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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 November 1, 1988 in accordance with the Electrical Revenue Adjustment Mechanism established by Decision 93892. (U 902-E)	Application 88-07-003 (Filed July 1, 1988)

Thomas G. Hankley, Michael R. Weinstein, and Debra Carrillo, Attorneys at Law, for San Diego Gas & Electric Company, applicant.

Michel P. Florio, Attorney at Law, for Toward Utility Rate Normalization; Norman Furuta, Attorney at Law, for Federal Executive Agencies; William Marcus, for JBS Energy; Chester & Schmidt Consultants, by Reed V. Schmidt, for California City-County Street Light Association; John W. Witt, City Attorney, by William S. Shaffran and Leslie Girard, for City of San Diego; Michael Shames, Attorney at Law, for Utility Consumers' Action Network; Brian Sibold, for Energy Factors; Barakat, Howard & Chamberlin, by Nancy Thompson, for Barakat, Howard & Chamberlin; Kevin Woodruff, for Henwood Energy Services, Inc.; Vanessa MaClaren Wray, for Energy Management Associates; Don Klein, for Rate Watchers; and Messrs. Armour, St. John, Wilcox, Goodin & Schlotz, by James D. Squeri, Attorney at Law, for Kelco Division of Merck and Company, Inc., and California Cogeneration Council; interested parties.

Carol L. Matchett, Attorney at Law, Bill Y. Lee, and Steve Linsey, for the Commission Advisory and Compliance Division

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OPINION

I. Summary

This Phase I decision in the San Diego Gas & Electric Company (SDG&E) annual Energy Cost Adjustment Clause (ECAC) Application (A.) 88-07-003 will set electric revenue requirements, rates, and Qualifying Facility (QF) pricing levels for the forecast period ending October 31, 1989. The net revenue requirement change is a decrease of $27.1 million based on an ECAC increase of $3.6 million, an Annual Energy Rate (AER) decrease of $0.1 million, and an Electric Revenue Adjustment Mechanism (ERAM) decrease of $30.8 million.

An Incremental Energy Rate (IER) of 8,769 British thermal units (Btu) per kilowatt-hour (kWh), and a capacity value of $65.00 per kW-year, are adopted for QF purchases. We will also adopt a 1.06 mils per kWh adder for QF purchases which makes an effective IER of 9,102 Btu per kWh.

II. Background

This is the annual ECAC filing which includes a review of the reasonableness of fuel-related operations during the annual record period, May 1, 1987 through April 30, 1988. The ECAC, AER, and ERAM rates are to be adjusted to reflect changes in the annual fuel and purchased power expenses for the forecast period, November 1, 1988 through October 31, 1989. The actual rate changes are expected to take effect January 1, 1989 concurrent with other pending rate changes for SDG&E.

In addition, beginning with this filing, SDG&E will regularly update in the annual ECAC filing the key components used in determining the variable prices to be paid for power it purchases from QFs.

The QF issues were added to ECAC by Decision (D.) 88-03-026 in the generic standard offer proceeding, A.82-04-044 et al. That decision determined that annual updating of variable QF payments should take place in ECAC at the same time and using the same assumptions used to adjust utility rates. The SCE General Rate Case (GRC) D.87-12-066 ordered that parties to future ECAC proceedings who present testimony using a production cost model (model) to develop marginal or avoided costs shall provide a base case run using the ELFIN model. Parties who so desire may also present testimony using its model of choice if different than ELFIN, and explain the basis for its preference of that model and the results it produces. That decision also ordered that workshops be held within a week of the SDG&E ECAC filing. The purpose of workshops is to determine the data sets, resource plans, load shape, heat rate input, unit commitment and dispatch, minimum load conditions, resource assumptions, and all other pertinent data to be used in determining SDG&E's IER. The workshop is also intended to be a forum in which parties can agree, to the extent possible, on the assumptions to be used and the appropriate source of those assumptions. The Director of the Commission Advisory and Compliance Division (CACD) appoints an arbiter to resolve disputes relating to the achievement of a common data set.

III. Filing

In the original filing SDG&E requested authority to decrease its electric rates by $7.535 million annualized from the rates in effect on July 1, 1988. In an amendment to the application SDG&E requested that the rates be reduced by $15.981 million from the rates in effect July 9, 1988. Finally, in the evidentiary hearings, SDG&E revised its request for a rate decrease to $22.607 million. The growing decrease in rates is due to the continuing overcollecting of ERAM, which more than compensates for the requested increases in ECAC and AER rates.

At the prehearing conference on July 28, 1988 the administrative law judge (ALJ) granted a motion by SDG&E to defer hearing on the reasonableness of purchased power issues until 45 days after the Commission issues a decision on rehearing in the SWPL A.84-12-015. The motion was granted subject to an additional condition requested by Division of Ratepayer Advocates (DRA) and agreed to by SDG&E, that if the Commission does not issue that decision by the end of 1988, SDG&E's showing on the reasonableness of purchased power issues will be due February 17, 1989. The basis of the motion is that SDG&E's showing on the reasonableness of purchased power issues including long-term agreements is affected by resolution of the pending decision in SWPL.

SDG&E also filed a motion to consolidate the Target Capacity Factor (TCF) issue with the TCF issue in the reasonableness portion of the 1988 SCE ECAC A.88-02-016. The TCF issue relates to SONGS 2&3. The TCF sets a level of operating capacity as a target, and offers rewards or penalties for actual operations that either exceed or fall short of the TCF. The basis of the motion is that SCE is the majority owner of SONGS 2&3 and SDG&E will rely on SCE's rationale in support of its requested modifications of the TCF. The motion was granted by ALJ Ruling on August 31, 1988.

As a result of the motions discussed above, and due to the need to implement interim rates as soon after the November 1, 1988 tariff revision date as possible, this application is being handled in three phases. Phase I addresses the forecast and QF issues, and sets interim rates for the forecast period. Phase II will deal with the reasonableness of ECAC operations during the record period, except for the reasonableness of purchased power issues which will be handled in Phase III. This order addresses Phase I.

IV. Forecast Issues

The traditional purpose of the forecast has been to set prospective ECAC, AER, and ERAM rates to reflect the changes in the forecasted fuel and purchase power expenses on an annual basis, outside the general rate case. This filing also is the beginning of the regular annual updating in ECAC of the key components used in calculating the prices paid for power sold to SDG&E by QFs. QF prices are based on two components, the capacity payment and the energy payment. Determination of these payments is dependent on the utility's Energy Reliability Index (ERI) and IER. The ERI is a ratio of the Expected Unserved Energy (EUE) for the year divided by the target EUE. The ERI reflects the utility's needs for new capacity on its system. EUE is determined by running two cases on the model with different resource assumptions, essentially a QFs-in case and a QFs-out case. The EUE is the average of the EUEs from the two runs. The capacity payment to be paid QFs is the capacity cost of the combustion turbine proxy multiplied by the ERI.

The IER is a measure of the utility's incremental thermal efficiency in producing electricity, expressed in Btu per kWh. The IER is multiplied by the utility's incremental fuel cost for electric generation to determine the price to pay for QF energy. The total of QF capacity and QF energy payments determine the total price to be paid QFs.

In compliance with the directives of D.87-12-066, two ELFIN workshops were held on July 21 and August 1, 1988, with Linda Gustafson of CACD as the arbiter. On August 15, 1988 the common data set for the base case ELFIN run was served on all parties to this application and on the workshop attendees.

Six days of hearings were held in Phase I, beginning with two days of hearings in La Mesa on September 12 and 13, 1988, starting with a Public Participation Hearing on the first day, followed by evidentiary hearings. Hearings were temporarily adjourned on September 13 to allow the parties to have a further workshop to attempt to resolve to the extent possible the modeling issues. The workshop was held in San Francisco on September 14, followed by evidentiary hearings in San Francisco from September 19 through 22, 1988.

This phase of the proceeding was submitted on the filing of concurrent opening briefs on October 7, 1988 and concurrent reply briefs on October 17, 1988.

The parties filing briefs in this phase include SDG&E, DRA, and Kelco Division of Merck & Company, Inc. (Kelco).

A. Production Cost Models (Models)

1. Positions of Parties

a. SDG&E

SDG&E believes that the PROMOD model is the only reasonable choice of models, that it has been successfully indexed with historic operational results, and that it appropriately determines the optimal resource mix considering operational constraints. SDG&E points out that PROMOD is currently the model of choice of utilities, that it is backed by significant support staff of its vendor, Energy Management Associates (EMA), and that its greater complexity allows it to simulate the utility operations more realistically without significant manipulations by the user. SDG&E believes that other models, notably ELFIN, are not comparable to PROMOD due to less complexity, that they are unreliable, and have not been benchmarked or proven in the Assembly Bill (AB) 475 benchmarking studies.

b. DRA

DRA supports the ELFIN model as equally appropriate and competent as PROMOD, and as more widely available without the considerable costs to the user associated with PROMOD. DRA believes that the ELFIN results are reliable although it is a somewhat simpler model. However, even the PROMOD model requires a user who is knowledgeable about the complexities of the utility's operations since it also requires manipulation in order for it to simulate the operations accurately. DRA points out that SDG&E's criticism of ELFIN relates primarily to the earlier version, ELFIN 1.58, not the current version, ELFIN 1.60, used in this proceeding. The two main improvements in the new version are a commitment logic that allows the model to select resources to meet load requirements, and the ability to treat resources on a time-differentiated basis. The earlier version, which was used for the AB 475 reports, did not have these capabilities. DRA believes that the costs of using PROMOD outweigh any possible advantages for DRA's use in ECACs at this time, and that if it were adopted as the model of choice, some parties would be precluded from participation due to cost.

c. <u>Kelco</u>

Kelco, an interested party representing QF interests, relied on the ELFIN model in its determination of IER and ERI, and supports ELFIN as equivalently capable of modeling SDG&E's operations as PROMOD. Kelco sees no advantage in using PROMOD instead of ELFIN.

2. <u>Differences in Input Assumptions</u>

The large spread between PROMOD and ELFIN results appears to be due mainly to different assumptions used by SDG&E between its PROMOD and ELFIN runs. These differences are in the areas of dispatching of Encina Units 4 and 5 and the firm purchase contracts with Public Service of New Mexico (PNM) and Arizona Public Service (APS).

The recommendations for the annual average IER are:

	PROMOD	ELFIN
SDG&E	8,330	8,926
DRA	-	9,009
Kelco	-	9,156

a. Encina Units 4 and 5

Kelco witness Younger points out that SDG&E assumes in PROMOD, but not in ELFIN, that the Encina units are slow-start units and therefore these units must be committed for all hours during a period, such as peaking, although they can operate at minimum load. SDG&E models the units as fast-start in its ELFIN run. SDG&E explains that in PROMOD it assumes the units are on economic dispatch, so that if committed during a month they must be run at minimum load for all hours of that entire month. Since they are assumed to be unable to shut down, they cause an unrealistic increase in the need for gas/oil resources, which reduces the ability to rely instead on less expensive purchases. In effect, the Encina units are forced on the system beyond the times they are actually needed. The result is that less expensive, more efficient resources become the avoided units, so the avoided cost and IER drop below the levels that otherwise would result. This partially explains why SDG&E's IER using PROMOD is dramatically lower than its ELFIN IER. It is also lower than the ELFIN IERs of DRA and Kelco.

DRA agrees with Kelco and models the units as fast-start. No explanation was given by SDG&E for the apparent inconsistency in its assumptions between PROMOD and ELFIN. We conclude that the Encina Units 4 and 5 units should be modeled as fast start.

b. PNM

Similar to the manner in which SDG&E models the Encina units, it assumes in its PROMOD run that the firm purchase contract with PNM does not allow spinning reserve unless some actual energy is taken. In this case, 20 megawatt (MW) is assumed as the minimum level required under the 100 MW contract. Younger argues that this assumption overstates the need for PNM energy, so that SDG&E is assumed to take the 20 MW amount whether it is economic or not. In doing so, the amount of economic energy is reduced, lowering the avoided energy cost and IER. Younger recommends that firm

3. Discussion

SDG&E, DRA, and Kelco agree that PROMOD is a more complex model than ELFIN. PROMOD is capable of more accurate and detailed simulation of actual system operations, and requires less operator manipulation of input data in order to achieve credible results than does ELFIN. PROMOD has two commitment variables, so for example, it can use one commitment variable to dispatch resources sufficient to cover the reserve margin, and use the other commitment variable to dispatch a different level of resources to be held on line for the next day. With ELFIN, only one of these conditions can be covered with its single commitment variable. The effect of the other condition must be otherwise compensated for by the user. However, this can routinely be accomplished by a competent user, who must similarly compensate for other operational conditions that cannot be simulated by either model.

SDG&E also points out that DRA relied on PROMOD for start-up costs, which cannot be determined with ELFIN. However, DRA responds that it used PROMOD only for convenience, and that otherwise it would have estimated start-up costs based on historic values. DRA estimates start-up costs at $298,000. SDG&E implicitly agrees with this estimate since it resulted from SDG&E's PROMOD run.

SDG&E argues that ELFIN has never been successfully backcast for SDG&E. Backcasting refers to verifying the model by running a historic period through it and comparing the results with the recorded results. SDG&E believes that PROMOD is the preferred model that should be adopted by the Commission for future ECAC proceedings.

DRA counters that ELFIN is the standard used not only by it and many interested parties, but that it has been used by other utilities. DRA argues that although SDG&E claims that PROMOD has been successfully backcast in AB 475 runs, in fact since the

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Similar to the manner in which SDG&E models the Encina units, it assumes in its PROMOD run that the firm purchase contract with PNM does not allow spinning reserve unless some actual energy is taken. In this case, 20 megawatt (MW) is assumed as the minimum level required under the 100 MW contract. Younger argues that this assumption overstates the need for PNM energy, so that SDG&E is assumed to take the 20 MW amount whether it is economic or not. In doing so, the amount of economic energy is reduced, lowering the avoided energy cost and IER. Younger recommends that firm purchases be modeled with a minimal first block such as one MW, so that capacity and spinning reserve can be used without a substantial commitment of energy, thereby allowing more economy energy to be used.

SDG&E apparently used the 20 MW minimum as a convenient assumption, and does not argue against using a lower minimum, such as one MW as suggested by Younger.

We agree that ELFIN runs should assume a one MW first block for firm energy purchases from PNM, in order to more accurately simulate actual operations.

c. APS

SDG&E and DRA used different methodologies to account for the actual costs of purchases from APS with regard to the demand charge. If SDG&E purchases any energy from APS it does not receive the demand charge credit that it would receive if it purchases no energy. In PROMOD SDG&E assumes that the demand charge credit applies during all periods whether or not energy is taken. SDG&E witness Higgins testified that SDG&E used that assumption because it is difficult to simulate in the model exactly what actually happens on the system, so a simplifying assumption was needed.

To compensate for the inability to exactly model purchase cost and demand charge credits, DRA used dispatch costs for the APS contract that include estimated start-up costs. The result is costs that are $2.00 per MWh and $1.30 per MWh higher than SDG&E for on-peak and off-peak, respectively. Kelco agrees with DRA's treatment of the APS contract. The higher dispatch costs used by DRA result in increased avoided costs and a higher IER.

The methodological differences between SDG&E and DRA on this item have only a minor impact, with an approximately $55,000 higher revenue requirement under DRA's approach. Because of this minor impact and the fact that we ordered that the final model runs be done on ELFIN, to which DRA's methodology is tailored, we will adopt DRA's method as a reasonable input assumption.

3. <u>Discussion</u>

SDG&E, DRA, and Kelco agree that PROMOD is a more complex model than ELFIN. PROMOD is capable of more accurate and detailed simulation of actual system operations, and requires less operator manipulation of input data in order to achieve credible results than does ELFIN. PROMOD has two commitment variables, so for example, it can use one commitment variable to dispatch resources sufficient to cover the reserve margin, and use the other commitment variable to dispatch a different level of resources to be held on line for the next day. With ELFIN, only one of these conditions can be covered with its single commitment variable. The effect of the other condition must be otherwise compensated for by the user. However, this can routinely be accomplished by a competent user, who must similarly compensate for other operational conditions that cannot be simulated by either model.

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DRA counters that ELFIN is the standard used not only by it and many interested parties, but that it has been used by other utilities. DRA argues that although SDG&E claims that PROMOD has been successfully backcast in AB 475 runs, in fact since the

recorded dispatching results were input to PROMOD, the results could not verify its dispatching accuracy. DRA additionally argues that PROMOD is not as accessible to parties to the proceeding due to the comparatively high costs of using it. The Commission currently has a short-term agreement with EMA for the use of PROMOD by Commission staff in ECAC and for other matters. The costs are approximately $2,000 per month and $100 per run (off-peak), plus fees for connection time, disk storage, and printer. In addition, the Commission paid a flat fee of $15,000 for customer support services by EMA. DRA believes that these costs would prevent the active participation of some interested parties and could handicap DRA, depending on the Commission budget, if PROMOD were chosen as the appropriate model for future ECAC use.

ELFIN is significantly less costly, both in initial cost and in operating cost. DRA witness Logan testified that the licensing agreement cost for ELFIN was about $5,000 a year as of a year ago. There is no added charge per run. Logan was not sure whether the current prices are the same. He estimated that DRA performed approximately two dozen runs on ELFIN in preparing for this proceeding.

Kelco believes that either model is equally capable, and that the fact that ELFIN has only one commitment variable makes no difference in terms of the model results on the SDG&E system.

We will not endorse either model as the model of choice in this proceeding. Both PROMOD and ELFIN appear to be capable of producing reliable results when used by knowledgeable persons using consistent and realistic assumptions. We are somewhat reluctant to adopt PROMOD due to cost, since as DRA points out, some parties could be handicapped in their participation if PROMOD were adopted. Since the models, especially ELFIN, also appear to be continuing to evolve, we will continue to monitor the comparative results in future proceedings. Meanwhile, we will not change our requirement that ELFIN be used for base case model runs to develop the ECAC marginal or avoided costs for QF pricing.

B. Sales Forecast

SDG&E estimates total on-system sales of 12,888 gigawatt-hours (gWh) for the forecast period. DRA independently estimated 12,823 gWh. Due to the minimal difference between the forecasts, about 0.5%, DRA recommends adopting the SDG&E forecast. Only the City of San Diego (City) offers other recommendations for the sales forecast. City suggests that a higher forecast of miscellaneous sales may be appropriate. Miscellaneous sales include sales to Mexico, to members of the California Power Pool, and to other California agencies. City points out that miscellaneous sales averaged 48 gWh per month in 1987 due to the drought and resultant lower availability of Pacific Northwest (PNW) economy energy. City asks whether a higher forecast of miscellaneous sales such as 40 gWh per month might be more realistic since there will likely be some carryover of the drought effects on availability of economy energy.

We note that the effect of an increase in miscellaneous sales would be only a slight reduction in revenue requirement since the associated increase in revenue would be nearly offset by the extra cost of generation.

We conclude that insufficient evidence exists on which to base a higher miscellaneous sales forecast. We believe that SDG&E's forecast of 30 gWh per month is reasonable since it is based on historic trends. We will adopt SDG&E's sales forecast of 12,888 gWh.

C. Forecast of Fuel and Purchased Power Expense

1. Resource Plan

SDG&E proposes a resource plan that is essentially the same as it presented in the SDG&E 1989 Test Year (TY) GRC A.87-12-003, revised to reflect the Commission required offer of 100 MW to Standard Offer 2 QFs. The result of the offer and 100 MW commitment was to remove the need for 75 MW of baseload purchases beginning in 1989.

No party opposes or presents a different resource plan. DRA and Kelco present different forecasts of purchase quantities and price forecasts, as we will consider below.

2. Fuel Expense

a. Nuclear Generation

SDG&E's forecast of nuclear generation is developed from an operational forecast of SCE, the majority owner and operator of SONGS units. The forecast generally agrees with the forecast used in SCE's GRC except that later refueling schedules are used here that were not available in the GRC. DRA accepts SDG&E's nuclear generation forecast assumptions, but obtains slightly different results using the ELFIN model. DRA forecasts 3,213 gWh at a cost of $34.35 million, compared to SDG&E's forecast of 3,211 gWh at a cost of $34.33 million. The unit costs are nearly identical at 1.069¢/kWh. We adopt 3,213 gWh of nuclear generation as determined by DRA's further ELFIN model run we ordered as a late-filed exhibit.

b. Gas Generation

SDG&E forecasts 3,845 gWh of gas generation at an average cost of 3.57¢/kWh, which includes 500 gWh of must-run generation to satisfy the Energy Factors Incorporated (EFI) contract. The contract provides steam recovered from the exhaust heat from combustion turbine (CT) units to EFI. Since the contract provides for continuous steam, the CTs are must-run units. SDG&E bases the average gas price for the forecast period on a commodity cost of gas of $1.959 per million Btu delivered to the California border, plus $0.21 per million Btu for transportation on the Southern California Gas Company (SoCal) system from the California border to SDG&E's system, for a delivered cost of $2.169 per million Btu. SDG&E assumes that the price for spot market gas will be lower than the oil fuel alternative, low sulfur fuel oil (LSFO), during the forecast period. As a result gas will be the fuel of choice for the gas/oil fired power plants. The forecast prices are based on SDG&E purchasing its own gas on the spot market. A level of service of about 95% is forecast, based on 18 days of curtailment.

DRA forecasts 3,667 gWh of gas generation at an average cost of 3.568¢/kWh. This is based on a forecast of commodity cost of gas at $1.918 per million Btu plus $0.213 per million Btu for transporting the gas across SoCal's system, and $0.021 per million Btu for compressor fuel at 1%. This yields an average delivered cost of $2.152 per million Btu. The delivered cost is an avoided cost that does not include demand charges. DRA forecasts a four-week curtailment (20 days) of gas supply for electric generation, resulting in a level of service of about 94%.

SDG&E's forecast does not indicate that it accounts for the fuel necessary for compression used to transport the gas. Adding compressor fuel to SDG&E's estimate would make it about four cents per million Btu higher than DRA.

Kelco supports the DRA cost forecast, and does not present its own estimate of the quantity of gas generation.

We conclude that DRA's forecast of the delivered cost of gas is reasonable, and we will adopt $2.349 per million Btu, which includes transportation on SoCal's system and shrinkage (gas used for compression) of 1%.

DRA and SDG&E also now agree on the likely level of gas curtailment, and no other party offers other forecasts. We also adopt a forecast of gas generation quantity and cost based on the further ELFIN run.

c. <u>Oil Generation</u>

SDG&E forecasts that 265 gWh, about 2% of generation, will be met by oil-fired generation, using 450,000 barrels (Bbl.) of oil, including both LSFO and diesel oil. This is based on power plant use due to the estimated four-week curtailment of gas for power plants plus about 100,000 Bbl. oil burn for testing purposes.

SDG&E estimates that the prices will be $19.83/Bbl. and $23.77/Bbl. for LSFO and diesel oil, respectively.

DRA forecasts 282 gWh of combined fuel oil burn, using average annual prices of $18.23/Bbl. for LSFO and $26.58/Bbl. for diesel oil. As discussed above, DRA also estimates four weeks of power plant gas curtailment.

No other parties offer other forecasts for oil generation.

DRA uses more current market data in its forecast of oil prices than SDG&E used in its filing. Current soft market conditions for LSFO make the DRA forecast appear more reasonable.

We conclude that DRA's forecast of LSFO and diesel oil prices for the forecast period is reasonable, and will adopt it.

3. <u>Fuel Oil Inventory Management</u>

SDG&E originally estimated fuel oil inventory carrying costs of $1.0406 million for the forecast period, based on a beginning of winter (November 1, 1988) target inventory level of 1,200,000 Bbl. LSFO and 70,120 Bbl. diesel oil. The target level is a level deemed necessary to begin the winter period with reasonable assurance that adequate inventory is available to insure reliable service under reasonably foreseeable conditions.

SDG&E determines its fuel oil inventory requirement using an Electric Power Research Institute Utility Fuel Inventory Model (UFIM), into which SDG&E feeds its estimates of probable gas supply curtailments and delivery constraints, and oil resupply constraints. UFIM is designed to determine the monthly inventory levels that will minimize the overall costs of oil inventory management.

SDG&E's forecast of fuel oil inventory carrying costs of $1,579,500 is based on a target level of LSFO of 1,576,500 Bbl. and an average 70,120 Bbl. of diesel oil. This is an increase from the original estimate, since the recent period of gas curtailment for UEG by SoCal caused SDG&E to increase the target level, since the duration of curtailment was uncertain at that time. Revisions to SDG&E's forecast result in a cost of fuel oil inventory management of $1.1 million.

DRA recommends that the Commission adopt $1,040,600 for carrying costs based on SDG&E's original LSFO target level. DRA argues that the economics of the additional purchases of LSFO must be evaluated after it is burned, when its purchase cost plus carrying cost can be compared to alternatives. DRA further recommends that a new ratemaking procedure be used for handling fuel oil inventory carrying costs. Under DRA's proposal, SDG&E would be allowed the $1,040,600 as a lump sum for fuel oil inventory carrying costs, independent of actual costs incurred.

The allowed lump sum carrying costs would be determined from the formula:

> Lump Sum Inventory Allowance = (Estimated Average Inventory Level) x (Estimated LSFO weighted-average Unit Price) x (Estimated Average Bankers' Acceptance Rate)

DRA estimates the values as follows:

Estimated LSFO Average Inventory Level	= 904,000 Bbl.
Estimated LSFO Weighted-Average Unit Price	= $12.28/Bbl.
Estimated Average Bankers' Acceptance Rate	= 8.25%
Estimated Diesel Oil Weighted-Average Unit Price	= $21.60/Bbl.

Using these estimated values DRA calculates LSFO carrying costs of $915,850 and diesel oil carrying costs of $124,722, for a total Lump Sum Fuel Oil Inventory Allowance of $1,040,570. The total allowance would be transferred into a subaccount of the ECAC balancing account in 12 equal monthly debits, not subject to the ECAC/AER split. The only adjustment to the allowance would be a true-up of the interest rate at the end of each ECAC reasonableness review period to reflect the actual average Bankers' Acceptance Rate during the period.

Under DRA's proposal SDG&E could operate its fuel oil inventory at higher costs than the lump sum allowance, such as by purchasing greater amounts of LSFO, and be allowed carrying costs on the additional amounts only after a showing that this resulted in benefits to the ratepayer. The showing would have to be made after the extra LSFO was actually burned.

DRA proposes this system as a means of allowing SDG&E greater freedom in managing its fuel inventory, and as a means of giving it an added incentive to operate more efficiently. DRA believes that this proposal is consistent with novel ratemaking concepts discussed in the Commission's Division of Strategic Planning (formerly Policy and Planning Division) Report "Risk, Return, and Ratemaking" issued in R.86-10-001.

DRA points out that the benefits to ratepayers would be that if SDG&E operated at a lower than forecast cost, even though it would keep all the savings in the ECAC year, the reduced costs would be reflected in lower future forecasts of fuel oil inventory costs, thereby resulting in lower rates. If actual costs exceeded the allowance, the converse would result.

SDG&E points out the perverse incentives it believes would result from adoption of this proposal. For example, if SDG&E had a choice between running an oil-fired plant overnight, or purchasing power, and if the former costs $6 per barrel more to operate, SDG&E could run the plant and benefit the stockholders at the expense of ratepayers. This assumes that carrying costs of a barrel of oil are about one dollar per year, based on a $12.50 per barrel LSFO cost and an 8% annual carrying cost. ($12.50 x .08 = $1.00.) The added cost to stockholders would be only 8% (the AER fraction) of the $6 per barrel additional operating cost, or 0.08 x $6.00 = $0.48. The net effect to stockholders would be a savings of 52 cents, the difference between saving $1.00 on oil carrying costs and spending $0.48 more for operating the plant overnight. In contrast, the net effect for ratepayers would be an added cost of \$5.52, which is 92% (the ECAC fraction) of the \$6.00 added cost of running the plant overnight.

Although SDG&E states that it would not operate in a manner that would penalize the ratepayers to benefit stockholders, nevertheless it is troubled by this proposal. SDG&E believes it would be a mistake to implement a system that would benefit either stockholder or ratepayer at the other's expense. Under the current ECAC/AER system, what benefits one party also benefits the other, although to a different degree, due to the different ECAC and AER percentages.

SDG&E also believes that the proposal to allow it to recover higher fuel inventory carrying costs only after a showing that the ratepayers benefited as a result is cumbersome and impractical. For example, if SDG&E purchased extra LSFO in one ECAC period, it might not burn it until the next ECAC period, in which case the determination of reasonableness could cause retroactive ratemaking concerns.

We do not believe that retroactive ratemaking would result from the proposal if interim rates or special accounts subject to reasonableness review were used. However, we are concerned with the other aspects of the proposal. DRA would have a more formidable policing task in attempting to uncover actions that could benefit SDG&E shareholders at ratepayers' expense. We are also concerned that an added perverse incentive might exist. SDG&E might not take risks that would be expected to benefit the ratepayer, because changing conditions would make it difficult to later show that an action was economic. For example, if SDG&E had an opportunity to buy extra LSFO at \$5.00 below the current market price, it might not buy it because by the time it was ready to burn the LSFO the market price could have dropped \$5.00, resulting in no savings to the ratepayer. Under that scenario, SDG&E would not be allowed to recover the carrying costs of that extra LSFO. In effect, it would be penalized for taking actions that would be expected to benefit the ratepayers. On the other hand, if burning the extra LSFO proved economic, SDG&E would be allowed to recover the carrying costs for the extra LSFO, but would receive no added incentive. In other words, in taking risks to attempt to benefit the ratepayer, it could break even or lose, but never win.

We conclude that the DRA proposal does not offer appropriate signals and incentives to SDG&E, and will not adopt it.

In considering SDG&E's revised forecast with its increased target level, we note that the uncertain duration of the recent curtailment of gas for UEG was the reason for the increase. Whether the increase is reasonable will be determined in a future reasonableness review. For forecasting purposes, we conclude that SDG&E's revised forecast of the cost of fuel oil inventory management, at $1.1 million is reasonable.

4. Purchased Power Expense

SDG&E purchases enough electrical energy to meet about half its requirements from two geographical areas, PNW which has abundant hydroelectric capability, and the Pacific Southwest (PSW) which has surplus electric power plant capacity including recently completed nuclear plants. Purchases consist of two basic types, firm, consisting of firm capacity and associated energy, and non-firm economy energy. Table 1 compares the purchase forecasts of SDG&E and DRA. Reasons for the differences are discussed in the sections following.

TABLE 1

Summary of Purchased Power

Item	DRA	SDG&E	SDG&E Exceeds	Pct. Diff.
Econ Purch. ($M)	$ 38,810	$ 53,231	$14,421	37%
Firm Energy ($M)	78,924	60,477	(18,447)	-23%
Firm Cap. ($M)	144,054	144,494	440	1%
Total Firm ($M)	222,978	204,971	(18,007)	8%
Total Purch. ($M)	261,788	258,202	(3,586)	-1%
Econ. Purch. (gWh)	2,221	2,929	708	-32%
Firm Purch. (gWh)	4,733	3,859	(874)	18%
Total Purch. (gWh)	6,954	6,788	(166)	-2%

(Red Figure)

a. Firm

(1) PNW

SDG&E purchases electrical energy from the PNW over the Pacific Intertie, which consists of two 500 kilovolt (kV) alternating current (AC) lines and one 1,000 kV direct current (DC) line. SDG&E's entitlement over these lines is 230 MW currently, and is expected to increase to 276 MW beginning April 1989 when the DC line capacity is upgraded from 2,000 MW to 3,100 MW.

SDG&E uses available line capacities that are the net capacities after the rated capacities are derated for operational restraints, including forced and scheduled line outages, AC loop flow, and system import limits, based on historic values. This derate varies by season and peak period. Line losses are estimated at 7.5%

SDG&E forecasts firm purchases from Portland General Electric, consisting of 75 MW of capacity during all periods and hours of the forecast, and storage purchases with a peaking capacity of 75 MW in November and December 1988 and 50 MW from January through March, and July through October 1989. An additional 110 MW of unidentified short-term firm purchases, assumed by SDG&E to come from the PNW, is forecasted during June through September 1989 by both SDG&E and DRA. SDG&E forecasts its dispatch using firm purchased capacity to meet spinning reserve requirements and peak loads. Energy requirements are then met by the least expensive available resource, with the energy associated with firm purchased capacity dispatched only if it is economic. SDG&E assumes a level of firm energy associated with firm purchase contracts based on average historic values. SDG&E further assumes that firm energy is purchased equally during all periods.

DRA derates the line capacities for all periods, assumes full firm purchases under firm contracts to be coincident during all periods, and that purchases of energy under firm contracts will be made at full contract availabilities at all times and coincident with each other. Coincident means that the energy from each firm contract flows at the same time, or coincident with the energy from the other firm contracts. This is a conservative assumption since it is not typical for all energy from firm contracts to flow on a coincident basis.

SDG&E and DRA agree on capacity costs for these purchases; but since DRA assumes more firm energy will be taken, it forecasts more total energy expenses. Kelco makes assumptions similar to DRA, derates line capacities, and assumes full firm energy purchases under the firm contracts. The remaining line capacity is available for economy purchases. Kelco's assumptions, similar to DRA, place all firm purchases coincident.

Both the basic approaches, SDG&E, and DRA/Kelco, have advantages and shortcomings, and result from the need to make simplifying assumptions due to the models' inability to totally simulate the complexities of the utility operations. SDG&E argues that its method more closely simulates actual operations. Historic levels of firm energy purchases are assumed. Additional firm energy is dispatched only to the minimum contract level unless it is economic to purchase added amounts. Otherwise, economy energy is purchased at more favorable prices. Although economy energy can be interrupted, SDG&E has the right to call on firm energy through its firm purchase contracts, so it can meet load and the 7% minimum spinning reserve requirements in that manner when necessary and otherwise benefit from the economy energy. For that reason, all firm purchases are considered fast-start units that contribute to spinning reserve.

SDG&E argues that for this reason recorded levels of firm energy purchases should be used in forecasting. Although this method results in overutilization of the lines at times, the duration of those times is short and has little effect on the accuracy of the forecast. SDG&E believes that DRA's method is less accurate and results in a greater degree of overforecasting of firm energy and resulting underforecasting of economy energy. In effect, DRA assumes peak demand during all hours of the forecast period.

SDG&E also believes that the line capacity derate used by DRA and Kelco is conservative since planned outages are scheduled during off-peak periods when possible and normally would not affect peak period capacity.

DRA and Kelco base their approach on the perceived need to prevent overscheduling purchases on the lines and exceeding the available line capacities. By assuming that all available firm energy is taken during all periods, the maximum capacity of the lines that can be used by firm purchases is assumed to be used; and, therefore, that capacity cannot be also committed to economy energy at the same time. We observe that these assumptions are conservative in that they prevent any overloading of the lines, which could happen under SDG&E's assumptions.

We agree that SDG&E's approach will result in assuming greater line capacity than will be available at certain times. This would be expected to occur most likely during peak periods when purchases of full or higher than average quantities of firm energy would be made. SDG&E points out that peak periods consist of a limited number of hours daily, and that DRA's method restricts economy energy during all hours of the day and night.

While DRA's approach somewhat understates economy purchases, the results appear to be more reasonable than the SDG&E approach. SDG&E's approach appears to overstate more significantly economy purchases by allowing economy purchases during all periods, resulting in forecasts of significantly more economy energy purchases than we believe is reasonable to forecast.

On balance, we believe that DRA's approach is more reasonable and that it provides a better approximation to actual operations.

We hope that continued evolution of the models will result in more accurate simulation of actual operations, so that these simplifying assumptions will no longer be needed. We encourage the parties to work toward that goal.

For this proceeding we will adopt DRA's method of forecasting as reasonably representing expected firm PNW purchases.

(2) PSW

SDG&E forecasts firm purchases from APS, Alamito/Tucson Electric Power, PNM, Commision Federal de Electricidad (CFE) of Mexico, Portland General Electric, El Paso Electric, and from various short-term firm suppliers. These purchases are transmitted over the 500 KV SWPL line using SDG&E's entitlement plus an additional 50 MW of entitlement to capacity on that line of other parties that is expected to be available to SDG&E. Line capacity is derated to reflect expected outages, curtailments, and loop flow. Line losses are estimated at 2.5%.

DRA has reviewed SDG&E's forecasted firm purchases and has not taken exception to the capacity costs associated with all sources, except for the short-term firm capacity, which has not yet been arranged. DRA forecasts $440,000 for four months' purchases at 110 MW per month from June through September 1989, based on a cost of $1.00 per kW-month. This compares to SDG&E's

forecast of $880,000 for the same quantity and period, based on a forecast of $2.00 per kW-month. Although DRA disagrees with SDG&E on this issue, very little evidence was presented to support its position. Similarly, SDG&E also offered little evidence to support its forecast. We conclude that based on the information available, it is reasonable to adopt a value midway between the two forecasts, at $1.50 per kW-month.

DRA has also expressed concern that the contract with CFE is uneconomic, i.e., that the purchases will be at costs higher than SDG&E's avoided cost. The high demand charges for firm purchases in the CFE contract cause the total price to CFE to be higher than SDG&E's avoided cost. DRA encourages SDG&E to make every effort to make the contract cost-effective.

We share DRA's concern that the CFE contract may be uneconomic to SDG&E's ratepayers. We encourage SDG&E to actively pursue renegotiation of those terms in the CFE contract that result in CFE energy costing more than alternate sources.

DRA may wish to pursue this issue in the reasonableness of operations phase of this proceeding, or alternately may wish to defer any recommendations on how it should be handled until future SDG&E ECAC proceedings.

SDG&E and DRA forecast substantially different quantities of firm energy for the same reasons as discussed in the PNW firm purchased power section above.

Similar conditions exist for PSW firm purchases as for PNW firm purchases. Therefore, for the same reasons we discussed in the section on PNW firm purchases, we will adopt DRA's forecast methodology for forecasting purposes. While DRA's forecast somewhat understates line capacity available for economy energy, we believe that SDG&E's forecast overstates capacity availability. We will adopt DRA's method of forecasting, reduced to reflect the adopted cost of short-term firm capacity of $1.50

per kW-month, as reasonably representing expected firm PSW purchases.

b. Non-firm

(1) PNW

SDG&E, DRA, and Kelco disagree on both the forecast quantities and prices for PNW economy energy. SDG&E assumes that the quantity of economy energy available is its entitlement on the lines, less the expected firm purchases and line derate. SDG&E determined that 95% of PNW entitlement is available off-peak and during spring run-off. During other periods on-peak availability is based on historical conditions. On this basis SDG&E estimates 1,107 gWh for the forecast period, at an average price of 1.743¢/kWh. Pricing assumes that PNW prices will remain above historical averages through March 1989 due to the drought conditions, then drop to normal levels beginning April 1989. The prices range from 2.000¢/kWh on-peak and 1.800¢/kWh off-peak during the first five months, to as low as 1.760¢/kWh on-peak and 1.350¢/kWh off-peak, during the remaining seven months.

DRA derates the line capacities for all periods, assumes full firm purchases under firm contracts to be coincident during all periods, and assumes the remaining capacity to be available for economy energy. DRA believes that price competition between the PSW and PNW will cause PNW prices to closely follow PSW. DRA based its PNW prices on its PSW billed price forecast plus 0.05¢/kWh for the first five months, and on the PSW billed price forecast for the remaining seven months. Dispatch prices are determined from the billed prices by adding an estimate of line losses, which DRA assumes to be 7.5% as does SDG&E. DRA's unit cost estimate is flatter than SDG&E's. It peaks in January and February 1989 at 1.981 and 1.846¢/kWh on- and off-peak, respectively, and has a low of 1.745 and 1.626¢/kWh on- and off-peak during spring and fall of 1989. On this basis DRA forecasts 807 gWh of PSW economy energy at an average price of 1.648¢/kWh.

Kelco forecasts the same prices used by DRA for April through October 1989, but increases the price to 2.44¢/kWh from November 1988 through March 1989 due to the drought. Kelco argues that recent prices paid by Pacific Gas and Electric Company (PG&E) for PNW economy energy justify this price. For example, in April 1988 PG&E paid 2.48¢/kWh, and the prior four months' prices were in the 2.4¢/kWh range. In May and June the price dropped due to greater supply availability as a result of the required fish flush when higher downstream water levels are maintained. The fish flush requires more flow through the dams, which makes more economy energy available.

Comparing the price forecasts, SDG&E, DRA, and Kelco all assume higher prices in the initial months of the forecast period due to the drought. SDG&E and DRA have similar forecasts, with SDG&E's prices slightly higher. Since SDG&E also forecasts higher purchase quantities, we believe that higher prices would result due to the increased demand. We conclude that SDG&E's price forecast is reasonable.

For the same reasons as discussed in the PNW firm purchase section, we believe that DRA's forecast more accurately represents expected economy purchases than the SDG&E forecast. We will adopt DRA's method for forecasting the quantity of PNW economy energy purchases. We do not believe that Kelco's pricing forecast for the first five months has been adequately supported with recorded data or trends. We conclude that DRA's pricing forecast is reasonable.

(2) PSW

SDG&E's economy energy purchases from the PSW consist primarily of economy energy from coal and nuclear plants in Arizona and New Mexico.

SDG&E forecasts the amount of economy energy available monthly, based on the available line capacity, including 50 MW entitlement from other entities and available economy energy.

The available line capacity is the derated capacity reduced by the forecasted firm capacity use. The 2.5% line loss is handled by reducing the economy energy by that amount. SDG&E forecasts enough available economy energy during the months of November through March and all weeknight hours for other months to fill the available capacity. During the balance of the forecast year less economy energy is available than line capacity.

SDG&E's forecast of PSW economy energy prices is based on the equation:

PSW economy energy price ($/MWh) = gas price ($/MMBtu) x 8.19

The equation was developed from the average cost of PSW economy energy and the average cost of gas for the period from January 1987 through March 1988. The resulting prices are lower than historical, reflecting recent trends in PSW prices and the expected greater availability of low cost baseload energy in the future. SDG&E forecasts a total of 1,462 gWh at an average price of 1.860¢/kWh.

DRA uses SDG&E's line capacity entitlement plus an added 50 MW assumed to be available from other entities owning capacity entitlements on SWPL. DRA uses the same 2.5% line loss factor as SDG&E but accounts for it differently than SDG&E by reducing the SWPL capacity by that amount.

DRA prices are based on the equation:

PSW economy energy price ($/MWh) = 4.44 + (gas price x 5.88)

The formula was developed using the relationship of the average cost of PSW economy energy to the average cost of gas, during the period from July 1985 through April 1988. The formula differs from SDG&E's due to the base period used.

DRA forecasts a total of 1,054 gWh of economy energy purchases from the PSW at an average cost of 1.75¢/kWh.

In considering the appropriate forecast quantity of economy energy, we note that SDG&E and DRA each handle line capacity limitations for PSW economy energy on SWPL in the same manner as each handles PNW line capacity limitations. Therefore, the same relative results exist, i.e., SDG&E at times exceeds line capacity availability, and DRA restricts economy energy by assuming full firm purchases during all periods. For the same reasons as discussed in the PNW section, we will adopt DRA's method of forecasting economy energy purchases as more representative of expected system operations than SDG&E's forecast.

The price forecasts range from 1.75¢/kWh for DRA to 1.86¢/kWh for SDG&E. The variation is in the direction we would expect, since with fewer purchases, the average price should be lower. As purchases increase, the purchaser must pay higher unit prices for the additional purchases, since the lower cost purchases will have been exhausted. DRA's price forecast, at 6% below SDG&E's, appears to follow this expected trend.

Although it does not precisely replicate system operations, we conclude that DRA's forecast method is more representative of expected pricing of economy energy from the PSW during the forecast period. We will adopt DRA's price forecast method.

Table 2 shows the comparative economy energy price forecasts of SDG&E and DRA.

TABLE 2

Economy Energy Price Forecasts
$/MWh as Billed

	PNW							
	On-Peak		Off-Peak		On-Peak		Off-Peak	
Month	SDG&E	DRA	SDG&E	DRA	SDG&E	DRA	SDG&E	DRA
Nov 88	20.00	17.97	18.00	16.74	18.00	18.02	16.75	16.17
Dec	20.00	18.27	18.00	17.03	19.41	18.34	18.05	16.45
Jan 89	20.00	19.81	18.00	18.46	21.85	19.93	20.39	17.88
Feb	20.00	19.81	18.00	18.46	21.17	19.93	19.71	17.88
Mar	20.00	18.58	18.00	17.32	20.29	18.66	18.83	16.74
Apr	17.60	17.45	13.50	16.26	18.44	18.02	17.17	16.17
May	17.60	17.45	13.50	16.26	18.44	18.02	17.17	16.17
Jun	17.70	17.57	13.60	16.37	18.54	18.15	17.27	16.28
Jul	17.90	17.57	13.80	16.37	18.83	18.15	17.46	16.28
Aug	17.90	17.57	13.80	16.37	18.83	18.15	17.46	16.28
Sep	18.00	17.45	13.80	16.26	18.93	18.02	17.56	16.17
Oct	18.00	17.45	13.80	16.26	18.93	18.02	17.56	16.17

(3) Miscellaneous Purchases and Sales

Miscellaneous economy energy purchases are forecast to come from California and Mexico. Those from California are from surplus hydroelectric in northern California, or from oil/gas fired resources. The Mexican purchases are expected to be from geothermal or oil/gas fired resources.

SDG&E forecasts 30 gWh per month at an average cost of 1.869¢/kWh for the forecast period based on recent historic values.

DRA agrees with the quantity, and forecasts an average purchase price of 1.831¢/kWh, based on the equation:

Purchase Price ($/kWh) = Gas Price ($/MMBtu) x 8.51

The equation DRA uses was developed by SDG&E. It is based on the ratio of the weighted-average cost of these purchases to the average gas dispatch price from January 1987 through March 1988. DRA and SDG&E agree on this item except for the price of gas. We will adopt DRA's purchase price forecast since we are adopting DRA's gas price forecast.

D. QF Payments

This area involves the appropriate avoided costs, and thereby the price to be paid variable priced QFs. The price has two components, a capacity cost and an energy cost, which are based on the utility's avoided capacity and energy costs. The capacity cost is intended to represent the capital cost a utility would otherwise incur, were it not for the QFs. For example, a utility might need to install an additional peaking turbine to meet peak demands if it did not have QFs to rely on in meeting that need.

Similarly, the energy cost is the unit cost that the utility would otherwise incur in operating its own facilities to provide the energy that it purchases from QFs. In D.88-03-079, we adopted the QFs-in/QFs-out approach to determine the costs a utility avoids by virtue of having QFs. The concept of the IER originated in the negotiating conference that developed the interim Standard Offer 4, and was intended to assist in determining a utility's avoided energy cost. The IER is a measure of the utility's thermal efficiency in converting fuel into electrical energy, expressed as Btu/kWh.

The procedure used in determining the IER is to perform two runs using a given model, one run with QFs "in", the other with QFs "out." The difference in total operating costs, or total costs, between the two runs, is the effect of the QFs on the utility operational costs. The gas cost component of the total costs is then adjusted to reflect the total cost of gas for Utility Electric Generation (UEG) which includes demand costs, resulting in UEG-adjusted total gas costs. From this a unit UEG gas rate is calculated. The IER is then determined by dividing the difference in UEG total costs by the quantity of QF generation, and dividing the result by the UEG gas rate.

The formula for calculating the IER (in Btu/kWh) follows:

$$\text{IER} = \Delta\ \text{total cost (\$)} \div \text{QF generation (gWh)} \div \text{UEG rate (\$/MMBtu)}$$

1. Capacity Cost

The parties stipulated to an avoided capacity cost of $65.00/kW-year for calendar year 1989, as the capacity cost proxy based on the cost of a combustion turbine on SDG&E's system. This value was proposed by SDG&E and DRA in the SDG&E GRC, A.87-12-003. The capacity cost is based on an average ERI of 1.0.

SDG&E performed the QFs-in run using the same resource plan it used in the 1989 TY GRC which includes all QFs currently in operation plus additional QFs considered Likely To Be Available. The QFs-out run assumes that the capacity associated with Standard Offer 1 and Standard Offer 3 QFs is not available. The result would normally be a higher EUE under the QFs-out case since the EUE would be higher with the reduced resources. In this instance, however, both EUEs are the same and therefore the resulting ERIs are the same at 1.0, since the additional capacity is needed in this timeframe. It follows that the average ERI is also 1.0.

The annualized capacity of $65.00 per kW/year is then multiplied by the ERI to obtain a capacity cost for QFs of $65.00/kW-year. The breakdown of capacity payments by time period proposed by SDG&E follows in Table 3.

TABLE 3

As-Available Capacity Payment Schedule
Proposed Effective November 1, 1988

Time Period	Hourly Allocation Factor	Payment Rate (¢/kWh)
Summer		
On-Peak	0.096	6.25
Semi-Peak	0.006	0.39
Off-Peak	0.000	0.00
Super-Off-Peak	0.000	0.00
Non-TOU	0.011	0.70
Winter		
On-Peak	0.013	0.82
Semi-Peak	0.008	0.50
Off-Peak	0.000	0.00
Super-Off-Peak	0.000	0.00
Non-TOU	0.002	0.13
Annual Average of TOU	0.011	0.74

DRA and Kelco agree with these values for capacity payments to QFs.

We conclude that these values, based on a capacity value of $65.00 per kW-year and on an ERI of 1.00, reasonably represent the value of capacity to SDG&E for the forecast period. We will adopt these values.

2. Energy Cost

a. UEG Gas Cost

Total gas cost for UEG includes the delivered cost plus the transmission cost based on the GTUEG tariff, for gas sold by SDG&E's gas department to its electric department. The GTUEG tariff consists of monthly demand charge and the volumetric rate and is designed to recover the fixed or demand costs on both the SoCal and SDG&E systems for transporting the gas from the California border to the system. The volumetric rates are based on two tiers. Tier I is used for the first 18.5% of UEG gas used each month, and is priced higher than Tier II. Tier I represents the baseload quantity of gas, while Tier II is the added discretionary quantity of gas.

(1) Sales Volume

SDG&E argues that the volumes recently adopted in D.87-12-039 in the gas OII (I.86-06-005) should be used with the Tier I rate to determine the Tier I gas cost, since the current GTUEG tariff is based on those volumes.

DRA argues that the most current forecast should be used, which is this ECAC proceeding's forecasted gas volumes.

The difference in gas expense between using the gas OII volumes and the ECAC forecast volumes is about $445,500. This is caused by the substantially lower ECAC gas volumes as compared to the gas OII volumes. The lower volumes applied to the Tier I rate result in less recovery, since the volumes above 18.5% are priced at the lower Tier II rate.

During the hearings and after examining rebuttal testimony of SDG&E, DRA stipulated to SDG&E's method for Tier I.

We agree that the Tier I sales volumes must be consistent with the sales volumes used to establish the tariffs. At this time, the tariffs are based on the gas OII volumes, and therefore Tier I should use the same sales volumes.

We will adopt the gas OII volumes for Tier I. ECAC volumes in excess of Tier I volumes will be billed under Tier II rates.

(2) Cost of Gas to UEG

As mentioned above, we will adopt the DRA forecast of the delivered price of gas to the SDG&E system at $2.349 per million Btu. This price is then adjusted by DRA to reflect all costs which include GTUEG demand charges of $38.562 million for the forecast period.

3. <u>QF Adders</u>

Two issues arose regarding adders to QF payments, involving the propriety of Operation and Maintenance (O&M) and of Administrative and General (A&G) adders. The considerations are whether SDG&E saves O&M and A&G expenses by virtue of QF purchases and resulting lower utilization of its own plants. If savings result, they must be quantified, and the method of compensating the QFs must be decided. We will address these issues individually.

a. <u>Avoided O&M Costs</u>

Avoided O&M concerns the O&M costs that SDG&E avoids by purchasing QF energy instead of using its own plants. O&M can be split into two types, fixed and variable. Fixed is routine activity that does not vary significantly with usage of the plant. Variable, on the other hand, is directly related to the amount of plant usage.

The second issue dealing with O&M is how the payment should be handled, i.e., as an adder to the QF payment, or as a component of the IER.

Kelco recommends an O&M adder of $0.003 or 3.0 mils per kWh, which is apparently based on the value recently considered in the SCE GRC.

SDG&E agrees that an O&M adder is appropriate, but recommends a value of $0.0002 or 0.2 mils per kWh based on a recommendation of the California Power Pool. SDG&E believes that differences on the SCE system are responsible for its higher O&M value, and that such a high value is not appropriate for SDG&E.

DRA points out that the O&M adder may be implicitly considered in the modeling assumptions used by SDG&E.

The issue of the O&M adders was raised in the proceeding, but was not extensively developed by the parties. Kelco recommends the 3.0 mils per kWhadder which we adopted in September, 1988 for SCE. This figure is much higher than the adder recommended by DRA and SDG&E in the current proceeding.

We are persuaded from our past treatment of O&M adders in ECAC proceedings for other electric utilities that such an inclusion is appropriate in this case. We will however, adopt an adder in the amount of the 1.8 mils per kWh adjusted for on-peak fossil generation. This is identical to the O&M adder we adopted for PG&E in November 1988 in its most recent ECAC decision, D.88-11-052. This results in an O&M adder of 1.06 mils per kWh.

Because this issue was not thoroughly explored in the proceeding, we will order SDG&E to provide a complete study of O&M costs avoidable by QF purchases relative to its system to the Commission Advisory and Compliance Division within 90 days after the effective date of this decision.

SDG&E must also show in its next general rate case filing that it has removed from its proposed level of O&M expenses the appropriate O&M expenses avoided by QFs.

b. <u>Reduced A&G Costs</u>

Kelco recommends an adder to the QF payments to reflect the reduced A&G costs due to less need for working capital by virtue of QF purchases. The theory is that SDG&E benefits in cash flow by the delay or lag in paying QFs, instead of using its own resources which require current or advance payment for investment and expenses.

SDG&E argues that its method of paying QFs does not have a significant lag, and that it is doubtful that SDG&E receives any benefit due to reduced need for working capital. In fact, SDG&E argues that a subtractor might be appropriate to reflect this item.

4. <u>Purchase Quantities</u>

SDG&E and DRA forecast similar purchase amounts from QFs, but substantially different costs, as shown in Table 4.

TABLE 4

Comparison of DRA and SDG&E Estimates

	DRA	SDG&E
Energy Purchases (gWh)	230.4	231.5
Energy Cost ($ million)	9.383	6.205

DRA's slightly lower purchase level is due to more current data on the expected on-line date for a new QF project.

DRA's dramatically higher costs are the result of its higher recommended IER (compared to SDG&E's PROMOD IER) and different gas price.

We conclude that DRA's forecast method is correct, and adopt a forecast for QF purchases of 231 gWh based on the further DRA ELFIN run.

E. Revenue Requirement

As a result of adopting various assumptions and forecasts of the parties, the level of forecasted ECAC and AER increases also change, due in part to gas pricing, resource assumptions, and purchased power results. The latest forecasts by SDG&E are a $7.669 million ECAC increase, a $0.520 million AER increase, and an ERAM overcollection of $30.796 million, for a combined net rate decrease of $22.607 million. We'll adopt an updated forecast of ECAC and AER increases based on its model run used to update the IER results in forecasts of a $3.639 million ECAC increase, a $0.1 million AER decrease, an ERAM overcollection at $30.8 million, for a net rate decrease of $27.027 million. We will adopt these forecast values.

We will adopt two changes in rate design in this proceeding. First, the agricultural Schedule PA-T-1 will become a permanent schedule, since we will remove the termination date currently in effect.

Second, we will adopt an optional AL-TOU schedule with a shorter peak period of noon to 6 p.m. compared to the 11 a.m. to 6 p.m. peak period in effect in the AL-TOU tariff. This optional schedule is intended to accommodate requests by school districts who normally end summer classes by noon.

F. Revenue Allocation and Rate Design

Since we intend to implement the revenue requirement changes herein concurrently with the SDG&E GRC A.87-12-003, we will reflect revenue allocation and rate design associated with revenues in this proceeding in the GRC.

G. Comments

Comments on the proposed decision were filed by DRA, Kelco, and SDG&E. DRA points out several typographical errors which have been corrected. DRA further suggests nonsubstantive editorial changes, some of which have been made.

Added Appendix A reflects the IER and revenue requirements based on the adopted assumptions and values.

Findings of Fact

1. SDG&E filed this A.88-07-003 on July 1, 1988 requesting a net rate decrease of $7.535 million on an annualized basis beginning November 1, 1988. This change is based on an ECAC increase of $4.679 million, no change in AER, and an ERAM decrease of $12.214 million.

2. The latest updated request by SDG&E is for a net revenue decrease of $22.607 million, based on an ECAC increase of $7.669 million, an AER increase of $0.520 million, and an ERAM reduction of $30.796 million.

3. DRA recommends a net revenue decrease of $29.626 million based on an ECAC increase of $1.300 million, an AER decrease of $0.130 million, and an ERAM reduction of $30.796 million.

4. SDG&E's current annual ECAC proceeding marks the beginning of the regular revision in ECAC of key components used in

the determination of prices to be paid for power sold to SDG&E by QFs.

5. It is the Commission policy to develop utility rates and QF prices on a consistent basis.

6. Parties who use a model to develop marginal or avoided costs may use their model of choice, but must also provide a base case using the ELFIN model.

7. The TCF issue for SONGS 2&3 has been consolidated with that issue in the SCE ECAC A.88-02-016 reasonableness review.

8. SDG&E supports PROMOD as the only model capable of accurately simulating its operations.

9. DRA and Kelco prefer the ELFIN 1.60 model, and believe it is equally capable of competent results.

10. PROMOD is significantly more costly to use than ELFIN 1.60.

11. ELFIN 1.60 is improved over earlier versions of ELFIN.

12. PROMOD has two commitment variables while ELFIN 1.60 has one.

13. Inconsistent assumptions used by SDG&E in its PROMOD and ELFIN runs are partly responsible for the large difference in IER between the two runs.

14. SDG&E and DRA agree on the forecast sales of 12,888 gWh.

15. City questions the forecast level of miscellaneous sales due to the recent drought effects.

16. All parties agree with SDG&E's proposed resource plan.

17. SDG&E agrees on the forecast delivered commodity cost of gas at $2.349 per million Btu.

18. SDG&E and DRA agree that four weeks of gas curtailment to power plants is likely during the forecast period.

19. About 2% of SDG&E's electrical requirements will be met with oil-fired generation using LSFO or diesel oil.

20. SDG&E meets about half of its electrical requirements with purchased power.

21. Purchased power comes primarily from the PNW and PSW.

22. SDG&E assumes average historic firm energy purchases during all periods, which at times overloads the lines.

23. DRA and Kelco assume full available firm energy purchases during all periods, which results in less line availability for energy purchases and prevents overloading the lines.

24. The assumptions used by SDG&E overstate the availability of economy energy.

25. SDG&E, DRA, and Kelco agree that the annualized capacity cost is $65.00 per kW-year.

26. SDG&E, DRA, and Kelco agree that SDG&E's ERI is 1.00.

27. All parties agree that an O&M adder is appropriate.

28. Kelco recommends an O&M adder of 3.0 mils per kWh.

<u>Conclusions of Law</u>

1. Both the PROMOD and the ELFIN 1.60 models competently simulate SDG&E's system operations, and should yield similar results when the same assumptions are used.

2. It is reasonable to adopt DRA's recommendation to use the ELFIN 1.60 model to develop SDG&E's revenue requirement and IER in this proceeding.

3. The resource plan submitted by SDG&E in this proceeding is reasonable.

4. A reasonable reserve margin requirement for dispatching resources is 7%.

5. It is reasonable to consider firm purchases as fast-start units that contribute to spinning reserve.

6. It is reasonable to consider Encina Units 4 and 5 as fast-start units.

7. It is reasonable to model firm purchases from PNM assuming a one MW first block.

8. Reasonable dispatch costs for the APS contract are $2.00 per MWh higher on-peak and $1.30 per MWh higher off-peak than the ELFIN base case dispatch costs.

9. Annual startup costs for SDG&E of $298,000 are reasonable.

10. A reasonable forecast of annual sales is 12,888 gWh.

11. A reasonable forecast of nuclear generation is 3,213 gWh at a cost of $34.35 million.

12. A forecast of four weeks of gas curtailment is reasonable.

13. A reasonable forecast of the delivered price of gas is $2.349 per million Btu including transportation and shrinkage.

14. A reasonable forecast of the cost of oil is $18.23 per Bbl. for LSFO and $26.58 per Bbl. for diesel oil.

15. A reasonable forecast of the cost of fuel oil inventory management is $1.1 million.

16. It is reasonable to forecast firm purchases assuming all available firm energy is taken during all periods.

17. It is reasonable to base line availabilities on rated capacities, derated to reflect normally expected curtailments based on historic values.

18. A reasonable estimate of line losses for the PNW lines is 7.5 %.

19. A reasonable estimate of line losses on SWPL is 2.5%.

20. It is reasonable to assume that SDG&E will be able to purchase 50 MW of additional capacity on SWPL from other parties.

21. It is reasonable to assume four months of short-term firm capacity purchases at a cost of $1.50 per kW-month.

22. SDG&E's equation for forecasting the price of PSW economy energy based on the gas price is reasonable.

23. It is reasonable to assume 30 gWh per month of miscellaneous economy energy purchases using using DRA's formula for price.

24. An avoided cost of $65.00 per kW-year is reasonable as a capacity cost proxy based on the cost of a combustion turbine on SDG&E's system.

25. A reasonable value of the ERI is 1.00 for SDG&E.

26. It is reasonable to use the gas OII adopted volumes for SDG&E in determining Tier I and Tier II commodity rates.

27. A reasonable forecast of the delivered price of gas to SDG&E's system is $2.349 per million Btu.

28. It is reasonable to remove the expiration date of the PA-T-1 tariff schedule, making it a permanent schedule.

29. It is reasonable to adopt an optional AL-TOU schedule with a reduced peak period of noon to 6 p.m.

30. It is reasonable to reflect the revenue requirement and rate changes resulting from this decision in coordination with changes in the SDG&E GRC A.87-12-003.

31. It is reasonable to adopt an adjusted O&M adder of 1.06 mils per kWh for this proceeding.

32. SDG&E should be ordered to conduct a study of avoidable O&M costs associated with QF production.

O R D E R

IT IS ORDERED that:

1. San Diego Gas & Electric Company (SDG&E) is authorized to decrease its total Energy Cost Adjustment Clause (ECAC) revenue requirement by $27.103 million, the net effect of an ECAC increase of $3.555 million, an Annual Energy Rate decrease of $0.130 million, and an Electric Revenue Adjustment Mechanism decrease of $30.788 million as shown in the tables in Appendix A.

2. The revenue requirement changes authorized by this decision will be effected in rates through coordination with the rate changes and rate design principles that will be adopted in the SDG&E General Rate Case decision in Application 87-12-003, except

that Schedule PA-T-1 shall become permanent and an optional AL-TOU schedule with reduced peak period shall be offered.

3. On or after the effective date of the final Phase I decision in this proceeding, and at least 3 days prior to the authorized date for tariff revision, SDG&E shall file revised tariff schedules for electric rates reflecting the revenue decrease authorized in the final Phase I order. The revised tariffs shall apply to service rendered on or after their effective date.

4. An Energy Reliability Index value of 1.0 is adopted in this proceeding.

5. An annual average Incremental Energy Rates (IER) of 8,769 British thermal units per kilowatt-hour is adopted in this proceeding. A 1.06 mils per kilowatt-hour adder is also adopted for purchases from qualifying facilities. Division of Ratepayer Advocates' proposed time-differentiated IERs shown in Appendix A are also adopted.

6. San Diego Gas and Electric Company will file a complete study on the avoided Operation and Maintenance costs associated with its electric purchases from Qualifying Facilities. The study will be filed with the Commission Advisory and Compliance Division within ninety days.

This order is effective today.

Dated December 19, 1988, at San Francisco, California.

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

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

Victor Weisser, Executive Director

APPENDIX A

Page 1

Table L-1
DRA Estimate of Revenue Requirements 12/16/88
and Changes
Per Alternate Decision

	(1)	(2) = (1) + (3)	(3)
	Present * Rate Revenues ($ 000)	Adopted ** Revenue Requirement ($ 000)	Change ($ 000)
ECAC	$356,580	$360,135	$3,555 ***
AER	$32,198	$32,328	$130 ****
ERAM	($4,379)	($35,167)	($30,788)*****
Total	$384,399	$357,296	($27,103)

* Includes FF&U.

** At sales of 12,879.1 GWh.

*** ($360,103 (Table L-2, line 22) - $356,580) * 1.00918 (SDFF)

**** Table L-5, line 14.

***** (($30,500 (Table L-5, line 24) + $8 (Table L-5, line 26) + $280 (SDFF)).

TABLE L-2

DRA ESTIMATE OF
ECAC REVENUE REQUIREMENT AND UNIFORM RATE CHANGE
PER ALTERNATE DECISION

(November 1, 1988 thru October 31, 1989)

	GWh	C/kWh	M$
1 Natural Gas	3,463	3.638	125,983
2 Residual Oil	282	2.601	7,337
3 Other Oil	0	5.541	5
4 Firm Purchases *	4,543	3.885	176,483
5 Econ Purchases	2,619	1.777	46,542
6 Alt/Cogen	231	4.186	9,651
7 Nuclear	3,213	1.069	34,350
8 Total	14,350	2.790	400,351
9 Variable Wheeling Expenses			384
10 Fixed Wheeling Expenses			8,553
11 Startup Fuel			298
12 Carrying Cost of Oil in Inventory			1,100
13 EFI Adjustment			(580)
14 Subtotal Expenses			410,106
15 Less AER Recovery Portion (8%)			(32,808)
16 Less NARCO Fuel Service Charge			(2,000)
17 Plus Alamito-Tucson Capacity (300 MW)			41,650
18 Subtotal			416,947
19 Non-Jurisdictional Amount at 2.71885%			11,336
20 Adjusted Subtotal			405,611
21 Less Projected ECAC Balance on November 1, 1988			(45,508)
22 Total Requirement			360,103
23 Less Revenue at Present ECAC Rates			356,580
24 ECAC Revenue Requirement			3,523
25 ECAC Rate Change - Forecast Sales of 12879.1 GWh			0.027 c/kWh
26 Franchise Fees and Uncollectible Expenses, at 1.2600%			0.000 c/kWh
27 Uniform ECAC Rate Change			0.028 c/kWh

* Excluding 300 MW Alamito-Tucson Capacity

TABLE L-3

DRA ESTIMATE OF
ANNUAL ENERGY RATE (AER)
PER ALTERNATE DECISION

(November 1, 1988 thru October 31, 1989)

	GWh	C/kWh	M$
1 Natural Gas	3,463	3.638	125,983
2 Residual Oil	282	2.601	7,337
3 Other Oil	0	5.541	5
4 Firm Purchases *	4,543	3.885	176,483
5 Econ Purchases	2,619	1.777	46,542
6 Alt/Cogen	231	4.186	9,651
7 Nuclear	3,213	1.069	34,350
8 Total	14,350	2.790	400,351
9 Variable Wheeling Expenses			384
10 Fixed Wheeling Expenses			8,553
11 Startup Fuel			298
12 Carrying Cost of Oil in Inventory			1,100
13 EFI Adjustment			(580)
14 Subtotal Expenses			410,106
15 AER Requirement (8% of Line 14)			32,808
16 Non-Jurisdictional Portion at 2.7189% of Line 15			892
17 Adjusted AER Requirement			31,916

18 Total Annual Energy Rate for 12879.1 GWh Applicable Sales	0.248 c/kWh
19 Franchise Fees and Uncollectible Expenses at 1.2600%	0.003 c/kWh
20 Adjusted Annual Energy Rate (Line 18 + Line 19)	0.251 c/kWh
21 Less Present Annual Energy Rate	0.250 c/kWh
22 Required Increase in AER	0.001 c/kWh
23 Current ECAC/AER Rate	3.024 c/kWh
24 Plus Proposed ECAC/AER Adjustments	0.029 c/kWh
25 Proposed ECAC/AER Rate	3.053 c/kWh

* Excluding 300 MW Alamito-Tucson Capacity

TABLE L-4

DRA ESTIMATE OF
PROPOSED UNIFORM ERAM RATE CHANGE
PER ALTERNATE DECISION

(November 1, 1988 thru October 31, 1989)

(M$)

1 Estimated ERAM Balance as of November 1, 1988	(35,191)
2 Net/Gross Factor Adjustment (0.88505%)	311
3 Adjusted ERAM Balance	(34,879)
4 Total ERAM Rate (Applicable Sales of 12879.1 GWh)	-0.271 c/kWh
5 Present ERAM Rate	-0.034 c/kWh
6 Proposed ERAM Rate	-0.237 c/kWh

TABLE L-5

DRA ESTIMATE OF
ECAC/AER/ERAM REVENUE REQUIREMENT
PER ALTERNATE DECISION

(November 1, 1988 thru October 31, 1989)

ITEM	(M$)
1 Natural Gas	125,983
2 Fuel Oil	7,341
3 Purchased Power	232,676
4 Nuclear	34,350
5 Subtotal	400,351
6 Other Expenses	9,754
7 Subtotal	410,106
8 AER Requirement (8%)	32,808
9 Less Adjustments	992
10 Less Revenue at Present Rate	32,198
11 AER Revenue Requirement	(381)
12 Revenue at Proposed Rate	129
13 SDFF Differential (0.918%)	1
14 Total AER Revenue Requirement	130
15 ECAC Requirement (92%)	377,297
16 Less Adjustments	17,195
17 Less Revenue at Present Rate	356,580
18 ECAC Revenue Requirement	3,523
19 Revenue at Proposed Rate	3,606
20 SDFF Differential (0.918%)	33
21 Total ECAC Revenue Requirement	3,639
22 Adjusted ERAM Balance	(34,879)
23 Less Revenue at Present Rate	(4,379)
24 ERAM Revenue Requirement	(30,500)
25 Revenue at Proposed Rate	(30,524)
26 Voltage Discount Adjustment	8
27 SDFF Differential (0.918%)	280
28 Total ERAM Revenue Requirement	(30,796)
29 Total AER/ECAC/ERAM Requirement	(27,027)

APPENDIX A
PAGE 6
SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED AVOIDED ENERGY COSTS
ECAC Forecast Period -- November 1, 1988 through October 31, 1989

	DESCRIPTION	SUMMER					WINTER					ANNUAL AVERAGE
		PEAK	SEMI-PEAK	OFF PEAK	SUPER OFF-PK	SEAS AVG	PEAK	SEMI-PEAK	OFF PEAK	SUPER OFF-PK	SEAS AVG	
1	INCREMENTAL ENERGY RATE-IER (BTU/KWH)	9213	8969	8480	7623	8280	9539	9254	8806	8113	8900	8769
2	EQUIVALENT IER or IER W/ O&M ADDER (BTU/KWH) ((L5 / L3) * 10 exp 6)	9546	9302	8813	7956	8613	9872	9587	9139	8446	9233	9102
3	G-UEG RATE ($/MMBTU)	3.1786	3.1786	3.1786	3.1786	3.1786	3.1786	3.1786	3.1786	3.1786	3.1786	3.1786
4	AVOIDED COST OF ENERGY ($/KWH) (L1 * L3)/(10 EXP 6)	0.02928	0.02851	0.02695	0.02423	0.02632	0.03032	0.02941	0.02799	0.02579	0.02829	0.02787
5	AVOIDED COST OF ENERGY WITH O&M Adder of 1.06 mill/kWh (L4 + .00106) $/KWH	0.030344	0.029568	0.02801	0.025290	0.027378	0.031380	0.03047	0.029050	0.026847	0.029349	0.028933
	TRANSMISSION ---------------											
6	ENERGY LOSS FACTOR	1.0313	1.0298	1.0214	1.0214	1.0244	1.0306	1.0282	1.0215	1.0215	1.0239	1.0241
7	AVOIDED ENERGY COST + LOSSES $/KWH (L5 * L6)	0.03129	0.03045	0.02861	0.02583	0.02805	0.03234	0.03133	0.02968	0.02743	0.03005	0.02963
	DISTRIBUTION -------------											
8	ENERGY LOSS FACTOR	1.0752	1.0714	1.0511	1.0511	1.0584	1.0734	1.0675	1.0512	1.0512	1.0571	1.0576
9	AVOIDED ENERGY COST + LOSSES $/KWH (L7 * L8)	0.03365	0.03262	0.03008	0.02715	0.02968	0.03471	0.03345	0.03119	0.02883	0.03177	0.03134

(END OF APPENDIX A)

O P I N I O N

I. Summary

This Phase I decision in the San Diego Gas & Electric Company (SDG&E) annual Energy Cost Adjustment Clause (ECAC) Application (A.) 88-07-003 will set electric revenue requirements, rates, and Qualifying Facility (QF) pricing levels for the forecast period ending October 31, 1989. The net revenue requirement change is a decrease of $27.0 million based on an ECAC increase of $3.6 million, an Annual Energy Rate (AER) decrease of $0.1 million, and an Electric Revenue Adjustment Mechanism (ERAM) decrease of $30.8 million.

An Incremental Energy Rate (IER) of 8,769 British thermal units (Btu) per kilowatt-hour (kWh), and a capacity value of $65.00 per kW-year, are adopted for QF purchases. We will also adopt a 3.0 mils per Kwh adder for QF purchases which makes an effective IER of 9,102 BTU per Kwh.

II. Background

This is the annual ECAC filing which includes a review of the reasonableness of fuel-related operations during the annual record period, May 1, 1987 through April 30, 1988. The ECAC, AER, and ERAM rates are to be adjusted to reflect changes in the annual fuel and purchased power expenses for the forecast period, November 1, 1988 through October 31, 1989. The actual rate changes are expected to take effect January 1, 1989 concurrent with other pending rate changes for SDG&E.

In addition, beginning with this filing, SDG&E will regularly update in the annual ECAC filing the key components used in determining the variable prices to be paid for power it purchases from QFs.

The QF issues were added to ECAC by Decision (D.) 88-03-026 in the generic standard offer proceeding, A.82-04-044 et al. That decision determined that annual updating of variable QF payments should take place in ECAC at the same time and using the same assumptions used to adjust utility rates. The SCE General Rate Case (GRC) D.87-12-066 ordered that parties to future ECAC proceedings who present testimony using a production cost model (model) to develop marginal or avoided costs shall provide a base case run using the ELFIN model. Parties who so desire may also present testimony using its model of choice if different than ELFIN, and explain the basis for its preference of that model and the results it produces. That decision also ordered that workshops be held within a week of the SDG&E ECAC filing. The purpose of workshops is to determine the data sets, resource plans, load shape, heat rate input, unit commitment and dispatch, minimum load conditions, resource assumptions, and all other pertinent data to be used in determining SDG&E's IER. The workshop is also intended to be a forum in which parties can agree, to the extent possible, on the assumptions to be used and the appropriate source of those assumptions. The Director of the Commission Advisory and Compliance Division (CACD) appoints an arbiter to resolve disputes relating to the achievement of a common data set.

III. Filing

In the original filing SDG&E requested authority to decrease its electric rates by $7.535 million annualized from the rates in effect on July 1, 1988. In an amendment to the application SDG&E requested that the rates be reduced by $15.981 million from the rates in effect July 9, 1988. Finally, in the evidentiary hearings, SDG&E revised its request for a rate decrease to $22.607 million. The growing decrease in rates is due to the continuing overcollecting of ERAM, which more than compensates for the requested increases in ECAC and AER rates.

At the prehearing conference on July 28, 1988 the administrative law judge (ALJ) granted a motion by SDG&E to defer hearing on the reasonableness of purchased power issues until 45 days after the Commission issues a decision on rehearing in the SWPL A.84-12-015. The motion was granted subject to an additional condition requested by Division of Ratepayer Advocates (DRA) and agreed to by SDG&E, that if the Commission does not issue that decision by the end of 1988, SDG&E's showing on the reasonableness of purchased power issues will be due February 17, 1989. The basis of the motion is that SDG&E's showing on the reasonableness of purchased power issues including long-term agreements is affected by resolution of the pending decision in SWPL.

SDG&E also filed a motion to consolidate the Target Capacity Factor (TCF) issue with the TCF issue in the reasonableness portion of the 1988 SCE ECAC A.88-02-016. The TCF issue relates to SONGS 2&3. The TCF sets a level of operating capacity as a target, and offers rewards or penalties for actual operations that either exceed or fall short of the TCF. The basis of the motion is that SCE is the majority owner of SONGS 2&3 and SDG&E will rely on SCE's rationale in support of its requested modifications of the TCF. The motion was granted by ALJ Ruling on August 31, 1988.

As a result of the motions discussed above, and due to the need to implement interim rates as soon after the November 1, 1988 tariff revision date as possible, this application is being handled in three phases. Phase I addresses the forecast and QF issues, and sets interim rates for the forecast period. Phase II will deal with the reasonableness of ECAC operations during the record period, except for the reasonableness of purchased power issues which will be handled in Phase III. This order addresses Phase I.

purchases be modeled with a minimal first block such as one MW, so that capacity and spinning reserve can be used without a substantial commitment of energy, thereby allowing more economy energy to be used.

SDG&E apparently used the 20 MW minimum as a convenient assumption, and does not argue against using a lower minimum, such as one MW as suggested by Younger.

We agree that ELFIN runs should assume a one MW first block for firm energy purchases from PNM, in order to more accurately simulate actual operations.

c. APS

SDG&E and DRA used different methodologies to account for the actual costs of purchases from APS with regard to the demand charge. If SDG&E purchases any energy from APS it does not receive the demand charge credit that it would receive if it purchases no energy. In PROMOD SDG&E assumes that the demand charge credit applies during all periods whether or not energy is taken. SDG&E witness Higgins testified that SDG&E used that assumption because it is difficult to simulate in the model exactly what actually happens on the system, so a simplifying assumption was needed.

To compensate for the inability to exactly model purchase cost and demand charge credits, DRA used dispatch costs for the APS contract that include estimated start-up costs. The result is costs that are $2.00 per MWh and $1.30 per MWh higher than SDG&E for on-peak and off-peak, respectively. Kelco agrees with DRA's treatment of the APS contract. The higher dispatch costs used by DRA result in increased avoided costs and a higher IER.

The methodological differences between SDG&E and DRA on this item have only a minor impact, with an approximately $55,000 higher revenue requirement under DRA's approach. Because of this minor impact and the fact that we ordered that the final model runs be done on ELFIN, to which DRA's methodology is tailored, we will adopt DRA's method as a reasonable input assumption.

3. Discussion

SDG&E, DRA, and Kelco agree that PROMOD is a more complex model than ELFIN. PROMOD is capable of more accurate and detailed simulation of actual system operations, and requires less operator manipulation of input data in order to achieve credible results than does ELFIN. PROMOD has two commitment variables, so for example, it can use one commitment variable to dispatch resources sufficient to cover the reserve margin, and use the other commitment variable to dispatch a different level of resources to be held on line for the next day. With ELFIN, only one of these conditions can be covered with its single commitment variable. The effect of the other condition must be otherwise compensated for by the user. However, this can routinely be accomplished by a competent user, who must similarly compensate for other operational conditions that cannot be simulated by either model.

SDG&E also points out that DRA relied on PROMOD for start-up costs, which cannot be determined with ELFIN. However, DRA responds that it used PROMOD only for convenience, and that otherwise it would have estimated start-up costs based on historic values. DRA estimates start-up costs at $298,000. SDG&E implicitly agrees with this estimate since it resulted from SDG&E's PROMOD run.

SDG&E argues that ELFIN has never been successfully backcast for SDG&E. Backcasting refers to verifying the model by running a historic period through it and comparing the results with the recorded results. SDG&E believes that PROMOD is the preferred model that should be adopted by the Commission for future ECAC proceedings.

DRA counters that ELFIN is the standard used not only by it and many interested parties, but that it has been used by other utilities. DRA argues that although SDG&E claims that PROMOD has been successfully backcast in AB 475 runs, in fact since the

forecast period. As a result gas will be the fuel of choice for the gas/oil fired power plants. The forecast prices are based on SDG&E purchasing its own gas on the spot market. A level of service of about 95% is forecast, based on 18 days of curtailment.

DRA forecasts 3,667 gWh of gas generation at an average cost of 3.568¢/kWh. This is based on a forecast of commodity cost of gas at $1.918 per million Btu plus $0.213 per million Btu for transporting the gas across SoCal's system, and $0.021 per million Btu for compressor fuel at 1%. This yields an average delivered cost of $2.152 per million Btu. The delivered cost is an avoided cost that does not include demand charges. DRA forecasts a four-week curtailment (20 days) of gas supply for electric generation, resulting in a level of service of about 94%.

SDG&E's forecast does not indicate that it accounts for the fuel necessary for compression used to transport the gas. Adding compressor fuel to SDG&E's estimate would make it about four cents per million Btu higher than DRA.

Kelco supports the DRA cost forecast, and does not present its own estimate of the quantity of gas generation.

We conclude that DRA's forecast of the delivered cost of gas is reasonable, and we will adopt $2.349 per million Btu, which includes transportation on SoCal's system and shrinkage (gas used for compression) of 1%.

DRA and SDG&E also now agree on the likely level of gas curtailment, and no other party offers other forecasts. We also adopt a forecast of gas generation quantity and cost based on the further ELFIN run.

c. Oil Generation

SDG&E forecasts that 265 gWh, about 2% of generation, will be met by oil-fired generation, using 450,000 barrels (Bbl.) of oil, including both LSFO and diesel oil. This is based on power plant use due to the estimated four-week curtailment of gas for power plants plus about 100,000 Bbl. oil burn for testing purposes. SDG&E estimates that the prices will be $19.83/Bbl. and $23.77/Bbl. for LSFO and diesel oil, respectively.

DRA forecasts 282 gWh of combined fuel oil burn, using average annual prices of $18.23/Bbl. for LSFO and $26.58/Bbl. for diesel oil. As discussed above, DRA also estimates four weeks of power plant gas curtailment.

No other parties offer other forecasts for oil generation.

DRA uses more current market data in its forecast of oil prices than SDG&E used in its filing. Current soft market conditions for LSFO make the DRA forecast appear more reasonable.

We conclude that DRA's forecast of LSFO and diesel oil prices for the forecast period is reasonable, and will adopt it.

3. Fuel Oil Inventory Management

SDG&E originally estimated fuel oil inventory carrying costs of $1.0406 million for the forecast period, based on a beginning of winter (November 1, 1988) target inventory level of 1,200,000 Bbl. LSFO and 70,120 Bbl. diesel oil. The target level is a level deemed necessary to begin the winter period with reasonable assurance that adequate inventory is available to insure reliable service under reasonably foreseeable conditions.

SDG&E determines its fuel oil inventory requirement using an Electric Power Research Institute Utility Fuel Inventory Model

(UFIM), into which SDG&E feeds its estimates of probable gas supply curtailments and delivery constraints, and oil resupply constraints. UFIM is designed to determine the monthly inventory levels that will minimize the overall costs of oil inventory management.

SDG&E's forecast of fuel oil inventory carrying costs of $1,579,500 is based on a target level of LSFO of 1,576,500 Bbl. and an average 70,120 Bbl. of diesel oil. This is an increase from the original estimate, since the recent period of gas curtailment for UEG by SoCal caused SDG&E to increase the target level, since the duration of curtailment was uncertain at that time. Revisions to SDG&E's forecast result in a cost of fuel oil inventory management of $1.1 million.

DRA recommends that the Commission adopt $1,040,600 for carrying costs based on SDG&E's original LSFO target level. DRA argues that the economics of the additional purchases of LSFO must be evaluated after it is burned, when its purchase cost plus carrying cost can be compared to alternatives. DRA further recommends that a new ratemaking procedure be used for handling fuel oil inventory carrying costs. Under DRA's proposal, SDG&E would be allowed the $1,040,600 as a lump sum for fuel oil inventory carrying costs, independent of actual costs incurred.

The allowed lump sum carrying costs would be determined from the formula:

> Lump Sum Inventory Allowance = (Estimated Average Inventory Level) x (Estimated LSFO weighted-average Unit Price) x (Estimated Average Bankers' Acceptance Rate)

DRA estimates the values as follows:

Estimated LSFO Average Inventory Level	= 904,000 Bbl.
Estimated LSFO Weighted-Average Unit Price	= $12.28/Bbl.
Estimated Average Bankers' Acceptance Rate	= 8.25%
Estimated Diesel Oil Weighted-Average Unit Price	= $21.60/Bbl.

Using these estimated values DRA calculates LSFO carrying costs of $915,850 and diesel oil carrying costs of $124,722, for a total Lump Sum Fuel Oil Inventory Allowance of $1,040,570. The total allowance would be transferred into a subaccount of the ECAC balancing account in 12 equal monthly debits, not subject to the ECAC/AER split. The only adjustment to the allowance would be a true-up of the interest rate at the end of each ECAC reasonableness review period to reflect the actual average Bankers' Acceptance Rate during the period.

Under DRA's proposal SDG&E could operate its fuel oil inventory at higher costs than the lump sum allowance, such as by purchasing greater amounts of LSFO, and be allowed carrying costs on the additional amounts only after a showing that this resulted in benefits to the ratepayer. The showing would have to be made after the extra LSFO was actually burned.

DRA proposes this system as a means of allowing SDG&E greater freedom in managing its fuel inventory, and as a means of giving it an added incentive to operate more efficiently. DRA believes that this proposal is consistent with novel ratemaking concepts discussed in the Commission's Division of Strategic Planning (formerly Policy and Planning Division) Report "Risk, Return, and Ratemaking" issued in R.86-10-001.

DRA points out that the benefits to ratepayers would be that if SDG&E operated at a lower than forecast cost, even though it would keep all the savings in the ECAC year, the reduced costs would be reflected in lower future forecasts of fuel oil inventory costs, thereby resulting in lower rates. If actual costs exceeded the allowance, the converse would result.

SDG&E points out the perverse incentives it believes would result from adoption of this proposal. For example, if SDG&E had a choice between running an oil-fired plant overnight, or purchasing power, and if the former costs $6 per barrel more to operate, SDG&E could run the plant and benefit the stockholders at the expense of ratepayers. This assumes that carrying costs of a barrel of oil are about one dollar per year, based on a $12.50 per barrel LSFO cost and an 8% annual carrying cost. ($12.50 x .08 = $1.00.) The added cost to stockholders would be only 8% (the AER fraction) of the $6 per barrel additional operating cost, or 0.08 x $6.00 = $0.48. The net effect to stockholders would be a savings of 52 cents, the difference between saving $1.00 on oil carrying costs and spending $0.48 more for operating the plant overnight. In contrast, the net effect for ratepayers would be an added cost of $5.52, which is 92% (the ECAC fraction) of the $6.00 added cost of running the plant overnight.

Although SDG&E states that it would not operate in a manner that would penalize the ratepayers to benefit stockholders, nevertheless it is troubled by this proposal. SDG&E believes it would be a mistake to implement a system that would benefit either stockholder or ratepayer at the other's expense. Under the current ECAC/AER system, what benefits one party also benefits the other, although to a different degree, due to the different ECAC and AER percentages.

SDG&E also believes that the proposal to allow it to recover higher fuel inventory carrying costs only after a showing that the ratepayers benefited as a result is cumbersome and impractical. For example, if SDG&E purchased extra LSFO in one ECAC period, it might not burn it until the next ECAC period, in which case the determination of reasonableness could cause retroactive ratemaking concerns.

We do not believe that retroactive ratemaking would result from the proposal if interim rates or special accounts subject to reasonableness review were used. However, we are concerned with the other aspects of the proposal. DRA would have a more formidable policing task in attempting to uncover actions that could benefit SDG&E shareholders at ratepayers' expense. We are also concerned that an added perverse incentive might exist. SDG&E

might not take risks that would be expected to benefit the ratepayer, because changing conditions would make it difficult to later show that an action was economic. For example, if SDG&E had an opportunity to buy extra LSFO at $5.00 below the current market price, it might not buy it because by the time it was ready to burn the LSFO the market price could have dropped $5.00, resulting in no savings to the ratepayer. Under that scenario, SDG&E would not be allowed to recover the carrying costs of that extra LSFO. In effect, it would be penalized for taking actions that would be expected to benefit the ratepayers. On the other hand, if burning the extra LSFO proved economic, SDG&E would be allowed to recover the carrying costs for the extra LSFO, but would receive no added incentive. In other words, in taking risks to attempt to benefit the ratepayer, it could break even or lose, but never win.

We conclude that the DRA proposal does not offer appropriate signals and incentives to SDG&E, and will not adopt it.

In considering SDG&E's revised forecast with its increased target level, we note that the uncertain duration of the recent curtailment of gas for UEG was the reason for the increase. Whether the increase is reasonable will be determined in a future reasonableness review. For forecasting purposes, we conclude that SDG&E's revised forecast of the cost of fuel oil inventory management, at $1.1 million is reasonable.

4. Purchased Power Expense

SDG&E purchases enough electrical energy to meet about half its requirements from two geographical areas, PNW which has abundant hydroelectric capability, and the Pacific Southwest (PSW) which has surplus electric power plant capacity including recently completed nuclear plants. Purchases consist of two basic types, firm, consisting of firm capacity and associated energy, and non-firm economy energy. Table 1 compares the purchase forecasts of SDG&E and DRA. Reasons for the differences are discussed in the sections following.

be interrupted, SDG&E has the right to call on firm energy through its firm purchase contracts, so it can meet load and the 7% minimum spinning reserve requirements in that manner when necessary and otherwise benefit from the economy energy. For that reason, all firm purchases are considered fast-start units that contribute to spinning reserve.

SDG&E argues that for this reason recorded levels of firm energy purchases should be used in forecasting. Although this method results in overutilization of the lines at times, the duration of those times is short and has little effect on the accuracy of the forecast. SDG&E believes that DRA's method is less accurate and results in a greater degree of overforecasting of firm energy and resulting underforecasting of economy energy. In effect, DRA assumes peak demand during all hours of the forecast period.

SDG&E also believes that the line capacity derate used by DRA and Kelco is conservative since planned outages are scheduled during off-peak periods when possible and normally would not affect peak period capacity.

DRA and Kelco base their approach on the perceived need to prevent overscheduling purchases on the lines and exceeding the available line capacities. By assuming that all available firm energy is taken during all periods, the maximum capacity of the lines that can be used by firm purchases is assumed to be used; and, therefore, that capacity cannot be also committed to economy energy at the same time. We observe that these assumptions are conservative in that they prevent any overloading of the lines, which could happen under SDG&E's assumptions.

We agree that SDG&E's approach will result in assuming greater line capacity than will be available at certain times. This would be expected to occur most likely during peak periods when purchases of full or higher than average quantities of firm energy would be made. SDG&E points out that peak periods consist of a limited number of hours daily, and that DRA's method restricts economy energy during all hours of the day and night.

While DRA's approach somewhat understates economy purchases, the results appear to be more reasonable than the SDG&E approach. SDG&E's approach appears to overstate more significantly economy purchases by allowing economy purchases during all periods, resulting in forecasts of significantly more economy energy purchases than we believe is reasonable to forecast.

On balance, we believe that DRA's approach is more reasonable and that it provides a better approximation to actual operations.

We hope that continued evolution of the models will result in more accurate simulation of actual operations, so that these simplifying assumptions will no longer be needed. We encourage the parties to work toward that goal.

For this proceeding we will adopt DRA's method of forecasting as reasonably representing expected firm PNW purchases.

(2) PSW

SDG&E forecasts firm purchases from APS, Alamito/Tucson Electric Power, PNM, Commision Federal de Electricidad (CFE) of Mexico, Portland General Electric, El Paso Electric, and from various short-term firm suppliers. These purchases are transmitted over the 500 kV SWPL line using SDG&E's entitlement plus an additional 50 MW of entitlement to capacity on that line of other parties that is expected to be available to SDG&E. Line capacity is derated to reflect expected outages, curtailments, and loop flow. Line losses are estimated at 2.5%.

DRA has reviewed SDG&E's forecasted firm purchases and has not taken exception to the capacity costs associated with all sources, except for the short-term firm capacity, which has not yet been arranged. DRA forecasts $440,000 for four months' purchases at 110 MW per month from June through September 1989, based on a cost of $1.00 per kW-month. This compares to SDG&E's forecast of $880,000 for the same quantity and period, based on a forecast of $2.00 per kW-month. Although DRA disagrees with SDG&E on this issue, very little evidence was presented to support its position. Similarly, SDG&E also offered little evidence to support its forecast. We conclude that based on the information available, it is reasonable to adopt a value midway between the two forecasts, at $1.50 per kW-month.

DRA has also expressed concern that the contract with CFE is uneconomic, i.e., that the purchases will be at costs higher than SDG&E's avoided cost. The high demand charges for firm purchases in the CFE contract cause the total price to CFE to be higher than SDG&E's avoided cost. DRA encourages SDG&E to make every effort to make the contract cost-effective.

We share DRA's concern that the CFE contract may be uneconomic to SDG&E's ratepayers. We encourage SDG&E to actively pursue renegotiation of those terms in the CFE contract that result in CFE energy costing more than alternate sources.

DRA may wish to pursue this issue in the reasonableness of operations phase of this proceeding, or alternately may wish to defer any recommendations on how it should be handled until future SDG&E ECAC proceedings.

SDG&E and DRA forecast substantially different quantities of firm energy for the same reasons as discussed in the PNW firm purchased power section above.

Similar conditions exist for PSW firm purchases as for PNW firm purchases. Therefore, for the same reasons we discussed in the section on PNW firm purchases, we will adopt DRA's forecast methodology for forecasting purposes. While DRA's forecast somewhat understates line capacity available for economy energy, we believe that SDG&E's forecast overstates capacity availability. We will adopt DRA's method of forecasting, reduced to reflect the adopted cost of short-term firm capacity of $1.50 per kW-month, as reasonably representing expected firm PSW purchases.

b. Non-firm

(1) PNW

SDG&E, DRA, and Kelco disagree on both the forecast quantities and prices for PNW economy energy. SDG&E assumes that the quantity of economy energy available is its entitlement on the lines, less the expected firm purchases and line derate. SDG&E determined that 95% of PNW entitlement is available off-peak and during spring run-off. During other periods on-peak availability is based on historical conditions. On this basis SDG&E estimates 1,107 gWh for the forecast period, at an average price of 1.743¢/kWh. Pricing assumes that PNW prices will remain above historical averages through March 1989 due to the drought conditions, then drop to normal levels beginning April 1989. The prices range from 2.000¢/kWh on-peak and 1.800¢/kWh off-peak during the first five months, to as low as 1.760¢/kWh on-peak and 1.350¢/kWh off-peak, during the remaining seven months.

DRA derates the line capacities for all periods, assumes full firm purchases under firm contracts to be coincident during all periods, and assumes the remaining capacity to be available for economy energy. DRA believes that price competition between the PSW and PNW will cause PNW prices to closely follow PSW. DRA based its PNW prices on its PSW billed price forecast plus 0.05¢/kWh for the first five months, and on the PSW billed price forecast for the remaining seven months. Dispatch prices are determined from the billed prices by adding an estimate of line losses, which DRA assumes to be 7.5% as does SDG&E. DRA's unit cost estimate is flatter than SDG&E's. It peaks in January and February 1989 at 1.981 and 1.846¢/kWh on- and off-peak, respectively, and has a low of 1.745 and 1.626¢/kWh on- and off-peak during spring and fall of 1989. On this basis DRA forecasts 807 gWh of PSW economy energy at an average price of 1.648¢/kWh.

Kelco forecasts the same prices used by DRA for April through October 1989, but increases the price to 2.44¢/kWh from November 1988 through March 1989 due to the drought. Kelco argues that recent prices paid by Pacific Gas and Electric Company (PG&E) for PNW economy energy justify this price. For example, in April 1988 PG&E paid 2.48¢/kWh, and the prior four months' prices were in the 2.4¢/kWh range. In May and June the price dropped due to greater supply availability as a result of the required fish flush when higher downstream water levels are maintained. The fish flush requires more flow through the dams, which makes more economy energy available.

Comparing the price forecasts, SDG&E, DRA, and Kelco all assume higher prices in the initial months of the forecast period due to the drought. SDG&E and DRA have similar forecasts, with SDG&E's prices slightly higher. Since SDG&E also forecasts higher purchase quantities, we believe that higher prices would result due to the increased demand. We conclude that SDG&E's price forecast is reasonable.

For the same reasons as discussed in the PNW firm purchase section, we believe that DRA's forecast more accurately represents expected economy purchases than the SDG&E forecast. We will adopt DRA's method for forecasting the quantity of PNW economy energy purchases. We do not believe that Kelco's pricing forecast for the first five months has been adequately supported with recorded data or trends. We conclude that DRA's pricing forecast is reasonable.

(2) PSW

SDG&E's economy energy purchases from the PSW consist primarily of economy energy from coal and nuclear plants in Arizona and New Mexico.

SDG&E forecasts the amount of economy energy available monthly, based on the available line capacity, including 50 MW entitlement from other entities and available economy energy. The available line capacity is the derated capacity reduced by the forecasted firm capacity use. The 2.5% line loss is handled by reducing the economy energy by that amount. SDG&E forecasts enough available economy energy during the months of November through March and all weeknight hours for other months to fill the available capacity. During the balance of the forecast year less economy energy is available than line capacity.

SDG&E's forecast of PSW economy energy prices is based on the equation:

PSW economy energy price ($/MWh) = gas price ($/MMBtu) x 8.19

The equation was developed from the average cost of PSW economy energy and the average cost of gas for the period from January 1987 through March 1988. The resulting prices are lower than historical, reflecting recent trends in PSW prices and the expected greater availability of low cost baseload energy in the future. SDG&E forecasts a total of 1,462 gWh at an average price of 1.860¢/kWh.

DRA uses SDG&E's line capacity entitlement plus an added 50 MW assumed to be available from other entities owning capacity entitlements on SWPL. DRA uses the same 2.5% line loss factor as SDG&E but accounts for it differently than SDG&E by reducing the SWPL capacity by that amount.

DRA prices are based on the equation:

PSW economy energy price ($/MWh) = 4.44 + (gas price x 5.88)

The formula was developed using the relationship of the average cost of PSW economy energy to the average cost of gas, during the period from July 1985 through April 1988. The formula differs from SDG&E's due to the base period used.

DRA forecasts a total of 1,054 gWh of economy energy purchases from the PSW at an average cost of 1.75¢/kWh.

In considering the appropriate forecast quantity of economy energy, we note that SDG&E and DRA each handle line capacity limitations for PSW economy energy on SWPL in the same manner as each handles PNW line capacity limitations. Therefore, the same relative results exist, i.e., SDG&E at times exceeds line capacity availability, and DRA restricts economy energy by assuming full firm purchases during all periods. For the same reasons as discussed in the PNW section, we will adopt DRA's method of forecasting economy energy purchases as more representative of expected system operations than SDG&E's forecast.

The price forecasts range from 1.75¢/kWh for DRA to 1.86¢/kWh for SDG&E. The variation is in the direction we would expect, since with fewer purchases, the average price should be lower. As purchases increase, the purchaser must pay higher unit prices for the additional purchases, since the lower cost purchases will have been exhausted. DRA's price forecast, at 6% below SDG&E's, appears to follow this expected trend.

Although it does not precisely replicate system operations, we conclude that DRA's forecast method is more representative of expected pricing of economy energy from the PSW during the forecast period. We will adopt DRA's price forecast method.

Table 2 shows the comparative economy energy price forecasts of SDG&E and DRA.

TABLE 2

Economy Energy Price Forecasts
$/MWh as Billed

	PNW							
	On-Peak		Off-Peak		On-Peak		Off-Peak	
Month	SDG&E	DRA	SDG&E	DRA	SDG&E	DRA	SDG&E	DRA
Nov 88	20.00	17.97	18.00	16.74	18.00	18.02	16.75	16.17
Dec	20.00	18.27	18.00	17.03	19.41	18.34	18.05	16.45
Jan 89	20.00	19.81	18.00	18.46	21.85	19.93	20.39	17.88
Feb	20.00	19.81	18.00	18.46	21.17	19.93	19.71	17.88
Mar	20.00	18.58	18.00	17.32	20.29	18.66	18.83	16.74
Apr	17.60	17.45	13.50	16.26	18.44	18.02	17.17	16.17
May	17.60	17.45	13.50	16.26	18.44	18.02	17.17	16.17
Jun	17.70	17.57	13.60	16.37	18.54	18.15	17.27	16.28
Jul	17.90	17.57	13.80	16.37	18.83	18.15	17.46	16.28
Aug	17.90	17.57	13.80	16.37	18.83	18.15	17.46	16.28
Sep	18.00	17.45	13.80	16.26	18.93	18.02	17.56	16.17
Oct	18.00	17.45	13.80	16.26	18.93	18.02	17.56	16.17

(3) Miscellaneous Purchases and Sales

Miscellaneous economy energy purchases are forecast to come from California and Mexico. Those from California are from surplus hydroelectric in northern California, or from oil/gas fired resources. The Mexican purchases are expected to be from geothermal or oil/gas fired resources.

SDG&E forecasts 30 gWh per month at an average cost of 1.869¢/kWh for the forecast period based on recent historic values.

DRA agrees with the quantity, and forecasts an average purchase price of 1.831¢/kWh, based on the equation:

Purchase Price (\$/kWh) = Gas Price (\$/MMBtu) x 8.51

The equation DRA uses was developed by SDG&E. It is based on the ratio of the weighted-average cost of these purchases to the average gas dispatch price from January 1987 through March 1988. DRA and SDG&E agree on this item except for the price of gas. We will adopt DRA's purchase price forecast since we are adopting DRA's gas price forecast.

D. QF Payments

This area involves the appropriate avoided costs, and thereby the price to be paid variable priced QFs. The price has two components, a capacity cost and an energy cost, which are based on the utility's avoided capacity and energy costs. The capacity cost is intended to represent the capital cost a utility would otherwise incur, were it not for the QFs. For example, a utility might need to install an additional peaking turbine to meet peak demands if it did not have QFs to rely on in meeting that need.

Similarly, the energy cost is the unit cost that the utility would otherwise incur in operating its own facilities to provide the energy that it purchases from QFs. In D.88-03-079, we adopted the QFs-in/QFs-out approach to determine the costs a utility avoids by virtue of having QFs. The concept of the IER originated in the negotiating conference that developed the interim

Standard Offer 4, and was intended to assist in determining a utility's avoided energy cost. The IER is a measure of the utility's thermal efficiency in converting fuel into electrical energy, expressed as Btu/kWh.

The procedure used in determining the IER is to perform two runs using a given model, one run with QFs "in", the other with QFs "out." The difference in total operating costs, or total costs, between the two runs, is the effect of the QFs on the utility operational costs. The gas cost component of the total costs is then adjusted to reflect the total cost of gas for Utility Electric Generation (UEG) which includes demand costs, resulting in UEG-adjusted total gas costs. From this a unit UEG gas rate is calculated. The IER is then determined by dividing the difference in UEG total costs by the quantity of QF generation, and dividing the result by the UEG gas rate.

The formula for calculating the IER (in Btu/kWh) follows:

IER = _ total cost ($) ÷ QF generation (gWh) ÷ UEG rate ($/MMBtu)

1. Capacity Cost

The parties stipulated to an avoided capacity cost of $65.00/kW-year for calendar year 1989, as the capacity cost proxy based on the cost of a combustion turbine on SDG&E's system. This value was proposed by SDG&E and DRA in the SDG&E GRC, A.87-12-003. The capacity cost is based on an average ERI of 1.0.

SDG&E performed the QFs-in run using the same resource plan it used in the 1989 TY GRC which includes all QFs currently in operation plus additional QFs considered Likely To Be Available. The QFs-out run assumes that the capacity associated with Standard Offer 1 and Standard Offer 3 QFs is not available. The result would normally be a higher EUE under the QFs-out case since the EUE would be higher with the reduced resources. In this instance, however, both EUEs are the same and therefore the resulting ERIs are the same at 1.0, since the additional capacity is needed in this timeframe. It follows that the average ERI is also 1.0.

The annualized capacity of $65.00 per kW/year is then multiplied by the ERI to obtain a capacity cost for QFs of $65.00/kW-year. The breakdown of capacity payments by time period proposed by SDG&E follows in Table 3.

TABLE 3

As-Available Capacity Payment Schedule
Proposed Effective November 1, 1988

Time Period	Hourly Allocation Factor	Payment Rate (¢/kWh)
Summer		
On-Peak	0.096	6.25
Semi-Peak	0.006	0.39
Off-Peak	0.000	0.00
Super-Off-Peak	0.000	0.00
Non-TOU	0.011	0.70
Winter		
On-Peak	0.013	0.82
Semi-Peak	0.008	0.50
Off-Peak	0.000	0.00
Super-Off-Peak	0.000	0.00
Non-TOU	0.002	0.13
Annual Average of TOU	0.011	0.74

DRA and Kelco agree with these values for capacity payments to QFs.

We conclude that these values, based on a capacity value of $65.00 per kW-year and on an ERI of 1.00, reasonably represent the value of capacity to SDG&E for the forecast period. We will adopt these values.

2. Energy Cost

a. UEG Gas Cost

Total gas cost for UEG includes the delivered cost plus the transmission cost based on the GTUEG tariff, for gas sold by SDG&E's gas department to its electric department. The GTUEG tariff consists of monthly demand charge and the volumetric rate and is designed to recover the fixed or demand costs on both the SoCal and SDG&E systems for transporting the gas from the California border to the system. The volumetric rates are based on two tiers. Tier I is used for the first 18.5% of UEG gas used each month, and is priced higher than Tier II. Tier I represents the baseload quantity of gas, while Tier II is the added discretionary quantity of gas.

(1) Sales Volume

SDG&E argues that the volumes recently adopted in D.87-12-039 in the gas OII (I.86-06-005) should be used with the Tier I rate to determine the Tier I gas cost, since the current GTUEG tariff is based on those volumes.

DRA argues that the most current forecast should be used, which is this ECAC proceeding's forecasted gas volumes.

The difference in gas expense between using the gas OII volumes and the ECAC forecast volumes is about $445,500. This is caused by the substantially lower ECAC gas volumes as compared to the gas OII volumes. The lower volumes applied to the Tier I rate result in less recovery, since the volumes above 18.5% are priced at the lower Tier II rate.

During the hearings and after examining rebuttal testimony of SDG&E, DRA stipulated to SDG&E's method for Tier I.

We agree that the Tier I sales volumes must be consistent with the sales volumes used to establish the tariffs. At this time, the tariffs are based on the gas OII volumes, and therefore Tier I should use the same sales volumes.

We will adopt the gas OII volumes for Tier I. ECAC volumes in excess of Tier I volumes will be billed under Tier II rates.

(2) Cost of Gas to UEG

As mentioned above, we will adopt the DRA forecast of the delivered price of gas to the SDG&E system at $2.349 per million Btu. This price is then adjusted by DRA to reflect all costs which include GTUEG demand charges of $38.562 million for the forecast period.

3. QF Adders

Two issues arose regarding adders to QF payments, involving the propriety of Operation and Maintenance (O&M) and of Administrative and General (A&G) adders. The considerations are whether SDG&E saves O&M and A&G expenses by virtue of QF purchases and resulting lower utilization of its own plants. If savings result, they must be quantified, and the method of compensating the QFs must be decided. We will address these issues individually.

a. Avoided O&M Costs

Avoided O&M concerns the O&M costs that SDG&E avoids by purchasing QF energy instead of using its own plants. O&M can be split into two types, fixed and variable. Fixed is routine activity that does not vary significantly with usage of the plant. Variable, on the other hand, is directly related to the amount of plant usage.

The second issue dealing with O&M is how the payment should be handled, i.e., as an adder to the QF payment, or as a component of the IER.

Kelco recommends an O&M adder of $0.003 or 3.0 mils per kWh, which is apparently based on the value recently considered in the SCE GRC.

SDG&E agrees that an O&M adder is appropriate, but recommends a value of $0.0002 or 0.2 mils per kWh based on a recommendation of the California Power Pool. SDG&E believes that

differences on the SCE system are responsible for its higher O&M value, and that such a high value is not appropriate for SDG&E.

DRA points out that the O&M adder may be implicitly considered in the modeling assumptions used by SDG&E.

Although the issue of the O&M adders was raised in the proceeding, we do not have a clear record on this matter. Kelco recommends the 3.0 mils per Kwh adder as the same number as SCE. While this was adopted for SCE, it is also much higher than the adder recommended by DRA and SDG&E.

We are persuaded from our past treatment of O&M adders in ECAC proceedings for other electric utilities that such an inclusion is appropriate in this case. Therefore, we will adopt, as a reasonable resolution, the 1.8 mils per Kwh O&M adder adjusted for on peak fossil generation that we adopted for PG&E in the our most recent ECAC decision, D.88-11-052. This results in an O&M adder of 1.06 mils per Kwh.

Because this issue was not thoroughly explored in the proceeding, we will order SDG&E to provide a complete study of O&M costs avoidable by QF purchases relative to its system to the Commission Advisory and Compliance Division within 90 days after the effective date of this Decision.

b. <u>Reduced A&G Costs</u>

Kelco recommends an adder to the QF payments to reflect the reduced A&G costs due to less need for working capital by virtue of QF purchases. The theory is that SDG&E benefits in cash flow by the delay or lag in paying QFs, instead of using its own

differences on the SCE system are responsible for its higher O&M value, and that such a high value is not appropriate for SDG&E.

DRA points out that the O&M adder may be implicitly considered in the modeling assumptions used by SDG&E.

The issue of the O&M adders was raised in the proceeding, but was not extensively developed by the parties. Kelco recommends the 3.0 mils per Kwh adder which we adopted in September, 1988 for SCE. This figure is much higher than the adder recmmended by DRA and SDG&E in the current proceeding.

We are persuaded from our past treatment of O&M adders in ECAC proceedings for other electric utilities that such an inclusion is appropriate in this case. We will however, adopt an adder in the amount of the 1.8 mils per Kwh adjusted for on-peak fossil generation. This is identical to the O&M adder we adopted for PG&E in November 1988 in its most recent ECAC decision, D.88-11-052. This results in an O&M adder of 1.06 mils per Kwh.

Because this issue was not thoroughly explored in the proceeding, we will order SDG&E to provide a complete study of O&M costs avoidable by QF purchases relative to its system to the Commission Advisory and Compliance Division within 90 days after the effective date of this Decision.

b. Reduced A&G Costs

Kelco recommends an adder to the QF payments to reflect the reduced A&G costs due to less need for working capital by virtue of QF purchases. The theory is that SDG&E benefits in cash flow by the delay or lag in paying QFs, instead of using its own

differences on the SCE system are responsible for its higher O&M value, and that such a high value is not appropriate for SDG&E.

DRA points out that the O&M adder may be implicitly considered in the modeling assumptions used by SDG&E.

The issue of the O&M adders was raised in the proceeding, but was not extensively developed by the parties. Kelco recommends the 3.0 mils per Kwh adder which we adopted in September, 1988 for SCE. This figure is much higher than the adder recmmended by DRA and SDG&E in the current proceeding.

We are persuaded from our past treatment of O&M adders in ECAC proceedings for other electric utilities that such an inclusion is appropriate in this case. We will however, adopt an adder in the amount of the 1.8 mils per Kwh adjusted for on-peak fossil generation. This is identical to the O&M adder we adopted for PG&E in November 1988 in its most recent ECAC decision, D.88-11-052. This results in an O&M adder of 1.06 mils per Kwh.

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4. <u>Purchase Quantities</u>

SDG&E and DRA forecast similar purchase amounts from QFs, but substantially different costs, as shown in Table 4.

TABLE 4

<u>Comparison of DRA and SDG&E Estimates</u>

	DRA	SDG&E
Energy Purchases (gWh)	230.4	231.5
Energy Cost ($ million)	9.383	6.205

DRA's slightly lower purchase level is due to more current data on the expected on-line date for a new QF project.

DRA's dramatically higher costs are the result of its higher recommended IER (compared to SDG&E's PROMOD IER) and different gas price.

We conclude that DRA's forecast method is correct, and adopt a forecast for QF purchases of 231 gWh based on the further DRA ELFIN run.

E. <u>Revenue Requirement</u>

As a result of adopting various assumptions and forecasts of the parties, the level of forecasted ECAC and AER increases also change, due in part to gas pricing, resource assumptions, and purchased power results. The latest forecasts by SDG&E are a $7.669 million ECAC increase, a $0.520 million AER increase, and an ERAM overcollection of $30.796 million, for a combined net rate decrease of $22.607 million. We'll adopt an updated forecast of ECAC and AER increases based on its model run used to update the IER results in forecasts of a $3.639 million ECAC increase, a $0.1 million AER decrease, an ERAM overcollection at $30.8 million, for a net rate decrease of $27.027 million. We will adopt these forecast values.

We will adopt two changes in rate design in this proceeding. First, the agricultural Schedule PA-T-1 will become a permanent schedule, since we will remove the termination date currently in effect.

Second, we will adopt an optional AL-TOU schedule with a shorter peak period of noon to 6 p.m. compared to the 11 a.m. to 6 p.m. peak period in effect in the AL-TOU tariff. This optional schedule is intended to accommodate requests by school districts who normally end summer classes by noon.

F. Revenue Allocation and Rate Design

Since we intend to implement the revenue requirement changes herein concurrently with the SDG&E GRC A.87-12-003, we will reflect revenue allocation and rate design associated with revenues in this proceeding in the GRC.

G. Comments

Comments on the proposed decision were filed by DRA, Kelco, and SDG&E. DRA points out several typographical errors which have been corrected. DRA further suggests nonsubstantive editorial changes, some of which have been made.

Added Appendix A reflects the IER and revenue requirements based on the adopted assumptions and values.

Findings of Fact

1. SDG&E filed this A.88-07-003 on July 1, 1988 requesting a net rate decrease of $7.535 million on an annualized basis beginning November 1, 1988. This change is based on an ECAC increase of $4.679 million, no change in AER, and an ERAM decrease of $12.214 million.

2. The latest updated request by SDG&E is for a net revenue decrease of $22.607 million, based on an ECAC increase of $7.669

million, an AER increase of \$0.520 million, and an ERAM reduction of \$30.796 million.

3. DRA recommends a net revenue decrease of \$29.626 million based on an ECAC increase of \$1.300 million, an AER decrease of \$0.130 million, and an ERAM reduction of \$30.796 million.

4. SDG&E's current annual ECAC proceeding marks the beginning of the regular revision in ECAC of key components used in the determination of prices to be paid for power sold to SDG&E by QFs.

5. It is the Commission policy to develop utility rates and QF prices on a consistent basis.

6. Parties who use a model to develop marginal or avoided costs may use their model of choice, but must also provide a base case using the ELFIN model.

7. The TCF issue for SONGS 2&3 has been consolidated with that issue in the SCE ECAC A.88-02-016 reasonableness review.

8. SDG&E supports PROMOD as the only model capable of accurately simulating its operations.

9. DRA and Kelco prefer the ELFIN 1.60 model, and believe it is equally capable of competent results.

10. PROMOD is significantly more costly to use than ELFIN 1.60.

11. ELFIN 1.60 is improved over earlier versions of ELFIN.

12. PROMOD has two commitment variables while ELFIN 1.60 has one.

13. Inconsistent assumptions used by SDG&E in its PROMOD and ELFIN runs are partly responsible for the large difference in IER between the two runs.

14. SDG&E and DRA agree on the forecast sales of 12,888 gWh.

15. City questions the forecast level of miscellaneous sales due to the recent drought effects.

16. All parties agree with SDG&E's proposed resource plan.

17. SDG&E agrees on the forecast delivered commodity cost of gas at $2.349 per million Btu.

18. SDG&E and DRA agree that four weeks of gas curtailment to power plants is likely during the forecast period.

19. About 2% of SDG&E's electrical requirements will be met with oil-fired generation using LSFO or diesel oil.

20. SDG&E meets about half of its electrical requirements with purchased power.

21. Purchased power comes primarily from the PNW and PSW.

22. SDG&E assumes average historic firm energy purchases during all periods, which at times overloads the lines.

23. DRA and Kelco assume full available firm energy purchases during all periods, which results in less line availability for energy purchases and prevents overloading the lines.

24. The assumptions used by SDG&E overstate the availability of economy energy.

25. SDG&E, DRA, and Kelco agree that the annualized capacity cost is $65.00 per kW-year.

26. SDG&E, DRA, and Kelco agree that SDG&E's ERI is 1.00.

27. All parties agree that an O&M adder is appropriate.

28. Kelco recommends an O&M adder of 3.0 mils per Kwh.

<u>Conclusions of Law</u>

1. Both the PROMOD and the ELFIN 1.60 models competently simulate SDG&E's system operations, and should yield similar results when the same assumptions are used.

2. It is reasonable to adopt DRA's recommendation to use the ELFIN 1.60 model to develop SDG&E's revenue requirement and IER in this proceeding.

3. The resource plan submitted by SDG&E in this proceeding is reasonable.

4. A reasonable reserve margin requirement for dispatching resources is 7%.

5. It is reasonable to consider firm purchases as fast-start units that contribute to spinning reserve.

6. It is reasonable to consider Encina Units 4 and 5 as fast-start units.

7. It is reasonable to model firm purchases from PNM assuming a one MW first block.

8. Reasonable dispatch costs for the APS contract are $2.00 per MWh higher on-peak and $1.30 per MWh higher off-peak than the ELFIN base case dispatch costs.

9. Annual startup costs for SDG&E of $298,000 are reasonable.

10. A reasonable forecast of annual sales is 12,888 gWh.

11. A reasonable forecast of nuclear generation is 3,213 gWh at a cost of $34.35 million.

12. A forecast of four weeks of gas curtailment is reasonable.

13. A reasonable forecast of the delivered price of gas is $2.349 per million Btu including transportation and shrinkage.

14. A reasonable forecast of the cost of oil is $18.23 per Bbl. for LSFO and $26.58 per Bbl. for diesel oil.

15. A reasonable forecast of the cost of fuel oil inventory management is $1.1 million.

16. It is reasonable to forecast firm purchases assuming all available firm energy is taken during all periods to avoid over loading the transmission lines.

17. It is reasonable to base line availabilities on rated capacities, derated to reflect normally expected curtailments based on historic values.

18. A reasonable estimate of line losses for the PNW lines is 7.5 %.

19. A reasonable estimate of line losses on SWPL is 2.5%.

20. It is reasonable to assume that SDG&E will be able to purchase 50 MW of additional capacity on SWPL from other parties.

21. It is reasonable to assume four months of short-term firm capacity purchases at a cost of $1.50 per kW-month.

22. SDG&E's equation for forecasting the price of PSW economy energy based on the gas price is reasonable.

23. It is reasonable to assume 30 gWh per month of miscellaneous economy energy purchases using using DRA's formula for price.

24. An avoided cost of $65.00 per kW-year is reasonable as a capacity cost proxy based on the cost of a combustion turbine on SDG&E's system.

25. A reasonable value of the ERI is 1.00 for SDG&E.

26. It is reasonable to use the gas OII adopted volumes for SDG&E in determining Tier I and Tier II commodity rates.

27. A reasonable forecast of the delivered price of gas to SDG&E's system is $2.349 per million Btu.

28. It is reasonable to remove the expiration date of the PA-T-1 tariff schedule, making it a permanent schedule.

29. It is reasonable to adopt an optional AL-TOU schedule with a reduced peak period of noon to 6 p.m.

30. It is reasonable to reflect the revenue requirement and rate changes resulting from this decision in coordination with changes in the SDG&E GRC A.87-12-003.

31. It is reasonable to adopt an adjusted O&M adder of 1.06 mils per Kwh for this proceeding.

32. SDG&E should be ordered to conduct a study of avoidable O&M costs associated with QF production.

ORDER

IT IS ORDERED that:

1. San Diego Gas & Electric Company (SDG&E) is authorized to decrease its total Energy Cost Adjustment Clause (ECAC) revenue requirement by $27.103 million, the net effect of an ECAC increase

of \$3.555 million, an Annual Energy Rate decrease of \$0.130 million, and an Electric Revenue Adjustment Mechanism decrease of \$30.788 million as shown in the tables in Appendix A.

2. The revenue requirement changes authorized by this decision will be effected in rates through coordination with the rate changes and rate design principles that will be adopted in the SDG&E General Rate Case decision in Application 87-12-003, except that Schedule PA-T-1 shall become permanent and an optional AL-TOU schedule with reduced peak period shall be offered.

3. On or after the effective date of the final Phase I decision in this proceeding, and at least 3 days prior to the authorized date for tariff revision, SDG&E shall file revised tariff schedules for electric rates reflecting the revenue decrease authorized in the final Phase I order. The revised tariffs shall apply to service rendered on or after their effective date.

4. An Energy Reliability Index value of 1.0 is adopted in this proceeding.

5. An annual average Incremental Energy Rates (IER) of 8,769 British thermal units per kilowatt-hour is adopted in this proceeding. A 1.06 mils per kilo-watt hour adder is also adopted for purchases from qualifying facilities. Division of Ratepayer Advocates' proposed time-differentiated IERs shown in Appendix A are also adopted.

6. San Diego Gas and Electric Company will file a complete study on the avoided Operation and Maintenance costs associated with its electric purchases from Qualifying Facilities. The study will be filed with the Commission Advisory and Compliance Division within ninety days.

This order is effective today.

Dated DEC 19 1988, at San Francisco, California.

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

21. It is reasonable to assume four months of short-term firm capacity purchases at a cost of $1.50 per kW-month.

22. SDG&E's equation for forecasting the price of PSW economy energy based on the gas price is reasonable.

23. It is reasonable to assume 30 gWh per month of miscellaneous economy energy purchases using using DRA's formula for price.

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31. It is reasonable to adopt an adjusted O&M adder of 1.06 mils per Kwh for this proceeding.

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O R D E R

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This order is effective today.

Dated ____________________, at San Francisco, California.

Table L-1
DRA Estimate of Revenue Requirements and Changes Per Alternate Decision 12/16/88

	(1)	(2) = (1) + (3)	(3)
	Present * Rate Revenues ($ 000)	Adopted ** Revenue Requirement ($ 000)	Change ($ 000)
ECAC	$356,580	$360,135	$3,555 ***
AER	$32,198	$32,328	$130 ****
ERAM	($4,379)	($35,167)	($30,788)*****
Total	$384,399	$357,296	($27,103)

* Includes FF&U.

** At sales of 12,879.1 GWh.

*** ($360,103 (Table L-2, line 22) - $356,580) * 1.00918 (SDFF)

**** Table L-5, line 14.

***** (($30,500 (Table L-5, line 24) + $8 (Table L-5, line 26) + $280 (SDFF)).

TABLE L-2

DRA ESTIMATE OF
ECAC REVENUE REQUIREMENT AND UNIFORM RATE CHANGE
PER ALTERNATE DECISION

(November 1, 1988 thru October 31, 1989)

	GWh	C/kWh	M$
1 Natural Gas	3,463	3.638	125,983
2 Residual Oil	282	2.601	7,337
3 Other Oil	0	5.541	5
4 Firm Purchases *	4,543	3.885	176,483
5 Econ Purchases	2,619	1.777	46,542
6 Alt/Cogen	231	4.186	9,651
7 Nuclear	3,213	1.069	34,350
8 Total	14,350	2.790	400,351
9 Variable Wheeling Expenses			384
10 Fixed Wheeling Expenses			8,553
11 Startup Fuel			298
12 Carrying Cost of Oil in Inventory			1,100
13 EFI Adjustment			(580)
14 Subtotal Expenses			410,106
15 Less AER Recovery Portion (8%)			(32,808)
16 Less NARCO Fuel Service Charge			(2,000)
17 Plus Alamito-Tucson Capacity (300 MW)			41,650
18 Subtotal			416,947
19 Non-Jurisdictional Amount at 2.71885%			11,336
20 Adjusted Subtotal			405,611
21 Less Projected ECAC Balance on November 1, 1988			(45,508)
22 Total Requirement			360,103
23 Less Revenue at Present ECAC Rates			356,580
24 ECAC Revenue Requirement			3,523
25 ECAC Rate Change - Forecast Sales of 12879.1 GWh			0.027 c/kWh
26 Franchise Fees and Uncollectible Expenses, at 1.2600%			0.000 c/kWh
27 Uniform ECAC Rate Change			0.028 c/kWh

* Excluding 300 MW Alamito-Tucson Capacity

TABLE L-3

DRA ESTIMATE OF
ANNUAL ENERGY RATE (AER)
PER ALTERNATE DECISION

(November 1, 1988 thru October 31, 1989)

	GWh	C/kWh	M$
1 Natural Gas	3,463	3.638	125,983
2 Residual Oil	282	2.601	7,337
3 Other Oil	0	5.541	5
4 Firm Purchases *	4,543	3.885	176,483
5 Econ Purchases	2,619	1.777	46,542
6 Alt/Cogen	231	4.186	9,651
7 Nuclear	3,213	1.069	34,350
8 Total	14,350	2.790	400,351
9 Variable Wheeling Expenses			384
10 Fixed Wheeling Expenses			8,553
11 Startup Fuel			298
12 Carrying Cost of Oil in Inventory			1,100
13 EFI Adjustment			(580)
14 Subtotal Expenses			410,106
15 AER Requirement (8% of Line 14)			32,808
16 Non-Jurisdictional Portion at 2.7189% of Line 15			892
17 Adjusted AER Requirement			31,916

18 Total Annual Energy Rate for 12879.1 GWh Applicable Sales	0.248 c/kWh
19 Franchise Fees and Uncollectible Expenses at 1.2600%	0.003 c/kWh
20 Adjusted Annual Energy Rate (Line 18 + Line 19)	0.251 c/kWh
21 Less Present Annual Energy Rate	0.250 c/kWh
22 Required Increase in AER	0.001 c/kWh
23 Current ECAC/AER Rate	3.024 c/kWh
24 Plus Proposed ECAC/AER Adjustments	0.029 c/kWh
25 Proposed ECAC/AER Rate	3.053 c/kWh

* Excluding 300 MW Alamito-Tucson Capacity

TABLE L-4

DRA ESTIMATE OF
PROPOSED UNIFORM ERAM RATE CHANGE
PER ALTERNATE DECISION

(November 1, 1988 thru October 31, 1989)

(M$)

1	Estimated ERAM Balance as of November 1, 1988	(35,191)
2	Net/Gross Factor Adjustment (0.88505%)	311
3	Adjusted ERAM Balance	(34,879)
4	Total ERAM Rate (Applicable Sales of 12879.1 GWh)	-0.271 c/kWh
5	Present ERAM Rate	-0.034 c/kWh
6	Proposed ERAM Rate	-0.237 c/kWh

TABLE L-5

DRA ESTIMATE OF
ECAC/AER/ERAM REVENUE REQUIREMENT
PER ALTERNATE DECISION

(November 1, 1988 thru October 31, 1989)

ITEM	(M$)
1 Natural Gas	125,983
2 Fuel Oil	7,341
3 Purchased Power	232,676
4 Nuclear	34,350
5 Subtotal	400,351
6 Other Expenses	9,754
7 Subtotal	410,106
8 AER Requirement (8%)	32,808
9 Less Adjustments	992
10 Less Revenue at Present Rate	32,198
11 AER Revenue Requirement	(381)
12 Revenue at Proposed Rate	129
13 SDFF Differential (0.918%)	1
14 Total AER Revenue Requirement	130
15 ECAC Requirement (92%)	377,297
16 Less Adjustments	17,195
17 Less Revenue at Present Rate	356,580
18 ECAC Revenue Requirement	3,523
19 Revenue at Proposed Rate	3,606
20 SDFF Differential (0.918%)	33
21 Total ECAC Revenue Requirement	3,639
22 Adjusted ERAM Balance	(34,879)
23 Less Revenue at Present Rate	(4,379)
24 ERAM Revenue Requirement	(30,500)
25 Revenue at Proposed Rate	(30,524)
26 Voltage Discount Adjustment	8
27 SDFF Differential (0.918%)	280
28 Total ERAM Revenue Requirement	(30,796)
29 Total AER/ECAC/ERAM Requirement	(27,027)

O&M Adder = 1.06 mill/KWh

SAN DIEGO GAS AND ELECTRIC COMPANY
ADOPTED AVOIDED ENERGY COSTS
ECAC Forecast Period — November 1, 1982 through October 31, 1989

	DESCRIPTION	SUMMER					WINTER					ANNUAL AVERAGE
		PEAK	SEMI-PEAK	OFF PEAK	SUPER OFF-PK	SEAS AVG	PEAK	SEMI-PEAK	OFF PEAK	SUPER OFF-PK	SEAS AVG	
1	INCREMENTAL ENERGY RATE-IER (BTU/KWH)	9213	8969	8480	7623	8280	9539	9254	8806	8113	8900	8739
2	EQUIVALENT IER or IER W/ O&M ADDER (BTU/KWH) ((L5 / L3) * 10 exp 6)	9546	9302	8813	7956	8613	9872	9587	9139	8446	9233	9102
3	G-UEG RATE ($/MMBTU)	3.1786	3.1766	3.1786	3.1786	3.1786	3.1786	3.1796	3.1786	3.1786	3.1786	3.1786
4	AVOIDED COST OF ENERGY ($/KWH) (L1 * L3)/(10 EXP 6)	0.02928	0.02851	0.02695	0.02423	0.02632	0.03032	0.02941	0.02799	0.02579	0.02829	0.02787
5	AVOIDED COST OF ENERGY WITH O&M Adder of 1.06 mill/kWh (L4 + .00106) $/KWH	0.030344	0.029566	0.02801	0.025290	0.027378	0.031380	0.03047	0.029050	0.026847	0.029349	0.028933
	TRANSMISSION											
6	ENERGY LOSS FACTOR	1.0313	1.0298	1.0214	1.0214	1.0244	1.0306	1.0282	1.0213	1.0213	1.0239	1.0241
7	AVOIDED ENERGY COST + LOSSES $/KWH (L5 * L6)	0.03129	0.03045	0.02861	0.02583	0.02805	0.03234	0.03133	0.02968	0.02743	0.03003	0.02963
	DISTRIBUTION											
8	ENERGY LOSS FACTOR	1.0732	1.0714	1.0511	1.0511	1.0384	1.0734	1.0673	1.0322	1.0312	1.0371	1.0376
9	$/KWH (L5 * L8)	0.03263	0.03168	0.02943	0.02638	0.02898	0.03368	0.03233	0.03054	0.02822	0.03103	0.03060