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Decision 91-04-063 April 24, 1991

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

Application of SAN DIEGO GAS & ELECTRIC COMPANY: (1) for Authority to Increase its Electric Rates Effective May 1, 1991; and (2) for a Commission Order Finding the Company's Gas and Electric Operations and Expenses Reasonable for the Applicable Record Periods. (U 902-E)	Application 90-10-003 (Filed October 17, 1990)

(Appearances are listed in Appendix A.)

INDEX

FORECAST PHASE OPINION

I. Summary of Decision

By this decision we approve an overall revenue requirement increase of $3.8 million, or 0.28%, effective May 1, 1991 for San Diego Gas & Electric Company (SDG&E). This increase includes a decrease of $0.6 million under SDG&E's Energy Cost Adjustment Clause (ECAC); an increase of $5.0 million under its Electric Revenue Adjustment Mechanism (ERAM); a base rate decrease of $19.4 million to reflect an increase in forecast sales; an increase of $21.3 million to implement previously approved demand-side management (DSM) program costs; a decrease of $0.1 million reflecting termination of the Electromagnetic Fields Study Expense Account; and a decrease of $2.4 million under its Low Income Rate Assistance (LIRA) program. We also adopt forecast-period payment factors used to compute prices for variably priced purchases from qualifying facilities (QFs).

SDG&E's request for a finding that its 1989-90 operations were reasonable will be considered in a separate phase of Application (A.) 90-10-003. This decision deals only with the forecast phase.

II. Background

A. Summary of the Application

SDG&E filed this application on October 1, 1990, requesting authority to increase electric rates by $93.7 million, an increase of 7.1%. Of this amount, $26.9 million was the subject of SDG&E's 1991 operational attrition filing (Advice Letter 799-E) which SDG&E had requested to be implemented January 1, 1991. Since this advice letter was approved by Resolution E-3209 dated December 19, 1990, the $26.9 million is withdrawn from the application.

SDG&E requests that the balance of the proposed increase, $66.8 million, be made effective May 1, 1991. The $66.8 million increase includes an increase of $17.6 million for financial attrition and a decrease of $0.1 million due to termination of SDG&E's Electromagnetic Fields Study Expense Account (amounts which are included in this proceeding for purposes of revenue allocation and rate design only) as well as the following rate changes:

1. An increase of $30.3 million under SDG&E's ECAC to offset the forecast cost of energy- and fuel-related expenses for the forecast period and to amortize the estimated ECAC balancing account undercollection of $25,979,189 as of May 1, 1991.

2. An increase of $15.9 million under SDG&E's ERAM to amortize the estimated ERAM balancing account undercollection of $6,400,639 as of May 1, 1991.

3. A decrease of $15.7 million in SDG&E's base rates due to increased sales forecasted in this proceeding.

4. An increase of $21.3 million for SDG&E's DSM programs, as authorized by D.90-08-068.

5. A decrease of $2.4 million under SDG&E's LIRA program.

By Order Instituting Investigation 90-08-006 dated August 8, 1990, the Commission suspended the annual energy rate (AER) for California's major electric utilities until further order. Thus, 100% of the forecast cost of energy-related expenses will be recovered through ECAC rates, subject to balancing account treatment. Accordingly, SDG&E proposes no AER for this proceeding.

In addition, SDG&E proposes to establish the forecast period Incremental Energy Rates (IERs) used to determine energy payments to QFs and cogeneration natural gas allowances. It also proposes to establish the Energy Reliability Index (ERI) and avoided capacity costs used to determine capacity payments to QFs during the forecast period. Finally, SDG&E requests an order finding that its gas and electric operations during the period August 1, 1989 through July 31, 1990 were reasonable.

B. <u>Energy Cost Adjustment Clause Proceedings</u>

The ECAC process enables an electric utility's rates to reflect changes in its fuel and purchase power expenses on an annual basis outside of the three-year general rate case cycle. This filing is made in accordance with the rate case plan for processing energy cost offset proceedings that was most recently modified by Decision (D.) 89-01-040. Under this plan, SDG&E's ECAC forecast period is the 12-month period beginning on May 1 of each year. Rates reflecting ECAC, AER, and ERAM revenue requirements are adjusted as of the May 1 revision date.

D.89-01-040 addressed the problem of the increasing complexity of ECAC proceedings by transferring rate design issues to annual "rate design window" proceedings. The Commission concluded in D.89-01-040 that electric rate design decisions should be coordinated with seasonal rate changes and provided for a common revision date of May 1 for SDG&E's electric rates. The rates adopted by this decision incorporate the rate design adjustments adopted by D.91-04-026 in A.87-12-003, SDG&E's 1991 rate design window proceeding.

D.90-08-068 and D.90-12-071 approved revitalized energy efficiency programs for California's major energy utilities. These demand-side management (DSM) programs focus on the customer side of the utility meter. These decisions authorized SDG&E to request recovery of certain DSM program costs in this ECAC proceeding.

By D.89-07-062 and D.89-09-044, which completed implementation of the baseline reform legislation known as Senate Bill 987 (Ch. 212, Stats. 1988), the Commission ordered energy utilities to give qualifying low-income ratepayers a 15% discount on their energy bills. The costs of this LIRA program are collected through a surcharge which is accorded balancing account treatment. The Commission determined that for SDG&E's electric rates, the LIRA surcharge would be updated in the company's ECAC proceedings.

For several years ECAC proceedings have combined conventional resource mix and energy cost issues with an updating of key components of the prices paid by the utility for purchases of variably priced power from QFs. The Incremental Energy Rate (IER) is a measure of the utility system's incremental efficiency in converting heat energy to electricity. It is combined with an "O&M adder", an estimate of avoided operational and maintenance costs, and the utility's incremental fuel cost to produce the price the utility pays QFs for the variably priced energy. The Energy Reliability Index (ERI) is used to adjust the utility's avoided capacity costs which form the basis for capacity payments to QFs. An ERI of less than 1.0 indicates that the utility has more than enough resources to maintain reliability, and the avoided capacity cost is lowered accordingly.

Computerized production cost models designed to simulate the manner in which utility resources meet system loads have been introduced into ECAC proceedings to forecast energy costs which underlie ECAC revenue requirement calculations as well as ERI and IER values. The simulations are driven by resource and load assumptions which are inputs to the model and which in many cases represent the resolutions of conventional ECAC issues that constitute the heart of an ECAC proceeding. SDG&E and other parties used the ELFIN production cost model for this proceeding.

D.89-10-040 integrated a requirement for a common data set modeling workshop into the rate case plan with a provision that it should occur early in the proceeding. Duly noticed workshops commenced on October 26, 1990, with Sarita Sarvate of the Commission Advisory and Compliance Division serving as arbitrator.

C. <u>Procedural Background</u>

In accordance with the rate case plan, the Administrative Law Judge (ALJ) ruled that SDG&E's request for a finding of reasonableness for its 1989-90 operations would be considered in a separate phase of A.90-10-003. As noted previously, this decision deals only with the forecast phase.

Prehearing conferences were held at San Diego on October 25, 1990 and January 14, 1991. On January 2, 1991, with the ALJ's assent, counsel for SDG&E and the Commission's Division of Ratepayer Advocates (DRA) provided notice of a settlement conference to be convened at the time and place scheduled for the January 14, 1991 prehearing conference. The notice was served on all appearances and on all other parties on the service list maintained by the Commission's Process Office for this proceeding.

The ALJ recessed the January 14 prehearing conference and deferred the commencement of hearings to give the parties an opportunity to discuss settlement of contested matters. These discussions resulted in a joint recommendation of all parties who were active in the forecast phase of this proceeding. In accordance with Rule 51.10 of the Commission's Rules of Practice and Procedure, the ALJ received the joint recommendation in evidence as joint testimony as Exhibit 18. A copy of the joint recommendation (excluding appendices) is attached hereto as Appendix B.

Parties to the joint recommendation are DRA; SDG&E; City of San Diego (City); Utility Consumers' Action Network (UCAN); JBS Energy Inc.; Kelco Division of Merck & Co., Inc. (Kelco); California Cogeneration Council (CCC); United States Department of the Navy and other Federal Executive Agencies; and San Diego Mineral Products Industry Coalition. The cover sheet of Exhibit 18 lists Toward Utility Rate Normalization (TURN) as a party to the joint recommendation. In fact, TURN entered an appearance but did not actively participate in this proceeding and did not sign the joint recommendation.

The joint recommendation represents the parties' settlement of all but two contested issues: disposition of Century Power Corporation settlement proceeds and recovery of variable fuel handling costs. Hearings on the joint recommendation and these issues were held at San Diego on January 15, 1991 and at San Francisco on January 31, 1991 and February 1 and 19, 1991. Briefs were filed by SDG&E, DRA, and UCAN. Reply briefs were filed by SDG&E, DRA, and jointly by UCAN and City. The forecast phase was submitted with the filing reply briefs on March 4, 1991.

Comments on the ALJ's proposed decision were filed by SDG&E. Reply comments were filed by DRA. Where appropriate, this order incorporates revisions proposed by the parties.

III. Joint Recommendation

The settlement contained in the joint recommendation was sponsored by all active parties in the forecast phase of this proceeding. It represents the only final proposal for the full range of ECAC issues before us, with a recommended disposition for all but two contested issues. The issue before us is whether adoption of the joint recommendation is reasonable and in the public interest.

In evaluating the pre-settlement positions of the parties we note that the principal areas of disagreement were the IER and O&M adder, both of which directly affect prices for QF payments, and revenue requirements associated with these factors. The parties' positions and their joint proposals are summarized in the following table:

Table 1

Comparisons of Fuel and Purchased Power Budget Forecast, IER, And O&M Adder Proposals

	DRA	SDG&E	CCC	Kelco	Settlement
Fuel & Purchased Power Budget (M$)	500,828	509,067	507,055	503,530	506,762
IER (Btu/kWh)	9,147	9,317	10,085	10,010	9,600
O&M Adder (cents/kWh)	0.08	0.08*	0.42	0.43	0.25

* Exhibit 18 shows SDG&E's recommended O&M adder was 0.08 cents/kWh. Exhibit 2 shows the recommendation as 0.04 cents/kWh.

As noted by DRA, unlike other ECAC items which are "trued up" based on actual energy expenses through the balancing account mechanism, IER and O&M adder expenses are based solely on forecasts adopted by the Commission in ECAC proceedings. Adoption of IER and O&M adder estimates which are too high could result in payments to QFs which are greater than necessary and in excessive rates. Adoption of estimates which are too low could thwart our policies for paying QFs on the basis of avoided costs. We are therefore particularly concerned with the joint recommendation's treatment of these items.

The joint recommendations for both the annual average IER of 9,600 Btu/kWh and the O&M adder of 0.25 cents/kWh are the products of compromise. While these values are significantly greater than those proposed by DRA and SDG&E, we are persuaded from our review of the testimony that it was reasonable for the parties to reach the compromised values.

The IER calculation was found to be very sensitive to changes in modeling conventions and resource assumptions, making it questionable whether too much reliance should be placed on any one value. For example, CCC noted that by correcting what it believed was a modeling error involving Southwest economy energy capacity forecasts, SDG&E's initial annual average IER calculation was increased from 9,291 Btu/kWh to 9,898 Btu/kWh and DRA's was increased from 9,327 Btu/kWh to 9,965 Btu/kWh. The adopted value compares favorably with SDG&E's currently adopted IER of 9,546 Btu/kWh. The O&M adder calculations offered by SDG&E and DRA were significantly below values adopted for California utilities (including SDG&E's currently adopted adder of 0.29 cents/kWh) in earlier proceedings. The methods used by SDG&E and DRA were strongly criticized by Kelco and CCC, who recommended use of the methodology adopted in D.89-09-093.

As noted by the parties in Exhibit 18, the recommended values are "within a reasonable bandwidth of the expected values for SDG&E's revenue requirements, IER, O&M adder, and ERI calculations." We find the proposed resolution of the remaining contested issues to be reasonable; no further discussion of them is necessary.

IV. Century Power Settlement

A. Background

The parties disagree on the appropriate ratemaking treatment of funds which SDG&E received from Century Power Corporation (Century) in December 1990. This $25 million payment was made in compliance with the terms of a settlement agreement (Century settlement) executed by SDG&E and Century on December 17, 1990. The Century settlement resolves all disputes between Century and SDG&E related to the Tucson/San Diego Ten-Year Power Sale and Interconnection Agreement (Ten-Year Agreement). The settlement is a compromise of numerous complaints which SDG&E has filed with the Federal Energy Regulatory Commission (FERC) and is subject to, and conditioned upon, acceptance or approval by FERC. SDG&E and Tucson Electric Power Company (Tucson) entered into the Ten-Year Agreement on November 29, 1978. In 1984, Tucson assigned the Ten-Year Agreement to Alamito Company, which has since been renamed Century Power Corporation.

In the event the Century settlement is not accepted by FERC, or is approved with material modifications to the terms, it may be rescinded at the option of either SDG&E or Century. In the case of rescission, SDG&E must immediately reimburse Century $23.5 million of the $25 million payment with interest. The Century settlement also acknowledges that SDG&E may be required to return the $25 million payment to Century for other reasons, including bankruptcy, insolvency, or creditors' rights laws.

SDG&E and Century filed the Century settlement with FERC on December 20, 1990. FERC's only action in this matter as of the date of the hearings has been to extend the time for comment to January 29, 1991. On that date, Arizona Corporation Commission and Tucson filed comments opposing the settlement. FERC staff has submitted comments in support of the settlement.

SDG&E has recorded the payment as a current liability in FERC Account 242. The funds are earning interest as if they had been booked in an ECAC account.

By a ruling dated January 22, 1991, the ALJ granted a motion made by UCAN at the hearing of January 15, 1991. The ruling directed SDG&E to provide testimony on the factual circumstances of the Century settlement and to make recommendations for ratemaking treatment of the funds.

B. <u>Positions of the Parties</u>

1. <u>SDG&E</u>

SDG&E argues that retention of the Century settlement proceeds is sufficiently tentative that ratemaking recognition of any proceeds is not yet appropriate. Under its terms, either party may rescind the settlement in the event it is not accepted by FERC, or is approved by FERC with material changes. Since rescission would require SDG&E immediately to reimburse to Century $23.5

million of the $25 million payment with interest, the company believes a favorable ruling by FERC should precede any recognition of the proceeds in rates.

SDG&E believes the arguments submitted by Arizona Corporation Commission and Tucson to FERC in opposition to the Century settlement are without merit. However, SDG&E asserts that there is a substantial controversy regarding the settlement which justifies the Commission "temporarily refraining from reflecting [the] proceeds in rates."

Furthermore, as SDG&E controller Ault testified, the financial strength of Century is uncertain and could deteriorate. A primary source of income for Century is its long-term contract with Tucson, which, according to a series of reports, faces a deteriorating financial condition. A Tucson bankruptcy might afford Tucson the ability to sever its contract with Century, stopping the flow of funds to Century and potentially forcing Century into bankruptcy.

Ault testified that if Century were to enter into bankruptcy, the bankruptcy court or an appellate court reviewing the bankruptcy decision could require SDG&E to return the entire $25 million to Century. SDG&E asserts that this possibility further justifies the interim accounting treatment that SDG&E has employed, and warrants caution in the timing of reflecting settlement proceeds in ECAC rates. According to SDG&E, the risk that it may have to return the funds due a bankruptcy filing remains a significant one for 90 days after the receipt of the funds, or until April 1, 1991.

SDG&E believes that until the likelihood of being required to return the funds to Century is substantially reduced, no portion of those proceeds should be transferred from Account 242 and reflected in ECAC rates.

SDG&E proposes that after April 1, 1991, and when FERC approval of the Century settlement has been obtained, it will record the customer portion of the settlement in its ECAC balancing account, including applicable interest from the date SDG&E received the funds. If FERC approval is obtained after May 1, 1991, SDG&E will inform the Commission of the ECAC entry by advice letter within ten days and request immediate authority to reduce its ECAC rates accordingly. If, despite FERC approval, it is required to return the settlement funds, SDG&E requests that the Commission authorize it to enter appropriate reversals of ECAC balancing account entries.

SDG&E intends that if the Commission authorizes a merger with Southern California Edison Company (Edison) before the Century settlement proceeds are returned to its ratepayers, only those ratepayers in its current service territory shall receive those proceeds.

2. DRA

DRA's position is that for purposes of this ECAC forecast, the $25 million settlement should be recorded in the ECAC balancing account for ratemaking purposes, and that the ECAC balance should be adjusted downward by $25 million as required by SDG&E's Preliminary Statement, Section 9(j)(3) which states:

> "If the utility receives from any of its gas or geothermal or purchased energy suppliers, cash refunds, including any associated interest, on and after the date this Energy Cost Adjustment Clause becomes effective, the amount thereof associated with sales of electricity shall be recorded as a credit to the Utility's Energy Cost Adjustment Account."

3. UCAN

UCAN, joined in its reply brief by City of San Diego, urges that SDG&E's ECAC balance be decreased by $25 million to reflect the Century refund payment. According to UCAN, this accounting treatment is consistent with the preliminary statement in SDG&E's tariffs and with Commission policy. By granting SDG&E an exception from its tariffs, UCAN believes the Commission would reduce the incentive for SDG&E to preserve this benefit for its customers, depriving them of a $25 million reduction in rates during an economically distressed year.

UCAN argues that there is no recognized exception in the Preliminary Statement for uncertainty, and that the ECAC account is designed to address exactly the kind of uncertainty that SDG&E cites as its basis for withholding the monies.

C. Discussion

SDG&E agrees that Century settlement proceeds should be returned to ratepayers. The principal issue is the timing of the return to ratepayers. To decide this issue we first address the contentions of the parties concerning Section 9(j)(3) of the Preliminary Statement (the refund rule).

1. SDG&E's Refund Rule

In essence, DRA and UCAN take the position that the Century settlement issue is a straightforward matter of compliance with the refund rule in SDG&E's tariffs. SDG&E on the other hand views the refund rule as a source of "general guidance" that is nevertheless inapplicable to the Century settlement, at least while it is subject to significant contingencies, for three reasons:

- The refund rule does not address refunds which are subject to regulatory approval or other conditions.

- The refund rule refers to "cash refunds", not to settlement proceeds. In the view of SDG&E witness Ault, the proceeds are not "'a refund' in the normal sense of refunds which are received on a periodic basis from gas suppliers and others as true ups of costs that we've incurred".

- The refund rule does not indicate when refunds should be credited to the ECAC balancing account. Thus, according to SDG&E, it is consistent with the refund rule to record the credit only after the conditions of the settlement have been satisfied.

We find none of SDG&E's arguments to be persuasive. The lack of any reference to conditions or contingencies in the refund rule does not, in our view, mean that the rule applies only to free and clear refunds. On the contrary, the lack of such reference means the rule is unqualified as to the presence or absence of conditions or contingencies. Only if SDG&E's refund rule specifically provided an exception therefor could we interpret the rule as SDG&E proposes.

We see little basis for the distinction that SDG&E attempts to draw between refunds, as referenced in the rule, and the Century settlement proceeds. The rule does not require refunds to be "periodic" to qualify. Even though the settlement undoubtedly represents an atypical refund situation, that fact does not change its essential characteristic--a return of charges paid by SDG&E. Certainly the fact that the return of funds is the product of litigation, rather than voluntary action on Century's part, does not disqualify the return as a "refund".

Finally, we reject the contention that the rule's lack of a time restraint makes the timing of the return open-ended, subject to utility discretion. On the contrary, as noted by DRA witness Charvez, the lack of such a time limit means that when refunds are received from a supplier they are to be booked "at that time", in other words immediately.

SDG&E argues that DRA's interpretation of the refund rule is not supported by specific information or authority. Given the unambiguous language of the tariff rule at issue, any such lack of support does not sway our view. We conclude that the refund rule in SDG&E's tariff, which is mandatory in its application, applies to the Century settlement proceeds. SDG&E does not have the option of determining whether or when it will record the amount of the proceeds associated with the sale of electricity as a credit to its Energy Cost Adjustment Account. Accordingly, we view SDG&E's

proposed ratemaking treatment as a request for waiver of the rule. We examine the rationale for such a request.

2. Rate Stability

SDG&E's reason for refraining from passing the benefits of the Century settlement on to its ratepayers at this time appears to be its concern about undesirable rate fluctuation. SDG&E's witness Ault foresees a two-fold adverse impact on customers if ECAC rates are reduced in the forecast phase of this ECAC proceeding and if the company is later required to return the funds to Century. First, rates would have to increase to bring them to the level they would have been in the absence of the settlement. Second, an additional rate increase would be required to recover the amount passed through to customers. SDG&E argues that the Commission should avoid such an impact.

Rate stability is an important objective in ratemaking policy, but it is not our only objective. If it were, we would design our system of utility rate regulation to avoid frequent, even annual rate changes. Rather, rate stability is an objective that sometimes conflicts with and must be balanced against other concerns.

Another objective is an equitable rate structure, including one that balances interests of present and future ratepayers. Although the Century settlement funds are accruing interest as if they were in an ECAC account, we do not believe that ratepayers are indifferent to when they receive the benefit of the settlement. In essence, ratepayers have paid amounts related to the settlement over the life of the Ten-Year agreement with Century and its predecessors. Over time, customers move away from the service territory, die, go out of business, and change their usage patterns, while new customers are added to the system. Even if the settlement proceeds were to be returned immediately to ratepayers, such proceeds would not be returned to exactly the same ratepayers (or in the same proportion) as those who paid the amounts being returned. If the return is delayed further while FERC approval is pending, this inequity, which results from the passage of time, will be further exacerbated.

Without attempting to pinpoint the likelihood that SDG&E will be required to return some portion or even all of the Century settlement, or to estimate when such a return might be required, we merely acknowledge that such a return remains possible. Nevertheless, this possibility and the resulting rate increases do not warrant waiver of the refund rule or further delay in returning the funds to ratepayers.

3. D.90-04-021

SDG&E argues that deferred ratemaking treatment of the Century settlement would be consistent with the Commission's action in D.90-04-021 in Pacific Gas and Electric Company's (PG&E) 1989-90 annual cost allocation proceeding (ACAP). There, the Commission approved deferred ratemaking treatment for a $19.8 million payment from El Paso Natural Gas Company because the U.S. Court of Appeals has issued a decision requiring PG&E to return the $19.8 million to El Paso. (Public Utilities Commission of the State of California v. FERC, Case No. 88-1530, DC Circuit). We agree with UCAN and DRA that the El Paso situation is distinguishable from the Century settlement. The former involves an appellate court decision, not pending litigation. As noted by UCAN in its reply brief, it was the certainty of the Court of Appeals decision, not the uncertainty of pending litigation, that led the Commission to defer ratemaking treatment of the El Paso payment.

SDG&E also points out that by D.90-04-021, the Commission adopted a DRA proposal to defer recovery of Account 191 costs to the next ACAP period due to pending legal challenges. Again, this situation is unlike the Century settlement. As DRA and UCAN note, this deferral involved rate increases for costs related to billings from El Paso, not decreases related to a refund already received. In fact, as UCAN argues, it would be more consistent with the

Commission's treatment of the Account 191 costs to preserve a benefit for ratepayers until and unless it is clear that the benefit should no longer exist.

We conclude that return of the Century settlement to ratepayers is consistent with D.90-04-021.

4. <u>Adopted Ratemaking Treatment</u>

We conclude that the refund rule requires reflection of the Century settlement in ECAC rates at this time, and that good cause for waiving application of the rule has not been shown. The ECAC rates adopted by this order reflect the adjusted ECAC balancing account balance.

During most if not all of the period that SDG&E incurred energy costs under the Ten-Year agreement with Century, SDG&E in essence recovered 92% of its energy costs in ECAC rates subject to balancing account treatment, and 8% of its forecast energy costs through the Annual Energy Rate (AER), which did not receive balancing account treatment. Shareholders and ratepayers were placed at some risk under the AER mechanism. SDG&E believes that the question of whether a portion of the settlement should be allocated to the company's shareholders, and the actual allocation, are issues to be considered in the reasonableness phase of a future ECAC proceeding. For the present, the company has not made an allocation. DRA agrees that, for purposes of this ECAC forecast, the entire $25 million should be booked into the ECAC balancing account for setting rates, and that any allocation of the settlement between ratepayers and shareholders should be addressed in SDG&E's next ECAC reasonableness phase. UCAN similarly agrees that whether some portion of the settlement will be allocated to shareholders is not at issue in this proceeding. Since the parties appear to be in agreement, we will not provide for an allocation by this order.

SDG&E recommends that the Commission authorize it to reverse any ECAC balancing account entries, with appropriate interest, in the event that it is required to return funds to

Century. DRA witness Charvez agrees with this approach, and UCAN does not object to such a provision. Our order will so provide.

SDG&E argues that if the Commission chooses to reflect the Century settlement proceeds in rates effective May 1, 1991, two other rate adjustments are appropriate. By Resolution E-3209 the Commission authorized the company to recover through the ERAM balancing account $4.1 million attributable to 1989 DSM activities. By Resolution E-3208 the Commission authorized the company to recover through the ERAM balancing account an estimated $10 million to eliminate any balance in its pre-COD MAAC account. SDG&E notes that neither of these ERAM adjustments was reflected in the joint recommendation. We agree with UCAN that precisely because these adjustments are not covered by the joint recommendation, they should not be adopted by this order.

SDG&E attached to its opening brief copies of comments submitted to FERC by Tucson and Arizona Corporations Commission in opposition to the Century settlement, reply comments of SDG&E, and a newspaper article concerning Tucson. SDG&E asks that we take official notice of the opposition comments and of the existence of these FERC filings and of the FERC proceeding. We deny this request. The record includes evidence of the existence of a contested settlement proceeding before FERC and of concerns about Tucson's financial condition. The attachments are disregarded.

V. Variable Fuel Handling Expense

When SDG&E receives a delivery of oil at its Encina Power Plant it incurs a variety of variable costs. These include costs of placing protective booms around the tanker to control spillage, the attendance of oil spill response vessels and required marine representatives, and independent inspection and lab analysis of the oil. Currently, these variable fuel handling (VFH) costs are recovered through base rates which are considered in general rate cases.

A. SDG&E's Position

SDG&E recommends that VFH costs be considered part of the commodity cost of oil deliveries, so that they are recorded in the ECAC account and recovered in ECAC rates. The company asserts that increased volatility of fuel oil prices has made deliveries much less predictable than they were when the practice of base rate recovery was established. In addition, oil spill precautionary measures are becoming increasingly costly.

Specifically, SDG&E recommends that its base rates be reduced by approximately $100,000 effective January 1, 1992, the date of the next scheduled base rate change pursuant to the company's request in its modified attrition filing (A.91-03-001). This is the estimated amount of VFH expense currently embedded in base rates. A corresponding increase of 22 cents per barrel in its forecast fuel costs would be recognized in this ECAC proceeding for oil deliveries in the remainder of the forecast period (January 1, 1992 through April 30, 1992).

Additionally, SDG&E proposes an increase in the forecast oil price of 11 cents per barrel, for 1991 only, due to costs caused by a new U.S. Coast Guard requirement for an additional oil spill recovery vessel to be present at each fuel delivery. The VFH expense currently embedded in base rates reflects only the expense of two such vessels.

Finally, SDG&E requests that the new Lempert-Keene-Seastrand Oil Spill Prevention and Response Act fee of 29 cents per barrel be included in the adopted forecast price of oil. SDG&E notes that ECAC recovery of this fee is uncontested by DRA and is reflected in the joint recommendation.

B. DRA's Position

DRA notes that it does not dispute the reasonableness of recovering VFH expenses, only the proper forum for recovery. DRA recommends that VFH expenses remain recoverable in general rate cases.

DRA emphasizes that VFH expenses are not distinctive from expenses already recovered in the general rate case. For accounting purposes the VFH expenses are similar to general rate case expenses such as pollution control. For 1991, the proposed 11 cents per barrel expense is for a third recovery vessel; yet, DRA notes, the vessel is similar to two other vessels whose costs are now recovered in the general rate case process. Further, DRA argues that with suspension of the AER, placing VFH expenses in the ECAC proceedings will have little risk for SDG&E. By keeping VFH expenses in the general rate case, DRA asserts that the utility will have to engage in risk management to forecast VFH expenses. Finally, DRA points out that two other utilities, Edison and PG&E, account for VFH expenses in general rate cases and not in ECAC proceedings.

C. Discussion

When the ECAC process was established by D.85731 in 1976, SDG&E received deliveries averaging 30,000 barrels per day under long-term contracts. Deliveries and transfers were frequent and handling costs were well known and stable. With SDG&E's present resource mix, fuel oil deliveries are infrequent, occurring perhaps once or twice per year. The joint recommendation contemplates a total of 100,000 barrels for the entire forecast period.

We agree that under these conditions it is much more difficult to forecast VFH expenses in the context of the three-year cycle of the general rate case than it was 15 years ago. This situation, combined with increasing government attention to and control of oil spill prevention and control measures, leads us to conclude that SDG&E's proposal for considering these expenses in ECAC proceedings has merit.

It is true that if VFH expenses are transferred to ECAC proceedings they will be subject to balancing account treatment (in whole if the AER remains suspended or is terminated; in large part if the AER is reinstituted). However, we see little danger of an inappropriate removal of management incentives by such a transfer. The activities that generate VFH expenses are largely driven by the amount of oil delivered and the number of deliveries, which are in turn subject to energy market forces, and by government-imposed regulations. To an important degree, the VFH expenses involve activities over which the company has limited control. Moreover, the ECAC process allows the Commission to review the reasonableness management actions related to ECAC expenses, preserving an incentive for management to act reasonably and prudently.

We find it telling that if the cost of oil spill recovery vessels were embedded in the supplier's oil price, the cost would indisputably be recovered in ECAC proceedings. We find that there is little substantive basis for retaining the current practice of evaluating SDG&E's VFH expenses in its general rate cases. SDG&E's proposal for VFH expenses will be adopted.

Findings of Fact

1. By this application, as originally filed, SDG&E requested an overall electric rate increase of $93.7 million, and an effective increase of $66.8 million effective May 1, 1991 due to withdrawal of the increases granted by Resolution E-3029.

2. The requested $66.8 million increase is composed of: an increase of $17.6 million for financial attrition; a decrease of $0.1 million due to termination of SDG&E's Electromagnetic Fields Study Expense Account; an increase of $30.3 million under SDG&E's ECAC; an increase of $15.9 million under SDG&E's ERAM; a decrease of $15.7 million in SDG&E's base rates due to increased sales; an increase of $21.3 million for SDG&E's DSM programs, as authorized

by D.90-08-068; and a decrease of $2.4 million under SDG&E's LIRA program.

3. Properly noticed hearings in this application were held at which all interested parties had an opportunity to be heard.

4. Parties were provided with notice of the settlement conference convened by SDG&E and DRA.

5. The joint recommendation attached as Appendix B was sponsored by all active parties in the forecast phase of this proceeding, and it represents the only final proposal before us.

6. The joint recommendation reflects the parties' proposals for resolution of all but two contested issues which are resolved by this decision.

7. The joint recommendation represents a reasonable settlement of contested issues.

8. Adoption of the joint recommendation is in the public interest.

9. The lack of any reference to conditions or contingencies in the refund rule means that the rule is unqualified as to the presence or absence of conditions or contingencies.

10. The refund rule does not distinguish periodic and non-periodic refunds, nor does it distinguish returns of funds due to litigation from those due to voluntary action.

11. The refund rule does not give the utility discretion to determine when to make an entry in the ECAC account.

12. Rate stability is an objective that sometimes conflicts with and must be balanced against other objectives.

13. We cannot assume that ratepayers are indifferent as to when they receive the benefit of the settlement.

14. Even if the settlement proceeds were to be returned immediately to ratepayers, such proceeds would not be returned to exactly the same ratepayers (or in the same proportion) as those who paid the amounts being returned; if the return is delayed further while FERC approval is pending, the inequity will be further exacerbated.

15. The possibility that SDG&E will be required to return all or part of the Century settlement and raise rates accordingly does not in our judgement warrant a waiver of the refund rule and further delay in returning the funds to ratepayers.

16. The parties agree that SDG&E should be authorized to reverse any ECAC balancing account entries, with appropriate interest, in the event that it is required to return funds to Century.

17. ERAM balancing account adjustments authorized by Resolution E-3209 and Resolution E-3208 were not covered by the joint recommendation.

18. With SDG&E's present resource mix, fuel oil deliveries are infrequent, occurring perhaps once or twice per year. The joint recommendation contemplates a total of 100,000 barrels for the entire forecast period.

19. It is significantly more difficult to forecast VFH expenses in the context of the three-year cycle of the general rate case than it was in general rate cases 15 years ago.

20. Governmental attention to and control of oil spill prevention and control measures has increased since the ECAC mechanism was adopted.

21. There is little danger that an inappropriate removal of management incentives will result from the transfer of VFH expenses to ECAC proceedings.

22. The ECAC process allows the Commission to review the reasonableness of management actions related to ECAC expenses, which will preserve an incentive for management to act reasonably and prudently.

23. The revenue requirements changes set forth in Appendix C are reasonable, and the increases are justified.

24. The increases in rates and charges authorized by this decision are justified and are reasonable, and the present rates and charges, insofar as they differ from those prescribed by this decision, are for the future unjust and unreasonable. The adopted rates are set forth in Appendixes C and D.

Conclusions of Law

1. The joint recommendation set forth in Appendix B should be adopted.

2. The refund rule in SDG&E's tariff applies to the Century settlement proceeds.

3. Return of the Century settlement to ratepayers at this time, despite contingencies, is consistent with D.90-04-021.

4. The Century settlement should be reflected in ECAC rates at this time.

5. SDG&E should be authorized to reverse any ECAC balancing account entries, with appropriate interest, in the event that it is required to return funds to Century.

6. ERAM balancing account adjustments authorized by Resolution E-3209 and Resolution E-3208 should not be adopted by this order.

7. SDG&E's proposal for VFH expenses which is described at page 19 should be adopted. SDG&E should reduce its base rates adopted for attrition year 1992 by the amount of VFH costs currently embedded in base rates (approximately $100,000).

8. SDG&E should be authorized to place into effect the increased rates found to be reasonable in the findings set forth above.

9. This order should be effective on the date signed because there is an immediate need for rate relief.

10. SDG&E should be authorized and directed to adjust its rates as set forth in Appendices C and D for the ECAC forecast period May 1, 1991 to April 30, 1992.

FORECAST PHASE ORDER

IT IS ORDERED that:

1. San Diego Gas & Electric Company (SDG&E) is authorized and directed to file revised rate schedules reflecting the rates and rate increases set forth in this decision and concurrently withdraw and cancel its presently effective schedules, to become

effective on or after May 1, 1991. Such filings shall comply with General Order 96-A and shall be effective on or after the date filed, but no sooner than May 1, 1991, and shall be applicable to service rendered on and after the effective date of the tariffs.

2. The factors for calculating prices for payments to qualifying facilities which are set forth in Appendix B, including the incremental energy rate (IER), time-differentiated Incremental Energy Rates, O&M adder, and Energy Reliability Index, are adopted for the Energy Cost Adjustment Clause forecast period May 1, 1991 to April 30, 1992.

3. This proceeding remains open for the receipt of evidence in the reasonableness phase.

4. For the purpose of setting forecast period rates in this proceeding, SDG&E shall immediately record a credit to its Energy Cost Adjustment account to reflect the receipt of $25 million in settlement proceeds from Century Power Corporation (Century), plus interest from the dates of receipt. SDG&E is authorized to reverse such entry, with appropriate interest, in the event that it is required to return funds to Century. The reasonableness of any allocation of the settlement proceeds to shareholders will be reviewed in the reasonableness phase of SDG&E's next ECAC filing.

This order is effective today.

Dated April 24, 1991, at San Francisco, California.

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

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

Neal J. Shulman

NEAL J. SHULMAN, Executive Director

APPENDIX A

List of Appearances

Applicant: David R. Clark, Attorney at Law, and Lynn G. Van Wagenen, for San Diego Gas & Electric Company.

Protestants: Michael Shames, Attorney at Law, for Utility Consumers' Action Network; Jeff Nahigian and William Marcus, for JBS Energy; and Joel Singer, Attorney at Law, for Toward Utility Rate Normalization.

Interested Parties: Messrs. Greve, Clifford, Diepenbrock & Paras, by Matthew Brady, Attorney at Law, for California Department of General Services; Norman J. Furuta, Attorney at Law, and Maureen C. Lindsey, for Consumer Interests of the Federal Executive Agencies; Messrs. Morrison & Foerster, by Jerry R. Bloom and Joseph M. Karp, Attorneys at Law, for California Cogeneration Council; Barry J. Lovell, for University Energy; William A. Monsen, for Morse, Richard, Weisenmiller and Associates; Steven D. Patrick, Attorney at Law, for Southern California Gas Company; Stephen E. Pickett, Attorney at Law, for Southern California Edison Company; William J. Shaffran and Deborah Berger, Deputy City Attorneys, for John Witt, City Attorney, for the City of San Diego; James D. Squeri, Attorney at Law, for Kelco Division of Merck & Company; and Paul A. Weir, for San Diego Mineral Products Industry Coalition.

Division of Ratepayer Advocates: Alberto Guerrero, Attorney at Law, and Linda Gustafson.

(END OF APPENDIX A)

Application 90-10-003

Exhibit No. ____________

Date ____________

Exhibit	18
CPUC Proceeding	A 90-10-003
Sponsor/Witness	Joint Testimony
Date Ident. 2/19/91	Recd. 2/19/91
Mark S. Wetzell Administrative Law Judge	MSW

**JOINT RECOMMENDATION OF
DIVISION OF RATEPAYER ADVOCATES, SAN DIEGO GAS & ELECTRIC
COMPANY, THE CITY OF SAN DIEGO, UTILITY CONSUMERS ACTION NETWORK,
TOWARD UTILITY RATE NORMALIZATION, KELCO DIVISION OF MERCK & CO.,
INC., CALIFORNIA COGENERATION COUNCIL, UNITED STATES
DEPARTMENT OF THE NAVY AND OTHER FEDERAL EXECUTIVE AGENCIES,
AND SAN DIEGO MINERAL PRODUCTS INDUSTRY COALITION**

JOINT RECOMMENDATION OF
DIVISION OF RATEPAYER ADVOCATES, SAN DIEGO GAS & ELECTRIC COMPANY, THE CITY OF SAN DIEGO, UTILITY CONSUMERS ACTION NETWORK, TOWARD UTILITY RATE NORMALIZATION, KELCO DIVISION OF MERCK & CO., INC., CALIFORNIA COGENERATION COUNCIL, AND UNITED STATES DEPARTMENT OF THE NAVY AND OTHER FEDERAL EXECUTIVE AGENCIES AND SAN DIEGO MINERAL PRODUCTS INDUSTRY COALITION

The parties to the recommendations contained in this document, including Appendices ("Joint Recommendation") are the Division of Ratepayer Advocates ("DRA"), San Diego Gas & Electric Company ("SDG&E"), The City of San Diego, Utility Consumers Action Network ("UCAN"), Toward Utility Rate Normalization ("TURN"), Kelco Division of Merck & Co., Inc. ("Kelco"), California Cogeneration Council ("CCC"), United States Department of the Navy and other Federal Executive Agencies ("FEA") and San Diego Mineral Products Industry Coalition ("MPI"). DRA, SDG&E, the City of San Diego, UCAN, TURN, Kelco, CCC, FEA and MPI are collectively referred to as the "Parties" and individually as a "Party."

Based upon the prepared direct testimony previously distributed by participants in the Forecast Phase of this Energy Cost Adjustment Clause ("ECAC") proceeding, the Parties perceived a potential to reach a compromise on various issues. Accordingly, with the assent of Administrative Law Judge Wetzell, the Parties engaged in discussions of the various issues presented in the case. As a result of these discussions of the positions initially advocated by each Party, the Parties make this Joint Recommendation. This Joint Recommendation does not reflect disposition of the Century Settlement Agreement proceeds or the treatment of variable fuel handling expense. By this Joint Recommendation, the Parties jointly recommend that the Commission adopt the following positions in this proceeding:

I. TOTAL REVENUE REQUIREMENT

The Parties jointly recommend that a total revenue requirement increase of $30,209,000 be adopted as set forth in Appendix A attached hereto. The revenue requirement associated with ECAC, ERAM and LIRA is set forth in Table 1 of Appendix A. The fuel and purchase power budget is set forth in Table 4, line 8. Balancing account forecasts include recorded data through December 31, 1990. The margin reflects certain changes effective January 1, 1991. This ECAC proceeding will produce base rate changes resulting from the ECAC sales forecast as well as certain changes in ECAC, ERAM, LIRA, EFSEA and DSM rates.

II. ANNUAL AVERAGE INCREMENTAL ENERGY RATE ("IER")

The Parties recommend that an annual average IER of 9600 btu/kwh be adopted. The Parties further recommend that the time-differentiated IERs should be as follows:

	Peak	Partial-peak	Off-peak	Super Off-peak
Summer	10,081	10,370	8,552	7,684
Winter	11,320	11,279	9,048	8,263

A comparison of Parties' pre-Joint Recommendation IER positions is provided in Appendix A, Table 16.

III. O&M ADDER

The Parties jointly recommend that the Commission adopt an Operations & Maintenance ("O&M") Adder for all variable-priced qualifying facilities ("QFs") payments of 2.5 mills/kwh. A comparison of Parties' pre-Joint Recommendation O&M Adder positions is provided in Appendix A, Table 16.

IV. REVENUE REQUIREMENT, IER AND O&M ADDER

Taken as a whole, the testimony of each Party that presented ELFIN model simulations supports a range of forecast revenue requirements and a range of IERs and O&M Adders. The Parties jointly believe that adoption of the revenue requirement, IER, and O&M Adder recommendations presented herein constitutes a reasonable compromise for ratemaking purposes and for calculating payments to variable-priced QFs. Accordingly, as the recommended values are within a reasonable range of the expected values, the Parties recommend that the Commission adopt the revenue requirement, IER, and O&M Adder values identified herein. The revenue requirement forecast is detailed in Appendix A, including oil inventory (Table 9). Gas transportation rates reflect SDG&E's most recent ACAP decision. The average gas price underlying the Joint Recommendation is provided in Appendix A, Table 8.

V. ENERGY RELIABILITY INDEX ("ERI")

The Parties jointly recommend an ERI of 1.0.

VI. AS-AVAILABLE CAPACITY PAYMENT SCHEDULE FOR QFs

The Parties recommend an as-available capacity payment of $70.94 per KW-year. The corresponding rates per time of use periods and seasons are reflected in Appendix B.

The Parties further recommend that the recommended payment schedule be subject to change should the Commission in the Biennial Resource Plan Update proceeding, or such other proceeding as the Commission may direct during this forecast period, adopt a different as-available capacity payment for use by SDG&E.

VII. VARIABLE FUEL HANDLING EXPENSES

SDG&E's variable costs associated with handling fuel oil deliveries are currently forecast in general rate case proceedings and recovered through base rates. Due to the increasing requirements for precautionary measures during the off-loading of fuel oil, and the difficulty of predicting in today's volatile markets the variable fuel handling expenses, SDG&E recommended in its prefiled testimony in this proceeding that the disposition of variable fuel handling expenses be considered at the same time as other fuel oil expenses in each annual ECAC proceeding, and be removed from base rate recovery. DRA recommends that this issue be addressed in SDG&E's general rate case or modified attrition where base rate revenues are addressed. This issue remains to be litigated.

VIII. REVENUE ALLOCATION

The Parties recommend that the Commission adopt the unit marginal energy costs specified in Appendix C. These marginal energy costs are produced by an ELFIN model simulation consistent with the revenue requirement and IER recommendations herein.

The Parties recommend that the unit marginal demand costs and the unit marginal customer costs adopted in SDG&E's 1989 Test Year General Rate Case (D.88-12-085, Appendix F) be utilized for revenue allocation purposes in this proceeding. These costs are also identified in Appendix C. The Parties further agree that the revenue allocation which SDG&E presents in the ECAC application that it is scheduled to file in September of 1991 will reflect updated unit marginal demand and customer costs based on a marginal cost study.

The Parties recommend that the Equal Percentage Marginal Cost ("EPMC") revenue allocation method be applied. The marginal cost revenue responsibility used in the recommended revenue allocation is presented in Appendix D. The recommended revenue allocation is presented in Appendix E.

IX. RATE DESIGN

The Parties recommend that the Commission adopt the proposed rates appended to this Joint Recommendation as Appendix F. The principles underlying SDG&E's initial rate design proposals were not contested, with four limited exceptions. These initial areas of dispute are described below, along with the Parties' recommendations concerning the appropriate resolution. Appendix F reflects the compromises reached.

A. The Residential Baseline/Non-Baseline Ratio. SDG&E initially proposed to close the ratio between residential baseline and non-baseline rates for schedules DR, DM, DS and DT from 1.40 to 1.36 by applying the revenue increase to baseline and non-baseline rates on an equal cents per kwh basis. DRA proposed a 20% decrease in the differential between baseline and non-baseline rates. SDG&E, UCAN and DRA have agreed that a 15% decrease in the differential between baseline and non-baseline rates is reasonable and generally consistent with Commission policy.

B. Average Rate Limiter. SDG&E proposed to continue the phaseout of the average rate limiter by increasing the limiter from \$0.21/kwh to \$0.28/kwh. The intent of this proposal is to reduce the intra-class subsidy consistent with D.87-12-069 and to bring the rates paid by low-load factor customers closer to the cost-based rate. FEA supported SDG&E's proposal. DRA proposed to increase the average rate limiter to 35¢/kwh, in order to produce a larger subsidy reduction. The Parties agree that DRA's proposed average rate limiter is reasonable and recommend its adoption.

C. On-peak Rate Limiters. SDG&E proposed to increase Large TOU on-peak rate limiters by 5% more than the rate schedule average increase. DRA proposed that the on-peak rate limiter only be increased by the Large TOU class percentage increase. This position was supported by FEA. SDG&E, DRA and FEA recommend that DRA's proposal be accepted.

D. **AL-TOU and A6-TOU Rate Increase.** SDG&E proposed that a uniform increase be applied to both demand charges and energy charges in the AL-TOU and A6-TOU rate schedules. FEA, however, proposed in a filing in SDG&E's November, 1990 rate window proceeding to increase demand charges in schedules AL-TOU and A6-TOU by 5% and to correspondingly reduce energy charges. The FEA proposal is currently pending in SDG&E's rate window proceeding. SDG&E and the DRA generally support FEA's proposed adjustment to the AL-TOU and A6-TOU schedules and urge that the results of the rate window proceeding be implemented with the rates that result from this ECAC proceeding.

X. CONTRIBUTION OF UCAN

For purposes of determining intervenor compensation, the Parties acknowledge UCAN's contribution to the workshop process. In its testimony, UCAN addressed the economy energy price and revenue allocation issues -- both of which were discussed in the workshop process. UCAN's contribution on the issue of the appropriate baseline/non-baseline differential closure also was of assistance to the Parties.

XI. THE JOINT RECOMMENDATION IS REASONABLE AND IN THE PUBLIC INTEREST

The Parties request that the Commission adopt the Joint Recommendation as reasonable and in the public interest.

Overall, this Joint Recommendation expresses the assent of all the Parties in this proceeding, representing the full range of affected interests, on the various issues presented in the Forecast Phase of this ECAC proceeding. This agreement represents a compromise of all the Parties, arrived at during a series of meetings which involved extensive negotiation and discussions of positions. Although this agreement reflects considerable efforts on the part of all the Parties, this result, which the Parties believe to be in the public interest, is accomplished without the even greater commitment of time and resources which would be necessary to litigate the case further.

XII. GENERAL TERMS

The Parties jointly recommend that the Commission adopt this Joint Recommendation because the recommended results are within a reasonable bandwidth of the expected values for SDG&E's revenue requirements, IER, O&M adder and ERI calculations.

No Party to this Joint Recommendation will contest in this proceeding, or in any other forum, or in any manner before this Commission, the recommendations contained in this Joint Recommendation. However, endorsement of this Joint Recommendation shall not be construed to be an acceptance or ratification of the principles, assumptions, methodologies, positions or arguments underlying the recommendations contained herein.

The Parties agree that the principles, assumptions, methodologies, positions and arguments underlying the specific items addressed in this Joint Recommendation are recommended only for purposes of this proceeding and are not to be deemed by the Commission or any other entity as precedent in any proceeding or litigation except as necessary to implement the recommendations contained herein in this proceeding. The Parties expressly reserve the right to advocate in other proceedings principles, assumptions, methodologies, arguments and positions different from those which may underlie, or appear to be implied by, this Joint Recommendation.

The Parties intend and agree that this Joint Recommendation is subject to each and every condition set forth herein, including its acceptance by the Commission in its entirety and without change or condition. Unless the Commission accepts the Parties' recommendations contained herein in their entirety, without change or condition, this Joint Recommendation shall be null and void, unless otherwise agreed upon by the Parties.

The Parties agree to extend their best efforts to ensure the adoption of this Joint Recommendation.

XIII. EXECUTION

The undersigned, on behalf of the Parties they represent in this proceeding, hereby agree to abide by the conditions and recommendations set forth herein.

Dated this 31 day of January, 1991.

Respectfully submitted,

Alberto Guerrero
DIVISION OF RATEPAYER ADVOCATES

David R. Clark
SAN DIEGO GAS & ELECTRIC COMPANY

William Shaffran
CITY OF SAN DIEGO

Michael Shames
UTILITY CONSUMERS ACTION NETWORK/
~~TOWARD UTILITY RATE NORMALIZATION~~/
JBS ENERGY, INC.

James Squeri
KELCO DIVISION OF MERCK CO., INC.

Jerry R. Bloom
CALIFORNIA COGENERATION COUNCIL

Norman J. Furuta
U.S. DEPARTMENT OF THE NAVY AND
OTHER FEDERAL EXECUTIVE AGENCIES

Paul Weir
SAN DIEGO MINERAL PRODUCTS INDUSTRY
COALITION

(END OF APPENDIX B)

APPENDIX C

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT

REVENUE REQUIREMENT, ALLOCATION AND RATE DESIGN

APPENDIX C
TABLE 1
Sheet 1 of 1

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED ENERGY COSTS
Forecast period: May 1, 1991 through April 30, 1992

TYPE OF ENERGY	PURCHASES/ GENERATION (GWH)	PERCENTAGE OF TOTAL	AVERAGE COST ($/Kwh)	TOTAL ECAC COSTS ($000) [1]	NON-JURISDICTIONAL COSTS ($000) [2]	CALIF. COSTS ($000) [3]
Natural Gas	3,612	21.68%	0.03614	$130,553	$7,167	$123,386
Residual Oil [4]	60	0.36%	0.03912	2,347	129	2,218
Other Oil	1	0.01%	0.08000	80	4	76
Firm Purchases	6,040	36.25%	0.03697	223,319	12,260	211,059
Economy Purchases	2,805	16.84%	0.01893	53,088	2,914	50,174
Cogen/Alternatives	1,000	6.00%	0.06420	64,202	3,525	60,677
Nuclear	3,143	18.86%	0.01056	33,190	1,822	31,368
Subtotal	16,661	100.00%	0.03042	506,779	27,821	478,958
Variable Wheeling Expenses				1,556	85	1,471
Fixed Wheeling Expenses				10,824	594	10,230
Carrying Cost of Oil in Inventory [4]				1,545	85	1,460
EFI Adjustment				0	0	0
Subtotal				520,704	28,586	492,118
EEDA Expenses				(624)	(34)	(590)
ECAC Offset				520,080	28,551	491,529
ECAC Balance on 5/1/91 [5]						(660)
ECAC Revenue Requirement						490,869

ECAC REVENUE REQUIREMENT ADJUSTED FOR FRANCHISE FEES & UNCOLLECTIBLES AT 1.30% $497,250
(Excluding City of San Diego Franchise Fee Differential (SDFFD))

ECAC Rate [6] 3.441 cents/kwh

NOTES:
[1] I.90-08-006 suspended the Annual Energy Rate (AER) mechanism effective August 8, 1990.
[2] Percentage of non-jurisdictional to total cost = 5.48980%
[3] Cost allocated to California jurisdiction = Total LESS Non-Jurisdictional.
[4] Reflects inclusion of Variable Fuel Handling costs.
[5] Reflects receipt of $25.0 million in settlement proceeds from Century Power Corp., plus interest.
[6] Does not include SDFFD. Based on adjusted sales of 14,451 Gwh.

Sheet 1 of 1

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
SUMMARY OF REVENUE CHANGES
Forecast period: May 1, 1991 through April 30, 1992

REVENUE ELEMENT	PRESENT RATE REVENUE ($000) [1]	REVENUE CHANGE ($000) [2]	ADOPTED REVENUE REQUIREMENT ($000) [3]	AVERAGE RATE (cents/Kwh) [4]
BASE RATE REVENUES: [5]				
Margin 1/91	$826,678	$0	$826,678	
Sales Adjustment	19,355	(19,355)	0	
Total Base Rate Revenue	846,033	(19,355)	826,678	5.670
MAJOR ADDITIONS ADJUSTMENT CLAUSE (MAAC):				
SONGS 2 and 3 pre-COO amortization	0	0	0	0.000
SONGS 2 and 3 post-COO amortization	12,981	0	12,981	0.089
Total MAAC	12,981	0	12,981	0.089
ERAM BALANCING ACCOUNT RATE:	(9,480)	4,958	(4,522)	(0.031)
ENERGY COST ADJMT. CLAUSE & ANNUAL ENERGY RATE:				
ECAC Offset	502,568	(585)	501,983	3.441
AER	0	0	0	0.000
Total ECAC and AER	502,568	(585)	501,983	3.441
MISCELLANEOUS OFFSETS:				
Electro. Fields Study Exp Acct. (EFSEA)	146	(146)	0	0.000
Demand Side Management (DSM)	0	21,296	21,296	0.146
Total Miscellaneous Offsets	146	21,150	21,296	0.146
SUBTOTAL:	1,352,248	6,168	1,358,416	9.315
LOW INCOME RATE ASSISTANCE (LIRA) PROGRAM	1,226	(2,354)	(1,128)	
REVENUE FROM RETAIL SALES	$1,353,474	$3,815	$1,357,289	
Percentage increase		0.28%		
Miscellaneous Revenues	17,005	0	17,005	
Non-Jurisdictional Revenues	1,445	0	1,445	
TOTAL REVENUES FOR ELECTRIC DEPARTMENT	$1,371,924	$3,815	$1,375,739	

NOTES:
[1], [2] and [3] Include City of San Diego Franchise Fee Differential (SDFFD).
[4] Does not include SDFFD. Based on adjusted sales of 14,451 Gwh.
[5] Margin reflects 1/91 changes including HEBER (Resolution E-3213 and Advice Letter 804-E-A).
Sales adjustment is amount by which Base Rate Revenues exceed Margin based on ECAC sales forecasts.
Total Present Base Rate Revenues = Present Base Rates * ECAC Sales Forecasts.

APPENDIX C
TABLE 3
Sheet 1 of 1

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED UNIT MARGINAL COSTS
Forecast period: May 1, 1991 through April 30, 1992

CUSTOMER GROUP	UNIT MARGINAL CUSTOMER COST ($/customer)
Residential	95.34
Commercial/Industrial	
General Service	153.99
GS-Demand Metered	508.82
Large TOU	2,412.33
Agriculture	545.63
Lighting ($/Kwh)	0.00787

VOLTAGE SERVICE LEVEL	UNIT DEMAND MARGINAL COSTS ($/Kw/Year)		
	GENERATION	TRANSMISSION	DISTRIBUTION
Transmission	76.99	23.06	N/A
Primary	80.18	24.01	90.71
Secondary	82.29	24.65	93.09

VOLTAGE SERVICE LEVEL	UNIT MARGINAL ENERGY COSTS ($/Kwh) SUMMER			WINTER		
	ON-PEAK	SEMI-PEAK	OFF-PEAK	ON-PEAK	SEMI-PEAK	OFF-PEAK
Transmission	0.0374	0.0382	0.0306	0.0417	0.0415	0.0324
Primary	0.0390	0.0396	0.0314	0.0434	0.0430	0.0332
Secondary	0.0400	0.0406	0.0319	0.0446	0.0439	0.0338

APPENDIX C
TABLE 4
Sheet 1 of 2

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED MARGINAL DEMAND COST REVENUE
Forecast period: May 1, 1991 through April 30, 1992

CUSTOMER GROUP	VOLTAGE SERVICE LEVEL	ALLOCATION DETERMINANTS (Kw/Yr)			ADOPTED MARGINAL DEMAND COST REVENUE ($000)			
		GENERATION	TRANSMISSION	DISTRIBUTION	GENERATION	TRANSMISSION	DISTRIBUTION	TOTAL
Residential (Schedules DR, DM, DS & DT)	Transmission voltage	0	0	0	0	0	0	0
	Primary voltage	5,237	7,535	12,323	420	181	1,118	1,719
	Secondary voltage	1,024,205	1,473,589	2,409,805	84,282	36,324	224,329	344,935
	Total				84,702	36,505	225,447	346,653
General Service (Schedule A)	Transmission voltage	0	0	0	0	0		0
	Primary voltage	484	597	831	39	14	75	129
	Secondary voltage	434,709	535,655	745,961	35,772	13,204	69,442	118,418
	Total				35,811	13,218	69,517	118,546
General Service Demand Metered 20 KW (Schedule AD)	Transmission voltage	0	0	0	0	0		0
	Primary voltage	11,037	13,223	17,778	885	317	1,613	2,815
	Secondary voltage	375,715	450,142	605,198	30,918	11,096	56,338	98,351
	Total				31,803	11,413	57,951	101,167
AL-TOU	Transmission voltage	0	0	0	0	0		0
	Primary voltage	429,527	468,667	550,209	34,439	11,253	49,909	95,602
	Secondary voltage	483,558	527,621	619,420	39,792	13,006	57,662	110,460
	Total				74,231	24,259	107,571	206,061

APPENDIX C
TABLE 4
Sheet 2 of 2

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED MARGINAL DEMAND COST REVENUE
Forecast period: May 1, 1991 through April 30, 1992

CUSTOMER GROUP	SERVICE VOLTAGE	ALLOCATION DETERMINANTS (Kw/Yr)			ADOPTED MARGINAL DEMAND COST REVENUE ($000)			
		GENERATION	TRANSMISSION	DISTRIBUTION	GENERATION	TRANSMISSION	DISTRIBUTION	TOTAL
A6-TOU	Transmission voltage	18,312	20,890	0	1,410	482		1,892
	Primary voltage	112,233	128,036	187,219	8,999	3,074	16,983	29,056
	Secondary voltage	7,235	8,254	10,376	595	203	966	1,765
	Total				11,004	3,759	17,949	32,712
Agriculture	Transmission voltage	0	0	0	0	0		0
	Primary voltage	127	166	247	10	4	22	37
	Secondary voltage	21,667	28,373	42,345	1,783	699	3,942	6,424
	Total				1,793	703	3,964	6,461
Street Lighting	Transmission voltage	0	0	0	0	0		0
	Primary voltage	0	0	0	0	0	0	0
	Secondary voltage	6,739	9,469	15,155	555	233	1,411	2,199
	Total				555	233	1,411	2,199

APPENDIX C
TABLE 5
Sheet 1 of 2

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED MARGINAL ENERGY COST REVENUE
Forecast period: May 1, 1991 through April 30, 1992

CUSTOMER GROUP	SERVICE VOLTAGE	ADOPTED SALES (GWh)							ADOPTED MARGINAL ENERGY COST REVENUE ($000)						
		SUMMER			WINTER			ANNUAL	SUMMER			WINTER			ANNUAL
		ON-PEAK	SEMI-PEAK	OFF-PEAK	ON-PEAK	SEMI-PEAK	OFF-PEAK		ON-PEAK	SEMI-PEAK	OFF-PEAK	ON-PEAK	SEMI-PEAK	OFF-PEAK	
Residential	Transmission	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0	0
(Schedules DR,	Primary	2.196	3.225	5.140	2.053	5.986	8.028	26.628	86	128	161	89	257	267	988
DM, DS & DT)	Secondary	451.379	662.990	1,056.752	422.003	1230.585	1650.431	5,474.140	18,067	26,897	33,739	18,817	54,075	55,710	207,305
	Total							5,500.768	18,153	27,024	33,901	18,906	54,332	55,977	208,295
General Service	Transmission	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0	0
(Schedule A)	Primary	0.269	0.254	0.358	0.125	0.547	0.481	2.034	10	10	11	5	23	16	77
	Secondary	234.183	221.024	311.286	108.942	475.438	418.593	1,769.466	9,374	8,967	9,939	4,858	20,892	14,130	68,158
	Total							1,771.500	9,384	8,977	9,950	4,863	20,915	14,146	68,235
General Service	Transmission	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0	0
Demand Metered	Primary	6.881	7.065	8.792	3.079	14.639	11.334	51.790	268	280	276	134	629	376	1,964
20 KW	Secondary	224.933	230.928	287.369	100.630	478.492	370.457	1,692.809	9,003	9,368	9,175	4,487	21,026	12,505	65,565
(Schedule AD)	Total							1,744.599	9,272	9,649	9,451	4,621	21,655	12,881	67,528
Large TOU	Transmission	8.527	10.751	17.729	4.486	21.338	24.604	87.435	319	411	543	187	885	797	3,142
(Schedules	Primary	317.560	366.506	543.090	158.981	735.067	737.784	2,858.988	12,385	14,531	17,061	6,907	31,575	24,504	106,964
AL-TOU &	Secondary	261.979	295.087	422.889	129.425	593.625	570.345	2,273.351	10,486	11,971	13,502	5,771	26,085	19,252	87,067
A6-TOU)	Total							5,219.774	23,190	26,914	31,106	12,865	58,544	44,553	197,173

APPENDIX C
TABLE 5
Sheet 2 of 2

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED MARGINAL ENERGY COST REVENUE
Forecast period: May 1, 1991 through April 30, 1992

CUSTOMER GROUP	SERVICE VOLTAGE	ADOPTED SALES (Gwh)							ADOPTED MARGINAL ENERGY COST REVENUE ($000)						
		SUMMER			WINTER			ANNUAL	SUMMER			WINTER			ANNUAL
		ON-PEAK	SEMI-PEAK	OFF-PEAK	ON-PEAK	SEMI-PEAK	OFF-PEAK		ON-PEAK	SEMI-PEAK	OFF-PEAK	ON-PEAK	SEMI-PEAK	OFF-PEAK	
Agriculture	Transmission	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0	0
	Primary	0.096	0.137	0.275	0.036	0.174	0.251	0.969	4	5	9	2	7	8	35
	Secondary	14.717	20.906	41.980	5.534	26.554	38.297	147.988	589	848	1,340	247	1,167	1,293	5,484
	Total							148.957	593	854	1,349	248	1,174	1,301	5,519
Street Lighting	Transmission	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0	0
	Primary	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0	0
	Secondary	0.000	4.576	22.030	6.065	6.396	36.446	75.513	0	186	703	270	281	1,230	2,671
	Total							75.513	0	186	703	270	281	1,230	2,671

APPENDIX C
TABLE 6
Sheet 1 of 1

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED TOTAL MARGINAL COST REVENUE
Forecast period: May 1, 1991 through April 30, 1992

CUSTOMER GROUP	NUMBER OF CUSTOMERS	MARGINAL COST REVENUE ($000)			TOTAL MARGINAL COST REVENUE ($000)
		CUSTOMER	DEMAND	ENERGY	
Residential	1,006,218	95,933	346,653	208,293	650,879
Commercial/Industrial					
General Service	96,880	14,919	118,546	68,235	201,699
GS-Demand Meter	5,933	3,019	101,167	67,528	171,714
Large TOU	6,926	16,708	238,773	197,173	452,654
Total Comm./Ind.	109,739	34,645	458,486	332,936	826,067
Agriculture	3,493	1,906	6,461	5,519	13,886
Street Lighting	75,513 GWh	594	2,199	2,671	5,464
TOTAL		$133,078	$813,799	$549,419	$1,496,296

FACILITY CHARGES

Customer Group	STREET LIGHTING CHARGES ($000) (E)	TOU METER CHARGES ($000) (F)	FACILITY CHARGES ($000) (G)
Residential	0	1	1
Commercial/Industr	0	0	0
General Service	0	0	0
GS-Demand Metere	0	0	0
Large TOU	0	0	0
Total Commercial/I	0	0	0
Agriculture	0	20	20
Lighting	3,072	0	3,072
Total	3,072	21	3,093

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED REVENUE ALLOCATION
Forecast period: May 1, 1991 through April 30, 1992

CUSTOMER GROUP	ADOPTED SALES (GWh)	TOTAL MARGINAL COST REVENUE ($000)	EPMC ALLOC. FACTOR	ADOPTED REVENUE ALLOCATION ($000): EPMC REVENUE ALLOCATION	FACILITY CHARGES	SUBTOTAL	LIRA ADJ.	ADOPTED REVENUE	AVG RATE ($/KWh)	PRESENT RATE REVENUES: AMOUNT ($000)	AVG RATE ($/KWh)	ADOPTED ALLOCATION CHANGE: AMOUNT ($000)	PER-CENT
Residential	5,500.768	$650,879	43.50%	$589,557	$1	$589,558	($4,810)	$584,748	$0.1063	$590,912	$0.1074	($6,164)	-1.0%
Commercial/Industrial													
General Service	1,771.500	201,699	13.48%	182,696	0	182,696	733	183,429	0.1035	181,311	0.1023	2,118	1.2%
GS-Demand Metered	1,744.599	171,714	11.48%	155,536	0	155,536	722	156,258	0.0896	150,908	0.0865	5,351	3.5%
Large TOU	5,219.774	452,654	30.25%	410,008	0	410,008	2,166	412,174	0.0790	409,068	0.0784	3,107	0.8%
Subtotal Comm./Industrial	8,735.873	826,067	55.21%	748,240	0	748,240	3,621	751,861	0.0861	741,286	0.0849	10,575	1.4%
Agriculture	148.957	13,886	0.93%	12,578	20	12,598	61	12,659	0.0850	12,979	0.0871	(320)	-2.5%
Street Lighting	75.513	5,464	0.37%	4,949	3,072	8,021	0	8,021	0.1062	8,297	0.1099	(276)	-3.3%
TOTAL	14,461.111	$1,496,296	100.00%	$1,355,323	$3,093	$1,358,416	($1,128)	$1,357,289	$0.0939	$1,353,474	$0.0936	$3,815	0.3%

APPENDIX C
TABLE 8
Sheet 1 of 3

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
RESIDENTIAL RATE DESIGN
Forecast period: May 1, 1991 through April 30, 1992

Revenues from ECAC & AER rates ($000's)		$497,250	
Uniform ECAC & AER rate for all customers		0.03441	
Revenues from Base Rates ($000's)		$399,265	
Base Rate - Tier I		$0.05999	/KWH
Comp. Base Rate (Tier I + Min. Bill Rate)	$0.06043		/KWH
Base Rate - Tier II	$0.08998	$0.08998	/KWH
Base Rate - Relative Tier Differential	1.489	1.500	
Tier I Adopted Rate		$0.09440	/KWH
Adopted Base Rate (Tier I+Min. Bill Rate)	$0.09484		/KWH
Tier II Adopted Rate	$0.12439	$0.12439	/KWH
Adopted rate - Relative Tier Differential	1.312	1.318	
Adopted rate - Absolute Tier Differential	$0.02955	$0.03000	/KWH
Absolute Tier Closure	15.00%	13.72%	
Revenues for residential rate design ($000's)		$589,558	

Total Tier Base Revenues ($000's)	$402,236
Adjusted Tier I sales (gwh)	3,180
Adjusted Tier II sales (gwh)	2,350
Minimum Bill Rate ($/kwh)	0.00044
Present Comp. Tier I Rate ($/kwh):	0.09412
Present Tier II Rate ($/kwh):	0.12889
Present Comp. Tier Diff.($/kwh)	0.03477
Absolute Tier Closure	15.00%
Adopted Abs. Tier Diff.($/kwh)	0.02955

* Total Energy Rates (including LIS): *
* Tier I $0.09481 *
* Tier II $0.12480 *

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
RESIDENTIAL RATE DESIGN
Forecast period: May 1, 1991 through April 30, 1992

RATE SCHEDULE	BILLING UNITS	PRESENT RATES (EXCL. LIRA) ($/UNIT)	EMPLOYEE DISCOUNT FACTOR (%)	SDFFD FACTOR (%)	ADJUSTED PRESENT RATES ($/UNIT)	PRESENT RATE REVENUES ($000's)	ADOPTED RATES (EXCL. LIRA) ($/UNIT)	REVENUES AT ADOPTED RATES ($000's)	ADOPTED LIRA REVENUES ($000's)	PRESENT LIRA REVENUES ($000's)
SCHEDULE DR										
Minimum Bill	8,556,000	0.164	0.1615%	0.699%	0.165	$1,411	0.164	$1,411		
Base Rates - Tier I (Baseline)	2,981,895,000	0.05865	0.1615%	0.699%	0.05896	175,826	0.05999	179,840	$1,093	$1,547
Base Rates - Tier II (Nonbaseline)	2,258,382,000	0.09386	0.1615%	0.699%	0.09436	213,109	0.08998	204,308	887	1,255
ECAC & AER Rates - Tier I (Baseline)	2,981,895,000	0.03445	0.1615%	0.699%	0.03463	103,277	0.03441	103,157		
ECAC & AER Rates - Tier II (Nonbaseline)	2,258,382,000	0.03445	0.1615%	0.699%	0.03463	78,219	0.03441	78,128		
Total	5,240,277,000					$571,841		$566,844	$1,981	$2,802
SCHEDULE DM										
Base Rates - Tier I (Baseline)	59,071,000	0.05865		0.823%	0.05913	$3,493	0.05999	$3,573	$24	$35
Base Rates - Tier II (Nonbaseline)	44,927,000	0.09386		0.823%	0.09463	4,252	0.08998	4,076	$19	$26
ECAC & AER Rates - Tier I (Baseline)	59,071,000	0.03445		0.823%	0.03473	2,052	0.03441	2,049		
ECAC & AER Rates - Tier II (Nonbaseline)	44,927,000	0.03445		0.823%	0.03473	1,560	0.03441	1,559		
Total	103,998,000					$11,357		$11,257	$43	$61
SCHEDULE DS										
Customer discounts	2,068,000	(0.110)		0.896%	(0.111)	($230)	(0.110)	($230)		
Base Rates - Tier I (Baseline)	15,785,000	0.05865		0.896%	0.05918	934	0.05999	955	$6	$8
Base Rates - Tier II (Nonbaseline)	2,443,000	0.09386		0.896%	0.09470	231	0.08998	222	1	1
ECAC & AER Rates - Tier I (Baseline)	15,785,000	0.03445		0.896%	0.03476	549	0.03441	548		
ECAC & AER Rates - Tier II (Nonbaseline)	2,443,000	0.03445		0.896%	0.03476	85	0.03441	85		
Total	18,228,000					$1,570		$1,581	$7	$10

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
RESIDENTIAL RATE DESIGN
Forecast period: May 1, 1991 through April 30, 1992

RATE SCHEDULE	BILLING UNITS	PRESENT RATES (EXCL. LIRA) ($/UNIT)	EMPLOYEE DISCOUNT FACTOR (%)	SDFFD FACTOR (%)	EFFECTIVE RATES ($/UNIT)	PRESENT RATE REVENUES ($000's)	ADOPTED RATES (EXCL. LIRA) ($/UNIT)	REVENUES AT ADOPTED RATES ($000's)	ADOPTED LIRA REVENUES ($000's)	PRESENT LIRA REVENUES ($000's)
SCHEDULE DT										
Customer discounts	13,284,000	(0.312)		0.201%	(0.313)	($4,153)	(0.312)	($4,153)		
Base Rates - Tier I (Baseline)	106,602,000	0.05865		0.201%	0.05877	6,265	0.05999	6,408	$40	$57
Base Rates - Tier II (Nonbaseline)	31,663,000	0.09386		0.201%	0.09405	2,978	0.08998	2,855	12	17
ECAC & AER Rates - Tier I (Baseline)	106,602,000	0.03445		0.201%	0.03452	3,680	0.03441	3,676		
ECAC & AER Rates - Tier II (Nonbaseline)	31,663,000	0.03445		0.201%	0.03452	1,093	0.03441	1,092		
Total	138,265,000					$9,863		$9,877	$52	$74
SUMMARY OF SCHEDULES DR, DM, DS, DT										
Customer discounts						($4,382)		($4,382)		
Minimum Bill						1,411		1,411		
Base, ECAC & AER Rates - Tier I	3,163,353,000					296,076		300,206	$1,164	$1,646
Base, ECAC & AER Rates - Tier II	2,337,415,000					301,526		292,324	919	1,300
Total	5,500,768,000					$594,630		$589,558	$2,083	$2,946
Customer Discounts, Min. Bill, Base Rates - Tier I & II						$404,116		$399,265	$2,083	$2,946
ECAC & AER Rates - Tier I & II						190,514		190,293		
Total	5,500,768,000					$594,630		$589,558	$2,083	$2,946
LIRA adjustment						($3,719)		($4,810)		
Adjusted total revenues						$590,912		$584,748		

APPENDIX C
TABLE 9
Sheet 1 of 1

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
LOW INCOME DISCOUNT RATES
Forecast period: May 1, 1991 through April 30, 1992

RATE SCHEDULE	BILLING UNITS (KWH)	ADOPTED RATES ($/KWH)	LIRA DISCOUNT ($/KWH)	ADOPTED DISCOUNT ($000s)	ADJUSTED ADOPTED DISCOUNT ($000s)	ADJUSTED PRESENT DISCOUNT ($000s)
Minimum Bill	739,000	0.164	0.02460	$18	$18	$18
LIRA sales at 15% discount (Tier I)	339,756,000	0.09440	0.01416	4,811	4,837	4,614
LIRA sales at 15% discount (Tier II)	108,633,000	0.12439	0.01866	2,027	2,038	2,033
Total LIRA discount	448,389,000			$6,856	$6,893	$6,665
Other LIRA costs:						
Administrative & general office				$457		
Franchise fee & uncollectable (1.3%)				6		
Prior period undercollection				(1,566)		
Subtotal				($1,103)		
Total LIRA program costs (w/o & w/ SDFFD)				$5,753	$5,765	
Total forecast sales	14,461,111,000					
Less: Street lighting sales	75,513,000					
Less: LIRA sales	448,389,000					
Less: LIRA min. bill sales	657,490					
Sales subject to LIRA surcharge	13,936,551,510					
LIRA surcharge ($/KWH)		* 0.00041 *				
LIRA Revenues from residential customers					$2,083	$2,946
LIRA Discount to residential customers					(6,893)	(6,665)
LIRA adjustment to residential revenues					($4,810)	($3,719)
LIRA Discount Rates:						
SCHEDULE DR-LI						
Minimum Bill	739,000	0.139				
Base Rate - Tier I	339,756,000	0.04583				
Base Rate - Tier II	108,633,000	0.07132				
ECAC & AER Rate - Tier I	339,756,000	0.03441				
ECAC & AER Rate - Tier II	108,633,000	0.03441				
Minimum Bill	739,000	0.139				
Total rate - Tier I	339,756,000	0.08024				
Total rate - Tier II	108,633,000	0.10573				

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
OPTIONAL RESIDENTIAL RATE DESIGN
Forecast period: May 1, 1991 through April 30, 1992

RATE SCHEDULE	TIER I RATE ($/UNIT)	TIER II RATE ($/UNIT)
Schedules DU-TOU & DA-TOU		
ADOPTED RESIDENTIAL	0.09481	0.12480
ADOPTED DA-TOU PEAK	0.14797	0.19478
ADOPTED DA-TOU OFF-PEAK	0.07398	0.09739
ADOPTED DU-TOU PEAK	0.10222	0.13456
ADOPTED DU-TOU OFF-PEAK	0.05111	0.06728

NOTE - THESE CALCULATIONS ARE BASED ON A 2:1 RATIO PEAK TO OFF-PEAK AND PEAK USAGE OF 28.15% AND 85.5% FOR DA-TOU AND DU-TOU RESPECTIVELY.

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
OPTIONAL RESIDENTIAL RATE DESIGN
Forecast period: May 1, 1991 through April 30, 1992

RATE SCHEDULE	ADOPTED RATE 1/ ($/UNIT)
SCHEDULE D-SMF	
Base Rate - Tier I	0.06040
ECAC/AER Rate - Tier I	0.03441
Total Rate - Tier I	0.09481
Base Rate - Tier II	0.09039
ECAC/AER Rate - Tier II	0.03441
Total Rate - Tier II	0.12480
Schedule DS Total Revenues	$1,565,084
Schedule DT Total Revenues	$9,755,162
DS and DT Total Revenues	$11,320,245
Adopted D-SMF On-Peak Demand Charge($/kw)	$9.35
Adopted D-SMF Customer Charge ($/cust/mo.	$20.00
Schedule DS Baseline Energy (Kwh)	15,785,000
Schedule DS Non-Baseline Energy (Kwh)	2,443,000
Schedule DT Baseline Energy (Kwh)	106,602,000
Schedule DT Non-Baseline Energy (Kwh)	31,663,000
Schedule DS SDFFD	0.896%
Schedule DT SDFFD	0.201%
On-Peak Energy/Total Energy Factor	16.17%
Calculated On-Peak Energy (Kwh)	25,376,266
On-Peak Demand Charge by $/Kwh	0.09479
Estimated Demand Charge Revenues	$2,405,502
DS & DT Rev. Less Demand Charge Revenues	$8,914,743
Schedule DS Discounts	($229,518)
Schedule DT Discounts	($4,152,939)
Total DS and DT Discounts	($4,382,457)
Balance for Energy Rate Derivation	$13,297,200
Non-Base to Base Rates Ratio	1.3164
Schedules DS & DT Adjd. Baseline Energy	122,742,704
Schedules DS & DT Adjd. Non-Bline Energy (Kwh)	34,191,532
Schedules DS & DT Rate Adjd. Energy(Kwh)	167,751,544

REVENUE PROOF:	
Demand Charge	$2,405,502
Baseline Energy	$9,729,474
Non-Baseline Energy	$3,567,726
Schedule DS Discounts	($229,518)
Schedule DT Discounts	($4,152,939)
Total Billing	$20,085,159

Summary of schedule D-SMF	NON-LIRA	LIRA
Total Baseline Rate ($/Kwh)	0.07927	0.06738
Baseline ECAC/AER	0.03441	0.03441
Baseline Base Rate	0.04486	0.03297
Total Non-Baseline Rate ($/Kwh)	0.10435	0.08869
Non-Baseline ECAC/AER Rate	0.03441	0.03441
Non-Baseline Base Rate	0.06994	0.05428

1/ = Reflect Decision 91-04-026.

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
OPTIONAL RESIDENTIAL RATE DESIGN
Forecast period: May 1, 1991 through April 30, 1992

ANNUAL USAGE DATA (%)	
ANNUAL USAGE ON-PEAK	16.9%
SUMMER USAGE ON-PEAK	17.7%
WINTER USAGE ON-PEAK	16.2%
ON-PEAK SUMMER AS % OF YEAR	8.5%
ON-PEAK WINTER AS % OF YEAR	8.4%
HOURS DATA (%)	
ANNUAL HOURS ON-PEAK	17.32877%
SUMMER HOURS ON-PEAK	17.52717%
WINTER HOURS ON-PEAK	17.12707%
MARGINAL ENERGY COSTS ($/KW)	
ANNUAL ON-PEAK	0.0357
ANNUAL OFF-PEAK AND SEMI-PEAK	0.0321
SUMMER ON-PEAK	0.0350
WINTER ON-PEAK	0.0368
MARGINAL CAPACITY COSTS ($/KW PER MONTH)	
ANNUAL COINCIDENT	9.76
SUMMER COINCIDENT	17.91
WINTER COINCIDENT	3.93
ANNUAL NCD	6.40
SUMMER NCD	7.12
WINTER NCD	5.88
MONTHLY CUST. COSTS($/CUSTOMER PER MOnth)	7.95
AVERAGE MONTHLY USAGE (KWH/MONTH)	432.00
AVERAGE CUST. DEMAND AT SYSTEM PEAK(KW)	1.0
AVERAGE NON-COINCIDENT DEMAND (KW)	1.40
BASELINE DISCOUNT (BASELINE-NON-BASELINE $/KWH)	
CURRENT DISCOUNT	(0.02825)
ADOPTED DISCOUNT	(0.03000)
LOSS OF LOAD PROBABILITY WEIGHTING FACTORS	
SUMMER ON-PEAK	88%
SUMMER OFF-PEAK	12%
RESIDENTIAL TOU REVENUE REQUIREMENTS	
SDG&E RESIDENTIAL REVENUE REQUIREMENT	$584,747,557
PG&E GRC D.89-12-057 E-7 Adopted Revenue	$60,377,000
PG&E GRC E-7 Sales (kWh)	669,286,000
PG&E GRC E-1 Adopted Revenue	$2,432,039,000
PG&E GRC E-1 Sales (kWh)	22,679,833,000
PG&E SCHEDULE E-7/E-1 GRC RATE RATIO	0.84126
SDG&E RESIDENTIAL TOU REVENUE REQUIREMENT	$491,923,447
GROSS-UP RATE ADJUSTMENTS	
EPMC ADJUSTMENT FACTOR FOR DR-TOU-2	1.06143
EPMC ADJUSTMENT FACTOR FOR DR-TOU	1.24519

ANNUAL OFF-PEAK COST	0.06561

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
OPTIONAL RESIDENTIAL RATE DESIGN
Forecast period: May 1, 1991 through April 30, 1992

(CONT. OF SHEET 3)

Peak: 12-6 Holidays off

MARGINAL ENERGY
+ NON-COINCIDENT DEMAND ALLOCATED ON PEAK HOURS ON A KWH BASIS
+ CUSTOMER COST ALLOCATED ON PEAK HOURS ON A KWH BASIS
+ SUMMER COINCIDENT DEMAND ALLOCATED BY LOLP ON OFF-PEAK HOURS ON A KWH BASIS

SUMMER ON-PEAK COST — 0.24723

SUMMER MARGINAL ENERGY
+ SUMMER COINCIDENT CAPACITY ALLOCATED ON A KWH BASIS
+ SUMMER NON-COINCIDENT DEMAND ALLOCATED ON PEAK HOURS ON A KWH BASIS
+ SUMMER CUSTOMER COST ALLOCATED ON PEAK HOURS ON A KWH BASIS
+ SUMMER COINCIDENT DEMAND ALLOCATED BY LOLP ON ON-PEAK HOURS ON A KWH BASIS

WINTER ON-PEAK COST — 0.09844

WINTER MARGINAL ENERGY
+ WINTER COINCIDENT CAPACITY ALLOCATED ON A KWH BASIS
+ WINTER NON-COINCIDENT DEMAND ALLOCATED ON PEAK HOURS ON A KWH BASIS
+ WINTER CUSTOMER COST ALLOCATED ON PEAK HOURS ON A KWH BASIS

APPENDIX C
TABLE 10
Sheet 4 of 4

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
OPTIONAL RESIDENTIAL RATE DESIGN
Forecast period: May 1, 1991 through April 30, 1992

RATE SCHEDULE	SCHEDULE DR SALES (KWH)	UNADJUSTED RATES ($/KWH)	UNADJUSTED REVENUES ($)	EMP. DISC FACTOR (%)	SDFFD FACTOR (%)	ADJUSTED REVENUES ($)	ADOPTED RATES ($/KWH)	ADOPTED REVENUES ($)
SCHEDULE DR-TOU-2								
SUMMER ON-PEAK	467,565,280	0.24723	$115,598,386	0.1615%	0.6990%	$116,218,422	0.26242	$123,358,202
WINTER ON-PEAK	462,064,512	0.09844	45,485,046	0.1615%	0.6990%	45,729,014	0.10449	48,538,337
ANNUAL OFF-PEAK	4,571,138,208	0.06561	299,895,697	0.1615%	0.6990%	301,504,251	0.06964	320,026,907
TOTAL	5,500,768,000		$460,979,129			$463,451,688		$491,923,447
SCHEDULE DR-TOU								
BASELINE DISCOUNT	2,823,597,000	(0.03000)	($84,707,910)	0.1615%	0.6990%	(85,162,259)	(0.03000)	($85,162,259)
SUMMER ON-PEAK	467,565,280	0.24723	115,598,386	0.1615%	0.6990%	116,218,422	0.30785	144,714,092
WINTER ON-PEAK	462,064,512	0.09844	45,485,046	0.1615%	0.6990%	45,729,014	0.12257	56,941,341
ANNUAL OFF-PEAK	4,571,138,208	0.06561	299,895,697	0.1615%	0.6990%	301,504,251	0.08169	375,430,272
TOTAL	5,500,768,000		$376,271,219			$378,289,429		$491,923,447

SUMMARY OF SCHEDULES DR-TOU-2, DR-TOU	UNITS	DR-TOU	DR-TOU-2	LIRA
METER CHARGE /1	$/MONTH	3.28	3.28	0.00041
ON-PEAK (SUMMER) /2	$/KWH	0.30826	0.26283	
ON-PEAK (WINTER) /2	$/KWH	0.12298	0.10490	
OFF-PEAK (ANNUAL)	$/KWH	0.08210	0.07005	
BASELINE CREDIT	$/KWH	0.03000	N/A	

Note:
/1 Meter Charge will not apply to qualifying low-income customers
/2 On-peak is defined as 12 Noon to 6 p.m. Monday through Friday, excluding holidays

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
COMMERCIAL AND AGRICULTURAL RATE DESIGN
Forecast period: May 1, 1991 through April 30, 1992

RATE SCHEDULE	BILLING UNITS	PRESENT RATES 1/ ($/UNIT)	VOLTAGE DISCOUNT FACTOR (%)	STANDBY ADJUSTMENT FACTOR (%)	SDFFD FACTOR (%)	PRESENT RATE REVENUES ($000's)	ADOPTED RATES 1/ ($/UNIT)	ADOPTED REVENUE ($000's)
SCHEDULE A								
Customer charge	1,162,558	5.00			0.865%	$5,863	5.00	$5,863
Base Rates	1,771,500,000	0.06374			0.865%	113,892	0.06497	116,081
ECAC & AER Rates	1,771,500,000	0.03445			0.865%	61,556	0.03441	61,485
Total						$181,311		$183,429
SCHEDULE AD								
Customer charge	71,196	15.00	-0.1090%	0.0230%	1.002%	$1,078	15.00	$1,078
Demand charge	5,705,000	6.26	-0.1090%	0.0230%	1.002%	36,029	6.48	37,315
Base Rates	1,744,599,000	0.03015	-0.1090%	0.0230%	1.002%	53,084	0.03250	57,218
ECAC & AER Rates	1,744,599,000	0.03445	0.0000%	0.0230%	1.002%	60,718	0.03441	60,647
Total						$150,908		$156,258
SCHEDULE PA								
Customer charge	41,242	8.00		0.0000%	0.336%	331	8.00	331
Base Rates	147,639,000	0.05007		0.0000%	0.336%	7,417	0.04797	7,106
ECAC & AER Rates	147,639,000	0.03445		0.0000%	0.336%	5,103	0.03441	5,097
Total						$12,851		$12,534
SCHEDULE PA-TOU								
Customer charge	672	8.00		0.0000%	0.000%	5	8.00	5
Metering charge	672	10.00		0.0000%	0.000%	7	10.00	7
BaseRate-On Peak	299,000	0.11726		0.0000%	0.000%	35	0.11209	34
BaseRate-Off Peak	1,019,000	0.03448		0.0000%	0.000%	35	0.03296	34
ECAC & AER Rates	1,318,000	0.03445		0.0000%	0.000%	45	0.03441	45
Total						$128		$125

1/ = Reflect Decision 91-04-026.

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
COMMERCIAL AND AGRICULTURAL RATE DESIGN
Forecast period: May 1, 1991 through April 30, 1992

RATE SCHEDULE	BILLING UNITS	PRESENT RATES 1/ ($/UNIT)	PRESENT UNADJUSTE REVENUES ($)	VOLTAGE DISCOUNT FACTOR (%)	SDFFD FACTOR (%)	PRESENT RATES REVENUES ($)	ADOPTED RATES 1/ ($/UNIT)	ADOPTED TOTAL RATES ($/UNIT)	ADOPTED REVENUES ($)
SCHEDULE PA-T-1 (AL-TOU DETERMINANTS)									
CUSTOMER CHARGE	82,542	30.00	$2,476	-2.7160%	1.227%	$2,439	30.00	30.00	$2,439
DEMAND CHARGE ON-PEAK	10,175,000	9.28	94,390	-2.7160%	1.227%	92,953	9.35	9.35	93,638
DEMAND CHARGE SEMI-PEA	0	0.50	0	-2.7160%	1.227%	0			0
ON-PEAK ENERGY BASE	767,114,000	0.09399	72,101	-2.7160%	1.227%	71,003	0.05185	0.08626	39,169
SEMI-PEAK ENERGY BASE	1,716,518,000	0.05380	92,349	-2.7160%	1.227%	90,943	0.02968	0.06409	50,169
OFF-PEAK ENERGY BASE	1,935,642,000	0.01385	26,809	-2.7160%	1.227%	26,401	0.00764	0.04205	14,564
ECAC/AER	4,419,274,000	0.03441	152,067	0.0000%	1.227%	153,933	0.03441		153,933
TOTAL	4,419,274,000		$440,192			$437,672			$353,912
SCHEDULE PA-T-1 (A-6 TOU DETERMINANTS)									
CUSTOMER CHARGE	571	600.00	$343	-3.9210%	1.235%	$333	600.00	600.00	$333
DEMAND CHARGE ON-PEAK	1,183,000	11.06	13,081	-3.9210%	1.235%	12,723	11.14	11.14	12,824
DEMAND CHARGE SEMI-PEA	0	0.50	0	-3.9210%	1.235%	0			0
ON-PEAK ENERGY BASE	120,853,000	0.09399	11,359	-3.9210%	1.235%	11,048	0.05185	0.08626	6,095
SEMI-PEAK ENERGY BASE	283,400,000	0.05380	15,247	-3.9210%	1.235%	14,830	0.02968	0.06409	8,181
OFF-PEAK ENERGY BASE	396,248,000	0.01385	5,488	-3.9210%	1.235%	5,338	0.00764	0.04205	2,945
ECAC/AER	800,501,000	0.03441	27,545	0.0000%	1.235%	27,885	0.03441		27,885
TOTAL	800,501,000		$73,063			$72,158			$58,263
TOTAL PA-T-1 (AL-TOU AND A-6 TOU DETERMINANTS)						$509,830			$412,174

REVENUE REQUIREMENT:	$412,174
INDEX FOR BASE ENERGY RATES:	0.55165
PROPOSED ECAC/AER:	0.03441

RATE SCHEDULE	RDW AL-TOU AVG. PEAK DMD RATES	RDW PA-T-1 PEAK DMD RATE	RATIO OF AL-TOU/ PA-T-1 RATES	ADOPTED AL-TOU AVG. PEAK DMD RATES	ADOPTED RATES
SCHEDULE PA-T-1 (FINAL)					
DEMAND CHARGES ($/KW)					
OPTION A (CONTRIBUTION TO PEAK)	$9.28	$11.05	1.1914	$9.35	$11.13
OPTION B (ON-PEAK)	$9.28	$9.71	1.0464	$9.35	$9.78
OPTION C (ON-PEAK)	$9.28	$9.50	1.0238	$9.35	$9.57
OPTION D (ON-PEAK)	$9.28	$9.90	1.0668	$9.35	$9.97
OPTION E (ON-PEAK)	$9.28	$9.70	1.0453	$9.35	$9.77
OPTION F (ON-PEAK)	$9.28	$9.28	1.0000	$9.35	$9.35
ENERGY RATES ($/KWH)					
PEAK	---	---	---	---	0.08626
SEMI-PEAK	---	---	---	---	0.06409
OFF-PEAK	---	---	---	---	0.04205

1/ = Reflect Decision 91-04-026.

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
COMMERCIAL AND AGRICULTURAL RATE DESIGN
Forecast period: May 1, 1991 through April 30, 1992

RATE SCHEDULE	BILLING UNITS	PRESENT RATES 1/ ($/UNIT)	STANDBY ADJUST. FACTOR (%)	RATE LIMITER FACTOR (%)	SDFFD FACTOR (%)	PRESENT RATE REVENUES ($000's)	ADOPTED RATES 1/ ($/UNIT)	ADOPTED REVENUES ($000'S)	ADOPTED TOTAL RATES ($/UNIT)	ADOPTED OPTIONAL ON-PEAK RATE ($/UNIT)
SCHEDULE AL-TOU										
CUSTOMER CHARGE	82,542	30.00	0.1560%	0.2400%	1.227%	$2,505	30.00	$2,505	30.00	30.00
NON-COINCIDENT DEMAND CHARGE										
SECONDARY	6,761,000	3.55	0.1560%	0.2400%	1.2270%	24,269	3.58	24,455	3.58	3.58
PRIMARY	4,773,000	2.82	0.1560%	0.2400%	1.2270%	13,635	2.85	13,740	2.85	2.85
TRANSMISSION	0	1.19	0.1560%	0.2400%	1.2270%	0	1.20	0	1.20	1.20
SUMMER PEAK DEMAND										
SECONDARY	2,640,000	16.79	0.1560%	0.2400%	1.2270%	44,830	16.92	45,174	16.92	19.00
PRIMARY	1,885,000	16.79	0.1560%	0.2400%	1.2270%	32,010	16.92	32,255	16.92	19.00
TRANSMISSION	0	10.56	0.1560%	0.2400%	1.2270%	0	10.64	0	10.64	11.95
WINTER PEAK DEMAND										
SECONDARY	3,294,000	3.91	0.1560%	0.2400%	1.2270%	13,013	3.94	13,113	3.94	3.94
PRIMARY	2,356,000	3.91	0.1560%	0.2400%	1.2270%	9,308	3.94	9,379	3.94	3.94
TRANSMISSION	0	1.56	0.1560%	0.2400%	1.2270%	0	1.58	0	1.58	1.58
SUMMER PEAK ENERGY										
SECONDARY	279,050,000	0.04692	0.1560%	0.2400%	1.2270%	13,243	0.04758	13,430	0.08199	0.05767
PRIMARY	201,745,000	0.04168	0.1560%	0.2400%	1.2270%	8,505	0.04230	8,632	0.07671	0.05175
TRANSMISSION	0	0.03940	0.1560%	0.2400%	1.2270%	0	0.04000	0	0.07441	0.04916
ECAC/AER	480,795,000	0.03445	0.1560%	0.2400%	1.2270%	16,753	0.03441	16,733		0.03441
SUMMER SEMI-PEAK ENERGY										
SECONDARY	322,416,000	0.01816	0.1560%	0.2400%	1.2270%	5,923	0.01861	6,067	0.05302	0.02513
PRIMARY	256,424,000	0.01567	0.1560%	0.2400%	1.2270%	4,063	0.01609	4,173	0.05050	0.02230
TRANSMISSION	0	0.01416	0.1560%	0.2400%	1.2270%	0	0.01458	0	0.04899	0.02061
ECAC/AER	578,840,000	0.03445	0.1560%	0.2400%	1.2270%	20,169	0.03441	20,146		0.03441
SUMMER OFF-PEAK ENERGY										
SECONDARY	456,284,000	0.00534	0.1560%	0.2400%	1.2270%	2,466	0.00569	2,625	0.04010	0.00569
PRIMARY	369,552,000	0.00280	0.1560%	0.2400%	1.2270%	1,046	0.00312	1,167	0.03753	0.00312
TRANSMISSION	0	0.00167	0.1560%	0.2400%	1.2270%	0	0.00199	0	0.03640	0.00199
ECAC/AER	825,836,000	0.03445	0.1560%	0.2400%	1.2270%	28,775	0.03441	28,742		0.03441
WINTER PEAK ENERGY										
SECONDARY	162,163,000	0.03852	0.1560%	0.2400%	1.2270%	6,317	0.03911	6,415	0.07352	0.03911
PRIMARY	124,156,000	0.03379	0.1560%	0.2400%	1.2270%	4,243	0.03435	4,314	0.06876	0.03435
TRANSMISSION	0	0.03174	0.1560%	0.2400%	1.2270%	0	0.03228	0	0.06669	0.03228
ECAC/AER	286,319,000	0.03445	0.1560%	0.2400%	1.2270%	9,976	0.03441	9,965		0.03441
WINTER SEMI-PEAK ENERGY										
SECONDARY	633,451,000	0.01157	0.1560%	0.2400%	1.2270%	7,413	0.01196	7,664	0.04637	0.01196
PRIMARY	504,227,000	0.00828	0.1560%	0.2400%	1.2270%	4,222	0.00864	4,409	0.04305	0.00864
TRANSMISSION	0	0.00699	0.1560%	0.2400%	1.2270%	0	0.00735	0	0.04176	0.00735
ECAC/AER	1,137,678,000	0.03445	0.1560%	0.2400%	1.2270%	39,641	0.03441	39,595		0.03441
WINTER OFF-PEAK ENERGY										
SECONDARY	603,045,000	0.00427	0.1560%	0.2400%	1.2270%	2,604	0.00461	2,809	0.03902	0.00461
PRIMARY	506,761,000	0.00078	0.1560%	0.2400%	1.2270%	402	0.00109	560	0.03550	0.00109
TRANSMISSION	0	-0.00028	0.1560%	0.2400%	1.2270%	0	0.00002	0	0.03443	0.00002
ECAC/AER	1,109,806,000	0.03445	0.1560%	0.2400%	1.2270%	38,669	0.03441	38,625		0.03441
TOTAL	4,419,274,000					$353,998		$356,690		

SUMMARY OF SCHEDULE AL-TOU	1/1/91 Rate Rev.	RDW 1/ Revenue	Adopted Rate Rev.
Customer Charge Revenues	$1,670	$2,505	$2,505
Demand Charge Revenues	130,538	137,065	138,115
Base Rate Revenues	67,482	60,446	62,265
ECAC/AER revenues	153,983	153,983	153,805
TOTAL AL-TOU Revenues	$353,673	$353,998	$356,690

1/ = Reflect Decision 91-04-026.

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
COMMERCIAL AND AGRICULTURAL RATE DESIGN
Forecast period: May 1, 1991 through April 30, 1992

RATE SCHEDULE	BILLING UNITS	PRESENT RATES 1/ ($/UNIT)	STANDBY ADJUST. FACTOR (%)	RATE LIMITER FACTOR (%)	SDFFD FACTOR (%)	PRESENT RATE REVENUES ($000's)	ADOPTED RATES 1/ ($/UNIT)	ADOPTED REVENUES ($000'S)	ADOPTED TOTAL RATES ($/UNIT)	ADOPTED OPTIONAL ON-PEAK RATES ($/UNIT)
SCHEDULE A6-TOU										
CUSTOMER CHARGE	571	600.00	0.5180%	0.1010%	1.2350%	$348	600.00	$348	600.00	600.00
NON-COINCIDENT DEMAND CHARGE										
PRIMARY	1,649,000	2.82	0.5180%	0.1010%	1.2350%	4,735	2.85	4,771	2.85	2.85
TRANSMISSION	208,000	1.19	0.5180%	0.1010%	1.2350%	251	1.20	253	1.20	1.20
SUMMER PEAK DEMAND										
PRIMARY	477,000	20.00	0.5180%	0.1010%	1.2350%	9,699	20.16	9,773	20.16	22.64
TRANSMISSION	51,000	12.82	0.5180%	0.1010%	1.2350%	665	12.92	670	12.92	14.51
WINTER PEAK DEMAND										
PRIMARY	586,000	4.67	0.5180%	0.1010%	1.2350%	2,783	4.71	2,805	4.71	4.71
TRANSMISSION	69,000	2.08	0.5180%	0.1010%	1.2350%	146	2.09	147	2.09	2.09
SUMMER PEAK ENERGY										
PRIMARY	65,487,000	0.04168	0.5180%	0.1010%	1.2350%	2,775	0.04230	2,816	0.07671	0.05175
TRANSMISSION	8,229,000	0.03940	0.5180%	0.1010%	1.2350%	330	0.04000	335	0.07441	0.04916
ECAC/AER	73,716,000	0.03445	0.5180%	0.1010%	1.2350%	2,582	0.03441	2,578		0.03441
SUMMER SEMI-PEAK ENERGY										
PRIMARY	87,087,000	0.01567	0.5180%	0.1010%	1.2350%	1,387	0.01609	1,424	0.05050	0.02230
TRANSMISSION	12,343,000	0.01416	0.5180%	0.1010%	1.2350%	178	0.01458	183	0.04899	0.02061
ECAC/AER	99,430,000	0.03445	0.5180%	0.1010%	1.2350%	3,482	0.03441	3,478		0.03441
SUMMER OFF-PEAK ENERGY										
PRIMARY	144,346,000	0.00280	0.5180%	0.1010%	1.2350%	411	0.00312	458	0.03753	0.00312
TRANSMISSION	25,372,000	0.00167	0.5180%	0.1010%	1.2350%	43	0.00199	51	0.03640	0.00199
ECAC/AER	169,718,000	0.03445	0.5180%	0.1010%	1.2350%	5,944	0.03441	5,936		0.03441
WINTER PEAK ENERGY										
PRIMARY	42,103,000	0.03379	0.5180%	0.1010%	1.2350%	1,446	0.03435	1,470	0.06876	0.03435
TRANSMISSION	5,034,000	0.03174	0.5180%	0.1010%	1.2350%	162	0.03228	165	0.06669	0.03228
ECAC/AER	47,137,000	0.03445	0.5180%	0.1010%	1.2350%	1,651	0.03441	1,649		0.03441
WINTER SEMI-PEAK ENERGY										
PRIMARY	166,122,000	0.00828	0.5180%	0.1010%	1.2350%	1,398	0.00864	1,460	0.04305	0.00864
TRANSMISSION	17,848,000	0.00699	0.5180%	0.1010%	1.2350%	127	0.00735	133	0.04176	0.00735
ECAC/AER	183,970,000	0.03445	0.5180%	0.1010%	1.2350%	6,443	0.03441	6,435		0.03441
WINTER OFF-PEAK ENERGY										
PRIMARY	199,987,000	0.00078	0.5180%	0.1010%	1.2350%	159	0.00109	222	0.03550	0.00109
TRANSMISSION	26,543,000	(0.00028)	0.5180%	0.1010%	1.2350%	(8)	0.00002	1	0.03443	0.00002
ECAC/AER	226,530,000	0.03445	0.5180%	0.1010%	1.2350%	7,933	0.03441	7,924		0.03441
TOTAL	800,501,000					$55,069		$55,485		

SUMMARY OF SCHEDULE A6-TOU	1/1/91 Rate Rev.	RDW 1/ Revenue	Adopted Rate Rev.
Customer Charge Revenues	$348	$348	$348
Demand Charge Revenues	17,409	18,279	18,418
Base Rate Revenues	9,604	8,408	8,719
ECAC/AER revenues	28,034	28,034	28,000
TOTAL A6-TOU Revenues	$55,395	$55,069	$55,485

SUMMARY OF SCHEDULES AL-TOU & A6-TOU		1/1/91 Rate Rev.	RDW % Change	RDW 1/ Revenue	Check:	Adopted Rate Rev.
Customer Charge Revenues		$2,018		$2,853		$2,853
DMND. Charge & Base Rate Revenues:						
Demand Charge		147,947	5.00%	155,344	5.00%	
Base Rate		77,086		68,854		
Subtotal		225,033		224,198		227,516
			Energy:		Energy:	
ECAC/AER revenues		182,017	-3.18%	182,017	-3.18%	181,806
TOTAL AL-TOU & A6-TOU	5,219,775,000	$409,068	0.00%	$409,068	-0.00%	$412,174

1/ = Reflect Decision 91-04-026.

APPENDIX C
TABLE 11
Sheet 5 of 9

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
COMMERCIAL AND AGRICULTURAL RATE DESIGN
Forecast period: May 1, 1991 through April 30, 1992

RATE SCHEDULE	BILLING UNITS	ADOPTED AL-TOU RATES ($/UNIT)	UADJUSTED REVENUES ($)	SEASONAL ADJUST. FACTOR (%)	STANDBY FACTOR (%)	RATE LIMITER FACTOR (%)	SDFFD FACTOR (%)	TOTAL REVENUES ($)	ADOPTED RATES 1/ ($/UNIT)	ADOPTED REVENUES ($)
SCHEDULE AY-TOU (AL-TOU DETERMINANTS)										
CUSTOMER CHARGE	82,542	30.00	$2,476	0.765%	0.156%	0.240%	1.227%	$2,485	30.00	$2,485
NON-COINCIDENT DEMAND										
SECONDARY	6,761,000	3.58	24,178	0.765%	0.156%	0.240%	1.227%	24,267	3.58	24,267
PRIMARY	4,773,000	2.85	13,584	0.765%	0.156%	0.240%	1.227%	13,634	2.85	13,634
YEAR PEAK DEMAND										
SECONDARY	5,934,000	9.71	57,614	0.765%	0.156%	0.240%	1.227%	57,826	9.71	57,826
PRIMARY	4,241,000	9.71	41,177	0.765%	0.156%	0.240%	1.227%	41,328	9.71	41,328
YEAR PEAK ENERGY										
SECONDARY	441,213,000	0.04447	19,621	0.765%	0.156%	0.240%	1.227%	19,693	0.04546	20,131
PRIMARY	325,901,000	0.03927	12,800	0.765%	0.156%	0.240%	1.227%	12,847	0.04020	13,149
ECAC/AER	767,114,000	0.03441	26,396	0.765%	0.156%	0.240%	1.227%	26,493	0.03441	26,493
YEAR SEMI-PEAK ENERGY										
SECONDARY	955,867,000	0.01420	13,576	0.765%	0.156%	0.240%	1.227%	13,626	0.01481	14,211
PRIMARY	760,651,000	0.01115	8,484	0.765%	0.156%	0.240%	1.227%	8,516	0.01173	8,952
ECAC/AER	1,716,518,000	0.03441	59,065	0.765%	0.156%	0.240%	1.227%	59,282	0.03441	59,282
YEAR OFF-PEAK ENERGY										
SECONDARY	1,059,329,000	0.00507	5,373	0.765%	0.156%	0.240%	1.227%	5,393	0.00557	5,919
PRIMARY	876,313,000	0.00195	1,708	0.765%	0.156%	0.240%	1.227%	1,714	0.00241	2,115
ECAC/AER	1,935,642,000	0.03441	66,605	0.765%	0.156%	0.240%	1.227%	66,850	0.03441	66,850
SUBTOTAL	4,419,274,000		$352,659					$353,955		$356,645
SCHEDULE AY-TOU (A-6 DETERMINANTS)										
CUSTOMER CHARGE	571	600.00	$343	0.765%	0.518%	0.101%	1.235%	$346	600.00	$346
NON-COINCIDENT DEMAND										
PRIMARY	1,649,000	2.85	4,700	0.765%	0.518%	0.101%	1.235%	4,741	2.85	4,741
TRANSMISSION	208,000	1.20	250	0.765%	0.518%	0.101%	1.235%	252	1.20	252
YEAR PEAK DEMAND										
PRIMARY	1,063,000	11.64	12,373	0.765%	0.518%	0.101%	1.235%	12,482	11.64	12,482
TRANSMISSION	120,000	6.69	803	0.765%	0.518%	0.101%	1.235%	810	6.69	810
YEAR PEAK ENERGY										
PRIMARY	107,590,000	0.03919	4,217	0.765%	0.518%	0.101%	1.235%	4,254	0.04012	4,354
TRANSMISSION	13,263,000	0.03707	492	0.765%	0.518%	0.101%	1.235%	496	0.03797	508
ECAC/AER	120,853,000	0.03441	4,159	0.765%	0.518%	0.101%	1.235%	4,195	0.03441	4,195
YEAR SEMI-PEAK ENERGY										
PRIMARY	253,209,000	0.01120	2,837	0.765%	0.518%	0.101%	1.235%	2,862	0.01178	3,008
TRANSMISSION	30,191,000	0.01030	311	0.765%	0.518%	0.101%	1.235%	314	0.01086	331
ECAC/AER	283,400,000	0.03441	9,752	0.765%	0.518%	0.101%	1.235%	9,838	0.03441	9,838
YEAR OFF-PEAK ENERGY										
PRIMARY	344,333,000	0.00194	669	0.765%	0.518%	0.101%	1.235%	675	0.00240	834
TRANSMISSION	51,915,000	0.00098	51	0.765%	0.518%	0.101%	1.235%	51	0.00143	75
ECAC/AER	396,248,000	0.03441	13,635	0.765%	0.518%	0.101%	1.235%	13,755	0.03441	13,755
SUBTOTAL	800,501,000		$54,591					55,073		55,530
TOTAL AL & A6	5,219,775,000		AL-TOU TRANSMISSION: SUMMER			10.64		$405,938		
(SEASONAL)			AL-TOU TRANSMISSION: WINTER			1.58				
TOTAL FOR AY (ANNUAL)	5,219,775,000		AY-TOU ON-PEAK DMND TRAN.			5.56		$409,028		$412,174

1/ = Reflect Decision 91-04-026.

APPENDIX C
TABLE 11
Sheet 6 of 9

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
COMMERCIAL AND AGRICULTURAL RATE DESIGN
Forecast period: May 1, 1991 through April 30, 1992

RATE SCHEDULE	BILLING UNITS	PRESENT RATES 1/ ($/UNIT)	PRESENT UNADJTD REVENUES ($)	VOLTAGE DISCOUNT FACTOR (%)	SDFFD (%)	PRESENT REVENUES ($)	ADOPTED RATES 1/ ($/UNIT)	ADOPTED TOTAL RATES ($/UNIT)	ADOPTED REVENUES ($)
SCHEDULE AO-TOU									
CUSTOMER CHARGE	82,542	50.00	$4,127	-2.7160%	1.154%	$4,061	50.00	50.00	$4,061
NON-COINCIDENT DEMAND	11,534,000	8.43	97,249	-2.7160%	1.154%	95,699	8.49	8.49	96,310
SUMMER ON-PEAK DEMAND	4,525,000	14.99	67,848	-2.7160%	1.154%	66,767	15.09	15.09	67,193
WINTER ON-PEAK DEMAND	5,650,000	4.03	22,781	-2.7160%	1.154%	22,418	4.06	4.06	22,561
ON-PEAK BASE	767,114,000	0.01013	7,769	-2.7160%	1.154%	7,645	0.01045	0.04486	7,890
ON-PEAK ECAC/AER	767,114,000	0.03445	26,427	0.0000%	1.154%	26,732	0.03441		26,701
SEMI-PEAK BASE	1,716,518,000	0.00284	4,873	-2.7160%	1.154%	4,795	0.00312	0.03753	5,265
SEMI-PEAK ECAC/AER	1,716,518,000	0.03445	59,134	0.0000%	1.154%	59,816	0.03441		59,747
OFF-PEAK BASE	1,935,642,000	-0.00112	(2,165)	-2.7160%	1.154%	(2,131)	-0.00087	0.03354	(1,649)
OFF-PEAK ECAC/AER	1,935,642,000	0.03445	66,683	0.0000%	1.154%	67,452	0.03441		67,374
TOTAL	4,419,274,000		$354,726			$353,256			$355,454
SCHEDULE A06-TOU									
CUSTOMER CHARGE	571	250.00	$143	-3.9210%	0.000%	$137	250.00	250.00	$137
NON-COINCIDENT DEMAND	1,857,000	8.43	15,657	-3.9210%	0.000%	15,043	8.49	8.49	15,139
SUMMER ON-PEAK DEMAND	528,000	17.87	9,436	-3.9210%	0.000%	9,066	17.98	17.98	9,120
WINTER ON-PEAK DEMAND	655,000	4.81	3,150	-3.9210%	0.000%	3,026	4.84	4.84	3,046
ON-PEAK BASE	120,853,000	0.01013	1,224	-3.9210%	0.000%	1,176	0.01045	0.04486	1,214
ON-PEAK ECAC/AER	120,853,000	0.03445	4,163	0.0000%	0.000%	4,163	0.03441		4,159
SEMI-PEAK BASE	283,400,000	0.00284	805	-3.9210%	0.000%	773	0.00312	0.03753	849
SEMI-PEAK ECAC/AER	283,400,000	0.03445	9,763	0.0000%	0.000%	9,763	0.03441		9,752
OFF-PEAK BASE	396,248,000	-0.00112	(443)	-3.9210%	0.000%	(426)	-0.00087	0.03354	(330)
OFF-PEAK ECAC/AER	396,248,000	0.03445	13,651	0.0000%	0.000%	13,651	0.03441		13,635
TOTAL	800,501,000		$57,548			$56,373			$56,720
TOTAL AO-TOU & A06-TOU	5,219,775,000		$412,274			$409,630			$412,174

SUMMARY OF SCHEDULES AO-TOU & A06-TOU	1/1/91 Rate Rev.	RDW % Change	RDW 1/ Revenue	Check:	Adopted Rate Rev.
Customer Charge Revenues	$4,198	0.00%	$4,198	-0.00%	$4,198
DMND. Charge Revenues	201,924	5.00%	$212,020	5.00%	$213,369
Base Rate Revenues	21,930	Base&ECAC	$11,833		$13,239
ECAC/AER revenues	181,578	-5.09%	$181,578	-4.96%	$181,367
TOTAL AO-TOU & A06-TOU	$409,630		$409,630	-0.00%	$412,174

REVENUE REQUIRMENT:	$412,174
Adopted DMND Charge & Base Rev.	$226,608
Adjtd. Adopted ECAC Rev.	$176,109
Present DMND Charge & Base Rev.	$223,853
Adjtd. present ECAC Rev.	$176,314
Index for energy & demand rates	1.00638
Adopted ECAC/AER rate:	0.03441

1/ = Reflect Decision 91-04-026.

APPENDIX C
TABLE 11
Sheet 7 of 9

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
COMMERCIAL AND AGRICULTURAL RATE DESIGN
Forecast period: May 1, 1991 through April 30, 1992

SCHEDULES A-E2, R-TOU-3, R-TOU-4 1/	A-E2		R-TOU-3		R-TOU-4	
1. Customer charge (excl. metering costs)	$140.00		$140.00		$140.00	
2. Ratcheted Maximum Demand Charge						
a. Secondary distribution	$3.58		$3.58		$3.58	
b. Primary distribution	$2.85		$2.85		$2.85	
c. Transmission distribution	$1.20		$1.20		$1.20	
3. Marginal Capacity Cost -- Coincident Portion						
a. Generation	$74.70					
b. 75.88% of Transmission	16.97					
c. 25.88% of Distribution	22.54					
d. Total	$114.22					
4. Contract Minimum Demand Charge						
a. At least (Line 3d * EPMC / 12 month	$10.75					
b. At least the monthly average AL-TOU on-peak demand charge	$9.35					
c. Resulting minimum demand charge	$10.75		$10.75		$10.75	
5. On-peak energy charge						
a. Estimated average number of hours of on-peak periods per year	20.00					
b. Capacity allocation (Line 3d / line 5a)	$5.71078					
c. + Marginal energy cost	$0.03525					
d. Total	$5.74602					
6. On-peak energy charge						
a. Marginal cost (energy + coincident capacity)						
i. Super On-peak	N/A		$1.14399		$0.44895	
ii. On-peak	$4.04600		$0.09253		$0.07419	
iii. Semi-peak	$0.06085		$0.04426		$0.04004	
iv. Off-peak	$0.02963		$0.02963		$0.02963	
b. Revenue at line 6a's marginal cost (Neglects customer & non-coincident demand costs)	317,654		316,726		317,519	
c. On-Peak energy charge (Line 6a * revenue reconcilliation)	$4.57078					
7. Recommended On-peak energy charge	$4.57078					
8. Sales (Use entire AL-TOU/ A-6 TOU class for revenue neutrality)						
a. Super On-peak			101,123	0.01937	297,866	0.05707
b. On-peak	17,183	0.00329	196,733	0.03769	339,938	0.06513
c. Semi-peak	3,010,286	0.57671	2,529,581	0.48462	2,189,633	0.41949
d. Off-peak	2,192,306	0.42000	2,392,338	0.45832	2,392,338	0.45832
d. Total	5,219,775	1.00000	5,219,775	5,219,775	5,219,775	5,219,775
e. Ratcheted Maximum Demand						
i. Secondary distribution	6,761		6,761		6,761	
ii. Primary distribution	6,422		6,422		6,422	
iii. Transmission distribution	208.00		208.00		208	
f. Customers	6,926		6,926		6,926	

APPENDIX C
TABLE 11
Sheet 8 of 9

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
COMMERCIAL AND AGRICULTURAL RATE DESIGN
Forecast period: May 1, 1991 through April 30, 1992

SCHEDULES A-E2, R-TOU-3, R-TOU-4 1/	A-E2		R-TOU-3		R-TOU-4	
(Cont. of sheet 7)						
9. Rate calculations						
a. Revenue target	412,174		412,174		412,174	
b. Customer charge revenue	11,636		11,636		11,636	
c. Ratcheted Maximum Demand Charge revenue						
i. Secondary distribution	24,204		24,204		24,204	
ii. Primary distribution	18,303		18,303		18,303	
iii. Transmission distribution	250		250		250	
d. Voltage Discount adjustment	(6,135)	0.01489	(6,135)		(6,135)	
e. Franchise Fee adjustment	5,061	0.01228	5,061		5,061	
f. On-peak energy charge revenue	78,542					
g. Remaining revenue requirement	280,314		358,856		358,856	
h. Ratio, semi/off-peak energy cost	2.05					
i. Off-peak rate (Floor Limit of ECAC)	0.03441					
(Line 9g / [(Line 9h * line 8b) + + line 8c]; use a cap of the AL/A6-TOU off-peak rate)	$0.03441					
j. Off-peak energy charge revenue	75,437					
k. Remaining revenue requirement	204,876					
l. Semi-peak rate	$0.06806					
m. Ratio, semi/off-peak energy charge	1.98					
n. Energy Charges						
i. Super On-peak			$1.28685	130,130	$0.50340	149,945
ii. On-peak			$0.10408	20,477	$0.08319	28,280
iii. Semi-peak			$0.04978	125,929	$0.04490	98,310
iv. Off-peak			$0.03441	82,320	$0.03441	82,320
d. Total				358,856		358,856

1/ = Adopted rates reflect Decision 91-04-026.

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
COMMERCIAL AND AGRICULTURAL RATE DESIGN
Forecast period: May 1, 1991 through April 30, 1992

SCHEDULE A-E1 1/

ON-PEAK ENERGY, CUSTOMER CHARGE, SEMI-PEAK DEMAND

CURRENT ON-PEAK ENERGY	$8.70795
CURRENT ECAC/AER	$0.03445
CURRENT BASE	$8.67350
ADOPTED ECAC/AER	$0.03441
ADOPTED ON-PEAK ENERGY	$8.70791
CUSTOMER CHARGE	$600.00
SEMI-PEAK DEMAND CHARGE	$0.50

AL-TOU AND A-6 TOU SALES DATA FOR REVENUE NEUTRAL DESIGN

ON-PEAK ENERGY	15,659,325
SEMI-PEAK ENERGY	2,949,172,875
OFF-PEAK ENERGY	2,254,942,800
TOTAL ENERGY (kwh)	5,219,775,000
SEMI-PEAK DEMAND	13,258,229
CUSTOMER MONTHS	6,926

SCHEDULE A-E1 RATE DESIGN

AL AND A-6 REVENUE ALLOCATION	$412,174,227
LESS CUSTOMER CHARGE REVENUE	$49,867,800
LESS SEMI-PEAK DEMAND CHARGE REVENUE	$6,629,114
LESS ON-PEAK ENERGY CHARGE REVENUE	$136,360,055
EQUALS REMAINING REVENUE REQUIREMENT FOR SEMI AND OFF-PEAK RATE	$219,317,257
APPROVED SEMI/OFF-PEAK ENERGY COST RATIO	1.83
OFF-PEAK RATE	$0.03441
OFF-PEAK ENERGY CHARGE REVENUE	$77,592,582
REMAINING REVENUE REQUIREMENT FOR OFF-PEAK RATE	$141,724,676
SEMI-PEAK RATE	$0.04806

SCHEDULE A-E1 DESIGNED RATE SUMMARY

CUSTOMER CHARGE	$600.00
SEMI-PEAK DEMAND CHARGE	$0.50
CONTRACT DEMAND CHARGE	$14.44
ON-PEAK ENERGY	$8.70791
SEMI-PEAK ENERGY	$0.04806
OFF-PEAK ENERGY	$0.03441

1/ = Adopted rates reflect Decision 91-04-026.

APPENDIX C
TABLE 12
Sheet 1 of 4

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
STREETLIGHT SCHEDULES
Forecast period: May 1, 1991 through April 30, 1992

WATTS	LUMENS	NUMBER OF LAMPS	PRESENT RATES ($/Lamp)	PRESENT RATE REVENUES ($000)	ADOPTED RATES ($/Lamp)	REVENUES AT ADOPTED RATES ($000)	REVENUES ADJTD. FOR SDFFD ($000) [1]
LS-1, Mercury Vapor, Class A							
175	7,000	7,858	10.29	81	10.01	79	79
250	10,000	123	13.64	2	13.26	2	2
400	20,000	2,074	18.73	39	18.12	38	38
700	35,000	56	35.99	2	34.52	2	2
LS-1, Mercury Vapor, Class C, 1-Lamp							
175	7,000	448	18.93	8	18.65	8	8
250	10,000	1	25.14	0	24.75	0	0
400	20,000	314	30.23	9	29.62	9	9
LS-1, Mercury Vapor, Class C, 2-Lamp							
175	7,000	34	28.95	1	28.40	1	1
400	20,000	1	49.55	0	48.34	0	0
LS-1, HPSV, Class A							
70	5,800	19,280	6.67	129	6.54	126	126
100	9,500	146,977	7.75	1,139	7.56	1,111	1112
150	16,000	5,593	9.21	52	8.95	50	50
200	22,000	146	11.09	2	10.77	2	2
250	30,000	19,269	13.99	270	13.58	262	262
400	50,000	168	17.58	3	16.95	3	3
1000	140,000	1	36.74	0	35.28	0	0
LS-1, HPSV, Class B, 1-Lamp							
70	5,800	7,656	7.35	56	7.22	55	55
100	9,500	17,969	8.43	151	8.24	148	148
150	16,000	1,995	9.89	20	9.64	19	19
200	22,000	527	11.97	6	11.64	6	6
250	30,000	4,192	14.87	62	14.46	61	61
400	50,000	90	18.56	2	17.92	2	2
1000	140,000	1	37.80	0	36.33	0	0

WATTS	LUMENS	NUMBER OF LAMPS	PRESENT RATES ($/Lamp)	PRESENT RATE REVENUES ($000)	ADOPTED RATES ($/Lamp)	REVENUES AT ADOPTED RATES ($000)	REVENUES ADJTD. FOR SDFFD ($000) [1]
LS-1, HPSV, Class B, 2-Lamp							
70	5,800	179	12.83	2	12.56	2	2
100	9,500	1,121	14.98	17	14.61	16	16
150	16,000	1,199	17.91	21	17.40	21	21
200	22,000	1	21.93	0	21.27	0	0
250	30,000	34	27.74	1	26.91	1	1
400	50,000	1	34.84	0	33.57	0	0
1,000	140,000	1	73.28	0	70.35	0	0
LS-1, HPSV, Class C, 1-Lamp							
70	5,800	13,877	15.30	212	15.17	211	211
100	9,500	52,326	16.38	857	16.20	847	848
150	16,000	4,147	17.86	74	17.61	73	73
200	22,000	1	22.58	0	22.26	0	0
250	30,000	5,268	25.48	134	25.07	132	132
400	50,000	1,569	30.53	48	29.90	47	47
1,000	140,000	1	50.66	0	49.20	0	0
LS-1, HPSV, Class C, 2-Lamp							
70	5,800	448	21.70	10	21.44	10	10
100	9,500	919	23.85	22	23.48	22	22
150	16,000	235	26.80	6	26.29	6	6
200	22,000	1	34.25	0	33.60	0	0
250	30,000	504	40.06	20	39.23	20	20
400	50,000	1	46.16	0	44.90	0	0
1,000	140,000	1	85.91	0	82.98	0	0
LS-1, LPSV, Class A							
35	4,800	1	8.08	0	7.99	0	0
55	8,000	560	8.75	5	8.64	5	5
90	13,500	370	10.84	4	10.65	4	4

APPENDIX C
TABLE 12
Sheet 2 of 4

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
STREETLIGHT SCHEDULES
Forecast period: May 1, 1991 through April 30, 1992

WATTS	LUMENS	NUMBER OF LAMPS	PRESENT RATES ($/Lamp)	PRESENT RATE REVENUES ($000)	ADOPTED RATES ($/Lamp)	REVENUES AT ADOPTED RATES ($000)	REVENUES ADJTD. FOR SDFFD ($000) [1]
135	22,500	112	13.41	2	13.15	1	1
180	33,000	1,928	14.58	28	14.28	28	28
LS-1, LPSV, Class B, 1-Lamp							
35	4,800	1	8.77	0	8.68	0	0
55	8,000	276	9.55	3	9.44	3	3
90	13,500	242	11.64	3	11.45	3	3
135	22,500	241	14.41	3	14.14	3	3
180	33,000	241	15.58	4	15.28	4	4
LS-1, LPSV, Class B, 2-Lamp							
35	4,800	1	15.66	0	15.49	0	0
55	8,000	1	17.11	0	16.89	0	0
90	13,500	1	21.29	0	20.92	0	0
135	22,500	1	26.70	0	26.17	0	0
180	33,000	1	29.04	0	28.44	0	0
LS-1, LPSV, Class C, 1-Lamp							
35	4,800	1	16.72	0	16.64	0	0
55	8,000	359	17.50	6	17.39	6	6
90	13,500	280	19.60	5	19.42	5	5
135	22,500	247	25.02	6	24.76	6	6
180	33,000	269	26.19	7	25.89	7	7
LS-1, LPSV, Class C, 2-Lamp							
35	4,800	1	24.53	0	24.36	0	0
55	8,000	1	25.98	0	25.76	0	0
90	13,500	1	30.18	0	29.81	0	0
135	22,500	1	39.02	0	38.50	0	0
180	33,000	1	41.37	0	40.77	0	0
LS-1, Facilities and Rates, Class A							
Center Suspension		12	4.77	0	4.77	0	0

WATTS	LUMENS	NUMBER OF LAMPS	PRESENT RATES ($/Lamp)	PRESENT RATE REVENUES ($000)	ADOPTED RATES ($/Lamp)	REVENUES AT ADOPTED RATES ($000)	REVENUES ADJTD. FOR SDFFD ($000) [1]
Non-Standard Wood Pole							
30-foot		9,264	2.39	22	2.39	22	22
35-foot		1,680	2.69	5	2.69	5	5
Recator Ballast Discount							
175		3,139	(0.98)	(3)	(0.98)	(3)	(3)
250		11	(0.38)	(0)	(0.38)	(0)	(0)
SUBTOTAL REVENUE LS-1				3,559		3,490	3,492
LS-2, Mercury Vapor, Rate A							
175	7,000	22,621	5.53	125	5.25	119	120
250	10,000	471	7.68	4	7.30	3	3
400	20,000	11,546	12.11	140	11.49	133	134
700	35,000	482	20.53	10	19.49	9	9
1,000	55,000	45	29.00	1	27.54	1	1
LS-2, Mercury Vapor, Rate B, Energy & Limited Maintenance							
175	7,000	6,401	6.13	39	5.85	37	38
250	10,000	22	8.29	0	7.90	0	0
400	20,000	1,625	12.72	21	12.10	20	20
LS-2, Mercury Vapor, Surcharge for series service							
175	7,000	804	0.40	0	0.40	0	0
250	10,000	1	0.50	0	0.50	0	0
400	20,000	3,900	0.72	3	0.72	3	3
700	35,000	312	1.32	0	1.32	0	0

APPENDIX C
TABLE 12
Sheet 3 of 4

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
STREETLIGHT SCHEDULES
Forecast period: May 1, 1991 through April 30, 1992

WATTS	LUMENS	NUMBER OF LAMPS	PRESENT RATES ($/Lamp)	PRESENT RATE REVENUES ($000)	ADOPTED RATES ($/Lamp)	REVENUES AT ADOPTED RATES ($000)	REVENUES ADJTD. FOR SDFFD ($000) [1]
LS-2, HPSV, Rate A							
50	3,300	1,334	1.53	2	1.45	2	2
70	5,800	46,452	2.66	124	2.52	117	118
100	9,500	85,808	3.71	318	3.52	302	304
150	16,000	23,697	5.08	120	4.82	114	115
200	22,000	26,622	6.47	172	6.15	164	165
250	30,000	48,010	8.24	396	7.82	376	378
310	37,000	3,441	10.08	35	9.57	33	33
400	50,000	3,654	12.53	46	11.89	43	44
1,000	140,000	1	29.00	0	27.54	0	0
LS-2, HPSV, Rate B, Energy & Limited Maintenance							
50	3,300	1	2.21	0	2.13	0	0
70	5,800	796	3.33	3	3.20	3	3
100	9,500	1,087	4.38	5	4.20	5	5
150	16,000	2,376	5.77	14	5.52	13	13
200	22,000	1	7.17	0	6.84	0	0
250	30,000	572	8.93	5	8.51	5	5
310	37,000	1	10.78	0	10.27	0	0
400	50,000	1	13.23	0	12.60	0	0
1,000	140,000	1	29.86	0	28.40	0	0
LS-2, HPSV, Reduction for 120-volt Reactor Ballast							
70	5,800	20,782	(0.40)	(8)	(0.40)	(8)	(8)
100	9,500	18,888	(0.53)	(10)	(0.53)	(10)	(10)
150	16,000	8,048	(0.49)	(4)	(0.49)	(4)	(4)

WATTS	LUMENS	NUMBER OF LAMPS	PRESENT RATES ($/Lamp)	PRESENT RATE REVENUES ($000)	ADOPTED RATES ($/Lamp)	REVENUES AT ADOPTED RATES ($000)	REVENUES ADJTD. FOR SDFFD ($000) [1]
LS-2, HPSV, Surcharge for Series Service							
50	3,300	1	0.45	0	0.45	0	0
70	5,800	1	(0.22)	(0)	(0.22)	(0)	(0)
100	9,500	336	(0.23)	(0)	(0.23)	(0)	(0)
150	16,000	156	0.02	0	0.02	0	0
200	22,000	132	0.48	0	0.48	0	0
LS-2, LPSV, Rate A							
35	4,800	22,183	1.71	38	1.63	36	36
55	8,000	259,621	2.25	584	2.13	554	558
90	13,500	70,832	3.70	262	3.52	249	251
135	22,500	57,796	5.26	304	5.00	289	291
180	33,000	16,680	6.00	100	5.70	95	96
LS-2, LPSV, Surcharge for series service							
35	4,800	15,108	(0.23)	(3)	(0.23)	(3)	(3)
55	8,000	13,788	(0.13)	(2)	(0.13)	(2)	(2)
90	13,500	1,596	0.45	1	0.45	1	1
135	22,500	16,572	0.80	13	0.80	13	13
180	33,000	120	0.51	0	0.51	0	0
LS-2, Incandescent Lamps, Rate A, Energy Only							
	1,000	493	1.87	1	1.77	1	1
	2,500	22	4.14	0	3.93	0	0
	4,000	1	6.23	0	5.92	0	0
	6,000	168	9.15	2	8.69	1	1
	10,000	34	15.53	1	14.75	1	1

APPENDIX C
TABLE 12
Sheet 4 of 4

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
STREETLIGHT SCHEDULES
Forecast period: May 1, 1991 through April 30, 1992

WATTS	LUMENS	NUMBER OF LAMPS	PRESENT RATES ($/Lamp)	PRESENT RATE REVENUES ($000)	ADOPTED RATES ($/Lamp)	REVENUES AT ADOPTED RATES ($000)	REVENUES ADJTD. FOR SDFFD ($000) [1]
LS-2, Incdsnt Lamps, Rate B, Energy and Limited Maintenance							
	4,000	1	8.19	0	7.88	0	0
	6,000	67	11.15	1	10.69	1	1
SUBTOTAL REVENUE LS-3				2,861		2,716	2,735
LS-3							
Energy Charge		5,673,000	0.08215	466	0.07653	434	439
Minimum Charge		1	5.81	0	5.81	0	0
SUBTOTAL REVENUE LS-2				466		434	439
OL-1, Mercury Vapor, Rate A, St Light Luminaire							
175	7,000	1	10.14	0	9.88	0	0
400	20,000	1	20.58	0	19.97	0	0
OL-1, HPSV, Rate A, Street Light Luminaire							
100	9,500	54,926	8.53	469	8.35	459	462
150	16,000	3,531	10.01	35	9.76	34	35
250	30,000	31,386	15.28	480	14.87	467	470
400	50,000	1,569	18.60	29	17.97	28	28
1,000	140,000	1	38.43	0	36.97	0	0
OL-1, HPSV, Rate B, Directional Luminaire							
250	30,000	1,681	18.20	31	17.57	30	30
400	50,000	560	22.60	13	21.63	12	12
1,000	140,000	168	40.17	7	37.93	6	6

WATTS	LUMENS	NUMBER OF LAMPS	PRESENT RATES ($/Lamp)	PRESENT RATE REVENUES ($000)	ADOPTED RATES ($/Lamp)	REVENUES AT ADOPTED RATES ($000)	REVENUES ADJTD. FOR SDFFD ($000) [1]
OL-1, LPSV, Rate A, Street Light Luminaire							
55.00	8,000	0.00	8.86	0	8.75	0	0
90.00	13,000	0.00	10.97	0	10.78	0	0
135.00	22,500	0.00	13.58	0	13.31	0	0
180.00	33,000	0.00	14.77	0	14.46	0	0
OL-1, Pole							
30 ft wood pole		14,040	3.16	44	3.16	44	45
35 ft wood pole		18,000	3.55	64	3.55	64	64
SUBTOTAL REVENUE OL-1				1,171		1,144	1,152
DWL, facilities Charges							
$ of Util invst.		8,500,000	0.0186	158	0.0186	158	159
DWL, Energy and Lamp Maintenance Charge							
50 Watt HPSV		13,732	3.28	45	3.21	44	44
DWL, Min. Charge		1	151.27	0	151.33	0	0
SUBTOTAL REVENUE DWL				203		202	203
TOTAL STREET LIGHT REVENUES				8,261		7,987	8,021

[1] Based on the following San Diego Franchise Fee Differential (SDFFD) Factors:

LS-1:	0.059%	OL-1:	0.689%
LS-2:	0.673%	DWL :	0.465%
LS-3:	1.165%		

(END OF APPENDIX C)

APPENDIX D

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT

SUMMARY OF RATES

Note: Rates in this appendix reflect the LIRA surcharge fee of $0.00041/kwh for applicable rate schedules.

For Streetlight Rate Schedules, see Appendix C, Table 12, pages 27 - 30.

APPENDIX D
TABLE 1
Sheet 1 of 2

SAN DIEGO GAS & ELECTRIC COMPANY - ELECTRIC DEPARTMENT

RESIDENTIAL RATES

RATE SCHEDULE	UNITS	1/1/91 RATE	RDW RATE 1/	RDW CHANGE %	ADOPTED RATE	CHANGE FROM 1/1/91 AMOUNT	CHANGE FROM 1/1/91 %
SCHEDULE DR							
Baseline Energy	$/Kwh	0.09368	0.09368	0.00%	0.09481	0.00113	1.20%
Non-Baseline Energy	$/Kwh	0.12889	0.12889	0.00%	0.12480	(0.00409)	-3.17%
Minimum Bill	$/Day	0.164	0.164	0.00%	0.164	0.000	0.00%
SCHEDULE DR-LI							
Baseline Energy	$/Kwh	0.07963	0.07963	0.00%	0.08024	0.00061	0.76%
Non-Baseline Energy	$/Kwh	0.10956	0.10956	0.00%	0.10573	(0.00383)	-3.49%
Minimum Bill	$/Day	0.139	0.139	0.00%	0.139	0.000	0.00%
SCHEDULE DM							
Baseline Energy	$/Kwh	0.09368	0.09368	0.00%	0.09481	0.00113	1.20%
Non-Baseline Energy	$/Kwh	0.12889	0.12889	0.00%	0.12480	(0.00409)	-3.17%
Minimum Bill	$/Day	0.164	0.164	0.00%	0.164	0.000	0.00%
SCHEDULE DS							
Baseline Energy	$/Kwh	0.09368	0.09368	0.00%	0.09481	0.00113	1.20%
Non-Baseline Energy	$/Kwh	0.12889	0.12889	0.00%	0.12480	(0.00409)	-3.17%
Baseline Energy L/I	$/Kwh	0.07963	0.07963	0.00%	0.08024	0.00061	0.76%
Non-Baseline Energy L/I	$/Kwh	0.10956	0.10956	0.00%	0.10573	(0.00383)	-3.49%
Unit Discount	$/Day	0.110	0.110	0.00%	0.110	0.000	0.00%
Minimum Bill	$/Day	0.164	0.164	0.00%	0.164	0.000	0.00%
Minimum Bill - L/I	$/Day	0.139	0.139	0.00%	0.139	0.000	0.00%
SCHEDULE DT							
Baseline Energy	$/Kwh	0.09368	0.09368	0.00%	0.09481	0.00113	1.20%
Non-Baseline Energy	$/Kwh	0.12889	0.12889	0.00%	0.12480	(0.00409)	-3.17%
Baseline Energy L/I	$/Kwh	0.07963	0.07963	0.00%	0.08024	0.00061	0.76%
Non-Baseline Energy L/I	$/Kwh	0.10956	0.10956	0.00%	0.10573	(0.00383)	-3.49%
Space Discount	$/Day	0.312	0.312	0.00%	0.312	0.000	0.00%
Minimum Bill	$/Day	0.164	0.164	0.00%	0.164	0.000	0.00%
Minimum Bill - L/I	$/Day	0.139	0.139	0.00%	0.139	0.000	0.00%
SCHEDULE D-SMF							
Customer Charge	$/Month	20.00	20.00	0.00%	20.00	0.00	0.00%
On-Peak Demand	$/KW	8.83	9.28	5.06%	9.35	0.52	5.83%
Baseline Energy	$/Kwh	0.07925	0.07866	-0.74%	0.07927	0.00002	0.02%
Non-Baseline Energy	$/Kwh	0.10903	0.10822	-0.74%	0.10435	(0.00468)	-4.30%
Baseline Energy L/I	$/Kwh	0.06736	0.06686	-0.74%	0.06738	0.00002	0.03%
Non-Baseline Energy L/I	$/Kwh	0.09268	0.09199	-0.74%	0.08869	(0.00399)	-4.30%
Unit Discount	$/Kwh	0.110	0.110	0.00%	0.110	0.000	0.00%
Space Discount	$/Kwh	0.312	0.312	0.00%	0.312	0.000	0.00%
SCHEDULE D-ATOU							
Minimum Bill	$/Day	0.164	0.164	0.00%	0.164	0.000	0.00%
Metering Charge	$/Day	0.06	0.06	0.00%	0.06	0.00	0.00%
Energy: Baseline/On-Peak	$/Kwh	0.14620	0.14620	0.00%	0.14797	0.00177	1.21%
Energy: Baseline/Off-Peak	$/Kwh	0.07310	0.07310	0.00%	0.07398	0.00088	1.21%
Energy: Non-BL/On-Peak	$/Kwh	0.20115	0.20115	0.00%	0.19478	(0.00637)	-3.17%
Energy: Non-BL/Off-Peak	$/Kwh	0.10058	0.10058	0.00%	0.09739	(0.00319)	-3.17%
Baseline Adjustment	$/Kwh	0.00000	0.00000	0.00%	0.00000	0.00000	0.00%
SCHEDULE D-UTOU							
Minimum Bill	$/Day	0.164	0.164	0.00%	0.164	0.000	0.00%
Metering Charge	$/Day	0.06	0.06	0.00%	0.06	0.00	0.00%
Energy: Baseline/On-Peak	$/Kwh	0.10100	0.10100	0.00%	0.10222	0.00122	1.21%
Energy: Baseline/Off-Peak	$/Kwh	0.05050	0.05050	0.00%	0.05111	0.00061	1.21%
Energy: Non-BL/On-Peak	$/Kwh	0.13896	0.13896	0.00%	0.13456	(0.00440)	-3.17%
Energy: Non-BL/Off-Peak	$/Kwh	0.06948	0.06948	0.00%	0.06728	(0.00220)	-3.17%
Baseline Adjustment	$/Kwh	0.00000	0.00000	0.00%	0.00000	0.00000	0.00%

1/ = Adopted in Decision 91-04-026.

APPENDIX D
TABLE 1
Sheet 2 of 2

SAN DIEGO GAS & ELECTRIC COMPANY - ELECTRIC DEPARTMENT

RESIDENTIAL RATES

RATE SCHEDULE	UNITS	1/1/91 RATE	RDW RATE 1/	RDW CHANGE %	ADOPTED RATE	CHANGE FROM 1/1/91 AMOUNT	CHANGE FROM 1/1/91 %
SCHEDULE DR-TOU							
Minimum Bill	$/Day	0.164	0.164	0.00%	0.164	0.000	0.00%
Metering Charge	$/Day	3.28	3.28	0.00%	3.28	0.00	0.00%
On-Peak Energy: Summer	$/Kwh	0.31214	0.31214	0.00%	0.30826	(0.00388)	-1.24%
Off-Peak Energy: Summer	$/Kwh	0.08570	0.08570	0.00%	0.08210	(0.00360)	-4.20%
On-Peak Energy: Winter	$/Kwh	0.13062	0.13062	0.00%	0.12298	(0.00764)	-5.85%
Off-Peak Energy: Winter	$/Kwh	0.08570	0.08570	0.00%	0.08210	(0.00360)	-4.20%
Baseline Adjustment	$/Kwh	0.03521	0.03521	0.00%	0.03000	(0.00521)	-14.81%
SCHEDULE DR-TOU-2							
Minimum Bill	$/Day	0.164	0.164	0.00%	0.164	0.000	0.00%
Metering Charge	$/Day	3.28	3.28	0.00%	3.28	0.00	0.00%
On-Peak Energy: Summer	$/Kwh	0.25852	0.25852	0.00%	0.26283	0.00431	1.67%
Off-Peak Energy: Summer	$/Kwh	0.07098	0.07098	0.00%	0.07005	(0.00093)	-1.31%
On-Peak Energy: Winter	$/Kwh	0.10818	0.10818	0.00%	0.10490	(0.00328)	-3.04%
Off-Peak Energy: Winter	$/Kwh	0.07098	0.07098	0.00%	0.07005	(0.00093)	-1.31%

1/ = Adopted in Decision 91-04-026.

APPENDIX D
TABLE 1
Sheet 1 of 6

SAN DIEGO GAS & ELECTRIC COMPANY - ELECTRIC DEPARTMENT

COMMERCIAL AND INDUSTRIAL RATES

RATE SCHEDULE	UNITS	1/1/91 RATE	RDW RATE 1/	RDW CHANGE %	ADOPTED RATE	CHANGE FROM 1/1/91 AMOUNT	CHANGE FROM 1/1/91 %
SCHEDULE A							
Customer Charge	$/Month	5.00	5.00	0.00%	5.00	0.00	0.00%
Energy Charge	$/Kwh	0.09819	0.09819	0.00%	0.09938	0.00119	1.21%
SCHEDULE AD							
Customer Charge	$/Month	10.00	15.00	50.00%	15.00	5.00	50.00%
Demand Charge	$/Kw	5.96	6.26	5.00%	6.48	0.52	8.75%
Energy Charge	$/Kwh	0.06578	0.06460	-1.79%	0.06691	0.00113	1.72%
On-peak Rate Limiter: Summer	$/Kw	0.67	0.67	0.00%	0.74	0.07	10.45%
On-peak Rate Limiter: Winter	$/Kw	0.26	0.26	0.00%	0.29	0.03	11.54%

1/ = Adopted in Decision 91-04-026.

SAN DIEGO GAS & ELECTRIC COMPANY - ELECTRIC DEPARTMENT

COMMERCIAL AND INDUSTRIAL RATES

RATE SCHEDULE	UNITS	1/1/91 RATE	RDW RATE 1/	RDW CHANGE %	ADOPTED RATE	CHANGE FROM 1/1/91 AMOUNT	CHANGE FROM 1/1/91 %
SCHEDULE AL-TOU (Default Times)							
Service Charge	$/Month	20.00	30.00	50.00%	30.00	10.00	50.00%
On-Peak Rate Limiter: Summer	$/Kwh	0.72	0.72	0.00%	0.74	0.02	2.78%
On-Peak Rate Limiter: Winter	$/Kwh	0.28	0.28	0.00%	0.29	0.01	3.57%
Average Rate Limiter	$/Kwh	0.21	0.21	0.00%	0.35	0.14	66.67%
Non-Coincident Demand							
Secondary	$/KW	3.38	3.55	5.00%	3.58	0.20	5.80%
Primary	$/KW	2.69	2.82	5.00%	2.85	0.16	5.80%
Transmission	$/KW	1.13	1.19	5.00%	1.20	0.07	5.80%
On-Peak Demand: Summer							
Secondary	$/KW	15.99	16.79	5.00%	16.92	0.93	5.80%
Primary	$/KW	15.99	16.79	5.00%	16.92	0.93	5.80%
Transmission	$/KW	10.06	10.56	5.00%	10.64	0.58	5.80%
On-Peak Demand: Winter							
Secondary	$/KW	3.72	3.91	5.00%	3.94	0.22	5.80%
Primary	$/KW	3.72	3.91	5.00%	3.94	0.22	5.80%
Transmission	$/KW	1.49	1.56	5.00%	1.58	0.09	5.80%
On-Peak Energy: Summer							
Secondary	$/Kwh	0.08404	0.08137	-3.18%	0.08199	(0.00205)	-2.44%
Primary	$/Kwh	0.07863	0.07613	-3.18%	0.07671	(0.00192)	-2.44%
Transmission	$/Kwh	0.07627	0.07385	-3.18%	0.07441	(0.00186)	-2.44%
Semi-Peak Energy: Summer							
Secondary	$/Kwh	0.05434	0.05261	-3.18%	0.05302	(0.00132)	-2.44%
Primary	$/Kwh	0.05176	0.05012	-3.18%	0.05050	(0.00126)	-2.44%
Transmission	$/Kwh	0.05021	0.04861	-3.18%	0.04899	(0.00122)	-2.44%
Off-Peak Energy: Summer							
Secondary	$/Kwh	0.04110	0.03979	-3.18%	0.04010	(0.00100)	-2.44%
Primary	$/Kwh	0.03847	0.03725	-3.18%	0.03753	(0.00094)	-2.44%
Transmission	$/Kwh	0.03731	0.03612	-3.18%	0.03640	(0.00091)	-2.44%
On-Peak Energy: Winter							
Secondary	$/Kwh	0.07536	0.07297	-3.18%	0.07352	(0.00184)	-2.44%
Primary	$/Kwh	0.07048	0.06824	-3.18%	0.06876	(0.00172)	-2.44%
Transmission	$/Kwh	0.06836	0.06619	-3.18%	0.06669	(0.00167)	-2.44%
Semi-Peak Energy: Winter							
Secondary	$/Kwh	0.04753	0.04602	-3.18%	0.04637	(0.00116)	-2.44%
Primary	$/Kwh	0.04413	0.04273	-3.18%	0.04305	(0.00108)	-2.44%
Transmission	$/Kwh	0.04280	0.04144	-3.18%	0.04176	(0.00104)	-2.44%
Off-Peak Energy: Winter							
Secondary	$/Kwh	0.03999	0.03872	-3.18%	0.03902	(0.00097)	-2.44%
Primary	$/Kwh	0.03639	0.03523	-3.18%	0.03550	(0.00089)	-2.44%
Transmission	$/Kwh	0.03529	0.03417	-3.18%	0.03443	(0.00086)	-2.44%

1/ = Adopted in Decision 91-04-026.

SAN DIEGO GAS & ELECTRIC COMPANY - ELECTRIC DEPARTMENT

COMMERCIAL AND INDUSTRIAL RATES

RATE SCHEDULE	UNITS	1/1/91 RATE	RDW RATE 1/	RDW CHANGE %	ADOPTED RATE	CHANGE FROM 1/1/91 AMOUNT	CHANGE FROM 1/1/91 %
SCHEDULE AL-TOU (Optional Times)							
Service Charge	$/Month	20.00	30.00	50.00%	30.00	10.00	50.00%
On-Peak Rate Limiter: Summer	$/Kwh	0.72	0.72	0.00%	0.74	0.02	2.78%
On-Peak Rate Limiter: Winter	$/Kwh	0.28	0.28	0.00%	0.29	0.01	3.57%
Average Rate Limiter	$/Kwh	0.21	0.21	0.00%	0.35	0.14	66.67%
Non-Coincident Demand							
Secondary	$/KW	3.38	3.55	5.00%	3.58	0.20	5.80%
Primary	$/KW	2.69	2.82	5.00%	2.85	0.16	5.80%
Transmission	$/KW	1.13	1.19	5.00%	1.20	0.07	5.80%
On-Peak Demand: Summer							
Secondary	$/KW	17.96	18.86	5.00%	19.00	1.04	5.79%
Primary	$/KW	17.96	18.86	5.00%	19.00	1.04	5.79%
Transmission	$/KW	11.30	11.87	5.00%	11.95	0.65	5.79%
On-Peak Demand: Winter							
Secondary	$/KW	3.72	3.91	5.00%	3.94	0.22	5.80%
Primary	$/KW	3.72	3.91	5.00%	3.94	0.22	5.80%
Transmission	$/KW	1.49	1.56	5.00%	1.58	0.09	5.80%
On-Peak Energy: Summer							
Secondary	$/Kwh	0.09439	0.09139	-3.18%	0.09208	(0.00231)	-2.44%
Primary	$/Kwh	0.08830	0.08549	-3.18%	0.08616	(0.00214)	-2.43%
Transmission	$/Kwh	0.08566	0.08294	-3.18%	0.08357	(0.00209)	-2.44%
Semi-Peak Energy: Summer							
Secondary	$/Kwh	0.06103	0.05909	-3.18%	0.05954	(0.00149)	-2.44%
Primary	$/Kwh	0.05813	0.05628	-3.18%	0.05671	(0.00142)	-2.44%
Transmission	$/Kwh	0.05639	0.05460	-3.18%	0.05502	(0.00137)	-2.44%
Off-Peak Energy: Summer							
Secondary	$/Kwh	0.04110	0.03979	-3.18%	0.04010	(0.00100)	-2.44%
Primary	$/Kwh	0.03847	0.03725	-3.18%	0.03753	(0.00094)	-2.44%
Transmission	$/Kwh	0.03731	0.03612	-3.18%	0.03640	(0.00091)	-2.44%
On-Peak Energy: Winter							
Secondary	$/Kwh	0.07536	0.07297	-3.18%	0.07352	(0.00184)	-2.44%
Primary	$/Kwh	0.07048	0.06824	-3.18%	0.06876	(0.00172)	-2.44%
Transmission	$/Kwh	0.06836	0.06619	-3.18%	0.06669	(0.00167)	-2.44%
Semi-Peak Energy: Winter							
Secondary	$/Kwh	0.04753	0.04602	-3.18%	0.04637	(0.00116)	-2.44%
Primary	$/Kwh	0.04413	0.04273	-3.18%	0.04305	(0.00108)	-2.44%
Transmission	$/Kwh	0.04280	0.04144	-3.18%	0.04176	(0.00104)	-2.44%
Off-Peak Energy: Winter							
Secondary	$/Kwh	0.03999	0.03872	-3.18%	0.03902	(0.00097)	-2.44%
Primary	$/Kwh	0.03639	0.03523	-3.18%	0.03550	(0.00089)	-2.44%
Transmission	$/Kwh	0.03529	0.03417	-3.18%	0.03443	(0.00086)	-2.44%

1/ = Adopted in Decision 91-04-026.

SAN DIEGO GAS & ELECTRIC COMPANY - ELECTRIC DEPARTMENT

COMMERCIAL AND INDUSTRIAL RATES

RATE SCHEDULE	UNITS	1/1/91 RATE	RDW RATE 1/	RDW CHANGE %	ADOPTED RATE	CHANGE FROM 1/1/91 AMOUNT	CHANGE FROM 1/1/91 %
SCHEDULE A-6 TOU (Default Times)							
Service Charge	$/Month	600.00	600.00	0.00%	600.00	0.00	0.00%
On-Peak Rate Limiter: Summer	$/Kwh	0.72	0.72	0.00%	0.74	0.02	2.78%
On-Peak Rate Limiter: Winter	$/Kwh	0.28	0.28	0.00%	0.29	0.01	3.57%
Average Rate Limiter	$/Kwh	0.21	0.21	0.00%	0.35	0.14	66.67%
Non-Coincident Demand							
Primary	$/KW	2.69	2.82	5.00%	2.85	0.16	5.80%
Transmission	$/KW	1.13	1.19	5.00%	1.20	0.07	5.80%
On-Peak Demand: Summer							
Primary	$/KW	19.05	20.00	5.00%	20.16	1.11	5.80%
Transmission	$/KW	12.21	12.82	5.00%	12.92	0.71	5.80%
On-Peak Demand: Winter							
Primary	$/KW	4.45	4.67	5.00%	4.71	0.26	5.80%
Transmission	$/KW	1.98	2.08	5.00%	2.09	0.11	5.80%
On-Peak Energy: Summer							
Primary	$/Kwh	0.07863	0.07613	-3.18%	0.07671	(0.00192)	-2.44%
Transmission	$/Kwh	0.07627	0.07385	-3.18%	0.07441	(0.00186)	-2.44%
Semi-Peak Energy: Summer							
Primary	$/Kwh	0.05176	0.05012	-3.18%	0.05050	(0.00126)	-2.44%
Transmission	$/Kwh	0.05021	0.04861	-3.18%	0.04899	(0.00122)	-2.44%
Off-Peak Energy: Summer							
Primary	$/Kwh	0.03847	0.03725	-3.18%	0.03753	(0.00094)	-2.44%
Transmission	$/Kwh	0.03731	0.03612	-3.18%	0.03640	(0.00091)	-2.44%
On-Peak Energy: Winter							
Primary	$/Kwh	0.07048	0.06824	-3.18%	0.06876	(0.00172)	-2.44%
Transmission	$/Kwh	0.06836	0.06619	-3.18%	0.06669	(0.00167)	-2.44%
Semi-Peak Energy: Winter							
Primary	$/Kwh	0.04413	0.04273	-3.18%	0.04305	(0.00108)	-2.44%
Transmission	$/Kwh	0.04280	0.04144	-3.18%	0.04176	(0.00104)	-2.44%
Off-Peak Energy: Winter							
Primary	$/Kwh	0.03639	0.03523	-3.18%	0.03550	(0.00089)	-2.44%
Transmission	$/Kwh	0.03529	0.03417	-3.18%	0.03443	(0.00086)	-2.44%
SCHEDULE A-6 TOU (Optional Times)							
Service Charge	$/Month	600.00	600.00	0.00%	600.00	0.00	0.00%
On-Peak Rate Limiter: Summer	$/Kwh	0.72	0.72	0.00%	0.74	0.02	2.78%
On-Peak Rate Limiter: Winter	$/Kwh	0.28	0.28	0.00%	0.29	0.01	3.57%
Average Rate Limiter	$/Kwh	0.21	0.21	0.00%	0.35	0.14	66.67%
Non-Coincident Demand							
Primary	$/KW	2.69	2.82	5.00%	2.85	0.16	5.80%
Transmission	$/KW	1.13	1.19	5.00%	1.20	0.07	5.80%
On-Peak Demand: Summer							
Primary	$/KW	21.40	22.47	5.00%	22.64	1.24	5.78%
Transmission	$/KW	13.71	14.40	5.00%	14.51	0.80	5.82%
On-Peak Demand: Winter							
Primary	$/KW	4.45	4.67	5.00%	4.71	0.26	5.80%
Transmission	$/KW	1.98	2.08	5.00%	2.09	0.11	5.80%
On-Peak Energy: Summer							
Primary	$/Kwh	0.08830	0.08549	-3.18%	0.08616	(0.00214)	-2.43%
Transmission	$/Kwh	0.08566	0.08294	-3.18%	0.08357	(0.00209)	-2.44%
Semi-Peak Energy: Summer							
Primary	$/Kwh	0.05813	0.05628	-3.18%	0.05671	(0.00142)	-2.44%
Transmission	$/Kwh	0.05639	0.05460	-3.18%	0.05502	(0.00137)	-2.44%
Off-Peak Energy: Summer							
Primary	$/Kwh	0.03847	0.03725	-3.18%	0.03753	(0.00094)	-2.44%
Transmission	$/Kwh	0.03731	0.03612	-3.18%	0.03640	(0.00091)	-2.44%
On-Peak Energy: Winter							
Primary	$/Kwh	0.07048	0.06824	-3.18%	0.06876	(0.00172)	-2.44%
Transmission	$/Kwh	0.06836	0.06619	-3.18%	0.06669	(0.00167)	-2.44%
Semi-Peak Energy: Winter							
Primary	$/Kwh	0.04413	0.04273	-3.18%	0.04305	(0.00108)	-2.44%
Transmission	$/Kwh	0.04280	0.04144	-3.18%	0.04176	(0.00104)	-2.44%
Off-Peak Energy: Winter							
Primary	$/Kwh	0.03639	0.03523	-3.18%	0.03550	(0.00089)	-2.44%
Transmission	$/Kwh	0.03529	0.03417	-3.18%	0.03443	(0.00086)	-2.44%

1/ = Adopted in Decision 91-04-026.

APPENDIX D
TABLE 2
Sheet 5 of 6

SAN DIEGO GAS & ELECTRIC COMPANY - ELECTRIC DEPARTMENT

COMMERCIAL AND INDUSTRIAL RATES

RATE SCHEDULE	UNITS	1/1/91 RATE	RDW RATE 1/	RDW CHANGE %	ADOPTED RATE	CHANGE FROM 1/1/91 AMOUNT	CHANGE FROM 1/1/91 %
SCHEDULE AO-TOU							
Customer Charge	$/Month	50.00	50.00	0.00%	50.00	0.00	0.00%
Non-Coincident Demand	$/KW	8.03	8.43	5.00%	8.49	0.46	5.67%
On-Peak Demand: Summer	$/KW	14.28	14.99	5.00%	15.09	0.81	5.67%
On-Peak Demand: Winter	$/KW	3.84	4.03	5.00%	4.06	0.22	5.67%
Energy: On-Peak	$/Kwh	0.04697	0.04458	-5.09%	0.04486	(0.00211)	-4.49%
Energy: Semi-Peak	$/Kwh	0.03929	0.03729	-5.09%	0.03753	(0.00176)	-4.49%
Energy: Off-Peak	$/Kwh	0.03512	0.03333	-5.09%	0.03354	(0.00158)	-4.49%
SCHEDULE A06-TOU							
Customer Charge	$/Month	250.00	250.00	0.00%	250.00	0.00	0.00%
Non-Coincident Demand	$/KW	8.03	8.43	5.00%	8.49	0.46	5.67%
On-Peak Demand: Summer	$/KW	17.02	17.87	5.00%	17.98	0.96	5.63%
On-Peak Demand: Winter	$/KW	4.58	4.81	5.00%	4.84	0.26	5.67%
Energy: On-Peak	$/Kwh	0.04697	0.04458	-5.09%	0.04486	(0.00211)	-4.49%
Energy: Semi-Peak	$/Kwh	0.03929	0.03729	-5.09%	0.03753	(0.00176)	-4.49%
Energy: Off-Peak	$/Kwh	0.03512	0.03333	-5.09%	0.03354	(0.00158)	-4.49%
SCHEDULE AY-TOU							
Service Charge	$/Month	20.00	30.00	50.00%	30.00	10.00	50.00%
On-Peak Rate Limiter	$/Kwh	0.46	0.46	0.00%	0.48	0.01	3.06%
Average Rate Limiter	$/Kwh	0.21	0.21	0.00%	0.35	0.14	66.67%
Non-Coincident Demand							
Secondary	$/KW	3.38	3.55	5.00%	3.58	0.20	5.80%
Primary	$/KW	2.69	2.82	5.00%	2.85	0.16	5.80%
Transmission	$/KW	1.13	1.19	5.00%	1.20	0.07	6.19%
On-Peak Demand							
Secondary	$/KW	9.29	9.64	3.77%	9.71	0.42	4.51%
Primary	$/KW	9.29	9.64	3.77%	9.71	0.42	4.51%
Transmission	$/KW	5.32	5.52	3.76%	5.56	0.24	4.57%
On-Peak Energy							
Secondary	$/Kwh	0.08191	0.07927	-3.22%	0.07987	(0.00204)	-2.49%
Primary	$/Kwh	0.07649	0.07402	-3.23%	0.07461	(0.00188)	-2.46%
Transmission	$/Kwh	0.07418	0.07183	-3.17%	0.07238	(0.00180)	-2.43%
Semi-Peak Energy							
Secondary	$/Kwh	0.05049	0.04885	-3.25%	0.04922	(0.00127)	-2.51%
Primary	$/Kwh	0.04734	0.04580	-3.25%	0.04614	(0.00120)	-2.54%
Transmission	$/Kwh	0.04640	0.04493	-3.17%	0.04527	(0.00113)	-2.43%
Off-Peak Energy							
Secondary	$/Kwh	0.04097	0.03967	-3.17%	0.03998	(0.00099)	-2.42%
Primary	$/Kwh	0.03774	0.03653	-3.21%	0.03682	(0.00092)	-2.45%
Transmission	$/Kwh	0.03672	0.03556	-3.16%	0.03584	(0.00088)	-2.40%
SCHEDULE A-E1							
Customer Charge	$/Month	600.00	600.00	0.00%	600.00	0.00	0.00%
Contract Demand	$/KW	13.75	14.44	5.00%	14.44	0.69	5.00%
Semi-Peak Demand	$/KW	0.50	0.50	0.00%	0.50	0.00	0.00%
Energy: On-Peak	$/Kwh	8.29493	8.70795	4.98%	8.70791	0.41298	4.98%
Energy: Semi-Peak	$/Kwh	0.05040	0.04697	-6.81%	0.04806	(0.00234)	-4.65%
Energy: Off-Peak	$/Kwh	0.03445	0.03445	0.00%	0.03441	(0.00004)	-0.12%
SCHEDULE A-E2							
Customer Charge	$/Month	600.00	600.00	0.00%	600.00	0.00	0.00%
Contract Demand	$/KW	10.77	10.67	-0.93%	10.75	(0.02)	-0.19%
Non-Coincident Demand							
Secondary	$/KW	3.38	3.55	5.00%	3.58	0.20	5.92%
Primary	$/KW	2.69	2.82	5.00%	2.85	0.16	5.95%
Transmission	$/KW	1.13	1.19	5.00%	1.20	0.07	6.19%
Energy: On-Peak	$/Kwh	4.57713	4.53618	-0.89%	4.57078	(0.00635)	-0.14%
Energy: Semi-Peak	$/Kwh	0.06816	0.06732	-1.23%	0.06806	(0.00010)	-0.15%
Energy: Off-Peak	$/Kwh	0.03445	0.03445	0.00%	0.03441	(0.00004)	-0.12%

1/ = Adopted in Decision 91-04-026.

SAN DIEGO GAS & ELECTRIC COMPANY - ELECTRIC DEPARTMENT

COMMERCIAL AND INDUSTRIAL RATES

RATE SCHEDULE	UNITS	1/1/91 RATE	RDW RATE 1/	RDW CHANGE %	ADOPTED RATE	CHANGE FROM 1/1/91 AMOUNT	CHANGE FROM 1/1/91 %
SCHEDULE R-TOU-3							
Customer Charge	$/Month	600.00	600.00	0.00%	600.00	0.00	0.00%
Contract Demand	$/KW	10.77	10.67	-0.93%	10.75	(0.02)	-0.19%
Non-Coincident Demand							
Secondary	$/KW	3.38	3.55	5.00%	3.58	0.20	5.92%
Primary	$/KW	2.69	2.82	5.00%	2.85	0.16	5.95%
Transmission	$/KW	1.13	1.19	5.00%	1.20	0.07	6.19%
Energy: Super-Peak	$/Kwh	1.28872	1.27376	-1.16%	1.28685	(0.00187)	-0.15%
Energy: On-Peak	$/Kwh	0.10424	0.10303	-1.16%	0.10408	(0.00016)	-0.15%
Energy: Semi-Peak	$/Kwh	0.04985	0.04928	-1.14%	0.04978	(0.00007)	-0.14%
Energy: Off-Peak	$/Kwh	0.03445	0.03445	0.00%	0.03441	(0.00004)	-0.12%
SCHEDULE R-TOU-4							
Customer Charge	$/Month	600.00	600.00	0.00%	600.00	0.00	0.00%
Contract Demand	$/KW	10.77	10.67	-0.93%	10.75	(0.02)	-0.19%
Non-Coincident Demand							
Secondary	$/KW	3.38	3.55	5.00%	3.58	0.20	5.92%
Primary	$/KW	2.69	2.82	5.00%	2.85	0.16	5.95%
Transmission	$/KW	1.13	1.19	5.00%	1.20	0.07	6.19%
Energy: Super-Peak	$/Kwh	0.50413	0.49828	-1.16%	0.50340	(0.00073)	-0.15%
Energy: On-Peak	$/Kwh	0.08331	0.08235	-1.15%	0.08319	(0.00012)	-0.14%
Energy: Semi-Peak	$/Kwh	0.04496	0.04440	-1.25%	0.04490	(0.00006)	-0.14%
Energy: Off-Peak	$/Kwh	0.03445	0.03445	0.00%	0.03441	(0.00004)	-0.12%
SCHEDULE S							
Contracted Demand							
Secondary	$/Kwh	2.70	2.84	5.00%	2.86	0.16	5.80%
Primary	$/Kwh	2.15	2.26	5.00%	2.28	0.12	5.80%
Transmission	$/Kwh	0.90	0.95	5.00%	0.96	0.05	5.80%
SCHEDULE I-1							
Rate A: Utility Control	$/KW	3.27	3.43	5.00%	3.43	0.16	5.00%
Rate B: Customer Control	$/KW	2.18	2.29	5.00%	2.29	0.11	5.00%
Rate C							
Utility Control	$/KW	3.27	3.43	5.00%	3.43	0.16	5.00%
Customer Control	$/KW	2.18	2.29	5.00%	2.29	0.11	5.00%
SCHEDULE I-2							
Rate A: 1 YR Cancellation							
Guaranteed Load	$/KW	5.33	5.60	5.00%	5.60	0.27	5.00%
Each Interruption	$/KW	0.27	0.28	5.00%	0.28	0.01	5.00%
Rate A: 5 YR Cancellation							
Guaranteed Load	$/KW	6.72	7.06	5.00%	7.06	0.34	5.00%
Each Interruption	$/KW	0.27	0.28	5.00%	0.28	0.01	5.00%
Rate B: 1 YR Cancellation							
Guaranteed Load	$/KW	4.90	5.15	5.00%	5.15	0.24	5.00%
Each Interruption	$/KW	0.27	0.28	5.00%	0.28	0.01	5.00%
Rate B: 5 YR Cancellation							
Guaranteed Load	$/KW	6.16	6.47	5.00%	6.47	0.31	5.00%
Each Interruption	$/KW	0.27	0.28	5.00%	0.28	0.01	5.00%
Rate C: 1 YR Cancellation							
Guaranteed Load	$/KW	3.95	4.15	5.00%	4.15	0.20	5.00%
Each Interruption	$/KW	0.27	0.28	5.00%	0.28	0.01	5.00%
Rate C: 5 YR Cancellation							
Guaranteed Load	$/KW	4.99	5.24	5.00%	5.24	0.25	5.00%
Each Interruption	$/KW	0.27	0.28	5.00%	0.28	0.01	5.00%
Rate D: 1 YR Cancellation							
Guaranteed Load	$/KW	3.62	3.80	5.00%	3.80	0.18	5.00%
Each Interruption	$/KW	0.27	0.28	5.00%	0.28	0.01	5.00%
Rate D: YR Cancellation							
Guaranteed Load	$/KW	4.57	4.80	5.00%	4.80	0.23	5.00%
Each Interruption	$/KW	0.27	0.28	5.00%	0.28	0.01	5.00%

1/ = Adopted in Decision 91-04-026.

APPENDIX D
TABLE 3
Sheet 1 of 1

SAN DIEGO GAS & ELECTRIC COMPANY - ELECTRIC DEPARTMENT

AGRICULTURAL RATES

RATE SCHEDULE	UNITS	1/1/91 RATE	RDW RATE 1/	RDW CHANGE %	ADOPTED RATE	CHANGE FROM 1/1/91 AMOUNT	CHANGE FROM 1/1/91 %
SCHEDULE PA							
Customer Charge	$/Month	8.00	8.00	0.00%	8.00	0.00	0.00%
Energy	$/Kwh	0.08452	0.08452	0.00%	0.08238	(0.00214)	-2.53%
SCHEDULE PA-TOU							
Metering Charge	$/Month	10.00	10.00	0.00%	10.00	0.00	0.00%
Customer Charge	$/Month	8.00	8.00	0.00%	8.00	0.00	0.00%
Energy: On-Peak	$/Kwh	0.15171	0.15171	0.00%	0.14650	(0.00521)	-3.43%
Energy: Off-Peak	$/Kwh	0.06893	0.06893	0.00%	0.06737	(0.00156)	-2.27%
SCHEDULE PA-T-1							
Customer Charge	$/Month	20.00	30.00	50.00%	30.00	10.00	50.00%
Demand: On-Peak							
Option A	$/KW	10.52	11.05	5.06%	11.13	0.61	5.83%
Option B	$/KW	9.24	9.71	5.06%	9.78	0.54	5.83%
Option C	$/KW	9.04	9.50	5.06%	9.57	0.53	5.83%
Option D	$/KW	9.42	9.90	5.06%	9.97	0.55	5.83%
Option E	$/KW	9.23	9.70	5.06%	9.77	0.54	5.83%
Option F	$/KW	8.83	9.28	5.06%	9.35	0.52	5.83%
Demand: Semi-Peak	$/KW	0.50	0.50	0.00%	0.50	0.00	0.00%
Energy: On-Peak	$/Kwh	0.08836	0.08522	-3.55%	0.08626	(0.00210)	-2.38%
Energy: Semi-Peak	$/Kwh	0.06531	0.06351	-2.76%	0.06409	(0.00122)	-1.87%
Energy: Off-Peak	$/Kwh	0.04239	0.04193	-1.09%	0.04205	(0.00034)	-0.80%

1/ = Adopted in Decision 91-04-026.

(END OF APPENDIX D)