ALJ/FJO/cac/pc

Decision 90 05 090 MAY 22 1990

ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company, for authority to revise its Energy Cost Adjustment Clause Rate, to revise its Annual Energy Rate, and to revise its Electric Base Rates effective May 1, 1990 in Accordance with the Electrical Revenue Adjustment Mechanism. (U 902-E)	Application 89-09-031 (Filed September 29, 1989)

(Appearances are listed in Appendix A.)

O P I N I O N

Background

This is San Diego Gas & Electric Company's (SDG&E) annual energy cost adjustment clause (ECAC) filing which covers the following:

1. Calculation of adjustments for ECAC, annual energy rate (AER), and electric revenue adjustment mechanism (ERAM) rates;

2. Revenue allocation and rate design to implement the rate adjustments;

3. Energy and capacity payments to certain qualifying facilities during the forecast period May 1, 1990 through April 30, 1991;

4. Reasonableness review of its gas and electric operations during the record period from May 1, 1988 through July 31, 1989.

As originally filed, the application requested increases as follows: ECAC, $67.8 million; AER, $3.6 million; and ERAM $29.3 million. SDG&E also requested authority to decrease base rates by $58 million because of increased sales.

A prehearing conference was held before Administrative Law Judge (ALJ) Frank J. O'Leary at San Francisco on October 16, 1989. It was determined that the hearing process would be bifurcated into two phases: first, the forecast phase and second, the reasonableness phase. This decision deals only with the forecast phase. The reasonableness phase will be considered in a subsequent decision.

Public hearings were held before ALJ O'Leary at San Diego on January 3 and 4, 1990 and at San Francisco on January 23, 1990. At the commencement of the hearings, counsel for applicant requested a recess in order that the various parties to the proceeding could meet and confer, because the exchange of information that was to have taken place prior to the January 3 hearing did not meet the established schedule. The schedule apparently was not met because of problems with the post office and various courier services not meeting anticipated delivery deadlines because of the Christmas holiday season. Counsel for applicant also indicated that a meet and confer session might well lead to the resolution of many of the issues in the proceeding. The ALJ granted the request for a recess and continued the matter to the following day and instructed the parties to meet and confer in a workshop setting and be prepared to proceed with the hearing process on the following day.

On January 4, 1990, counsel for applicant advised the ALJ that all matters, with the exception of residential rate design, were resolved at the workshop conducted the previous day. At the hearing of January 23, 1990, counsel for applicant advised that except for a few minor details the agreement reached by the parties was ready to be signed by all the parties.

Also at the January 23, 1990 hearing, Division of Ratepayer Advocates (DRA) submitted revised tables to its Exhibit 5 (DRA's Forecast Phase Report) which tables had previously been revised as set forth in Exhibits 7 and 7a. This had been agreed to by the parties at the January 3 workshop. One of the tables submitted is entitled "Street Light Current and Proposed Rates." (Exhibit 21.) There was no Table 14-6 in DRA's original filing of Exhibit 6 and no discussion of streetlight rates in Chapter 14 of Exhibit 6. The only discussion of streetlight rates and proposed rates is in SDG&E's Exhibit 4, Chapter II G, pages II-41 through II-58.

The matter was then submitted subject to the filing of late-filed Exhibit 24, which is a stipulation by all of the parties except the City of San Diego (City) to a settlement of all issues except for residential rate design, and concurrent briefs limited to the disputed residential rate design issue due on or before February 23, 1990. On January 30, 1990, a document entitled "Joint ECAC Forecast Workshop Report of the Parties" was received as Exhibit 24. A copy of Exhibit 24 is attached hereto as Appendix B.

Exhibit 24 was signed by all of the appearances to the proceeding with the exception of the City. Counsel for the City refused to sign the exhibit, because at the hearing of January 23, 1990 the DRA presented a new rate design with respect to street lighting (Exhibit 21).

Comments concerning the presentation of the rate design for street lighting by DRA were filed by the City on February 9, 1990. The comments describe City's objections to the streetlight rate design submitted by DRA.

Briefs were filed by SDG&E and DRA. Utility Consumers' Action Network (UCAN) also filed a brief; however, it was rejected by the Commission's Docket Office because its certificate of service was defective as it incorporated both its brief and its request for eligibility which it attempted to file simultaneously with its brief.

On March 8, 1990, UCAN filed a motion requesting that its brief be accepted as timely. The brief was rejected by the Docket Office because of a technical deficiency. The motion states that its deficiency has been corrected. No objections to a granting of the motion have been received.

In view of the agreement reached in Exhibit 24, there are only two issues which need be discussed, namely, residential rate design and the street lighting rate design proposed by DRA and the objections thereto voiced by City.

Residential Rate Design

Rate design scenarios were submitted by SDG&E, DRA, and UCAN as follows:

Scenario 1 - DRA's proposal which reduces the differential between baseline and nonbaseline by 20 percent.

Scenario 2 - SDG&E's proposal which increases the baseline and nonbaseline rates on an equal cents per kilowatt-hour (kWh) basis.

Scenario 3 - UCAN's second alternative which allocates the combined ECAC and attrition increase entirely to baseline rates.

Scenario 4 - UCAN's primary alternative which applies the ECAC portion of the revenue increase entirely to baseline and allocates the attrition revenue increase on an equal cents per kWh basis to both baseline and nonbaseline.

A comparison of residential rates under each of the scenarios together with the present rates is set forth in Table 1.

TABLE 1

	Present Rates	Scenario #1	Scenario #2	Scenario #3	Scenario #4
Baseline	$0.08148	$0.08850	$0.08477	$0.08725	$0.08539
Non-Baseline	0.12535	0.12370	0.12864	0.12535	0.12781
Tier Closure		20%	0%	13%	3%
Tier Ratio (T2/T1)	1.54	1.40	1.52	1.44	1.50

Table 2 sets forth a comparison of typical monthly bills at various usages under present rates and proposed rates under the four scenarios with the basic baseline allowance of 250 kWh.

TABLE 2

KWHR	Current SDG&E Rates	Scenario #1 Rates	Pct. Inc.	Scenario #2 Rates	Pct. Inc.	Scenario #3 Rates	Pct. Inc.	Scenario #4 Rates	Pct. Inc.
50	$ 5.00	$ 5.00	0.00%	$ 5.00	0.00%	$ 5.00	0.00%	$ 5.00	0.00%
100	8.16	8.86	8.58	8.49	4.04	8.74	7.11	8.55	4.78
150	12.24	13.30	8.66	12.74	4.08	13.11	7.11	12.83	4.82
200	16.32	17.72	8.58	16.97	3.98	17.47	7.05	17.10	4.78
250	20.40	22.16	8.63	21.22	4.02	21.84	7.06	21.38	4.80
300	26.68	28.35	6.26	27.66	3.67	28.12	5.40	27.78	4.12
350	32.95	34.54	4.83	34.10	3.49	34.39	4.37	34.17	3.70
400	39.22	40.73	3.85	40.54	3.37	40.67	3.70	40.57	3.44
450	45.49	46.92	3.14	46.97	3.25	46.93	3.17	46.96	3.23
469	47.88	49.28	2.92	49.42	3.22	49.32	3.01	49.40	3.17
500	51.77	53.11	2.59	53.41	3.17	53.21	2.78	53.36	3.07
550	58.04	59.30	2.17	59.85	3.12	59.49	2.50	59.76	2.96
600	64.31	65.49	1.83	66.29	3.08	65.76	2.25	66.15	2.86
650	70.59	71.69	1.56	72.73	3.03	72.03	2.04	72.55	2.78
700	76.86	77.87	1.31	79.16	2.99	78.30	1.87	78.94	2.71
750	83.14	84.07	1.12	85.60	2.96	84.58	1.73	85.34	2.65
800	89.41	90.26	0.95	92.04	2.94	90.86	1.62	91.74	2.61
850	95.68	96.45	0.80	98.48	2.93	97.12	1.51	98.13	2.56
900	101.96	102.64	0.67	104.92	2.90	103.40	1.41	104.53	2.52
950	108.22	108.82	0.55	111.35	2.89	109.67	1.34	110.92	2.49
1000	114.50	115.02	0.45	117.79	2.87	115.95	1.27	117.33	2.47
1100	127.05	127.40	0.28	130.67	2.85	128.49	1.13	130.12	2.42
1200	139.59	139.78	0.14	143.54	2.83	141.04	1.04	142.91	2.38
1300	152.15	152.17	0.01	156.42	2.81	153.59	0.95	155.71	2.34
1400	164.69	164.55	-0.09	169.30	2.80	166.14	0.88	168.50	2.31
1500	177.24	176.93	-0.17	182.17	2.78	178.68	0.81	181.29	2.29

Effective June 28, 1988, the California legislature enacted Senate Bill (SB) 987 which, among other things, mandated a realignment of Tier 1 and Tier 2 electric and gas residential rates in order to correct the escalation of winter energy bills.

With respect to the rates at issue in this proceeding, the relevant statutory changes resulting from the enactment of SB 987 are the amendment of Public Utilities (PU) Code § 739(c)(1) and the addition of PU Code §§ 739(g) and 739.7.

A key element in the legislation is the authorization to provide assistance to low-income customers. § 739(g) provides:

> "The commission shall establish a program of assistance to low-income electric and gas customers, the cost of which shall not be borne solely by any single class of customer."

The amendment of § 739(c)(1) reaffirmed the underlying structure of graduated rates incorporating a baseline rate to mark the "first or lowest block of an increasing block rate structure..." The amendment provides:

> "In establishing these rates, the commission shall avoid excessive rate increases for residential customers, and shall establish an appropriate gradual differential between the rates for the respective blocks of usage."

The most specific direction for realigning residential rates is found in the new § 739.7:

> "In establishing residential rates, the commission shall reduce high nonbaseline residential rates as rapidly as possible. If the commission increases baseline rates pursuant to Section 739, revenues resulting from those increases shall be used exclusively to reduce nonbaseline residential rates. In any event, baseline rates may not be increased so as to result in the substantial elimination of any significant differential between baseline and nonbaseline residential rates in less than 30 months following the effective date of this section."

The stated purpose of SB 987 was to "...grant the Public Utilities Commission greater flexibility in pricing the baseline quantity of service, while at the same time assuring the residential ratepayers that in the future they will not be economically worse off, relative to other customers, than they are currently as a consequence of changes in baseline rates pursuant to the amendments to Section 739 of the Public Utilities Code enacted by this act." (Stats. 1988, Ch. 212, Section 1 (b).)

SDG&E prefers its proposal (Scenario 2) over the other scenarios. Nevertheless, SDG&E views Scenario 4 as nearly equivalent to Scenario 2 and believes the two scenarios can be treated as such. If for some reason the Commission should reject either Scenario 2 or 4, then SDG&E believes that Scenario 3 would be a reasonable alternative. SDG&E is of the opinion that the DRA proposal (Scenario 1) is excessive and unacceptable.

SDG&E argues that its proposal satisfies the following rate design criteria:

1. The design will not excessively eliminate the differential between customers in less than 30 months from the effective date of the Dills Bill, and therefore SDG&E complies with the bill.

2. The design will reduce the ratio between baseline and nonbaseline rates, and therefore SDG&E complies with the Dills Bill.

3. The design will keep the percentage bill increases for low consumption customers roughly equal to the average residential rate increase.

4. The design avoids a bill decrease for any customer in the midst of a rate increase proceeding.

5. The design will not cause any residential ratepayers to be more economically worse off than other ratepayers.

6. The design will result in easy communication between SDG&E and its ratepayers.

UCAN supports the SDG&E proposal (Scenario 2). Should the Commission reject SDG&E's proposal it recommends Scenarios 4 and 3 in that order.

DRA alleges that it designed its proposal for this proceeding in accordance with the legislature's directions to reduce Tier 2 rates by reducing the differential between Tier 1 and Tier 2. DRA further alleges that it considered the Commission's concern with a timely implementation of the program.

SDG&E argues that the DRA proposal should not be adopted because it fails to satisfy five of the six prescribed rate design criteria set forth above.

Implementation of Scenario 1 would result in an excessive elimination of the differential between baseline and nonbaseline rates in less than 30 months of the effective date of the Dills Bill, given that DRA proposes an additional 20 percent closure to the 30 percent closure that SDG&E has already executed. This would appear to violate the Dills Bill and therefore does not satisfy Design Criterion 1.

Moreover, DRA's proposal will result in bill increases of 3.5 times the average residential rate increase for customers below the basic service baseline allowance. This result fails to meet the objectives of Design Criterion 3; that is, the design must keep the percentage bill increases for low consumption customers roughly equal to the average residential rate increase. Further, Scenario 1 does not satisfy Design Criterion 4, which requires that the design avoid a bill decrease for any customer in the midst of a rate increase proceeding, in that it will result in a decrease for customers consuming over 1,400 kWh. Given these two factors, the proposal will cause low consumption customers to be economically worse off than other ratepayers, thereby transgressing Design Criterion 5.

Finally, as the increase will not be uniformly spread among residential customers, this design will create difficult communication of the rate change to the ratepayers, especially to low consumption customers. This result is contrary to Design Criterion 6.

UCAN argues that the DRA proposal should not be adopted because customers using less than 250 kWh monthly will experience rate increases of between 8.58-8.66 percent. Meanwhile, customers with high monthly consumption will receive nominal rate increases, with some actually benefiting from rate decreases.

In a proceeding where the residential class, on average, is scheduled to receive a 2.4 percent rate increase, we should not impose upon the utility's most modest customers an increase that is 300 percent higher than the average residential class increase and approximately 900 percent higher than customers with monthly electric consumption exceeding 1,500 kWh.

Additionally, DRA's proposed rate design is premature; it would go into effect in May 1990 - eight months prior to the Dills Bill "30-month" phase-in period.

The DRA proposal overlooks another critical factor; SDG&E's rates have been repeatedly adjusted since June 28, 1988 to reduce the baseline differential.

The unrebutted record in this case shows that since passage of SB 987, SDG&E has been ordered to close the differential three separate times. Over this period of time, the closure between nonbaseline and baseline rates was 30 percent.

In November 1988, the nonbaseline rate was reduced from 14.463 to 14.412. In January 1989, the baseline rate was nominally reduced by 1 percent, while nonbaseline rates were dropped to 12.609 - a drop of 12 percent. Again, in May 1989, nonbaseline rates were dropped to 12.535 while baseline rates were held constant. It is important to note that in all three instances the Commission chose not to increase baseline rates, so as not to impose rate increases upon customers when an overall rate decrease was being granted.

UCAN also argues that in a recent PG&E application Application (A.) 88-03-033), DRA argued that a proposed 50 percent tier differential reduction clearly contradicts SB's prohibition of the substantial elimination of the substantial differentiation prior to the end of a 30-month period. It also points out that DRA's argument in that case prevailed.

We are not persuaded by the arguments of SDG&E and UCAN that the rate design proposal of DRA should not be adopted. Although Scenario 1 proposes an additional 20 percent closure between baseline and nonbaseline, resulting in a total closure of 50 percent when added to the previous closures totaling 30 percent, we do not believe that to be excessive elimination of the differential between baseline and nonbaseline. DRA's proposal can be differentiated from the argument in the PG&E application. In that application PG&E's proposal was a 50 percent closure at one time whereas in this instance the 50 percent closure has taken place in three separate steps.

In response to the enactment of SB 987, the Commission issued Order Instituting Investigation (I.) 88-07-009. The interim opinion in that investigation took the first step in realigning Tier 1 and Tier 2 residential rates for seven utilities, including SDG&E.

In the final opinion of I.88-07-009, the Commission established the Low Income Ratepayer Assistance (LIRA) program in compliance with PU Code § 739(g). (Decision (D.) 89-09-044, mimeo. p. 2 and Ordering Paragraph 1 at p. 25.)

The Commission stated that the adoption of LIRA was "inextricably linked" to the baseline program. (D.89-09-044, mimeo. p. 3. See also the PG&E general rate case D.89-12-057, mimeo. p. 262.)

This linkage was emphasized by the Commission's directive to assure a vigorous and timely implementation of SB 987:

> "It is clear from the enabling legislation that the LIRA program's continued existence depends

> on the closure of Tier 1 and Tier 2. To ensure that such realignment will be pursued vigorously, the Commission will examine its progress in baseline reform in May of 1991, the 30 month deadline in SB 987." (D.89-09-044, mimeo. p. 7.)

DRA's proposal provides for the progress in baseline reform called for by the Commission and provides for the LIRA rates set at a 15 percent discount as ordered by the Commission in. D.89-09-044. The rate design proposed by DRA will be adopted.

UCAN's Request for Compensation

On March 8, 1990, pursuant to Rule 76.54 of the Commission's Rules of Practice and Procedure, UCAN filed for a finding of eligibility and an award of intervenor compensation. UCAN alleges that in D.89-10-032 it has been found to have met its burden of showing financial hardship for calendar year 1990 and that it has met its burden under the rule.

We find that UCAN has not met its burden of showing financial hardship for 1990. Rule 76.54 states in (a)(1):

> "A showing by the customer that participation in the hearing or proceeding would pose a significant financial hardship. A summary of the finances of the customer shall distinguish between grant funds committed to specific projects and discretionary funds. If the customer has met its burden of showing financial hardship in the same calendar year, as determined by the Commission under Rule 76.05, 76.25, or 76.55, the customer shall make reference to that decision by number to satisfy this requirement;..."

A decision, issued in 1989, awarding compensation does not satisfy the requirement for a finding of financial hardship in 1990. On April 11, 1990 UCAN filed another "Request for Finding of Eligibility." That request will be the subject of a separate decision.

Comments to the Proposed Decision

The ALJ's proposed decision was filed and mailed to the parties on April 4, 1990. Comments on the proposed decision were filed by SDG&E and DRA. The comments of both support the proposed decision, with the exception of the treatment of streetlighting.

The proposed decision does not adopt DRA's recommendation with respect to streetlighting because the rate design was not presented until the last day of hearing and streetlight rate design was not listed as an exception to the agreement set forth in Exhibit 24.

In its comments SDG&E points out that Paragraph G(3) of Exhibit 24 provides that the parties recommend using the ELFIN model outputs necessary to calculate time of use marginal energy costs for revenue allocation, rather than the PROMOD production costs on which SDG&E relied in developing Exhibit 4. The resulting change in marginal cost revenue responsibility for streetlighting together with the other revenue requirement changes noted produces the increase in streetlight rates which the City desires to avoid. Thus, the higher streetlight rates are the direct result of the use of the ELFIN-produced marginal energy costs specifically identified as an exception to the use of SDG&E Exhibit 4 for revenue allocation and rate design purposes. Accordingly, it is entirely consistent with the Joint Report for the Commission to adopt streetlight rates reflecting the recommended revenue allocation without the $434,000 expense adjustment.

The comments of DRA also deal with the streetlighting issue. The comments specifically recommend the following:

1. Findings of Fact 4 and 5 be deleted.

2. The rates adopted in Appendixes C and D, as referenced in Finding of Fact 8, be modified to restore $434,000 in revenues.

3. Conclusion of Law 3 be deleted.

4. The portion of the discussion in the proposed decision entitled streetlighting Rate Design, at pages 11 and 12, be deleted.

On April 26, 1990 City filed its reply to the comments. The reply states that SDG&E would have the Commission believe that the streetlighting rates proposed by DRA are based on the same rate design and revenue allocation methodology as the streetlight rates proposed in SDG&E's Exhibit 4.

We have carefully reviewed the comments and reply thereto and concur with SDG&E and DRA that the streetlighting rates proposed by DRA are a result of the ELFIN model outputs recommended by the parties and therefore should be adopted.

We have changed the proposed decision to reflect this change.

In its comments SDG&E points out that there is some confusion in the proposed decision concerning the minimum bill provision for LIRA customers. This confusion has been clarified herein (Appendixes C and D).

Findings of Fact

1. By this application, as originally filed, SDG&E requested as follows: ECAC, $67.8 million, AER, $3.6 million; and ERAM $29.3 million. SDG&E also requested authority to decrease base rates by $58 million because of increased sales.

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

3. SDG&E; DRA; UCAN; California Cogeneration Council; Kelco Division of Merck and Co., Inc.; and the United States Department of the Navy and other federal executive agencies have entered into the agreement set forth in Exhibit 24.

4. The City did not sign Exhibit 24 because of the presentation of a new rate design for street lighting by DRA.

5. The agreement set forth in Appendix B is reasonable. ✓

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

2. The motion of UCAN requesting its brief be accepted as timely should be granted.

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

O R D E R

IT IS ORDERED that:

1. San Diego Gas & Electric Company is authorized 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. Such filings shall comply with General Order 96-A and shall be effective five days after filing and shall be applicable to service rendered on and after the effective date of the tariffs.

2. The motion of UCAN requesting its brief be accepted as timely is granted.

This order is effective today.

Dated MAY 22 1990, at San Francisco, California.

G. MITCHELL WILK
President
STANLEY W. HULETT
JOHN B. OHANIAN
PATRICIA M. ECKERT
Commissioners

Commissioner Frederick R. Duda, being necessarily absent, did not participate.

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

Neal J. Shulman

NEAL J. SHULMAN, Executive Director

PB

APPENDIX A

List of Appearances

Applicant: Thomas G. Hankley, Attorney at Law, for San Diego Gas & Electric Company.

Interested Parties: Richard O. Baish, Michael D. Ferguson, and Randolph Wu, Attorneys at Law, for El Paso Natural Gas Company; Patrick J. Bittner, Attorney at Law, for California Energy Commission; Jerry Bloom and Lynn Haugh, Attorneys at Law, for California Cogeneration Council; Maurice Brubaker, for Drazen-Brubaker & Associates; Frank J. Cooley and Bruce A. Reed, Attorneys at Law, for Southern California Edison Company; Sam DeFrawi, for Naval Facilities Engineering Command; Norman J. Furuta, Attorney at Law, for Federal Executive Agencies; Jeff Nahagian, for JBS Energy, Inc.; Kevin Woodruff, by Janet Rinaldi, for Henwood Energy Services; Reed V. Schmidt and Chester Schmidt, for California City-County Street Light Association; John W. Witt, City Attorney, by William S. Shaffran and Leslie Girard, Deputy City Attorneys, for City of San Diego; Michael Shames, Attorney at Law, for Utility Consumers' Action Network; Brian B. Sibold, for Energy Factors, Incorporated; James Squeri, Attorney at Law, for Kelco Division of Merck & Co., Inc.; Nancy Thompson, for Barakat, Howard & Chamberlin; Harry K. Winters, for Regents of the University of California; Martin A. Katz, for Sierra Energy and Risk Assessment; and Edward Duncan, for himself.

Division of Ratepayer Advocates: Ida M. Passamonti and Judith Allen, and John S. Wong, Attorneys at Law, and Bill Y. Lee.

Commission Advisory and Compliance Division: Sarita Sarvate.

(END OF APPENDIX A)

APPENDIX B

Application No.: 89-09-031

Exhibit No.:

Date: January 23, 1990

Exhibit 24
CPUC Proceeding A89-09-031
Sponsor/Witness Joint Counsel
Date Iden. 1/23/90 Recd. 1/30/90
Frank J. O'Leary
Administrative Law Judge

SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E)
ECAC FORECAST PHASE

JOINT ECAC FORECAST WORKSHOP REPORT OF THE PARTIES

BEFORE THE
PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
JANUARY 23, 1990

JOINT ECAC FORECAST WORKSHOP REPORT OF THE PARTIES

A. INTRODUCTION

San Diego Gas & Electric Company ("SDG&E"), Division of Ratepayer Advocates ("DRA"), City of San Diego ("San Diego"), Utility Consumers' Action Network ("UCAN"), California Cogeneration Council ("CCC"), Kelco Division of Merck and Co., Inc. ("Kelco") and United States Department of the Navy and other Federal Executive Agencies ("FEA") (collectively referred to herein as the parties) jointly recommend that the California Public Utilities Commission ("Commission") adopt the following workshop recommendations in this proceeding:

B. REVENUE REQUIREMENT

The parties jointly recommend that the Commission adopt a total revenue requirement change (increase) of $22,621,000.

C. INCREMENTAL ENERGY RATE

The parties jointly recommend that the Commission adopt an Annual Average Incremental Energy Rate ("IER") of 9546 BTU/kWh. Based upon this recommended IER, the parties agree that the time differentiated IER's for the forecast period should be as follows:

	Peak	Mid	Off	Super Off-Peak
Summer	9234	9192	8599	7963
Winter	11225	11225	9912	8006

D. O&M ADDER

The parties jointly recommend that the Commission adopt an Operating & Maintenance ("O&M") adder to Qualifying Facilities ("QFs") payments of 2.9 mills/kwh.

E. REVENUE REQUIREMENT, IER, AND O&M ADDER

The Parties' testimony and ELFIN simulations support a range of forecast revenue requirement and a range of IERs and O&M Adders. However, the parties believe that adoption of the revenue requirement, IER, and O&M Adder recommendations herein represent a reasonable compromise for ratemaking purposes and payments to qualifying facilities. The parties recommend that the Commission adopt these recommendations without any further ELFIN or PROMOD modelling simulations because the revenue requirement, IER, and O&M Adder recommendations are within a reasonable bandwith of their expected values.

F. ENERGY RELIABILITY INDEX

The parties jointly recommend an Energy Reliability Index ("ERI") of one.

G. REVENUE ALLOCATION AND RATE DESIGN

The parties understand that the attrition increase from D. 89-11-068 and the increase resulting from this proceeding will become effective on the same date. The parties recommend that for both increases the Commission adopt the revenue allocation and rate design as set forth in SDG&E Exhibit No. 4 in this proceeding, except for those matters below:

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1. WINTER ADDER

DRA believed that the gas demand charges that SDG&E pays SoCal Gas were not included in the marginal energy costs that were developed by Time-of-Use periods using a post-processing program based on outputs from the ELFIN production costing model. Accordingly, DRA proposed to include these charges as a "winter adder" to the final marginal costs developed. SDG&E, FEA, and UCAN all believed that the subject costs were already included in the post-processing program based on outputs of the ELFIN model and, as such, an "adder" to the final numbers was not necessary. This "winter adder" results in a significant change in revenue allocation. No other parties had a position.

Closer examination of the workpapers revealed that the subject costs were included in the DRA marginal energy costs. DRA agrees that an "winter adder" to the final marginal energy costs is not necessary. The parties jointly recommend that the Commission not adopt a "winter adder."

2. LIRA ADJUSTMENT

SDG&E calculates a Low Income Ratepayer Assistance (LIRA) rate for use in revenue allocation of the Residential Class before the proposed rate design. The DRA calculates the LIRA rate for the Residential Class after the proposed rate design. The differences in revenue allocation between the two methods is relatively minor. No other parties had a position.

SDG&E agrees to adopt the DRA calculational method, and calculate a LIRA rate after the proposed rate design. The parties recommend that the Commission adopt the DRA LIRA calculation method.

3. CALCULATION OF MARGINAL ENERGY COSTS FOR REVENUE ALLOCATION

SDG&E proposed using outputs from the PROMOD production cost program as the basis of marginal energy costs. DRA proposed using outputs from the ELFIN production cost program as the basis of marginal energy costs. The marginal energy costs should be on the same basis as the avoided costs calculated for QF payments. The selection of the production cost model has a significant impact on the resulting revenue allocation.

The ELFIN production cost model was agreed upon by the parties for use in avoided costs for QF payments as one of the avoided cost issues. SDG&E agrees and the parties recommend using the ELFIN model outputs and post-processing necessary to calculate the Time-of-Use marginal energy costs for revenue allocation purposes.

4. LARGE COMMERCIAL AND INDUSTRIAL RATE DESIGN

In its application, SDG&E proposed designing large commercial and industrial rates for AL-TOU and A-6 TOU using a combined revenue allocation by allocating the entire revenue increase to the energy rates on an equal percentage basis, while holding demand and customer charges at their current levels. The DRA proposed allocating the revenue increase by holding the customer charge at its current level and increasing demand and energy revenues on an equal percentage basis. The FEA proposed to hold energy rates at their current level, increase customer charges by ten percent, and allocate the remaining revenue increase to demand charges while increasing the non-coincident demand charge by twice the percentage increase in on-peak the demand charge. Furthermore, the FEA proposed to design AL-TOU separately from A-6 TOU rates by using each schedule's revenue allocation. The DRA and SDG&E designed rates for the two schedules using a combined revenue allocation.

The parties agree to the following:

1. AL-TOU and A-6 TOU rates should be designed together using a combined revenue allocation for AL-TOU and A-6 TOU.

2. AL-TOU and A-6 TOU rates will be designed according to DRA's proposed methodology; no increase to customer charge, equal percentage change to all demand and energy rates.

3. It is reasonable to address FEA's proposed AL-TOU and A-6 TOU design methodology which moves towards aligning rates and rate components with marginal costs in the next Electric Rate Window Filing; and SDG&E and DRA agree to support consideration of these issues in that proceeding.

5. <u>AVERAGE AND ON-PEAK RATE LIMITERS FOR LARGE COMMERCIAL AND INDUSTRIAL</u>

SDG&E proposed to increase the average and on-peak rate limiter by the percentage increase in energy rates equal to 9% in the original filing. This would increase the average, on-peak summer and on-peak winter limiters to 18, 74 and 29 cents per kwr respectively. DRA proposed to increase the average limiter by 5 percentage points over and above the percentage increase in demand and energy charges. DRA proposed to increase the on-peak limiters by an amount equal to the percentage increase in the demand and energy charges. These increases would result in limiters of 17.674, 70.661 and 27.421 cents per kwh for the average, on-peak summer and on-peak winter respectively. Later the DRA modified its proposal to increase the average limiter to 21 cents per kwh.

The parties agree to increase the average rate limiter to 21 cents per kwh to achieve approximately a 1/3 reduction in revenue loss from the rate limiters. The parties also agree to increase the on-peak rate limiter by the same percentage increase as the large TOU demand charge.

6. RESIDENTIAL RATE DESIGN

SDG&E proposed to design residential rates by applying the revenue increase to the baseline and non-baseline on an equal cents per kwh basis. The DRA proposed to design rates by closing the baseline and non-baseline rate differential by 20%.

DRA, SDG&E and UCAN cannot reach a joint agreement on residential rate design. UCAN opposes DRA's methodology on the basis that it imposes unnecessary rate shock upon small electric users. Since no agreement was reached, the parties will litigate this issue.

H. INTERVENOR CONTRIBUTION

For purposes of determining intervenor compensation, the parties acknowledge UCAN's contribution to the workshop process. In its testimony, UCAN addressed revenue requirement and revenue allocation issues -- both of which were discussed in the workshop process. UCAN's contribution was particularly notable in the parties' reaching consensus on the Winter Adder dispute.

I. GENERAL TERMS

With the exception of the residential rate design issue described in Paragraph 6 of Section G above, the parties do not contest in this proceeding the recommendations contained in this exhibit. As to the recommendations agreed to without contest, the agreement of the parties shall not be construed to be an acceptance of the methodology or assumptions, including resource assumptions, underlying the parties' estimate of SDG&E's revenue requirement charge, the Incremental Energy Rate, the O&M Adder, the revenue allocation, or rate design.

None of the principles or the methodologies underlying this joint exhibit shall be deemed by the Commission or any other entity as precedent in any proceeding or litigation except in order to implement in this proceeding the recommendations contained herein. The parties expressly reserve the right to advocate different principles and methodologies from those underlying this joint exhibit in other proceedings.

The parties understand and agree that this joint exhibit is subject to each and every condition set forth herein, including its acceptance by the Commission in its entirety and without change or condition. The parties agree to extend their best

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efforts to assure the adoption of these recommendations for the forecast period.

Jointly submitted by counsel of record for the following parties:

Division of Ratepayer Advocates

San Diego Gas & Electric Company

City of San Diego

Utility Consumers' Action Network

California Cogeneration Council.

Kelco Division of Merck and Co., Inc.

United States Department of the Navy
and other Federal executive agencies

Dated: January 23, 1990

efforts to assure the adoption of these recommendations for the forecast period.

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Kelco Division of Merck and Co., Inc.

James D. Squeri

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Kelco Division of Merck and Co., Inc.

____

United States Department of the Navy
and other Federal executive agencies

____

Dated: January 23, 1990

(END OF APPENDIX B)

APPENDIX C
TABLE 1

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED ENERGY COSTS
Forecast period: May 1, 1990 through April 30, 1991

TYPE OF ENERGY	PURCHASES/ GENERATION (GWh)	%	AVERAGE COST ($/KWh)	TOTAL COSTS ($000's)	ECAC COSTS ($000's)	AER COSTS ($000's)
Natural Gas	3,621.0	22.79%	0.03341	$120,980	$111,302	$9,678
Residual Oil	970.0	6.11%	0.03234	31,368	28,859	2,509
Other Oil	3.0	0.02%	0.05833	175	161	14
Firm Purchases	2,671.0	16.81%	0.05248	140,167	128,954	11,213
Economy Purchases	4,393.0	27.65%	0.01853	81,399	74,887	6,512
Cogen/Alternatives	1,007.0	6.34%	0.05973	60,147	55,335	4,812
Nuclear	3,223.0	20.29%	0.01019	32,850	30,222	2,628
Subtotal	15,888.0	100.00%	0.02940	$467,086	$429,719	$37,367
Variable Wheeling Expenses				1,080	994	86
Fixed Wheeling Expenses				7,004	6,444	560
Carrying Cost of Oil in Inventory				1,207	1,110	97
EFI Adjustment				0	0	0
Subtotal				476,377	438,267	38,110
EEOA Expenses				(330)	(330)	0
Subtotal				$476,047	$437,937	$38,110
Less Non-jurisdictional Amount at 4.47929%	711.7			21,324	19,616	1,707
TOTALS: CALIF JURISDICTION	15,176.3			$454,723	$418,320	$36,403

Note: ECAC costs are 92% of total costs; AER costs are 8% of total costs.

APPENDIX C
TABLE 2

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
SUMMARY OF REVENUE CHANGES
Forecast period: May 1, 1990 through April 30, 1991

REVENUE ELEMENT	PRESENT RATE REVENUE ($000's)	REVENUE CHANGE ($000's)	ADOPTED REVENUE REQUIREMENT1/ ($000's)	AVERAGE 2/ RATE (cents/Kwh)
Presently Authorized Base Rate Revenue	832,826		774,873	
1990 Attrition 3/	0		30,382	
Heber Expenses 4/	0		(1,987)	
Less: San Diego Franchise Fee Differential	7,837		7,323	
Subtotal Base Rate Revenue	824,989	(29,044)	795,945	5.658
Major Additions Adjustment Clause (MAAC):				
SONGS 2 and 3 pre-COD amortization	(28,966)		(28,966)	
SONGS 2 and 3 post-COD amortization	12,637		12,637	
Less: San Diego Franchise Fee Differential	(149)		(149)	
Subtotal MAAC rate revenues	(16,180)	0	(16,180)	(0.115)
ERAM Balancing Rate	(37,847)	28,650	(9,197)	(0.065)
Electromagnetic Field Study Expense Account	0	142	142	0.001
Base Rates	770,962	(252)	770,710	5.479
Energy Cost Adjustment Clause (ECAC):				
Adopted ECAC Costs			418,320	
Add: Estimated undercollection thru 4/90			23,752	
ECAC costs amortized over the forecast period			442,072	
Add: Franchise Fees and Uncollectibles @ 1.3%			5,747	
ECAC revenue requirements	401,956	45,863	447,819	3.183
Annual Energy Rate (AER):				
Adopted AER costs			36,403	
Add: Franchise Fees and Uncollectibles @ 1.3%			473	
AER revenue requirements	35,205	1,671	36,876	0.262
ECAC/AER Rate	437,161	47,534	484,695	3.445
SUBTOTAL 6/	1,208,123	47,282	1,255,405	8.924
Low Income Ratepayer Assistance Program (LIRA)				
Undercollection from previous period	0	2,395	2,395	
Administrative costs from previous period	0	83	83	
Administrative costs for forecast period	0	551	551	
Subtotal LIRA Rate Net Revenues	0	3,029	3,029	
SUBTOTAL	1,208,123	50,311	1,258,434	
PERCENTAGE INCREASE		4.16%		

APPENDIX C
TABLE 2
(con't)

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
SUMMARY OF REVENUE CHANGES
Forecast period: May 1, 1990 through April 30, 1991

REVENUE ELEMENT	PRESENT RATE REVENUE ($000's)	REVENUE CHANGE ($000's)	ADOPTED REVENUE REQUIREMENT1/ ($000's)	AVERAGE 2/ RATE (cents/Kwh)
SOFFD Revenue from Base, ECAC and AER rates	11,014	459	11,472	
Miscellaneous Revenues	17,005	0	17,005	
Non-Jurisdictional Revenues	1,445	0	1,445	
TOTAL	$1,237,587	$50,770	$1,288,357	

1/ Adjusted for Franchise Fees and Uncollectibles at a factor of 1.013.
2/ Computed on a 14,067.65 Gwh.
3/ Resolution E-3171
4/ Advice Letter 784-E
5/ Resolution E-3130
6/ Revenue used for revenue allocation and rate design.

TABLE 3

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED UNIT MARGINAL COSTS
Forecast period: May 1, 1990 through April 30, 1991

CUSTOMER GROUP		UNIT MARGINAL CUSTOMER COST ($/customer)
Residential		95.34
Commercial/Industrial		
General Service		153.99
GS-Demand Metered		508.82
AL-TOU	2506.85	2,414.79
A6-TOU		13,111.72
Agriculture		545.63
Lighting ($/KWHR)		0.00787

VOLTAGE SERVICE LEVEL	UNIT DEMAND MARGINAL COSTS ($/KW/YR)		
	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	0.0318	0.0315	0.0285	0.0387	0.0386	0.0312
Primary	0.0332	0.0327	0.0292	0.0403	0.0399	0.0320
Secondary	0.0340	0.0334	0.0297	0.0414	0.0409	0.0325

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED MARGINAL DEMAND COST REVENUE
Forecast period: May 1, 1990 through April 30, 1991

CUSTOMER GROUP	VOLTAGE SERVICE LEVEL	ALLOCATION DETERMINANTS (KW/YR)			ADOPTED MARGINAL DEMAND COST REVENUE ($000's)			
		GENERATION	TRANSMISSION	DISTRIBUTION	GENERATION	TRANSMISSION	DISTRIBUTION	TOTAL
Residential (Schedules DR, DM, DS, DT)	Transmission voltage	0	0	0	0	0		0
	Primary voltage	2,668	3,605	5,549	214	87	503	804
	Secondary voltage	915,850	1,237,808	1,905,266	75,368	30,508	177,363	283,238
	Total				75,582	30,594	177,866	284,042
General Service (Schedule A)	Transmission voltage	0	0	0	0	0		0
	Primary voltage	590	689	895	47	17	81	145
	Secondary voltage	392,819	458,997	596,190	32,326	11,313	55,500	99,139
	Total				32,373	11,329	55,581	99,284
General Service Demand Metered 20 KW (Schedule AD)	Transmission voltage	0	0	0	0	0		0
	Primary voltage	10,915	12,141	14,682	875	292	1,332	2,499
	Secondary voltage	374,763	416,855	504,116	30,840	10,274	46,929	88,043
	Total				31,715	10,566	48,260	90,541
AL-TOU	Transmission voltage	0	0	0	0	0		0
	Primary voltage	375,948	400,282	450,730	30,145	9,613	40,884	80,641
	Secondary voltage	363,612	387,147	435,940	29,923	9,542	40,582	80,046
	Total				60,067	19,155	81,466	160,688

APPENDIX C
TABLE 4
(con't)

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED MARGINAL DEMAND COST REVENUE
Forecast period: May 1, 1990 through April 30, 1991

CUSTOMER GROUP	SERVICE VOLTAGE	ALLOCATION DETERMINANTS (KW/YR)			ADOPTED MARGINAL DEMAND COST REVENUE ($000's)			
		GENERATION	TRANSMISSION	DISTRIBUTION	GENERATION	TRANSMISSION	DISTRIBUTION	TOTAL
A6-TOU	Transmission voltage	14,679	15,594	0	1,130	360		1,490
	Primary voltage	114,836	121,995	136,838	9,208	2,930	12,412	24,550
	Secondary voltage	3,206	3,406	3,821	264	84	356	703
	Total				10,602	3,373	12,768	26,743
Agriculture	Transmission voltage	0	0	0	0	0		0
	Primary voltage	16	20	27	1	0	2	4
	Secondary voltage	21,087	26,173	36,717	1,735	645	3,418	5,798
	Total				1,737	646	3,420	5,803
Street Lighting	Transmission voltage	0	0	0	0	0		0
	Primary voltage	0	0	0	0	0	0	0
	Secondary voltage	4,967	8,082	14,540	409	199	1,354	1,961
	Total				409	199	1,354	1,961

TABLE 5

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED MARGINAL ENERGY COST REVENUE
Forecast period: May 1, 1990 through April 30, 1991

CUSTOMER GROUP	SERVICE VOLTAGE	ADOPTED SALES (GWH)							ADOPTED MARGINAL ENERGY COST REVENUE ($000's)						
		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	1.170	1.722	2.885	1.052	3.128	4.339	14.296	39	56	84	42	125	139	485
DM, DS, DT)	Secondary	441.465	649.792	1,088.805	397.202	1180.643	1637.784	5,395.691	15,020	21,718	32,297	16,430	48,249	53,181	186,895
	Total							5,409.987	15,059	21,774	32,381	16,472	48,374	53,320	187,380
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	0.384	0.341	0.486	0.162	0.732	0.650	2.755	13	11	14	7	29	21	95
	Secondary	245.901	218.343	311.328	103.532	468.340	416.031	1,763.475	8,366	7,298	9,235	4,283	19,139	13,509	61,830
	Total							1,766.230	8,379	7,309	9,249	4,289	19,169	13,530	61,924
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	7.684	7.713	10.075	3.098	16.087	12.498	57.155	255	252	294	125	643	399	1,968
20 KW	Secondary	250.165	251.119	328.015	100.870	523.761	406.904	1,860.834	8,511	8,393	9,730	4,172	21,404	13,213	65,424
(Schedule AD)	Total							1,917.989	8,766	8,645	10,024	4,297	22,047	13,612	67,391
AL-TOU	Transmission	0.082	0.088	0.127	0.037	0.179	0.169	0.682	3	3	4	1	7	5	23
	Primary	258.692	278.282	401.068	117.149	567.698	537.254	2,160.143	8,576	9,090	11,706	4,722	22,678	17,166	73,937
	Secondary	212.072	228.131	328.789	96.037	465.390	440.433	1,770.852	7,215	7,625	9,753	3,973	19,019	14,302	61,886
	Total							3,931.677	15,794	16,717	21,463	8,696	41,704	31,473	135,846

APPENDIX C
TABLE 5
(con't)

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED MARGINAL ENERGY COST REVENUE
Forecast period: May 1, 1990 through April 30, 1991

CUSTOMER GROUP	SERVICE VOLTAGE	ADOPTED SALES (GWH)							ADOPTED MARGINAL ENERGY COST REVENUE ($000's)						
		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	
A6-TOU	Transmission	8.527	10.429	17.955	4.294	20.926	24.580	86.711	271	329	511	166	807	766	2,850
	Primary	70.757	86.534	148.980	35.633	173.634	203.955	719.493	2,346	2,827	4,348	1,436	6,936	6,517	24,410
	Secondary	1.515	1.852	3.189	0.763	3.717	4.366	15.402	52	62	95	32	152	142	533
	Total							821.606	2,669	3,217	4,954	1,634	7,895	7,424	27,792
Agriculture	Transmission	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0	0
	Primary	0.017	0.022	0.044	0.007	0.029	0.041	0.160	1	1	1	0	1	1	5
	Secondary	16.508	21.280	42.462	6.646	27.792	39.630	154.318	562	711	1,260	275	1,136	1,287	5,230
	Total							154.478	562	712	1,261	275	1,137	1,288	5,235
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	4.565	21.632	5.939	6.295	36.077	74.508	0	153	642	246	257	1,171	2,469
	Total							74.508	0	153	642	246	257	1,171	2,469

APPENDIX C
TABLE 6

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED TOTAL MARGINAL COST REVENUE
Forecast period: May 1, 1990 through April 30, 1991

CUSTOMER GROUP	NUMBER OF CUSTOMERS	MARGINAL COST REVENUE ($000's) CUSTOMER	DEMAND	ENERGY	TOTAL MARGINAL COST REVENUE ($000's)
Residential	989,072	94,296	284,042	187,380	565,718
Commercial/Indust					
General Service	93,725	14,432	99,284	61,924	175,640
GS-Demand Meter	6,491	3,303	90,541	67,391	161,235
AL-TOU	4,839	11,685	160,688	135,846	308,219
A6-TOU	42	551	26,743	27,792	55,086
Total Commercial/	105,097	29,971	377,256	292,954	700,180
Agriculture	3,702	2,020	5,803	5,235	13,058
Street Lighting	74.508 GWHR	586	1,961	2,469	5,016
Total		$126,873	$669,062	$488,037	$1,283,972

APPENDIX C
TABLE 7

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
ADOPTED REVENUE ALLOCATION
Forecast period: May 1, 1990 through April 30, 1991

CUSTOMER GROUP	ADOPTED SALES (GWHR)	TOTAL MARGINAL COST REVENUE	EPMC ALLOC. FACTOR (%)	ADOPTED REVENUE ALLOCATION ($000's)						PRESENT RATE REVENUES ($000's)		ADOPTED ALLOCATION CHANGE	
				EPMC REVENUE ALLOCATION	FACILITY CHARGES	SUBTOTAL	LIRA ADJ.	ADOPTED REVENUE	AVG RATE ($/KWH)	AMOUNT	AVG RATE ($/KWH)	AMOUNT	(%)
Residential	5,409.987	$565,718	44.06%	$551,769	$1	$551,770	($1,950)	$549,820	0.1016	$539,273	0.0997	$10,547	2.0%
Commercial/Industrial													
General Service	1,766.230	175,640	13.68%	171,310	0	171,310	1,024	172,333	0.0976	165,096	0.0935	7,237	4.4%
GS-Demand Metered	1,917.989	161,235	12.56%	157,260	0	157,260	1,111	158,371	0.0826	151,228	0.0788	7,143	4.7%
AL-TOU	3,931.677	308,219	24.01%	300,619	0	300,619	2,278	302,897	0.0770	282,256	0.0718	20,641	7.3%
A6-TOU	821.606	55,086	4.29%	53,728	0	53,728	476	54,204	0.0660	50,707	0.0617	3,497	6.9%
Subtotal	8,437.502	700,180	54.53%	682,915	0	682,915	4,890	687,805	0.0815	649,287	0.0770	38,519	5.9%
Agriculture	154.478	13,058	1.02%	12,736	20	12,756	90	12,845	0.0832	11,898	0.0770	947	8.0%
Street Lighting	74.508	5,016	0.39%	4,893	3,072	7,965	0	7,965	0.1069	7,665	0.1029	299	3.9%
Total	14,076.475	$1,283,972	100.00%	$1,252,313	$3,093	$1,255,406	$3,029	$1,258,435	0.0894	$1,208,123	0.0858	$50,312	4.2%

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
RESIDENTIAL RATE SCHEDULES
Forecast period: May 1, 1990 through April 30, 1991

Revenues from ECAC & AER rates		$484,696	
Uniform ECAC & AER rate for all customers		0.03445	
Tier I Adopted Rate		$0.08752	
Adopted rate (Min. bill revenues & Tier I	$0.08807		/KWH
Tier II Adopted Rate	$0.12273	$0.12273	/KWH
Adopted rate - Relative Tier Differential	1.394	1.402	
Adopted rate - Absolute Tier Differential	$0.03466	$0.03520	/KWH
Absolute Tier Closure	20.00%	19.75%	
Revenues from Base Rates ($000's)		$365,725	
Base Rate - Tier I		$0.05308	/KWH
Base Rate (Min. bill revenues & Tier I)	$0.05362		/KWH
Base Rate - Tier II	$0.08828	$0.08828	/KWH
Base Rate - Relative Tier Differential	1.646	1.663	
Revenues for residential rate design ($000's)		$551,770	

Total Rates (including LIS):	
Tier I	$0.08810
Tier II	$0.12331

RATE SCHEDULE	BILLING UNITS	PRESENT RATES ($/UNIT)	EMPLOYEE DISCOUNT FACTOR (%)	EFFECTIVE RATES ($/UNIT)	PRESENT RATE REVENUES ($000's)	ADOPTED RATES ($/UNIT)	REVENUES AT ADOPTED RATES ($000's)
SCHEDULE DR							
Minimum Bill	9,614,000	0.16400	0.1714%	0.16372	1,574	0.16400	1,574
Base Rates - Tier I (Baseline)	2,895,236,000	0.06870	0.1714%	0.06858	198,562	0.05308	153,408
Base Rates - Tier II (Nonbaseline)	2,251,633,000	0.06870	0.1714%	0.06858	154,422	0.08828	198,437
ECAC & AER Rates - Tier I (Baseline)	2,895,238,000	0.01278	0.1714%	0.01276	36,938	0.03445	99,556
ECAC & AER Rates - Tier II (Nonbaseline)	2,251,633,000	0.05665	0.1714%	0.05655	127,336	0.03445	77,425
Total	5,146,871,000				$518,832		$530,400
SCHEDULE DM							
Base Rates - Tier I (Baseline)	65,108,000	0.06870		0.06870	4,473	0.05308	3,456
Base Rates - Tier II (Nonbaseline)	44,072,000	0.06870		0.06870	3,028	0.08828	3,891
ECAC & AER Rates - Tier I (Baseline)	65,108,000	0.01278		0.01278	832	0.03445	2,243
ECAC & AER Rates - Tier II (Nonbaseline)	44,072,000	0.05665		0.05665	2,497	0.03445	1,518
Total	109,180,000				$10,829		$11,107

APPENDIX C
TABLE 8
(con't)

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
RESIDENTIAL RATE SCHEDULES
Forecast period: May 1, 1990 through April 30, 1991

RATE SCHEDULE	BILLING UNITS	PRESENT RATES ($/UNIT)	EMPLOYEE DISCOUNT FACTOR (%)	EFFECTIVE RATES ($/UNIT)	PRESENT RATE REVENUES ($000's)	ADOPTED RATES ($/UNIT)	REVENUES AT ADOPTED RATES ($000's)
SCHEDULE DS							
Customer discounts	2,076,000	(0.11000)		(0.11000)	(228)	(0.11000)	(228)
Base Rates - Tier I (Baseline)	15,376,000	0.06870		0.06870	1,056	0.05308	816
Base Rates - Tier II (Nonbaseline)	2,157,000	0.06870		0.06870	148	0.08828	190
ECAC & AER Rates - Tier I (Baseline)	15,376,000	0.01278		0.01278	197	0.03445	530
ECAC & AER Rates - Tier II (Nonbaseline)	2,157,000	0.05665		0.05665	122	0.03445	74
Total	17,533,000				$1,295		$1,382
SCHEDULE DT							
Customer discounts	13,194,000	(0.31200)		(0.31200)	(4,117)	(0.31200)	(4,117)
Base Rates - Tier I (Baseline)	106,335,000	0.06870		0.06870	7,305	0.05308	5,644
Base Rates - Tier II (Nonbaseline)	30,067,000	0.06870		0.06870	2,066	0.08828	2,654
ECAC & AER Rates - Tier I (Baseline)	106,335,000	0.01278		0.01278	1,359	0.03445	3,663
ECAC & AER Rates - Tier II (Nonbaseline)	30,067,000	0.05665		0.05665	1,703	0.03445	1,036
Total	136,602,000				$8,317		$8,880
SUMMARY OF SCHEDULES DR, DM, DS, DT							
Customer discounts					(4,345)		(4,345)
Minimum Bill					1,574		1,574
Base, ECAC & AER Rates - Tier I	3,082,057,000				250,722		269,315
Base, ECAC & AER Rates - Tier II	2,327,929,000				291,322		285,225
Total	5,409,986,000				$539,273		$551,770
Customer discounts, min. bill, Base Rates - Tier I & II					368,289		365,725
ECAC & AER Rates - Tier I & II					170,984		186,045
Total	5,409,986,000				$539,273		$551,770

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
LOW INCOME DISCOUNT RATES
Forecast period: May 1, 1990 through April 30, 1991

	BILLING UNITS (KWH)	ADOPTED RATES ($/KWH)	LIRA DISCOUNT ($/KWH)	DISCOUNT AMOUNT ($000's)
LIRA sales at 15% discount (Tier I)	181,401,930	0.08752	0.01313	2,382
LIRA sales at 15% discount (Tier II)	136,847,070	0.12273	0.01841	2,519
Total LIRA subsidy	318,249,000			4,901
Prior period undercollection				2395
A&G costs for LIRA program				634
Total LIRA costs				7,930
Total sales	14,076,475,000			
Less: Street Lighting sales	74,508,000			
Less: LIRA sales	318,249,000			
Sales subject to LIRA surcharge	13,683,718,000			
LIRA subsidy rate		0.00058		
Sales to residential customers	5,409,986,000			554,720
LIRA subsidy to residential customers	318,249,000			(4,901)
Total revenues from residential customers				$549,820
Low Income Discount Rates (LID):				
Base Rate - Tier I		0.03995		
Base Rate - Tier II		0.06987		
ECAC & AER Rate - Tier I		0.03445		
ECAC & AER Rate - Tier II		0.03445		
Total rate - Tier I		0.07439		
Total rate - Tier II		0.10432		

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
COMMERCIAL AND AGRICULTURAL RATE SCHEDULES
Forecast period: May 1, 1990 through April 30, 1991

RATE SCHEDULE	BILLING UNITS	PRESENT RATES ($/UNIT)	VOLTAGE DISCOUNT FACTOR (%)	STANDBY ADJUSTMENT FACTOR (%)	PRESENT RATE REVENUES ($000's)	ADOPTED RATES ($/UNIT)	REVENUES AT ADOPTED RATES ($000's)
SCHEDULE A							
Customer charge	1,124,697	5.00000			$5,623	5.00000	$5,623
Base Rates	1,766,230,000	0.05963			105,320	0.05994	105,871
ECAC & AER Rates	1,766,230,000	0.03066			54,153	0.03445	60,838
Total					$165,096		$172,333
SCHEDULE AD							
Customer charge	77,897	10.00	-0.1110%	0.0250%	778	10.00	778
Demand charge	6,195,000	5.50	-0.1110%	0.0250%	34,043	5.76114	35,660
Base Rates	1,917,989,000	0.03005	-0.1110%	0.0250%	57,586	0.02914	55,851
ECAC & AER Rates	1,917,989,000	0.03066	0.0000%	0.0250%	58,820	0.03445	66,082
Total					$151,228		$158,371
SCHEDULE PA							
Customer charge	41,571	8.00			333	8.00	333
Base Rates	153,024,000	0.04412			6,751	0.04646	7,110
ECAC & AER Rates	153,024,000	0.03066			4,692	0.03445	5,271
Total					$11,776		$12,713
SCHEDULE PA-TOU							
Customer charge	804	8.00			6	8.00	6
Metering charge	804	10.00			8	10.00	8
BaseRate-On Peak	277,000	0.10227			28	0.10838	30
BaseRate-Off Peak	1,175,000	0.03007			35	0.03187	37
ECAC & AER Rates	1,452,000	0.03066			45	0.03445	50
Total					$123		$132

APPENDIX C
TABLE 10
(con't)

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
COMMERCIAL AND AGRICULTURAL RATE SCHEDULES
Forecast period: May 1, 1990 through April 30, 1991

RATE SCHEDULE	BILLING UNITS	PRESENT RATES ($/UNIT)	STANDBY ADJUSTMENT FACTOR (%)	RATE LIMITER FACTOR (%)	PRESENT RATE REVENUES ($000's)	ADOPTED RATES ($/UNIT)	REVENUES AT ADOPTED RATES ($000's)	ADOPTED TOTAL RATES ($/UNIT)	ADOPTED OPTIONAL ON-PEAK RATE ($/UNIT)
SCHEDULE AL-TOU									
CUSTOMER CHARGE	60,118	20.00	0.4510%	0.5240%	1,201	20.00	1,201	20.00	20.00
NON-COINCIDENT DEMAND CHARGE									
SECONDARY	5,481,000	3.05	0.4510%	0.5240%	16,705	3.27	17,921	3.27	3.27
PRIMARY	5,380,000	2.42	0.4510%	0.5240%	13,010	2.60	13,958	2.60	2.60
SUMMER PEAK DEMAND									
SECONDARY	2,127,000	14.42	0.4510%	0.5240%	30,649	15.47	32,881	15.47	17.37
PRIMARY	2,026,000	14.42	0.4510%	0.5240%	29,194	15.47	31,320	15.47	17.37
WINTER PEAK DEMAND									
SECONDARY	2,542,000	3.36	0.4510%	0.5240%	8,535	3.60	9,156	3.60	3.60
PRIMARY	2,320,000	3.36	0.4510%	0.5240%	7,790	3.60	8,357	3.60	3.60
SUMMER PEAK ENERGY									
SECONDARY	222,499,000	0.04512	0.4510%	0.5240%	10,032	0.04685	10,417	0.08130	0.05686
PRIMARY	220,746,000	0.04024	0.4510%	0.5240%	8,876	0.04162	9,180	0.07606	0.05098
ECAC/AER	443,245,000	0.03066	0.4510%	0.5240%	13,580	0.03445	15,257		0.03445
SUMMER SEMI-PEAK ENERGY									
SECONDARY	254,018,000	0.01834	0.4510%	0.5240%	4,655	0.01812	4,600	0.05257	0.02459
PRIMARY	276,006,000	0.01601	0.4510%	0.5240%	4,416	0.01562	4,309	0.05007	0.02179
ECAC/AER	530,024,000	0.03066	0.4510%	0.5240%	16,239	0.03445	18,243		0.03445
SUMMER OFF-PEAK ENERGY									
SECONDARY	341,714,000	0.00640	0.4510%	0.5240%	2,185	0.00531	1,814	0.03976	0.00531
PRIMARY	386,880,000	0.00402	0.4510%	0.5240%	1,554	0.00276	1,067	0.03721	0.00276
ECAC/AER	728,594,000	0.03066	0.4510%	0.5240%	22,322	0.03445	25,078		0.03445
WINTER PEAK ENERGY									
SECONDARY	124,000,000	0.03729	0.4510%	0.5240%	4,621	0.03845	4,765	0.07290	0.03845
PRIMARY	121,726,000	0.03289	0.4510%	0.5240%	4,001	0.03373	4,103	0.06818	0.03373
ECAC/AER	245,726,000	0.03066	0.4510%	0.5240%	7,528	0.03445	8,458		0.03445
WINTER SEMI-PEAK ENERGY									
SECONDARY	498,429,000	0.01220	0.4510%	0.5240%	6,076	0.01154	5,746	0.04598	0.01154
PRIMARY	518,877,000	0.00913	0.4510%	0.5240%	4,734	0.00824	4,274	0.04269	0.00824
ECAC/AER	1,017,306,000	0.03066	0.4510%	0.5240%	31,168	0.03445	35,016		0.03445
WINTER OFF-PEAK ENERGY									
SECONDARY	459,633,000	0.00539	0.4510%	0.5240%	2,476	0.00423	1,943	0.03868	0.00423
PRIMARY	507,149,000	0.00215	0.4510%	0.5240%	1,090	0.00075	382	0.03520	0.00075
ECAC/AER	966,782,000	0.03066	0.4510%	0.5240%	29,620	0.03445	33,277		0.03445
TOTAL	3,931,677,000				$282,256		$302,723		

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
COMMERCIAL AND AGRICULTURAL RATE SCHEDULES
Forecast period: May 1, 1990 through April 30, 1991

RATE SCHEDULE	BILLING UNITS	PRESENT RATES ($/UNIT)	STANDBY ADJUSTMENT FACTOR (%)	RATE LIMITER FACTOR (%)	PRESENT RATE REVENUES ($000's)	ADOPTED RATES ($/UNIT)	REVENUES AT ADOPTED RATES ($000's)	ADOPTED TOTAL RATES ($/UNIT)	ADOPTED OPTIONAL ON-PEAK RATE ($/UNIT)
SCHEDULE A6-TOU									
CUSTOMER CHARGE	501	600.00	0.2640%		301	600.00	301	600.00	600.00
NON-COINCIDENT DEMAND CHARGE									
PRIMARY	1,596,000	2.42	0.2640%		3,873	2.60	4,155	2.60	2.60
TRANSMISSION	194,000	1.02	0.2640%		198	1.09	213	1.09	1.09
SUMMER PEAK DEMAND									
PRIMARY	512,000	17.18	0.2640%		8,819	18.43	9,462	18.43	20.70
TRANSMISSION	68,000	11.01	0.2640%		751	11.81	805	11.81	13.27
WINTER PEAK DEMAND									
PRIMARY	589,000	4.01	0.2640%		2,368	4.30	2,541	4.30	4.30
TRANSMISSION	74,000	1.79	0.2640%		133	1.92	142	1.92	1.92
SUMMER PEAK ENERGY									
PRIMARY	72,661,000	0.04024	0.2640%		2,932	0.04162	3,032	0.07606	0.05098
TRANSMISSION	6,978,000	0.03811	0.2640%		267	0.03933	275	0.07378	0.04841
ECAC/AER	79,639,000	0.03066	0.2640%		2,448	0.03445	2,750		0.03445
SUMMER SEMI-PEAK ENERGY									
PRIMARY	89,183,000	0.01601	0.2640%		1,432	0.01562	1,397	0.05007	0.02179
TRANSMISSION	8,923,000	0.01461	0.2640%		131	0.01412	126	0.04857	0.02010
ECAC/AER	98,106,000	0.03066	0.2640%		3,016	0.03445	3,388		0.03445
SUMMER OFF-PEAK ENERGY									
PRIMARY	155,231,000	0.00402	0.2640%		626	0.00276	430	0.03721	0.00276
TRANSMISSION	18,591,000	0.00298	0.2640%		56	0.00164	31	0.03609	0.00164
ECAC/AER	173,822,000	0.03066	0.2640%		5,343	0.03445	6,003		0.03445
WINTER PEAK ENERGY									
PRIMARY	35,799,000	0.03289	0.2640%		1,181	0.03373	1,211	0.06818	0.03373
TRANSMISSION	4,457,000	0.03098	0.2640%		138	0.03168	142	0.06613	0.03168
ECAC/AER	40,256,000	0.03066	0.2640%		1,238	0.03445	1,390		0.03445
WINTER SEMI-PEAK ENERGY									
PRIMARY	176,023,000	0.00913	0.2640%		1,611	0.00824	1,455	0.04269	0.00824
TRANSMISSION	20,094,000	0.00793	0.2640%		160	0.00696	140	0.04140	0.00696
ECAC/AER	196,117,000	0.03066	0.2640%		6,029	0.03445	6,773		0.03445
WINTER OFF-PEAK ENERGY									
PRIMARY	204,232,000	0.00215	0.2640%		440	0.00075	154	0.03520	0.00075
TRANSMISSION	29,434,000	0.00116	0.2640%		34	-0.00031	(9)	0.03414	(0.00031)
ECAC/AER	233,666,000	0.03066	0.2640%		7,183	0.03445	8,070		0.03445
TOTAL	821,606,000				$50,707		$54,377		
TOTAL CUSTOMER CHARGE REVENUE					1,503		1,503		
Total revenue from demand charges and energy base rates					185,745		191,894		
Total ECAC/AER revenue					145,714		163,704		
TOTAL AL-TOU & A6-TOU	4,753,283,000				$332,962		$357,101		

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
STREETLIGHT SCHEDULES
Forecast period: May 1, 1990 through April 30, 1991

WATTS	LUMENS	# LAMPS	PRESENT RATES ($/Lamp)	PRESENT RATE REVENUES (000's)	ADOPTED RATES ($/Lamp)	REVENUES AT ADOPTED RATES (000's)
LS-1, Mercury Vapor, Class A						
175	7,000	7,858	9.57	75	9.89	78
250	10,000	123	12.65	2	13.09	2
400	20,000	2,074	17.22	36	17.86	37
700	35,000	56	32.53	2	33.91	2
LS-1, Mercury Vapor, Class C, 1-Lamp						
175	7,000	448	18.05	8	18.52	8
250	10,000	1	23.94	0	24.56	0
400	20,000	314	28.51	9	29.34	9
LS-1, Mercury Vapor, Class C, 2-Lamp						
175	7,000	34	27.36	1	28.14	1
400	20,000	1	46.32	0	47.79	0
LS-1, HPSV, Class A						
70	5,800	19,280	6.29	121	6.48	125
100	9,500	146,977	7.25	1,066	7.48	1,099
150	16,000	5,593	8.55	48	8.84	49
200	22,000	146	10.26	1	10.62	2
250	30,000	19,269	12.94	249	13.39	258
400	50,000	168	16.05	3	16.68	3
1000	140,000	1	33.27	0	34.66	0
LS-1, HPSV, Class B, 1-Lamp						
70	5,800	7,656	6.96	53	7.16	55
100	9,500	17,969	7.92	142	8.16	147
150	16,000	1,995	9.22	18	9.53	19
200	22,000	527	11.13	6	11.50	6
250	30,000	4,192	13.81	58	14.28	60
400	50,000	90	17.01	2	17.65	2
1000	140,000	1	34.30	0	35.71	0

WATTS	LUMENS	# LAMPS	PRESENT RATES ($/Lamp)	PRESENT RATE REVENUES (000's)	ADOPTED RATES ($/Lamp)	REVENUES AT ADOPTED RATES (000's)
LS-1, HPSV, Class B, 2-Lamp						
70	5,800	179	12.08	2	12.44	2
100	9,500	1,121	13.99	16	14.44	16
150	16,000	1,199	16.60	20	17.17	21
200	22,000	1	20.28	0	20.99	0
250	30,000	34	25.64	1	26.54	1
400	50,000	1	31.78	0	33.04	0
1,000	140,000	1	66.33	0	69.12	0
LS-1, HPSV, Class C, 1-Lamp						
70	5,800	13,877	14.77	205	15.10	210
100	9,500	52,326	15.73	823	16.10	842
150	16,000	4,147	17.05	71	17.48	72
200	22,000	1	21.55	0	22.09	0
250	30,000	5,268	24.23	128	24.87	131
400	50,000	1,569	28.77	45	29.61	46
1,000	140,000	1	46.94	0	48.56	0
LS-1, HPSV, Class C, 2-Lamp						
70	5,800	448	20.80	9	21.30	10
100	9,500	919	22.71	21	23.30	21
150	16,000	235	25.33	6	26.05	6
200	22,000	1	32.38	0	33.30	0
250	30,000	504	37.74	19	38.85	20
400	50,000	1	42.90	0	44.34	0
1,000	140,000	1	78.74	0	81.73	0
LS-1, LPSV, Class A						
35	4,800	1	7.77	0	7.95	0
55	8,000	560	8.37	5	8.58	5
90	13,500	370	10.28	4	10.56	4

APPENDIX C
TABLE 11
(con't)

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
STREETLIGHT SCHEDULES
Forecast period: May 1, 1990 through April 30, 1991

WATTS	LUMENS	# LAMPS	PRESENT RATES ($/Lamp)	PRESENT RATE REVENUES (000's)	ADOPTED RATES ($/Lamp)	REVENUES AT ADOPTED RATES (000's)
135	22,500	112	12.66	1	13.03	1
180	33,000	1,928	13.74	26	14.14	27
LS-1, LPSV, Class B, 1-Lamp						
35	4,800	1	8.45	0	8.64	0
55	8,000	276	9.16	3	9.38	3
90	13,500	242	11.07	3	11.36	3
135	22,500	241	13.64	3	14.02	3
180	33,000	241	14.72	4	15.14	4
LS-1, LPSV, Class B, 2-Lamp						
35	4,800	1	15.05	0	15.40	0
55	8,000	1	16.37	0	16.77	0
90	13,500	1	20.19	0	20.74	0
135	22,500	1	25.20	0	25.92	0
180	33,000	1	27.36	0	28.16	0
LS-1, LPSV, Class C, 1-Lamp						
35	4,800	1	16.25	0	16.57	0
55	8,000	359	16.97	6	17.32	6
90	13,500	280	18.90	5	19.32	5
135	22,500	247	24.06	6	24.62	6
180	33,000	269	25.14	7	25.73	7
LS-1, LPSV, Class C, 2-Lamp						
35	4,800	1	23.76	0	24.26	0
55	8,000	1	25.08	0	25.63	0
90	13,500	1	28.92	0	29.62	0
135	22,500	1	37.30	0	38.23	0
180	33,000	1	39.46	0	40.47	0
LS-1, Facilities and Rates, Class A						
Center Suspension		12	4.69	0	4.77	0

WATTS	LUMENS	# LAMPS	PRESENT RATES ($/Lamp)	PRESENT RATE REVENUES (000's)	ADOPTED RATES ($/Lamp)	REVENUES AT ADOPTED RATES (000's)
Non-Standard Wood Pole						
30-foot		9,264	2.35	22	2.39	22
35-foot		1,680	2.64	4	2.68	5
Recator Ballast Discount						
175		3,139	(0.96)	(3)	(0.97)	(3)
250		11	(0.38)	(0)	(0.38)	(0)
Subtotal Revenue LS-1				3,362		3,458
LS-2, Mercury Vapor, Rate A						
175	7,000	22,621	4.88	110	5.17	117
250	10,000	471	6.78	3	7.18	3
400	20,000	11,546	10.68	123	11.31	131
700	35,000	482	18.12	9	19.19	9
1,000	55,000	45	25.60	1	27.11	1
LS-2, Mercury Vapor, Rate B, Energy & Limited Maintenance						
175	7,000	6,401	5.47	35	5.77	37
250	10,000	22	7.37	0	7.79	0
400	20,000	1,625	10.65	17	11.93	19
LS-2, Mercury Vapor, Surcharge for series service						
175	7,000	804	0.39	0	0.40	0
250	10,000	1	0.49	0	0.51	0
400	20,000	3,900	0.71	3	0.73	3
700	35,000	312	1.29	0	1.33	0

APPENDIX C
TABLE 11
(con't)

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
STREETLIGHT SCHEDULES
Forecast period: May 1, 1990 through April 30, 1991

WATTS	LUMENS	# LAMPS	PRESENT RATES ($/Lamp)	PRESENT RATE REVENUES (000's)	ADOPTED RATES ($/Lamp)	REVENUES AT ADOPTED RATES (000's)
LS-2, HPSV, Rate A						
50	3,300	1,334	1.35	2	1.43	2
70	5,800	46,452	2.35	109	2.48	115
100	9,500	85,808	3.27	281	3.47	298
150	16,000	23,697	4.48	106	4.75	113
200	22,000	26,622	5.71	152	6.05	161
250	30,000	48,010	7.27	349	7.70	370
310	37,000	3,441	8.90	31	9.42	32
400	50,000	3,654	11.06	40	11.71	43
1,000	140,000	1	25.60	0	27.11	0
LS-2, HPSV, Rate B, Energy & Limited Maintenance						
50	3,300	1	2.02	0	2.11	0
70	5,800	796	3.01	2	3.16	3
100	9,500	1,087	3.93	4	4.15	5
150	16,000	2,376	5.16	12	5.45	13
200	22,000	1	6.39	0	6.75	0
250	30,000	572	7.95	5	8.39	5
310	37,000	1	9.58	0	10.13	0
400	50,000	1	11.74	0	12.41	0
1,000	140,000	1	26.44	0	27.97	0
LS-2, HPSV, Reduction for 120-volt Reactor Ballast						
70	5,800	20,782	(0.39)	(8)	(0.40)	(8)
100	9,500	18,888	(0.52)	(10)	(0.54)	(10)
150	16,000	8,048	(0.48)	(4)	(0.49)	(4)

WATTS	LUMENS	# LAMPS	PRESENT RATES ($/Lamp)	PRESENT RATE REVENUES (000's)	ADOPTED RATES ($/Lamp)	REVENUES AT ADOPTED RATES (000's)
LS-2, HPSV, Surcharge for Series Service						
50	3,300	1	0.44	0	0.45	0
70	5,800	1	(0.21)	(0)	(0.22)	(0)
100	9,500	336	(0.22)	(0)	(0.23)	(0)
150	16,000	156	0.02	0	0.02	0
200	22,000	132	0.47	0	0.48	0
LS-2, LPSV, Rate A						
35	4,800	22,183	1.51	33	1.60	35
55	8,000	259,621	1.98	514	2.10	545
90	13,500	70,832	3.27	232	3.46	245
135	22,500	57,795	4.65	269	4.92	284
180	33,000	16,680	5.30	88	5.61	94
LS-2, LPSV, Surcharge for series service						
35	4,800	15,108	(0.22)	(3)	(0.23)	(3)
55	8,000	13,788	(0.13)	(2)	(0.13)	(2)
90	13,500	1,596	0.44	1	0.45	1
135	22,500	16,572	0.78	13	0.80	13
180	33,000	120	0.50	0	0.52	0
LS-2, Incandescent Lamps, Rate A, Energy Only						
	1,000	493	1.65	1	1.74	1
	2,500	22	3.65	0	3.87	0
	4,000	1	5.52	0	5.83	0
	6,000	168	8.11	1	8.55	1
	10,000	34	13.71	0	14.52	0

APPENDIX C
TABLE 11
(con't)

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
STREETLIGHT SCHEDULES
Forecast period: May 1, 1990 through April 30, 1991

WATTS	LUMENS	# LAMPS	PRESENT RATES ($/Lamp)	PRESENT RATE REVENUES (000's)	ADOPTED RATES ($/Lamp)	REVENUES AT ADOPTED RATES (000's)
LS-2, Incdsnt Lamps, Rate B, Energy and Limited Maintenance						
	4,000	1	7.42	0	7.79	0
	6,000	67	10.03	1	10.56	1
Subtotal Revenue LS-2				2,523		2,673
LS-3						
Energy Charge		6,300,000	0.07614	480	0.07800	491
Minimum Charge		1	5.81	0	5.88	0
SUBTOTAL REVENUE LS-3				480		491
OL-1, Mercury Vapor, Rate A, St Light Luminaire						
175	7,000	1	9.46	0	9.83	0
400	20,000	1	19.05	0	19.83	0
OL-1, HPSV, Rate A, Street Light Luminaire						
100	9,500	54,926	8.03	441	8.32	457
150	16,000	3,531	9.34	33	9.70	34
250	30,000	31,386	14.22	446	14.78	464
400	50,000	1,569	17.07	27	17.81	28
1,000	140,000	1	34.96	0	36.59	0
OL-1, HPSV, Rate B, Directional Luminaire						
250	30,000	1,681	17.38	29	17.74	30
400	50,000	560	21.42	12	21.86	12
1,000	140,000	168	37.67	6	38.41	6
OL-1, LPSV, Rate A, Street Light Luminaire						
55	8,000	0	8.47	0	8.69	0
90	13,000	0	10.41	0	10.69	0
135	22,500	0	12.82	0	13.19	0
180	33,000	0	13.91	0	14.32	0
OL-1, Pole						
30 ft wood pole		14,040	3.10	44	3.17	45
35 ft wood pole		18,000	3.48	63	3.56	64
SUBTOTAL REVENUE OL-1				1,101		1,140
OWL, Facilities Charges						
$ of Util Invst.		8,500,000	0.01860	158	0.01860	158
OWL, Energy and Lamp Maintenance Charge						
50 Watt HPSV		13,732	3.08000	42	3.18830	44
OWL, Min. Charge		1	148.58	0	151.68	0
SUBTOTAL REVENUE OWL				201		202
TOTAL STREET LIGHT REVENUES				7,665		7,965

(END OF APPENDIX C)

APPENDIX D

SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT

SUMMARY OF RATES

- Residential Rate Schedules
- Commercial and Industrial Rate Schedules
- Agricultural Rate Schedules

Note: Rates in this appendix reflect the LIRA surcharge fee of $.00058/kWh for applicable rate schedules.

See Appendix C, Table 11, pages 17 - 20, for Streetlight Rate Schedules.

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
RESIDENTIAL RATES

CLASSIFICATION	UNITS	PREVIOUS RATE	ADOPTED RATE	CHANGE AMOUNT	CHANGE %
SCHEDULE DR					
Baseline Energy	$/Kwh	0.08148	0.08810	0.00662	8.12
Non-Baseline Energy	$/Kwh	0.12535	0.12331	(0.00204)	(1.63)
Minimum Bill	$/Day	0.164	0.164	0.000	0.00
SCHEDULE DR-LI					
Baseline Energy	$/Kwh	0.06926	0.07439	0.00513	7.41
Non-Baseline Energy	$/Kwh	0.10655	0.10432	(0.00223)	(2.09)
Minimum Bill	$/Day	0.164	0.139	(0.025)	(15.24)
SCHEDULE DM					
Baseline Energy	$/Kwh	0.08148	0.08810	0.00662	8.12
Non-Baseline Energy	$/Kwh	0.12535	0.12331	(0.00204)	(1.63)
Minimum Bill	$/Day	0.164	0.164	0.000	0.00
SCHEDULE DS					
Baseline Energy	$/Kwh	0.08148	0.08810	0.00662	8.12
Non-Baseline Energy	$/Kwh	0.12535	0.12331	(0.00204)	(1.63)
Baseline Energy Low Income	$/Kwh	0.06926	0.07439	0.00513	7.41
Non-Baseline Energy Low Income	$/Kwh	0.10655	0.10432	(0.00223)	(2.09)
Unit Discount	$/Day	0.110	0.110	0.000	0.00
Minimum Bill	$/Day	0.164	0.164	0.000	0.00
Minimum Bill - Low Income	$/Day	-	0.139	-	-
SCHEDULE DT					
Baseline Energy	$/Kwh	0.08148	0.08810	0.00662	8.12
Non-Baseline Energy	$/Kwh	0.12535	0.12331	(0.00204)	(1.63)
Baseline Energy Low Income	$/Kwh	0.06926	0.07439	0.00513	7.41
Non-Baseline Energy Low Income	$/Kwh	0.10655	0.10432	(0.00223)	(2.09)
Space Discount	$/Day	0.312	0.312	0.000	0.00
Minimum Bill	$/Day	0.164	0.164	0.000	0.00
Minimum Bill - Low Income	$/Day	-	0.139	-	-
SCHEDULE D-SMF					
Customer Charge	$/Month	20.00	20.00	0.000	0.00
On-Peak Demand	$/KW	8.15	8.55	0.400	4.91
Baseline Energy	$/Kwh	0.06991	0.07516	0.00525	7.51
Non-Baseline Energy	$/Kwh	0.10775	0.10519	(0.00256)	(2.38)
Baseline Energy Low Income	$/Kwh	0.05769	0.06388	0.00619	10.73
Non-Baseline Energy Low Income	$/Kwh	0.08875	0.08941	0.00066	0.74
Unit Discount	$/Kwh	0.110	0.110	0.000	0.00
Space Discount	$/Kwh	0.312	0.312	0.000	0.00

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
RESIDENTIAL RATES

CLASSIFICATION	UNITS	PREVIOUS RATE	ADOPTED RATE	CHANGE AMOUNT	%
SCHEDULE D-ATOU					
Minimum Bill	$/Day	0.164	0.164	0.000	0.00
Metering Charge	$/Day	0.06	0.06	0.00	0.00
Energy: Baseline/On-Peak	$/Kwh	0.12716	0.13750	0.01034	8.13
Energy: Baseline/Off-Peak	$/Kwh	0.06358	0.06875	0.00517	8.13
Energy: Non-BL/On-Peak	$/Kwh	0.19563	0.19245	(0.00318)	(1.63)
Energy: Non-BL/Off-Peak	$/Kwh	0.09782	0.09622	(0.00160)	(1.64)
Baseline Adjustment	$/Kwh	0.00000	0.00000	0.00000	0.00
SCHEDULE D-UTOU					
Minimum Bill	$/Day	0.164	0.164	0.000	0.00
Metering Charge	$/Day	0.06	0.06	0.00	0.00
Energy: Baseline/On-Peak	$/Kwh	0.08785	0.09499	0.00714	8.13
Energy: Baseline/Off-Peak	$/Kwh	0.04392	0.04749	0.00357	8.13
Energy: Non-BL/On-Peak	$/Kwh	0.13515	0.13295	(0.00220)	(1.63)
Energy: Non-BL/Off-Peak	$/Kwh	0.06757	0.06647	(0.00110)	(1.63)
Baseline Adjustment	$/Kwh	0.00000	0.00000	0.00000	0.00

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
COMMERCIAL AND INDUSTRIAL RATES

CLASSIFICATION	UNITS	PREVIOUS RATE	ADOPTED RATE	CHANGE AMOUNT	CHANGE %
SCHEDULE A					
Customer Charge	$/Month	5.00	5.00	0.00	0.00
Energy Charge	$/Kwh	0.09029	0.09439	0.00410	4.54
SCHEDULE AD					
Customer Charge	$/Month	10.00	10.00	0.00	0.00
Demand	$/KW	5.50	5.76	0.26	4.73
Energy	$/Kwh	0.06071	0.06359	0.00288	4.74

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
COMMERCIAL AND INDUSTRIAL RATES

CLASSIFICATION	UNITS	PREVIOUS RATE	ADOPTED RATE	CHANGE AMOUNT	CHANGE %
SCHEDULE AL-TOU (Default Times)					
Service Charge	$/Month	20.00	20.00	0.00	0.00
On-Peak Rate Limiter: Summer	$/Kwh	0.67	0.72	0.05	7.46
On-Peak Rate Limiter: Winter	$/Kwh	0.26	0.28	0.02	7.69
Average Rate Limiter	$/Kwh	0.16	0.21	0.05	31.25
Non-Coincident Demand					
Secondary	$/KW	3.05	3.27	0.22	7.21
Primary	$/KW	2.42	2.60	0.18	7.44
Transmission	$/KW	1.02	1.09	0.07	6.86
On-Peak Demand: Summer					
Secondary	$/KW	14.42	15.47	1.05	7.28
Primary	$/KW	14.42	15.47	1.05	7.28
Transmission	$/KW	9.07	9.73	0.66	7.28
On-Peak Demand: Winter					
Secondary	$/KW	3.36	3.60	0.24	7.14
Primary	$/KW	3.36	3.60	0.24	7.14
Transmission	$/KW	1.34	1.44	0.10	7.46
On-Peak Energy: Summer					
Secondary	$/Kwh	0.07578	0.08130	0.00552	7.28
Primary	$/Kwh	0.07090	0.07606	0.00516	7.28
Transmission	$/Kwh	0.06877	0.07378	0.00501	7.29
On-Peak Energy: Winter					
Secondary	$/Kwh	0.06795	0.07290	0.00495	7.28
Primary	$/Kwh	0.06355	0.06818	0.00463	7.29
Transmission	$/Kwh	0.06164	0.06613	0.00449	7.28
Semi-Peak Energy: Summer					
Secondary	$/Kwh	0.04900	0.05257	0.00357	7.29
Primary	$/Kwh	0.04667	0.05007	0.00340	7.29
Transmission	$/Kwh	0.04527	0.04857	0.00330	7.29
Semi-Peak Energy: Winter					
Secondary	$/Kwh	0.04286	0.04598	0.00312	7.28
Primary	$/Kwh	0.03979	0.04269	0.00290	7.29
Transmission	$/Kwh	0.03859	0.04140	0.00281	7.28
Off-Peak Energy: Summer					
Secondary	$/Kwh	0.03706	0.03976	0.00270	7.29
Primary	$/Kwh	0.03468	0.03721	0.00253	7.30
Transmission	$/Kwh	0.03364	0.03609	0.00245	7.28
Off-Peak Energy: Winter					
Secondary	$/Kwh	0.03605	0.03868	0.00263	7.30
Primary	$/Kwh	0.03281	0.03520	0.00239	7.28
Transmission	$/Kwh	0.03182	0.03414	0.00232	7.29

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
COMMERCIAL AND INDUSTRIAL RATES

CLASSIFICATION	UNITS	PREVIOUS RATE	ADOPTED RATE	CHANGE AMOUNT	%
SCHEDULE AL-TOU (Optional Times)					
Service Charge	$/Month	20.00	20.00	0.00	0.00
On-Peak Rate Limiter: Summer	$/Kwh	0.67	0.72	0.05	7.46
On-Peak Rate Limiter: Winter	$/Kwh	0.26	0.28	0.02	7.69
Average Rate Limiter	$/Kwh	0.16	0.21	0.05	31.25
Non-Coincident Demand					
Secondary	$/KW	3.05	3.27	0.22	7.21
Primary	$/KW	2.42	2.60	0.18	7.44
Transmission	$/KW	1.02	1.09	0.07	6.86
On-Peak Demand: Summer					
Secondary	$/KW	16.19	17.37	1.18	7.29
Primary	$/KW	16.19	17.37	1.18	7.29
Transmission	$/KW	10.19	10.93	0.74	7.26
On-Peak Demand: Winter					
Secondary	$/KW	3.36	3.60	0.24	7.14
Primary	$/KW	3.36	3.60	0.24	7.14
Transmission	$/KW	1.34	1.44	0.10	7.46
On-Peak Energy: Summer					
Secondary	$/Kwh	0.08510	0.09131	0.00621	7.30
Primary	$/Kwh	0.07963	0.08543	0.00580	7.28
Transmission	$/Kwh	0.07724	0.08286	0.00562	7.28
On-Peak Energy: Winter					
Secondary	$/Kwh	0.06795	0.07290	0.00495	7.28
Primary	$/Kwh	0.06355	0.06818	0.00463	7.29
Transmission	$/Kwh	0.06164	0.06613	0.00449	7.28
Semi-Peak Energy: Summer					
Secondary	$/Kwh	0.05503	0.05904	0.00401	7.29
Primary	$/Kwh	0.05241	0.05624	0.00383	7.31
Transmission	$/Kwh	0.05084	0.05455	0.00371	7.30
Semi-Peak Energy: Winter					
Secondary	$/Kwh	0.04286	0.04598	0.00312	7.28
Primary	$/Kwh	0.03979	0.04269	0.00290	7.29
Transmission	$/Kwh	0.03859	0.04140	0.00281	7.28
Off-Peak Energy: Summer					
Secondary	$/Kwh	0.03706	0.03976	0.00270	7.29
Primary	$/Kwh	0.03468	0.03721	0.00253	7.30
Transmission	$/Kwh	0.03364	0.03609	0.00245	7.28
Off-Peak Energy: Winter					
Secondary	$/Kwh	0.03605	0.03868	0.00263	7.30
Primary	$/Kwh	0.03281	0.03520	0.00239	7.28
Transmission	$/Kwh	0.03182	0.03414	0.00232	7.29

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
COMMERCIAL AND INDUSTRIAL RATES

CLASSIFICATION	UNITS	PREVIOUS RATE	ADOPTED RATE	CHANGE AMOUNT	CHANGE %
SCHEDULE A-6 TOU (Default Times)					
Service Charge	$/Month	600.00	600.00	0.00	0.00
On-Peak Rate Limiter: Summer	$/Kwh	0.67	0.72	0.05	7.46
On-Peak Rate Limiter: Winter	$/Kwh	0.26	0.28	0.02	7.69
Average Rate Limiter	$/Kwh	0.16	0.21	0.05	31.25
Non-Coincident Demand					
Primary	$/KW	2.42	2.60	0.18	7.44
Transmission	$/KW	1.02	1.09	0.07	6.86
On-Peak Demand: Summer					
Primary	$/KW	17.18	18.43	1.25	7.28
Transmission	$/KW	11.01	11.81	0.80	7.27
On-Peak Demand: Winter					
Primary	$/KW	4.01	4.30	0.29	7.23
Transmission	$/KW	1.79	1.92	0.13	7.26
On-Peak Energy: Summer					
Primary	$/Kwh	0.07090	0.07606	0.00516	7.28
Transmission	$/Kwh	0.06877	0.07378	0.00501	7.29
On-Peak Energy: Winter					
Primary	$/Kwh	0.06355	0.06818	0.00463	7.29
Transmission	$/Kwh	0.06164	0.06613	0.00449	7.28
Semi-Peak Energy: Summer					
Primary	$/Kwh	0.04667	0.05007	0.00340	7.29
Transmission	$/Kwh	0.04527	0.04857	0.00330	7.29
Semi-Peak Energy: Winter					
Primary	$/Kwh	0.03979	0.04269	0.00290	7.29
Transmission	$/Kwh	0.03859	0.04140	0.00281	7.28
Off-Peak Energy: Summer					
Primary	$/Kwh	0.03468	0.03721	0.00253	7.30
Transmission	$/Kwh	0.03364	0.03609	0.00245	7.28
Off-Peak Energy: Winter					
Primary	$/Kwh	0.03281	0.03520	0.00239	7.28
Transmission	$/Kwh	0.03182	0.03414	0.00232	7.29

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
COMMERCIAL AND INDUSTRIAL RATES

CLASSIFICATION	UNITS	PREVIOUS RATE	ADOPTED RATE	CHANGE AMOUNT	CHANGE %
SCHEDULE A-6 TOU (Optional Times)					
Service Charge	$/Month	600.00	600.00	0.00	0.00
On-Peak Rate Limiter: Summer	$/Kwh	0.67	0.72	0.05	7.46
On-Peak Rate Limiter: Winter	$/Kwh	0.26	0.28	0.02	7.69
Average Rate Limiter	$/Kwh	0.16	0.21	0.05	31.25
Non-Coincident Demand					
Primary	$/KW	2.42	2.60	0.18	7.44
Transmission	$/KW	1.02	1.09	0.07	6.86
On-Peak Demand: Summer					
Primary	$/KW	19.29	20.70	1.41	7.31
Transmission	$/KW	12.37	13.27	0.90	7.28
On-Peak Demand: Winter					
Primary	$/KW	4.01	4.30	0.29	7.23
Transmission	$/KW	1.79	1.92	0.13	7.26
On-Peak Energy: Summer					
Primary	$/Kwh	0.07963	0.08543	0.00580	7.28
Transmission	$/Kwh	0.07724	0.08286	0.00562	7.28
On-Peak Energy: Winter					
Primary	$/Kwh	0.06355	0.06818	0.00463	7.29
Transmission	$/Kwh	0.06164	0.06613	0.00449	7.28
Semi-Peak Energy: Summer					
Primary	$/Kwh	0.05241	0.05624	0.00383	7.31
Transmission	$/Kwh	0.05084	0.05455	0.00371	7.30
Semi-Peak Energy: Winter					
Primary	$/Kwh	0.03979	0.04269	0.00290	7.29
Transmission	$/Kwh	0.03859	0.04140	0.00281	7.28
Off-Peak Energy: Summer					
Primary	$/Kwh	0.03468	0.03721	0.00253	7.30
Transmission	$/Kwh	0.03364	0.03609	0.00245	7.28
Off-Peak Energy: Winter					
Primary	$/Kwh	0.03281	0.03520	0.00239	7.28
Transmission	$/Kwh	0.03182	0.03414	0.00232	7.29
SCHEDULE AO-TOU					
Customer Charge	$/Month	50.00	50.00	0.00	0.00
Non-Coincident Demand	$/KW	7.31	7.67	0.36	4.92
On-Peak Demand: Summer	$/KW	13.00	13.64	0.64	4.92
On-Peak Demand: Winter	$/KW	3.50	3.67	0.17	4.86
Energy: On-Peak	$/Kwh	0.04275	0.04485	0.00210	4.91
Energy: Semi-Peak	$/Kwh	0.03577	0.03752	0.00175	4.89
Energy: Off-Peak	$/Kwh	0.03196	0.03353	0.00157	4.91

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
COMMERCIAL AND INDUSTRIAL RATES

CLASSIFICATION	UNITS	PREVIOUS RATE	ADOPTED RATE	CHANGE AMOUNT	CHANGE %
SCHEDULE AOS-TOU					
Customer Charge	$/Month	250.00	250.00	0.00	0.00
Non-Coincident Demand	$/KW	7.31	7.67	0.36	4.92
On-Peak Demand: Summer	$/KW	15.49	16.25	0.76	4.91
On-Peak Demand: Winter	$/KW	4.17	4.37	0.20	4.80
Energy: On-Peak	$/Kwh	0.04275	0.04485	0.00210	4.91
Energy: Semi-Peak	$/Kwh	0.03577	0.03752	0.00175	4.89
Energy: Off-Peak	$/Kwh	0.03196	0.03353	0.00157	4.91
SCHEDULE A-E1					
Customer Charge	$/Month	600.00	600.00	0.00	0.00
Contract Demand	$/KW	13.75	13.75	0.00	0.00
Semi-Peak Demand	$/KW	0.50	0.50	0.00	0.00
Energy: On-Peak	$/Kwh	8.29114	8.29493	0.00379	0.05
Energy: Semi-Peak	$/Kwh	0.04770	0.04714	(0.00056)	(1.17)
Energy: Off-Peak	$/Kwh	0.03066	0.03445	0.00379	12.36
SCHEDULE A-E2					
Customer Charge	$/Month	600.00	600.00	0.00	0.00
Contract Demand	$/KW	9.87	10.45	0.58	5.88
Non-Coincident Demand					
Secondary	$/KW	3.05	3.27	0.22	7.21
Primary	$/KW	2.42	2.60	0.18	7.44
Transmission	$/KW	1.02	1.09	0.07	6.86
Energy: On-Peak	$/Kwh	4.19740	4.44312	0.24572	5.85
Energy: Semi-Peak	$/Kwh	0.06306	0.06543	0.00237	3.76
Energy: Off-Peak	$/Kwh	0.03072	0.03445	0.00373	12.14
SCHEDULE R-TOU-1					
Customer Charge	$/Month	600.00	600.00	0.00	0.00
Contract Demand	$/KW	13.75	13.75	0.00	0.00
Semi-Peak Demand	$/KW	0.50	0.50	0.00	0.00
Energy: Super-Peak	$/Kwh	0.94458	0.94837	0.00379	0.40
Energy: On-Peak	$/Kwh	0.29627	0.30006	0.00379	1.28
Energy: Semi-Peak	$/Kwh	0.04024	0.04097	0.00073	1.81
Energy: Off-Peak	$/Kwh	0.03066	0.03445	0.00379	12.36

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
COMMERCIAL AND INDUSTRIAL RATES

CLASSIFICATION	UNITS	PREVIOUS RATE	ADOPTED RATE	CHANGE AMOUNT	CHANGE %
SCHEDULE R-TOU-2					
Customer Charge	$/Month	600.00	600.00	0.00	0.00
Contract Demand	$/KW	13.75	13.75	0.00	0.00
Semi-Peak Demand	$/KW	0.50	0.50	0.00	0.00
Energy: Super-Peak	$/Kwh	0.49458	0.49837	0.00379	0.77
Energy: On-Peak	$/Kwh	0.13537	0.09495	(0.04042)	(29.86)
Energy: Semi-Peak	$/Kwh	0.02942	0.03445	0.00503	17.10
Energy: Off-Peak	$/Kwh	0.03066	0.03445	0.00379	12.36
SCHEDULE R-TOU-3					
Customer Charge	$/Month	600.00	600.00	0.00	0.00
Contract Demand	$/KW	9.87	10.45	0.58	5.88
Non-Coincident Demand					
Secondary	$/KW	3.05	3.27	0.22	7.21
Primary	$/KW	2.42	2.60	0.18	7.44
Transmission	$/KW	1.02	1.09	0.07	6.86
Energy: Super-Peak	$/Kwh	1.13855	1.23976	0.10121	8.89
Energy: On-Peak	$/Kwh	0.09209	0.10028	0.00819	8.89
Energy: Semi-Peak	$/Kwh	0.04405	0.04796	0.00391	8.88
Energy: Off-Peak	$/Kwh	0.03072	0.03445	0.00373	12.14
SCHEDULE R-TOU-4					
Customer Charge	$/Month	600.00	600.00	0.00	0.00
Contract Demand	$/KW	9.87	10.45	0.58	5.88
Non-Coincident Demand					
Secondary	$/KW	3.05	3.27	0.22	7.21
Primary	$/KW	2.42	2.60	0.18	7.44
Transmission	$/KW	1.02	1.09	0.07	6.86
Energy: Super-Peak	$/Kwh	0.44539	0.48498	0.03959	8.89
Energy: On-Peak	$/Kwh	0.07361	0.08015	0.00654	8.88
Energy: Semi-Peak	$/Kwh	0.03972	0.04325	0.00353	8.89
Energy: Off-Peak	$/Kwh	0.03072	0.03445	0.00373	12.14
SCHEDULE S					
Contracted Demand					
Secondary	$/Kwh	2.44	2.62	0.18	7.38
Primary	$/Kwh	1.94	2.08	0.14	7.22
Transmission	$/Kwh	0.82	0.88	0.06	7.32

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
COMMERCIAL AND INDUSTRIAL RATES

CLASSIFICATION	UNITS	PREVIOUS RATE	ADOPTED RATE	CHANGE AMOUNT	CHANGE %
SCHEDULE I-1					
Rate A: Utility Control	$/KW	3.27	3.27	0.00	0.00
Rate B: Customer Control	$/KW	2.18	2.18	0.00	0.00
Rate C					
Utility Control	$/KW	3.27	3.27	0.00	0.00
Customer Control	$/KW	2.18	2.18	0.00	0.00
SCHEDULE I-2					
Rate A: 1 YR Cancellation					
Guaranteed Load	$/KW	5.33	5.33	0.00	0.00
Each Interruption	$/KW	0.27	0.27	0.00	0.00
Rate A: 5 YR Cancellation					
Guaranteed Load	$/KW	6.72	6.72	0.00	0.00
Each Interruption	$/KW	0.27	0.27	0.00	0.00
Rate B: 1 YR Cancellation					
Guaranteed Load	$/KW	4.90	4.90	0.00	0.00
Each Interruption	$/KW	0.27	0.27	0.00	0.00
Rate B: 5 YR Cancellation					
Guaranteed Load	$/KW	6.16	6.16	0.00	0.00
Each Interruption	$/KW	0.27	0.27	0.00	0.00
Rate C: 1 YR Cancellation					
Guaranteed Load	$/KW	3.95	3.95	0.00	0.00
Each Interruption	$/KW	0.27	0.27	0.00	0.00
Rate C: 5 YR Cancellation					
Guaranteed Load	$/KW	4.99	4.99	0.00	0.00
Each Interruption	$/KW	0.27	0.27	0.00	0.00
Rate D: 1 YR Cancellation					
Guaranteed Load	$/KW	3.62	3.62	0.00	0.00
Each Interruption	$/KW	0.27	0.27	0.00	0.00
Rate D: YR Cancellation					
Guaranteed Load	$/KW	4.57	4.57	0.00	0.00
Each Interruption	$/KW	0.27	0.27	0.00	0.00

SAN DIEGO GAS AND ELECTRIC COMPANY - ELECTRIC DEPARTMENT
AGRICULTURAL

CLASSIFICATION	UNITS	PREVIOUS RATE	ADOPTED RATE	CHANGE AMOUNT	CHANGE %
SCHEDULE PA					
Customer Charge	$/Month	8.00	8.00	0.00	0.00
Energy	$/Kwh	0.07478	0.08091	0.00613	8.20
SCHEDULE PA-TOU					
Metering Charge	$/Month	10.00	10.00	0.00	0.00
Customer Charge	$/Month	8.00	8.00	0.00	0.00
Energy: On-Peak	$/Kwh	0.13293	0.14283	0.00990	7.45
Energy: Off-Peak	$/Kwh	0.06073	0.06632	0.00559	9.20
Schedule PA-T-1					
Customer Charge	$/Month	20.00	20.00	0.00	0.00
Demand: On-Peak					
Option A	$/KW	9.50	10.19	0.69	7.26
Option B	$/KW	8.34	8.95	0.61	7.31
Option C	$/KW	8.16	8.75	0.59	7.23
Option D	$/KW	8.50	9.12	0.62	7.29
Option E	$/KW	8.33	8.94	0.61	7.32
Option F	$/KW	7.97	8.55	0.58	7.28
Demand: Semi-Peak	$/KW	0.50	0.50	0.00	0.00
Energy: On-Peak	$/Kwh	0.08063	0.08410	0.00347	4.30
Energy: Semi-Peak	$/Kwh	0.05926	0.06287	0.00361	6.09
Energy: Off-Peak	$/Kwh	0.03802	0.04177	0.00375	9.86

(END OF APPENDIX D)