 2 pursuant to the Nuclear Unit Incentive Procedure.

<u>PGE Contract</u>

DRA agreed that the execution of the long-term firm purchase power contract between Edison and PGE was reasonable.

**ECAC and Electric Revenue Adjustment**
<u>Mechanism (ERAM) Balancing Account Adjustments</u>

DRA's audit report recommended that (1) the ECAC balancing account be credited for $339,100 due to the sale of energy exploration and development adjustment property, and (2) the ERAM balancing account be credited $54,066,300 to reflect the effect of the Tax Reform Act of 1986 and Senate Bill 572. Edison made an adjustment to the ECAC balancing account of $(339,100) in March 1988 to reflect the EEDA adjustment and an adjustment of $(51,155,853) in October and November 1988 to reflect the effect of the Tax Reform Act. In Advice Letter 783-E, dated March 28, 1988, Edison estimated that its ERAM balancing account should be adjusted by a credit of $54,066,300 to be recorded April 1, 1988. However, a protest to the advice letter was filed. After a decision on the protest became final, Edison recorded adjustments to the ERAM balancing account in October and November 1988 which totaled $(51,155,852). The difference between the estimated credit and the net recorded amount is due to the effect of accrued interest from April 1988 and the operation of the ERAM balancing account. Therefore, the proper ERAM balancing account adjustment has already been made.

Nuclear Enrichment Cost

Nuclear fuel must be enriched to make it usable. DRA examined Edison's four most recent batches which were enriched (1983-1984) and determined that Edison may have overpaid by $21 million. Edison used U.S. Department of Energy (DOE) services for enrichment at a time when, DRA asserts, international market prices were much lower. DRA recommends that the Commission order Edison to furnish a report providing its economic justification for continuing with DOE after the international market opened. Edison believes that the costs it has incurred for enrichment services since 1983 are reasonable. Edison made an affirmative showing in A.89-05-064 on the reasonableness of its enrichment contracts. A separate report is unnecessary and the reasonableness of Edison's enrichment costs should be reviewed in A.89-05-064.

We do not understand why this is an issue. DRA can certainly request the information by way of a data request. It does not need a Commission order. We will hear the matter in A.89-05-064.

**Comments**

This decision was issued as a Proposed Decision and comments were filed by Edison and DRA, which have been considered. Some of the comments pointed out ambiguities in the text. We have adopted Edison's comment on clarifying the TCF and DRA's comment regarding the commencement of Edison's nuclear incentive program. DRA says that beginning Edison's nuclear incentive program with the start of the next full fuel cycle after this decision becomes final eliminates any need to prorate or average past performances that have already been rewarded or penalized in past record periods. We agree to a great extent with DRA, except that we would start the three-fuel cycle with the first fuel cycle that has not been considered for reward or penalty in past record periods. Each group of three fuel cycles is to consist of consecutive fuel cycles which have not been considered for reward or penalty. That is, for six fuel cycles there will be only two penalty/reward determinations.

Edison's comments regarding fuel oil carrying costs are merely a reargument of its position taken in its brief. They are accorded no weight. (Rule 77.3.)

**Findings of Fact**

1. The MOA between Edison and PP&L dated December 31, 1985 was a legally binding agreement that contained all the terms necessary to constitute a long-term power purchase agreement.

2. An escape clause in the MOA was not needed because the MOA was to be a long-term firm resource.

3. At the time the MOA was executed Edison's November 1984 and November 1985 resource plans identified a need to supply 1,250 MW of additional on-peak capacity and energy purchases to meet its load requirements for the next 20 years beginning in 1987. The MOA met a portion of that need.

4. The LTPSA is more favorable for the ratepayers than the MOA and is reasonable.

5. Edison sold 500,000 barrels of fuel oil in April 1987 and 443,000 barrels of fuel oil in May 1987. In determining whether the sale was in the ratepayers' interest Edison calculated its carrying costs for the fuel oil at a rate of 21% per year, based on Edison's cost of capital. During the time in question, this Commission determined that carrying costs of fuel oil inventory should be calculated using the short-term interest rate, which at the time was approximately 7%. Edison was imprudent in using a carrying cost of 21% in its calculation of whether to sell or hold the fuel oil.

6. The unreasonable portion of the April fuel oil sale loss was $301,000; the unreasonable portion of the May fuel oil sale loss was $1,256,000.

7. Edison's current practices of minimizing debris outages are reasonable and to expand its efforts would not be cost-effective.

8. The issue of changing Edison's EDM in developing a heat rate efficiency measurement should be deferred to A.90-06-001 where we expect a more thorough analysis to be presented. In the meantime we urge Edison to provide DRA with all the information DRA requests to perform a thorough analysis of this subject.

9. Edison's nuclear unit incentive procedure should be modified to permit Edison to use a 3-fuel-cycle average instead of a 1-fuel-cycle average for the TCF procedure.

10. Edison's nuclear incentive program shall commence with the first fuel cycle that has not been considered for reward or penalty in past record periods. Each group of three fuel cycles is to consist of consecutive fuel cycles which have not been considered for reward or penalty. That is, for six fuel cycles there will be only two penalty/reward determinations.

11. Edison's proposed tariff modification to its TCF procedure to apply economic modifiers to remove or reduce a nuclear unit incentive procedure penalty, or cause or increase a nuclear unit incentive procedure reward, is reasonable.

12. Economic modifiers include NRC-required outages, and all economic modifiers should be considered on a case-by-case basis.

13. Edison's request to change the deadband range from 55-80% to 55-75% is unreasonable and will not be adopted.

14. The reward to Edison for the coal plant incentive procedure for the record period should be $7,061,230. The reward to Edison for the SONGS Unit No. 2, pursuant to the nuclear unit incentive procedure, is $1,294,755.

15. The long-term firm purchase power contract between Edison and PG&E was reasonable.

16. The recorded adjustments made to Edison's ERAM balancing account in October and November 1988 were reasonable. The proper ERAM balancing account adjustments have been made.

17. The request for the Commission to order Edison to furnish a report providing its economic justification for continuing with the DOE in its nuclear enrichment program after the international market opened is denied. DRA does not need a Commission order to obtain this material; DRA can request this information by way of a data request. This matter will be heard in A.89-05-064. Should DRA make that data request, we expect Edison to comply.

## Conclusion of Law

Except as provided in this decision and except for further proceedings regarding (1) the reasonableness of nuclear enrichment costs, (2) the reasonableness of nonstandard QF contracts between December 1, 1984 and November 30, 1987, and (3) the rehearing of D.90-09-088, it is concluded that Edison's operations during the period from December 1, 1986 through November 30, 1987 were reasonable.

**O R D E R**

IT IS ORDERED that:

1. Southern California Edison Company (Edison) shall remove $1,557,000 from its ECAC balancing account to compensate for unreasonable losses from the sale of fuel oil in April and May 1987.

2. Modification of Edison's Efficiency Deviation Method will be considered in A.90-06-001.

3. Edison's nuclear unit incentive procedure shall be modified to permit a 3-fuel-cycle average.

4. Edison's nuclear incentive program shall commence with the first fuel cycle that has not been considered for reward or penalty in past record periods. Each group of three fuel cycles is to consist of consecutive fuel cycles which have not been considered for reward or penalty. That is, for six fuel cycles there will be only two penalty/reward determinations.

5. Edison may use economic modifiers in determining its nuclear unit incentive procedure as set forth in this decision.

6. Edison may receive a reward of $7,061,230 for its coal plant incentive results and an award of $1,294,755 for its nuclear unit incentive results for the reasonableness period December 1, 1986 through November 30, 1987.

7. The reasonableness of nuclear enrichment costs shall be heard in A.89-05-064.

8. The reasonableness of nonstandard QF contracts for the period December 1, 1984 through November 30, 1987 remains open, as does the rehearing of D.90-09-088.

9. In all other respects Edison's operations during the period from December 1, 1986 through November 30, 1987 were reasonable.

This order becomes effective 30 days from today.

Dated May 22, 1991, at San Francisco, California.

PATRICIA M. ECKERT
President
G. MITCHELL WILK
DANIEL Wm. FESSLER
NORMAN D. SHUMWAY
Commissioners

Commissioner John B. Ohanian, being necessarily absent, did not participate.

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

Neal J. Shulman

NEAL J. SHULMAN, Executive Director

pB

**APPENDIX A**
**Page 1**

List of Appearances

Applicant: Bruce A. Reed, Frank J. Cooley, Richard K. Durant, Carol B. Henningson, Michael Gonzales, and Julie A. Miller, John R. McDonough, Attorneys at Law, for Southern California Edison Company.

Interested Parties: Lindsay, Hart, Neil & Weigler, by Michael Alcantar and Paul J. Kaufman, Attorneys at Law, for Cogenerators of Southern California; Barbara Barkovich, for CLECA, California Steel Producers Group; Jackson, Tufts, Cole & Black, by Allan Thompson, William Booth, and Evelyn K. McCormish, Attorneys at Law, for CLECA; Morrison & Foerster, by Jerry R. Bloom, Attorney at Law, for California Cogeneration Council; R. H. Berby, for CLECA; Matthew Brady and Dian M. Grueneich, Attorneys at Law, for California Department of General Services; Deborah Bosch, for Energy Modeling Forum; David Branchcomb, for Henwood & Associates, Inc.; McCracken, Byers & Martin, by David J. Byers, Attorney at Law, and Reed V. Schmidt, for California Street Light Association; Bryan Cope, for Sierra Energy and Risk Assessment, Inc.; Brobeck, Phleger & Harrison, by Gordon E. Davis, Attorney at Law, for California Manufacturers Association; Sam DeFrawi, for Naval Facilities Engineering Command; Karen Edson, for KKE & Associates; Mike Florio, Attorney at Law, for TURN; Steven Geringer, Attorney at Law, for California Farm Bureau Federation; Cynthia Hall, Attorney at Law, for Department of the Navy; Biddle & Hamilton, by Richard L. Hamilton, Attorney at Law, for Western Mobile Home Association; Jan Hamrin and Jan Smutny-Jones, for Independent Energy Producers; William Marcus, for JBS Energy, Inc.; Graham & James, by Robert C. Lopardo and Martin A. Mattes, Attorneys at Law, for California Hotel and Motel Association; A. Kirk McKenzie and Antonia Radillo, Attorneys at Law, for California Energy Commission; John D. Quinley, for Cogeneration Service Bureau; Thomas D. Clarke, Jeffrey E. Jackson, and Lisa T. Horwitz, Attorneys at Law, and Roy M. Rawlings, for Southern California Gas Company; Donald G. Salow, for Association of California Water Agencies; Donald W. Schoenbeck, for Cogenerators of Southern California; Gary Simon and Steve Harris, for El Paso Natural Gas; Clark Smith, for Transwestern Pipeline Company; James D. Squeri, for California Building Industry Association; Downey, Brand, Seymour & Rohwer, by Philip A. Stohr and Christopher T. Ellison, Attorneys at Law,

**APPENDIX A**
**Page 2**

for Industrial Users; Michael R. Weinstein and Thomas G. Hankley, Attorneys at Law, for San Diego Gas & Electric Company; Harry K. Winters, for University of California; Bill Dixon, Bernie Garcia, and John Chabot, for Utility Workers Union of America; Lawrence E. DeSimone, for Energy Management Associates, Inc.; Norman Furuta, Attorney at Law, for Federal Executive Agencies; and Harvey Mark Eder, for Public Solar Power Coalition and himself; Baker G. Clay, for the City of Vernon, Paul Crost and Glenn Rothner, Attorneys at Law, for IBEW, Local 47 and WWUA, Local 246; Rae Sanborn and Willie Stewart, for Local Union 47 and IBEW; Wayne Meeks, Kathi Robertson, and Victor Scocci, for Simpson Paper Company; Ray R. Coulter, for Winter, Ltd.; and Graham & James, by Norman Pederson, Attorney at Law, Kathryn L. Stein, Robert Weisenmiller, and Joseph G. Meyer, for themselves.

Division of Ratepayer Advocates: Robert C. Cagen and Hallie Yacknin, Attorneys at Law, Bill Y. Lee, and Meg Gottstein.

Commission Advisory and Compliance Division: Frank Crua.

**(END OF APPENDIX A)**