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Decision 89-07-018 July 6, 1989

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of Sierra Pacific Power Company for Authority to Implement its Energy Cost Adjustment Clause (ECAC).	Application 88-09-013 (Filed September 7, 1989)
In the Matter of the Application of Sierra Pacific Power Company for Authority to Implement its Electric Revenue Adjustment Mechanism (ERAM).	Application 88-09-028 (Filed September 13, 1989)

John Madariaga and James D. Salo, Attorneys at Law, for Sierra Pacific Power Company, applicant.
Catherine A. Johnson, Attorney at Law, and James M. Barnes, for the Division of Ratepayer Advocates.

O P I N I O N

I. Summary of Decision

This is the annual Energy Cost Adjustment Clause (ECAC) and Electric Revenue Adjustment Mechanism (ERAM) proceeding for Sierra Pacific Power Company (SPPC). We authorize a net revenue increase of $2,052,500 annually, or 5.7%, based on an ECAC increase of $2,684,700, an Annual Energy Rate (AER) increase of $33,600, and an ERAM decrease of $665,800.

SPPC's fuel and purchased power transactions and related operations for the review period July 1, 1987 through June 30, 1988 are found to be reasonable. The company is directed to submit, for consideration in future reasonableness reviews, reports on studies addressing transmission outages, the out-of-service Washoe hydroelectric plant, and adjustments to thermal efficiency standards for the large oil and gas plants.

II. Background

SPPC is a Nevada corporation engaged in public utility electric operations in California and Nevada. Its principal California operations are in the Lake Tahoe area. SPPC is also engaged in public utility gas and water operations in Nevada.

On September 7, 1988 SPPC filed Application (A.) 88-09-013, requesting authority to increase its Energy Cost Adjustment Clause Billing Factor (ECACBF) rates to offset an under-recovery of $2,604,000 which it estimates would occur if the current ECACBF rates were continued in effect for the twelve months commencing January 1, 1989. SPPC also proposes to increase its AER from $.00609 per kWh to $.00632 per kWh, or $94,000 annually. The combined effect of these proposed increases is an overall 7.52% revenue increase for all classes of service.

On September 13, 1988 SPPC filed A.88-09-028, requesting authority to reduce its ERAM rate from the present rate of $.00296 per kWh to $.00168 per kWh. The estimated annual effect of this proposed reduction is $528,000, or 1.47%. This application was consolidated with A.88-09-013.

The Division of Ratepayer Advocates (DRA) conducted an investigation which included an audit of SPPC's financial records for the record period July 1, 1987 through June 30, 1988, a review of the reasonableness of operations during the record period, and a forecast of operations for calendar year 1989. DRA accepted most aspects of SPPC's filings as reasonable, and SPPC accepted most of DRA's recommendations, with the result that very few issues are in controversy. The parties agree on audit and ERAM issues, and, for this proceeding, DRA accepts SPPC's proposed rate design and revenue allocation. Contested forecast issues involve projected operation dates and capacity factors of qualifying facilities (QFs), and required diesel oil inventory levels. Contested reasonableness issues involve DRA's recommended disallowances and reporting requirements related to record period transmission outages and power plant performance.

Public hearings were held in San Francisco on December 7, 8, and 9, 1988. At the conclusion of hearings the Administrative Law Judge (ALJ) determined that due to disagreement on forecast issues affecting resource mix and energy costs, it would be necessary for SPPC to make a post-hearing run of a production model which simulates system operations to forecast resource mix and energy costs. The results of the final model run, incorporating the ALJ's recommended determination of the related forecast issues, were received as late-filed Exhibit 13 on April 17, 1989. The matter stood submitted on that date. Comments on the ALJ's proposed decision were filed by SPPC and DRA. Since the changes requested by SPPC can be appropriately accomplished by Advice Letter filings, no changes have been made in the proposed decision.

III. Forecast Issues

A. California Sales

In its original forecast report, SPPC projected total California sales of 412.5 gWh. DRA's forecast, derived from econometric models for residential, A-1, A-2, and A-3 service classes, yields a sales estimate of 421.7 gWh, which is 2.2% greater than the company's estimate. SPPC indicates that while it disagrees with the methodology employed by DRA to forecast sales, it accepts as reasonable for the purposes of this proceeding the end result of DRA's estimates for all but the A-3 category of sales. SPPC's revised sales forecast is 418.3 gWh.

Disagreement on the level of A-3 sales results from different estimates of when a biomass QF (designated Project N by the parties), currently under development at a Sierra Pacific Industries lumber mill, will become operational. (Sierra Pacific Industries is not related to SPPC). SPPC believes the QF will commence commercial operations on October 1, 1989. DRA believes the project will be delayed until January 1990, after the forecast period. The parties do agree that sales to Sierra Pacific Industries will be lost as of the commercial operation date (COD) of the facility, and that the sales forecast should be consistent with the adopted COD.

As discussed below, we find that the best COD estimate for Project N is December 1, 1989. Since this date is later than the COD estimated by SPPC and before that estimated by DRA, the adopted sales forecast, 420.56 gWh, falls between the parties' forecasts.

B. Purchased Power: Qualifying Facilities

In its resource mix forecast, SPPC estimates that total system power purchased from QFs will be 392.4 gWh, or 36.2% more than DRA's forecast of 288.1 gWh. The difference is attributable to DRA's modeling assumption that the CODs of four new QF projects will be one to three months later than the dates used by SPPC, and to DRA's use of lower capacity factors for the majority of QFs.

1. Commercial Operation Dates

For the four projects scheduled to start operations during the forecast period, the CODs projected by the parties are as follows:

Project	SPPC	DRA
K-Far West II	12/31/88	2/89
L-AMOR IV	4/01/89	6/89
M-Truckee-Carson Irrigation Dist.	7/01/89	10/89
N-Sierra Pacific Industries	10/01/89	1/90

Based on its experience with hundreds of contracts in California, DRA has found that QF projects consistently experience delays. It therefore believes that a forecast which includes new QFs should include the likelihood that there will be such delays. DRA also notes that while SPPC has focused on project start-up dates, i.e., when a project starts generating some power into the system, the significant dates for forecast purposes are the CODs. The contract rates become effective as of the COD. Prior to that time, QFs are paid the lower as-available price.

DRA believes the tendency for utilities, including SPPC, to be overly optimistic regarding QF project schedules is illustrated by a review of forecasted and actual operation dates of seven QF projects included in SPPC's 1987 ECAC filing. Of those seven projects, only one met its projected operation date. Two were cancelled, and the remaining four were delayed. DRA concludes that despite SPPC's good faith efforts to meet its projected dates, it is realistic to factor in some delay.

SPPC asserts that each of the four projects now under development has progressed to the point that such delays are no longer likely. Additionally, SPPC notes that there are economic incentives for the QF developers to meet their completion schedules. For example, contracts with each of the developers of these projects contain termination clauses providing construction milestones and dates for commercial operation to begin. If commercial operations are not established by the contracted date, the project will no longer qualify for higher long-term QF rates. SPPC indicates that it intends to assert its rights to terminate these contracts if milestone dates and CODs are not met. To illustrate this intent, the company notes that it has previously terminated one agreement and is currently in litigation with four other QF projects because milestone dates were not met.

We agree with DRA that for forecasting purposes it is appropriate to use CODs, not initial start-up dates. Since higher long-term rates apply once commercial operations are established, CODs have more impact on revenue requirements than initial start-up dates. We also agree that as a general rule, based on the experience with California QFs, it is reasonable to anticipate some delay for most projects. On the other hand, for projects which are already well under way, some weight should be accorded to the judgment of QF developers and utility officials when that judgment reflects specific, updated information about a project's status. It does not necessarily follow that because a project has experienced delays in its early stages, additional delays will occur as it approaches completion. It stands to reason that the closer a project is to completion, the more precise and reliable estimates of a completion date can be.

While we are mindful of DRA's experience with waiver of termination clauses in California, we believe that some weight should also be given to the economic incentives created by contract termination dates which give the utility the right to offer lower non-firm rates. While it is true that termination dates do not provide assurance that a project deadline will be met, and it is possible a utility will tolerate minor delays if a project is included in a utility's resource plan, the dates are not unimportant to QF developers. If it is both technically feasible and economically advantageous for a developer to complete a project on schedule, a presumption is created in favor of an on-time forecast.

We are persuaded that the QF developers and financiers have significant economic incentives to complete the projects on or before the termination dates. This must be balanced by an extensive history showing that project delays nevertheless can and do occur. With this background, we address the COD of each project separately, since we do not uniformly adopt either SPPC's or DRA's forecast dates, but instead reach different results depending on the circumstances involved.

a. Project K

SPPC's projected COD of December 31, 1988 and DRA's projection of February 1989 are both well in advance of the termination date of March 31, 1989. Project K went on line at the end of October 1988, and the contract provides that a lower rate will be paid if commercial operations begin after December 31, 1988.

DRA's witness personally inspected the project site and also interviewed project representatives by telephone. He determined that completion of testing was not anticipated until the end of January 1989. Since the record shows that extensive testing is required before firm commercial operations can be established, and testing was not due to be completed until late January, we find DRA's projected date of February 1, 1989 to be reasonable.

b. Project L

In the original forecast report, SPPC projected a start-up date of April 1989. Based on updated information about the project status, it revised the estimated start-up date to January 1989. DRA assumes this project will be delayed two months from the the April date originally projected by SPPC.

SPPC explains the revision by noting that it took a conservative approach in its original projection. When it made the updated estimate, SPPC found that it had progressed further in the development of transmission facilities needed for interconnection than it had originally projected would be the case. Also, the developer stood to enjoy a $3 million energy tax credit if it could spin units by December 31, 1988. As of mid-December 1988 the developer planned to spin eight of the twelve units by December 31 in order to receive the tax credit.

We believe that the developer was faced with a significant incentive to initiate some operations by December 31, 1988, and that it was feasible to do so. We are also satisfied with the company's explanation for the revised start-up projection of January 1, 1989. We note that SPPC's projected COD of April 1, 1989 is three months after its projected start-up date, whereas DRA assumed a two-month interval from start-up to the COD. SPPC has in effect assumed a more conservative "cushion" for delays after initial start-up. We find that SPPC's projected COD of April 1, 1989 is reasonable.

c. Project M

DRA assumes that the COD for this project will be three months after the July start-up date originally projected by SPPC.

Based on the execution of a special facilities agreement between SPPC and the developer (the Truckee-Carson Irrigation District) after the original projection was made, SPPC revised the estimated start-up date from July to June, 1989. It now projects a COD of July 1, 1989 for this hydroelectric project. The contract's termination date is July 15, 1989.

SPPC determined from the developer's project engineer that it intends to spin the units in May. The District has an additional incentive to complete the project on schedule because the facility's operations are effectively limited to the irrigation season.

In view of indications that the project is proceeding on schedule, and the incentives created by the termination date and the potential revenue loss if the facility is not operated commercially during the irrigation season, we accept SPPC's projected COD of July 1, 1989 as reasonable.

d. Project N

This project has already experienced substantial delay. In SPPC's 1987 ECAC proceeding the forecasted operation date was December 1, 1988. Based on site inspections and discussions with the developer's project engineer and SPPC's project leader for construction of the utility's interconnection facilities, SPPC's witness believes that the project will be on-line between August and September of 1989. He projects a COD of October 1, 1989.

DRA bases its COD estimate of January 1990 in part on the fact that biomass projects such as Project N require longer construction times and longer testing periods than, for example, cogeneration projects. DRA determined from its discussions with a representative of the developer that commercial operations are not anticipated until November 1989.

In view of DRA's experience with delays involving biomass projects, and the developer's projection of a COD that is one month later than SPPC's, we find that the company's COD estimate to be somewhat optimistic. Assuming that initial operations do begin in September, it is reasonable to anticipate a longer delay (beyond October 1) for testing before commercial operations begin. At the same time, however, there are indications that the project is now progressing to completion, and that the previous delays may no longer be factors in the current projections. Staff's witness acknowledged that in evaluating the earlier delays, he was not aware of their being caused by regulatory delays for contract approval. We find it is feasible for the project to commence commercial operations by the contract's termination date of December 1, 1989, and therefore adopt that date for forecast purposes.

2. Capacity Factors

DRA's estimated capacity factors for fourteen QF projects are lower than the utility's estimates in ten cases, the same in three cases, and higher in one case. Because most of its capacity factors are lower, DRA's forecast of purchased power from QFs is 43,754 MWh less than SPPC's.

Ten of the QFs are geothermal projects. SPPC initially used a 90% capacity factor for the majority of these, based on data for only two such QFs recorded over short periods of three to six months. In response to DRA concerns over the reliability of this limited amount of data, the company revised its capacity factor estimates for one hydroelectric and nine geothermal projects. SPPC indicates that the revised estimates are based on information derived from project developers, and upon actual operating data for the QFs which are on-line.

Where data from actual operations was available, DRA relied on recorded capacity factors for its projections. For projects without recorded data, DRA generally used an 80% capacity factor as representative of projects with recorded data. When a new project was the same design as an existing project, DRA applied the capacity factor for the existing project. DRA asserts that combustion turbine on line. A unit which contributes to spinning reserve must be available to deliver load immediately. DRA believes that because of their high heat rates and low efficiencies, it is very unlikely that these units would be on-line and able to contribute to spinning reserve. We are persuaded by DRA's analysis, and have included this convention in the adopted model run.

SPPC modeled conventional oil and gas units as burning gas exclusively due to forecast gas prices being below forecast oil prices. However, to reflect gas curtailment in December of the forecast period, the company implicitly modeled residual oil burns in that month by replacing the price of gas with the price of oil. DRA explicitly modeled the units to burn residual oil during December by inputing both gas and oil data sets and allowing the model to dispatch only gas burns for December and only oil burns from January through November. This allowed the model to reflect the lower heat rates for oil, which in turn results in a more accurate commitment and dispatch of these units in the correct economic sequence, and correct calculation of burns and fuel consumption.

SPPC accepts DRA's modeling convention that these units be explicitly modeled to burn oil in December, but disagrees with DRA's estimate that the efficiency gain for oil burns is 5.6%. The company used a 4.0% gain based on its own experience with its facilities. DRA's estimate was taken from information provided by PG&E, and DRA's witness concedes that 5.6% may not be the correct number for SPPC. DRA subsequently accepted SPPC's 4.0% estimate, which we will adopt as more representative of the company's operations than the PG&E-based estimate.

E. <u>Diesel Oil Inventory</u>

The parties have a minor difference regarding fuel oil inventory carrying cost which stems from disagreement on the required diesel oil inventory. SPPC burns diesel oil in its combustion turbines and diesel generators for emergency purposes, and for testing the turbines. It also uses diesel for start-up purposes at the North Valmy Power Plant (Valmy). Because diesel oil is an expensive resource, its use by SPPC is relatively minor.

SPPC's inventory forecast of 6,079 barrels is based on winter stocking of diesel fuel for system reliability purposes. The utility states that this estimate reflects a policy of topping off diesel tanks in remote areas at the beginning of each winter snow season.

DRA recommends an inventory of 4,477 barrels. Slightly more than half of this amount, or 2,257 barrels, is for the Valmy plant. DRA's inventory recommendation for combustion turbine units is based on a method which takes into consideration actual diesel usage from July, 1986 to June, 1988, and which provides a margin of safety for emergencies by adding the "average worst case" monthly usage over the last two years plus the "absolute worst case" usage. DRA states that this effectively provides for double consideration of emergency needs. For the Portola and Kings Beach generators, which sometimes become relatively inaccessible in winter months, DRA incorporated SPPC's specifications for the minimum number of barrels. For the Valmy plant, DRA assumed that diesel oil is an emergency fuel only to restart the plant after a forced outage. For scheduled outages such as boiler inspections, SPPC should be able to purchase diesel oil as needed beforehand. To provide for emergency requirements at the Valmy plant, DRA used a methodology similar to the one it used for combustion turbines.

Because of the double consideration of emergency usage requirements, we find that DRA's recommended diesel inventory level should serve to maintain system reliability. Since DRA's recommended inventory level is an annual average, SPPC is not precluded from seasonal stocking of additional inventory in less accessible locations.

IV. Reasonableness Issues

DRA accepted most aspects of SPPC's reasonableness of operations report for the record period July 1, 1987 to June 30, 1988. The only areas in which DRA made recommendations are purchased power, hydroelectric generation, and power plant performance. SPPC contests two of DRA's recommended disallowances:

	System	California Jurisdictional
Purchased Power: Emergency Purchase From PG&E Due to Transmission Outage	$ 47,150	$ 5,172
Power Plant Performance: Valmy Heat Rates	647,770	56,226

DRA also recommends that SPPC be required to submit reports addressing certain areas of concern, as discussed below.

A. Transmission Outages

1. Purchased Power Disallowance

In response to a DRA data request, SPPC identified "significant transmission outages" which occurred during the record period. SPPC defined these outages as system disturbances that are required to be reported to the Western System Coordinating Council, the Department of Energy, the California Public Utilities Commission, or the Public Service Commission of Nevada, or that interrupt service to a large number of customers.

DRA believes that a particularly serious outage on the morning of March 9, 1988, together with five other significant outages (including one later in the day on March 9), demonstrates a pattern of inadequate operator training, poor preparation for transmission trips, poor or faulty equipment, and poor timing of maintenance procedures. DRA asserts that while there does not seem to be a situation of extreme neglect or carelessness, SPPC should work to improve its performance in preventing outages. Acknowledging that the loss of load and loss of customer confidence due to the outages may be penalty enough, DRA also recommends disallowance of certain related expenses in the hope that this will provide additional incentives for SPPC to implement corrective actions. The amount of the recommended disallowance, $5,172, represents the California jurisdictional share of a $47,150 emergency power purchase from PG&E during the morning outage of March 9, 1988. DRA recommends the disallowance as a penalty to signal the Commission's concern with the operational problems which led to the outages.

In arriving at its determination that the company has not adequately trained system operators, DRA appears to have placed considerable reliance on its finding that operator error caused or aggravated two of the six significant outages. During the March 9 morning outage (which was triggered by an error on the Idaho Power Company system), an SPPC operator at the Valmy plant chose to use an automatic operating mode while restoring load. Valmy Unit 2 then tripped, delaying system restoration. Although there were certain advantages in remaining in the automatic mode, the normal procedure for returning load is to convert to a manual mode. The other incident relied on by DRA occurred on September 20, 1987, affecting the Tonopah area. According to SPPC's energy control manager, this outage resulted when a system operator opened a wrong switch as a result of a data entry error.

DRA's determination that there was poor timing of maintenance procedures is also based on the March 9 morning outage. At the time of the outage, a microwave communications link was out of service for scheduled maintenance. Until the link was restored at 10:17 a.m., system operators were forced to rely on information relayed from power plants for indications of system status along the Utah tieline. DRA maintains that the microwave maintenance should not have been scheduled during the morning peak. SPPC asserts there was no reason to believe there would be any problems on that date. There were no seasonal load or weather conditions indicating the work should not proceed. Although it acknowledges that such work should not be scheduled during summer or winter peak loads, SPPC notes that performing some procedures at night may cost extra because overtime must be paid, and may involve safety considerations. In scheduling maintenance procedures, the utility believes that it must consider safety and economics as well as system reliability.

We have reviewed DRA's showing on these transmission outages as well as SPPC's response. We hesitate to conclude that operator actions in the March 9 and September 20 incidents demonstrate a pervasive pattern of error which will only be corrected with our intervention in the form of a disallowance penalty. Nor do we conclude that the company acted unreasonably in scheduling the microwave communication system maintenance on March 9. While the conditions and the events leading to the outages perhaps warrant some concern, they do not warrant the recommended disallowance. The record shows that SPPC also considers these outages to be matters of significant concern. We believe the utility recognizes an ongoing need to improve system reliability, and that it has taken reasonable steps to achieve such improvements in areas such as training and investigation of the outages.

2. <u>Follow-Up Reporting</u>

In addition to the purchased power disallowance for these outages, DRA recommends that SPPC be required to report on the following for the next ECAC proceeding:

> 1. Corrective steps taken to increase and improve plant operator and system dispatch operator training to minimize similar failures.
>
> 2. Corrective steps taken to record system malfunctions (e.g., repairs to strip recorders, coordinating oscillograph timing to a known standard, and installing a high resolution digital frequency recorder).

3. Corrective actions taken to properly set switches and circuit breakers.

4. The results of studies to determine whether it is reasonable to provide detection of zero voltage 3 phase faults on the critical transmission paths.

5. The results of studies to determine the costs and benefits of providing backup communication systems along critical paths.

DRA indicates that its recommended reporting merely reiterates the steps SPPC already intends to take, while adding the requirement that the Commission be informed.

SPPC notes that it has already furnished detailed "System Disturbance Reports" for the record in this proceeding in response to DRA's data request. The utility objects to further reporting which merely reiterates the information already furnished, but agrees to provide a status report in connection with the next ECAC filing.

We will direct SPPC to include with its next ECAC filing an updated status report which describes any follow-up studies it has made or actions it has taken at the time of the filing. The report should address not only those studies and actions specifically related to the six outages, but also those which are related to the five areas of concern enumerated by DRA and listed above.

B. Hydroelectric Generation-Washoe Facilities

SPPC operates eleven hydroelectric generating units at six plants. In recent years these plants have provided from 1.5% to 2.0% of the total system energy requirements. With the exception of the Washoe Plant, DRA found SPPC'S operation of the hydroelectric plants to be reasonable for the review period. DRA is concerned that the company's Washoe facility has been out of operation since October 1984. Since that time, the utility has been evaluating the economic feasibility of rehabilitating the Washoe Plant.

DRA is particularly concerned with the delay of resolution of this issue. In prior ECAC proceedings it has raised the concern, which we have indicated we share, that SPPC might try to abandon the Washoe plant without adequate justification (Decision (D.) 87-06-009). According to DRA's estimates, the utility loses an average of 10,200 MWh per year while the plant is out of service, and the annual replacement cost of that lost power (at the 1988/89 forecasted cost of fossil fuel) is $228,600. If the plant is not returned to service, DRA indicates that it will recommend disallowance of the then-current replacement cost of the lost power in a future reasonableness review, unless the company makes a showing to the Commission that it is reasonable either to abandon the plant or to delay its rehabilitation.

By D.88-04-016 in SPPC's most recent ECAC proceeding, we approved a stipulation between SPPC and DRA which required the company to file quarterly reports on the status of reconstruction of the facilities. At the time of the hearings, SPPC had just recently submitted the first such report. DRA now requests that SPPC be ordered to submit a more comprehensive and more current report by June 30, 1989 on the economic, financial, and physical feasibility of rebuilding the Washoe facilities. The requested report would include a comparison of the costs of rehabilitation with the costs of replacement power, enabling DRA to independently judge the reasonableness of rebuilding the facility. DRA indicates the report should be similar to a June 1985 SPPC report entitled "Truckee River Hydroelectric Facility Evaluation and Recommendations," and that it could be filed as one of the required quarterly reports. SPPC agrees to provide such a report, but indicates that it may not be able to meet the June 30 deadline.

We share DRA's concern with delays in the resolution of this issue. It has been nearly five years since the Washoe plant was taken out of service, and nearly two years since we addressed the issue in D.87-06-009. In response to the company's assertion that it might not be able to meet the June 30 reporting date, we will extend the date to July 31, 1989. This should allow DRA adequate time for review and evaluation in preparation for SPPC's 1989 ECAC proceeding.[1] We place SPPC on notice that we expect it to meet the July 31 deadline, and that failure to do so could possibly result in a future disallowance as recommended by DRA. If there are circumstances which prevent SPPC from making a conclusive feasibility determination by that date, those circumstances should be described in the report.

C. Power Plant Performance

1. Heat Rate Adjustments for Large Oil & Gas Units

In SPPC's last ECAC proceeding we adopted a thermal performance standard to be used in determining the reasonableness of operations of SPPC's large oil and gas units (D.88-04-016). We determined that if actual record period heat rates fall within 3% of the standard, a rebuttable presumption of reasonableness of operation of these plants is created.

The adopted performance standard methodology included procedures for adjusting the standard to account for circulating water temperature, fuel type, oil tank farm and building heating requirements, and turbine valve loop effects. DRA recommends that an additional heat rate adjustment be made to account for the gain in efficiency expected whenever the circulating water temperature in the condenser cools to a certain point under the design value.

1 By D.89-01-040 dated January 27, 1989, we adopted revised time schedules for processing general rate cases and energy offset proceedings. The schedule established for SPPC's reasonableness review proceedings provides that the DRA report will be mailed in November.

To accomplish this, DRA specifically recommends that SPPC be ordered to make a study to determine the effects of cold temperatures on the condensers, the overall gain in plant efficiency, and an appropriate adjustment to the heat rate standard. DRA requests that the study be submitted within 90 days of the effective date of this decision, and that SPPC be directed to make the appropriate adjustment in its next reasonableness report.

SPPC agrees to make such a study. We adopt DRA's recommendation, except that instead of requiring the report to be submitted within 90 days after this decision, we will require that it be made a part of the next reasonableness filing.

2. North Valmy Power Plant Disallowance

SPPC uses the coal-fired North Valmy Power Plant as a base load resource. During the record period, this facility produced 74% of SPPC's internal generation. The recorded average heat rates for Units 1 and 2 were 10,299 Btu/kWh and 10,522 Btu/kWh, respectively. By comparison, the design values were 9,791 Btu/kWh and 9,951 Btu/kWh, respectively. According to SPPC, "[t]his indicates that both units operated well during the record period."

DRA evaluated the thermal performance of the Valmy plant by comparing these deviations from design heat rates with historical average deviations. For Unit 1, the record period deviation was 5.19%, while the deviations in the three prior record periods were 3.02%, 3.47% and 2.33%, or an average of 2.94%. For Unit 2, the record period deviation was 5.74%, while the deviations of the two prior record periods were 6.70% and 1.25%, or an average of 3.98%. (Since Unit 2 is relatively new, only two prior record periods were used for the comparison.)

DRA is especially concerned with the thermal efficiency of the Valmy plant because of its importance as a base load resource. It asserts that there was "an unacceptable increase" in the heat rates of both units in the record period. According to DRA:

> "Had the units performed closer to historical average deviations, the total system savings to ratepayers would have been $647,770. The estimated savings for the California ratepayers would have totaled $56,226. Therefore, DRA finds that the thermal performance of the North Valmy units was not reasonable for the record period and requests that SPPCo be disallowed $56,226."

Although the parties have reached substantial agreement on a thermal performance standard for the large oil and gas plants over the last several ECAC proceedings, they have not reached a similar agreement for the coal plant. SPPC believes that the record period deviations of 5.19% and 5.74% indicate reasonable operations, and a company engineer who is responsible for efficiency monitoring and performance testing is of the opinion that deviations of as much as 7% to 8% are reasonable. For internal purposes, SPPC uses a guideline providing for deviations of up to 700 to 800 Btu/kWh. DRA on the other hand believes that a standard which is based on the historical performance of each unit is appropriate. This standard currently allows a 2.94% deviation from the design heat rate for Unit 1, and a 3.98% deviation for Unit 2.

We find the increases in the record period heat rates to be somewhat troubling, but there is nothing in this record (other than the historical performance record) demonstrating that the coal plant heat rate deviations in the 5% to 6% range were unreasonable. The performance record used by DRA reflects just three data points for Unit 1 and two data points for Unit 2, and alone is not sufficient to justify such a conclusion. In the case of Unit 2, one of the two historical record year deviations was 6.7% for 1985-86, or approximately 1% greater than the value which DRA considers unreasonable for this proceeding. We did not find that amount of deviation to be unreasonable in the reasonableness review for that year. We note that the DRA approach will presumably allow a greater deviation in the next reasonableness review because the historical average will then reflect this year's much higher values.

The higher heat rate in the 1987-88 period appears to be explained at least in part by the burning of coal with a lower heat content, unavoidable equipment failures, and high load factors. SPPC estimates that the burning of Black Butte coal during the record period resulted in a 2% to 3% deterioration in the heat rates. Also, performance testing to identify causes of reduced efficiency better was delayed by SPPC because it could have adversely affected plant operations.

While we find fault with the historically based performance standard used by DRA, we are not yet prepared to accept SPPC's contention that actual heat rates within 8% of design values are reasonable (nor are we prepared to say that for the future deviations in the 5% to 6% range will necessarily be found reasonable). We have previously adopted a performance standard, which is subject to various adjustments and periodic refinement, for evaluating the reasonableness of gas and oil plant operations. Because the Valmy coal plant represents a significant component of SPPC's system, a valid thermal performance standard for that facility is at least as important as it is for oil and gas plants. As they have already done in developing a workable oil and gas plant standard, the parties should pursue a cooperative effort to develop a comparable standard for the Valmy plant.

V. Audit Report

DRA's Energy Auditing Branch conducted a review to determine the reasonableness of recorded data underlying the ECAC and ERAM balancing accounts as well as related data contained in SPPC's applications. The parties generally concur on the issues addressed in DRA's audit report (as revised during the hearings), including all issues relating to the ERAM application (A.88-09-028). The following recommendations were proposed by DRA and agreed to by SPPC:

1. That removal of $1,171 plus related interest from the ECAC balancing account be reflected in the ECACBF rates. For this proceeding and in the future, fuel oil inventory carrying costs will be recovered only through the ECAC rates rather than both the ECAC and AER rates on a 78%/22% basis.

2. That a similar removal of $325 plus related interest be reflected in the ECACBF rates. This adjustment reflects the use of the lower of adopted or average fuel oil inventory price, instead of just the average, to compute inventory carrying costs.

3. That SPPC be directed to file a revised preliminary statement to reflect the fixed fuel oil inventory carrying cost methodology set forth by DRA in this proceeding.

4. That $874 be disallowed from the ECAC balancing account due to an expected refund from SPPC's fuel oil suppliers.

5. That the current Valmy plant surcharge be discontinued upon amortization of the related balancing account.

6. That the ERAM rate decrease proposed by SPPC be increased by $7,724 to $535,724. This revision reflects an adjustment to base rates which incorporate authorized base revenue changes and DRA's current sales forecast data.

The rate changes authorized in this decision incorporate Recommendations 1, 2, 4, and 6, with an adjustment to the ERAM decrease to reflect the sales level adopted in this decision. We will direct SPPC to file the revised preliminary statement referred to in Recommendation 3. By Recommendation 5, DRA simply intends to place the company on notice that the Valmy surcharge should be discontinued when appropriate. SPPC agrees to do so. The recommendation requires no action in this proceeding.

VI. Rate Changes

Summaries of the adopted ECAC, AER, and ERAM rate calculations are included in Appendix A. SPPC notes in the application that mid-month rate changes are confusing and administratively inconvenient. We will therefore provide that the adopted rate changes may be implemented on the first of the month. Since SPPC originally requested that the implementation date be set for April 1, we will make the order effective on the date it is signed.

The issues of revenue allocation and rate design were uncontested. We will adopt the System Average Percentage Change methodology used in Sierra Pacific's last general rate case for revenue allocation to customer class and rate design for each tariff schedule. In accordance with D.88-10-062 which realigned residential rates to comply with SB 987, we will maintain residential baseline rates at 87% of system average rate.

Findings of Fact

1. Sales to Sierra Pacific Industries will be lost as of the commercial operation date (COD) of a biomass QF (Project N) under development at that company's lumber mill.

2. Based on a December 1, 1989 COD for Project N, the adopted sales forecast is 420.56 gWh.

3. Of the seven QF projects included in SPPC's 1987 ECAC filing, only one met its projected operation date. Two were cancelled, and the remaining four were delayed.

11. Project N has already experienced substantial delay, and commercial operations are not anticipated by the developer until November 1989.

12. SPPC's COD estimate for Project N is somewhat too optimistic, but because of indications that the project is now progressing to completion, and that the previous delays may no longer be factors in the current projections, it appears to be feasible for the project to commence commercial operations by the contract's termination date of December 1, 1989.

13. DRA's estimated capacity factors for fourteen QF projects are based on recorded data.

14. The agreed-on fuel oil prices are $16.05 per barrel for residual oil and $26.90 per barrel for diesel oil.

15. SPPC agrees to a forecasted price of $17.69 per MWh for Northwest Economy power.

16. The parties agree on the use of the PROMOD production simulation model.

17. Combustion turbines at Tracy and Winnemucca have very high heat rates of 18,000 and 17,000 Btu/kWh, respectively, and it takes approximately ten minutes to bring them on line.

18. A unit which contributes to spinning reserve must be available to deliver load immediately.

19. It is very unlikely that the Tracy and Winnemucca units would be able to contribute to spinning reserve.

20. SPPC's estimated 4.0% efficiency gain for oil burns compared to gas burns is based on its own experience with its facilities.

21. SPPC burns diesel oil in its combustion turbines and diesel generators for emergency purposes, and for testing the turbines. It also uses diesel for start-up purposes at the Valmy power plant.

22. SPPC's inventory forecast of 6,079 barrels is based on winter stocking of diesel fuel for system reliability purposes, and

reflects a policy of topping off diesel tanks in remote areas at the beginning of each winter snow season.

23. DRA's recommended inventory of 4,477 barrels takes into consideration actual diesel usage from July 1986 to June 1988, and provides a margin of safety for emergencies which should serve to maintain system reliability.

24. SPPC is not precluded by the DRA inventory methodology from seasonal stocking of additional diesel inventory in less accessible locations.

25. DRA recommends a disallowance of $5,172 for an emergency power purchase from PG&E during the morning outage of March 9, 1988.

26. During the March 9 morning outage, an SPPC operator at the Valmy plant chose to use an automatic operating mode while restoring load. Valmy Unit 2 then tripped, delaying system restoration. The normal procedure for restoring load is to convert to a manual mode.

27. A September 20, 1987 outage affecting the Tonopah area resulted when a system operator opened a wrong switch as a result of a data entry error.

28. At the time of the March 9 morning outage, a microwave communications link was out of service for scheduled maintenance, forcing system operators to rely on information relayed from power plants for indications of system status along the Utah tieline.

29. There were no seasonal load or weather conditions indicating the communications maintenance work should not proceed.

30. In scheduling maintenance procedures, the utility must consider safety and economics as well as system reliability.

31. The conditions and the events leading to the transmission outages do not warrant the recommended disallowance.

32. With respect to the transmission outages, SPPC agrees to provide a status report which describes any follow-up studies it has made or actions it has taken with its next ECAC filing.

33. SPPC has been evaluating the economic feasibility of rehabilitating the Washoe Plant since it went out of service in October 1984.

34. The utility loses an average of 10,200 MWh per year while the Washoe Plant is out of service, and the annual replacement cost of that lost power (at the 1988/89 forecasted cost of fossil fuel) is $228,600.

35. DRA requests that SPPC be ordered to submit a comprehensive and current report, by June 30, 1989, on the economic, financial, and physical feasibility of rebuilding the Washoe facilities.

36. DRA recommends that SPPC be ordered to make a study to determine the effects of cold temperatures on the condensers, the overall gain in plant efficiency, and an appropriate adjustment to the heat rate standard for the large oil and gas plants.

37. DRA recommends a disallowance of $56,226 due to high heat rates at the Valmy plant.

38. The average heat rates for Valmy Units 1 and 2 during the record period were 10,299 Btu/kWh and 10,522 Btu/kWh, respectively, or 5.19% and 5.74% greater than the respective design values of 9,791 Btu/kWh and 9,951 Btu/kWh.

39. For Unit 1, the deviations in the three prior record periods were 3.02%, 3.47% and 2.33%, or an average of 2.94%. For Unit 2, the deviations of the two prior record periods were 6.70% and 1.25%, or an average of 3.98%.

40. SPPC believes that deviations from design heat rates of as much as 7% to 8% are reasonable.

41. DRA believes that a standard which is based on the historical performance of each unit is appropriate. This standard currently allows a 2.94% deviation from the design heat rate for Unit 1, and a 3.98% deviation for Unit 2.

42. The performance record used by DRA reflects three data points for Unit 1 and two data points for Unit 2. In the case of

Unit 2, one of the two historical record year deviations was 6.7% for 1985-86, or approximately 1% greater than the value which DRA considers unreasonable for this proceeding.

43. The historical standard will allow greater deviations in the next reasonableness review because the historical average will then reflect the much higher values experienced in the 1987-88 period.

44. The higher heat rate in the 1987-88 period appears to be explained at least in part by the burning of coal with a lower heat content, unavoidable equipment failures, and high load factors.

45. Burning of Black Butte coal during the record period resulted in an estimated 2% to 3% deterioration in the heat rates.

46. Performance testing to better identify causes of reduced efficiency at the Valmy plant was delayed by SPPC because it could have adversely affected plant operations.

47. Coal plant heat rate deviations in the 5% to 6% range have not been shown to be unreasonable.

48. SPPC's fuel and purchased power transactions and related operations for the review period July 1, 1987 through June 30, 1988 were reasonable.

49. The parties have reached agreement on the issues addressed in DRA's audit report, including all issues relating to the ERAM application (A.88-09-028). The rate changes authorized in this decision incorporate these agreements.

50. The agreed-upon ERAM rate decrease of $535,724 reflects DRA's sales forecast data, and should be adjusted to reflect the sales level adopted in this decision.

51. Summaries of the revenue requirement calculations and the ECAC, AER, and ERAM rate calculations are included in Appendix A.

52. The ECAC and AER rate increases shown in Appendix A are justified.

53. Mid-month rate changes are confusing and administratively inconvenient.

54. SPPC's recommendation to use the System Average Percentage Change methodology for revenue allocation and rate design is undisputed.

55. The Commission determined that SPPC's residential baseline rate should be set at 87% of system average rate in D.88-10-062.

Conclusions of Law

1. Sales and resource forecasts reflecting the following QF commercial operating dates should be adopted:

Project	COD
K-Far West II	2/01/89
L-AMOR IV	4/01/89
M-Truckee-Carson Irrigation Dist.	7/01/89
N-Sierra Pacific Industries	12/01/89

2. DRA's estimated capacity factors for the fourteen QF projects in the resource forecast should be adopted.

3. Fuel oil prices and economy energy prices forecasted by DRA and accepted by SPPC should be adopted.

4. It is appropriate to use the PROMOD production simulation model to forecast resource mix and energy costs without the contribution of combustion turbines to spinning reserve and with a 4.0% efficiency gain for oil burns.

5. DRA's recommended diesel oil inventory level of 4,477 barrels should be adopted.

6. DRA's recommended disallowances for transmission outages and for heat rate increases at the Valmy coal plant should not be adopted.

7. SPPC should be authorized to file the ECAC and AER rate increases set forth in Appendix A.

8. SPPC should be authorized to file the ERAM rate decreases set forth in Appendix A.

9. SPPC should be ordered to submit reports addressing the status of efforts to remedy transmission outages, the feasibility

of rebuilding the Washoe plant, and adjustments to oil and gas plant heat rate standards to consider potential efficiency gains due to cold ambient temperatures.

10. SPPC should be ordered to file a revised preliminary statement to reflect the fixed fuel oil inventory carrying cost methodology set forth by DRA in this proceeding.

11. The applications should be granted to the extent provided by the following order.

12. Because there is an immediate need for rate relief, the order should be made effective today.

O R D E R

IT IS ORDERED that:

1. Sierra Pacific Power Company (SPPC) is authorized and directed to file, in compliance with General Order (GO) 96-A, on or after the effective date of this order, and at least 5 days prior to their effective date, revised tariff schedules incorporating the ECAC and AER rate increases set forth in Appendix A.

2. SPPC is authorized and directed to file, in compliance with GO 96-A, on or after the effective date of this order, and at least 5 days prior to their effective date, revised tariff schedules incorporating the ERAM rate decreases set forth in Appendix A.

3. SPPC shall prepare a report which addresses the status of efforts to remedy transmission outages problems, including any follow-up studies it has made or actions it has taken as of the time of the filing. The report shall address any actions and studies undertaken which are specifically related to the six significant outages reported in the 1987-88 record period as well those which are related to the five areas of concern enumerated by DRA and listed in the opinion. The report shall be submitted as part of the next ECAC filing.

4. By July 31, 1989 SPPC shall submit a report which addresses the economic, financial, and physical feasibility of rebuilding the Washoe hydroelectric plant. The report shall be submitted to the Director of the Commission Advisory and Compliance Division with a copy to DRA.

5. SPPC shall prepare a report which addresses studies to determine the effects of cold temperatures on the condensers, the overall gain in plant efficiency, and an appropriate adjustment to the heat rate standard. The report shall be submitted as part of the next ECAC filing.

This order is effective today.

Dated JUL 6 1989, at San Francisco, California.

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

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

Victor Weisser, Executive Director

SIERRA PACIFIC POWER COMPANY
Electric Department - Total Company
ADOPTED ENERGY COSTS
ECAC Forecast Period January 1, 1989 to December 31, 1989

Type of energy	Purchases/ Generation (Gwh)	%	Average cost (cents/Kwh)	Total costs (000's of $)	ECAC costs 1/ (000's of $)	AER costs 1/ (000's of $)	
Coal Plants - Valmy Unit #1 and #2	1,856.3	33.5%	2.02	$37,552.0	$29,290.6	$8,261.4	
Steam Plants	341.3	6.2%	2.92	9,989.0	7,791.4	2,197.6	
Hydroelectric Plants	59.7	1.1%	0.00	0.0	0.0	0.0	
Gas Standby Charge				144.0	112.3	31.7	
Other fuel costs				60.0	46.8	13.2	
Purchased Electric Energy							
Idaho Power Company	451.8	8.2%	1.18	5,352.0	4,174.6	1,177.4	
Utah Power & Light	622.0	11.2%	3.08	19,136.0	14,926.1	4,209.9	
Cogeneration & other QFs	331.8	6.0%	5.74	19,050.0	14,859.0	4,191.0	
Pacific Northwest	1,873.1	33.8%	2.44	45,701.0	35,646.8	10,054.2	
PG&E Standby Charges				180.0	140.4	39.6	
Oil Inventory Carrying Cost (100% ECAC)				257.1	257.1	0.0	3/
TOTALS	5,536.5	100.0%	2.48	$137,421.1	$107,245.0	$30,176.1	
Allocation to California Jurisdiction	469.4			$11,652.1	$9,093.4	$2,558.7	2/

1/ ECAC costs are 78% of Total costs and AER costs are 22% of Total costs, unless otherwise specified.

2/ Jurisdictionalized at California sales of 420.56 Gwh which is 8.48% of 4959.96 Gwh System sales.

3/ 188,076 barrels of Residual Oil at $16.05 per barrel and 4,477 barrels of Diesel Oil at $26.90 per barrel at a Bankers Acceptance Rate of 8.19% p.a.

SIERRA PACIFIC POWER COMPANY
Electric Department - California Jurisdiction
ADOPTED CHANGES IN ECAC, AER AND ERAM REVENUES
ECAC Forecast Period January 1, 1989 to December 31, 1989

	Revenues (000's of $)	Uniform rate at forecasted sales 1/ (cents/Kwh)
ECAC REVENUES		
Adopted ECAC costs	$9,093.4	2.162
Add: Recorded ECAC undercollection as of 5/1/89	1,213.0	
ECAC costs amortized over the forecast period	10,306.4	2.451
Uncollectibles & Franchise Fee Factor 2/ 3/	1.014302	
Adopted ECAC revenue requirements for the forecast period	10,453.8	2.486
Less: Present rate ECAC revenues at rates effective on 5/1/88	7,771.0	1.848
Change in ECAC revenues	$2,682.8	0.638
AER REVENUES		
Adopted AER costs	$2,558.7	0.608
Uncollectibles & Franchise Fee Factor	1.014302	
Adopted AER rev. reqr. for the forecast period	2,595.3	0.617
Less: Present rate AER revenues at rates effective on 5/1/88	2,561.2	0.609
Change in AER revenues	$34.0	0.008
ERAM REVENUES		
Authorized Base Revenue Amount effective 5/1/88	$23,822.0	5.664
Add: Recorded ERAM undercollection as of 5/1/89 (incl. FF&U)	306.3	0.073
Adopted ERAM revenue requirements for the forecast period	24,128.3	5.737
Less: Present rate rev. at existing base rates (excl. Valmy bal. rate)	23,550.0	5.600
Less: Present rate ERAM billing factor revenues	1,244.9	0.296
Change in ERAM revenues	(666.5)	(0.158)
TOTAL CHANGE IN ECAC, AER AND ERAM REVENUE	2,050.3	0.488

1/ Computed at adopted California jurisdiction sales of 420.56 Gwh.
2/. Adopted in the last GRC proceeding, A.85-05-017, D.86-02-030.
3/ Computed at FF&U of 1.41% which translates to a factor of 1.014302

SIERRA PACIFIC POWER COMPANY
Electric Department - California Jurisdiction
SUMMARY OF REVENUE CHANGES
Forecast Period January 1, 1989 to December 31, 1989

Revenue Element	Present rate revenues (000's of $)	Revenue change (000's of $)	Adopted Revenue Requirement (000's of $)	Average Rate 1/ (cents/Kwh)	
Previously authorized base rates	$23,550.0	$272.0	$23,822.0	5.664	2/
Electrical Revenue Adjustment Mechanism (ERAM) billing factor	1,244.9	(937.8)	307.0	0.073	2/ 3/
Subtotal ERAM revenues	24,794.9	(665.8)	24,129.0	5.737	
Valmy balancing account rate revenues	660.3	0.0	660.3	0.157	3/
Energy Cost Adjustment Clause (ECAC)					
Offset Rate	9,057.9	165.5	9,223.5	2.193	
Balancing Rate	(1,286.9)	2,519.2	1,232.2	0.293	3/
Subtotal ECAC rate revenues	7,771.0	2,684.7	10,455.7	2.486	
Annual Energy Rate (AER)	2,561.2	33.6	2,594.9	0.617	3/
Conservation Financing Adjustment	0.0	0.0	0.0	0.000	
TOTALS	35,787.3	2,052.5	37,839.8		
PERCENTAGE INCREASE		5.74%			

1/ Computed at adopted California juris. sales of 420.56 Gwh.

2/ In lieu of changing both base rates and the ERAM billing factor, Sierra Pacific Company may retain existing base rates and reduce the ERAM billing factor from 0.296 cents/Kwh to 0.138 cents/Kwh as the change in base rates is insignificant.

3/ Rounded off to the nearest 0.001 cents/Kwh.

(END OF APPENDIX A)

APPENDIX B

CACD/sl/1

SIERRA PACIFIC POWER COMPANY
Electric Department - California Jurisdiction
ADOPTED SYSTEM AVERAGE PERCENTAGE CHANGE REVENUE ALLOCATION
Forecast Period: January 1 to December 31, 1989 1/

CUSTOMER GROUP	SALES (GWH)	PRESENT RATE REV ($000's)	SAPC ($000's)	(%) INCR.	AVERAGE RATE ($/KWH)
RESIDENTIAL	221.66	19,264	20,376	5.77	0.092
COMMERCIAL					
A-1	86.80	7,710	8,155	5.77	0.094
A-2	45.11	3,722	3,937	5.77	0.087
A-3	65.45	4,775	5,051	5.77	0.077
AGRICULTURE	0.25	11	12	5.77	0.047
STREETLIGHTS	1.29	305	311	2.10	0.241
TOTAL	420.56	35,787	37,841	5.74	0.090

1/ Streetlighting facilities charges have been excluded from the revenue allocation process. However, that amount has been added to the figures in this table to obtain the correct percentage increases and average rate calculations.

(END APPENDIX B)

ALJ/MSW/tcg

Item 5
Agenda 7/6/89

Decision 89 07 018 JUL 6 1989 ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of Sierra Pacific Power Company for Authority to Implement its Energy Cost Adjustment Clause (ECAC).	Application 88-09-013 (Filed September 7, 1989)
In the Matter of the Application of Sierra Pacific Power Company for Authority to Implement its Electric Revenue Adjustment Mechanism (ERAM).	Application 88-09-028 (Filed September 13, 1989)

Mailed

JUL 7 1989

John Madariaga and James D. Salo, Attorneys at Law, for Sierra Pacific Power Company, applicant.
Catherine A. Johnson, Attorney at Law, and James M. Barnes, for the Division of Ratepayer Advocates.

O P I N I O N

I. Summary of Decision

This is the annual Energy Cost Adjustment Clause (ECAC) and Electric Revenue Adjustment Mechanism (ERAM) proceeding for Sierra Pacific Power Company (SPPC). We authorize a net revenue increase of $2,052,500 annually, or 5.7%, based on an ECAC increase of $2,684,700, an Annual Energy Rate (AER) increase of $33,600, and an ERAM decrease of $665,800.

SPPC's fuel and purchased power transactions and related operations for the review period July 1, 1987 through June 30, 1988 are found to be reasonable. The company is directed to submit, for consideration in future reasonableness reviews, reports on studies addressing transmission outages, the out-of-service Washoe hydroelectric plant, and adjustments to thermal efficiency standards for the large oil and gas plants.

II. Background

SPPC is a Nevada corporation engaged in public utility electric operations in California and Nevada. Its principal California operations are in the Lake Tahoe area. SPPC is also engaged in public utility gas and water operations in Nevada.

On September 7, 1988 SPPC filed Application (A.) 88-09-013, requesting authority to increase its Energy Cost Adjustment Clause Billing Factor (ECACBF) rates to offset an under-recovery of $2,604,000 which it estimates would occur if the current ECACBF rates were continued in effect for the twelve months commencing January 1, 1989. SPPC also proposes to increase its AER from $.00609 per kWh to $.00632 per kWh, or $94,000 annually. The combined effect of these proposed increases is an overall 7.52% revenue increase for all classes of service.

On September 23, 1988 SPPC filed A.88-09-028, requesting authority to reduce its ERAM rate from the present rate of $.00296 per kWh to $.00168 per kWh. The estimated annual effect of this proposed reduction is $528,000, or 1.47%. This application was consolidated with A.88-09-013.

The Division of Ratepayer Advocates (DRA) conducted an investigation which included an audit of SPPC's financial records for the record period July 1, 1987 through June 30, 1988, a review of the reasonableness of operations during the record period, and a forecast of operations for calendar year 1989. DRA accepted most aspects of SPPC's filings as reasonable, and SPPC accepted most of DRA's recommendations, with the result that very few issues are in controversy. The parties agree on audit and ERAM issues, and, for this proceeding, DRA accepts SPPC's proposed rate design and revenue allocation. Contested forecast issues involve projected operation dates and capacity factors of qualifying facilities (QF's), and required diesel oil inventory levels. Contested reasonableness issues involve DRA's recommended disallowances and reporting requirements related to record period transmission outages and power plant performance.

Public hearings were held in San Francisco on December 7, 8, and 9, 1988. At the conclusion of hearings the Administrative Law Judge (ALJ) determined that due to disagreement on forecast issues affecting resource mix and energy costs, it would be necessary for SPPC to make a post-hearing run of a production model which simulates system operations to forecast resource mix and energy costs. The results of the final model run, incorporating the ALJ's recommended determination of the related forecast issues, were received as late-filed Exhibit 13 on April 17, 1989. The matter stood submitted on that date.

III. Forecast Issues

A. California Sales

In its original forecast report, SPPC projected total California sales of 412.5 gWh. DRA's forecast, derived from econometric models for residential, A-1, A-2, and A-3 service classes, yields a sales estimate of 421.7 gWh, which is 2.2% greater than the company's estimate. SPPC indicates that while it disagrees with the methodology employed by DRA to forecast sales, it accepts as reasonable for the purposes of this proceeding the end result of DRA's estimates for all but the A-3 category of sales. SPPC's revised sales forecast is 418.3 gWh.

Disagreement on the level of A-3 sales results from different estimates of when a biomass QF (designated Project N by the parties), currently under development at a Sierra Pacific Industries lumber mill, will become operational. (Sierra Pacific Industries is not related to SPPC). SPPC believes the QF will commence commercial operations on October 1, 1989. DRA believes the project will be delayed until January 1990, after the forecast period. The parties do agree that sales to Sierra Pacific

Industries will be lost as of the commercial operation date (COD) of the facility, and that the sales forecast should be consistent with the adopted COD.

As discussed below, we find that the best COD estimate for Project N is December 1, 1989. Since this date is later than the COD estimated by SPPC and before that estimated by DRA, the adopted sales forecast, 420.56 gWh, falls between the parties' forecasts.

B. Purchased Power: Qualifying Facilities

In its resource mix forecast, SPPC estimates that total system power purchased from QF's will be 392.4 gWh, or 36.2% more than DRA's forecast of 288.1 gWh. The difference is attributable to DRA's modeling assumption that the COD's of four new QF projects will be one to three months later than the dates used by SPPC, and to DRA's use of lower capacity factors for the majority of QF's.

1. Commercial Operation Dates

For the four projects scheduled to start operations during the forecast period, the COD's projected by the parties are as follows:

Project	SPPC	DRA
K-Far West II	12/31/88	2/89
L-AMOR IV	4/01/89	6/89
M-Truckee-Carson Irrigation Dist.	7/01/89	10/89
N-Sierra Pacific Industries	10/01/89	1/90

Based on its experience with hundreds of contracts in California, DRA has found that QF projects consistently experience delays. It therefore believes that a forecast which includes new QF's should include the likelihood that there will be such delays. DRA also notes that while SPPC has focused on project start-up dates, i.e., when a project starts generating some power into the system, the significant dates for forecast purposes are the COD's. The contract rates become effective as of the COD. Prior to that time, QF's are paid the lower as-available price.

the project will be delayed until January 1990, after the forecast period. The parties do agree that sales to Sierra Pacific Industries will be lost as of the commercial operation date (COD) of the facility, and that the sales forecast should be consistent with the adopted COD.

As discussed below, we find that the best COD estimate for Project N is December 1, 1989. Since this date is later than the COD estimated by SPPC and before that estimated by DRA, the adopted sales forecast, 420.56 gWh, falls between the parties' forecasts.

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DRA believes the tendency for utilities, including SPPC, to be overly optimistic regarding QF project schedules is illustrated by a review of forecasted and actual operation dates of seven QF projects included in SPPC's 1987 ECAC filing. Of those seven projects, only one met its projected operation date. Two were cancelled, and the remaining four were delayed. DRA concludes that despite SPPC's good faith efforts to meet its projected dates, it is realistic to factor in some delay.

SPPC asserts that each of the four projects now under development has progressed to the point that such delays are no longer likely. Additionally, SPPC notes that there are economic incentives for the QF developers to meet their completion schedules. For example, contracts with each of the developers of these projects contain termination clauses providing construction milestones and dates for commercial operation to begin. If commercial operations are not established by the contracted date, the project will no longer qualify for higher long-term QF rates. SPPC indicates that it intends to assert its rights to terminate these contracts if milestone dates and COD's are not met. To illustrate this intent, the company notes that it has previously terminated one agreement and is currently in litigation with four other QF projects because milestone dates were not met.

We agree with DRA that for forecasting purposes it is appropriate to use COD's, not initial start-up dates. Since higher long-term rates apply once commercial operations are established, COD's have more impact on revenue requirements than initial start-up dates. We also agree that as a general rule, based on the experience with California QF's, it is reasonable to anticipate some delay for most projects. On the other hand, for projects which are already well under way, some weight should be accorded to the judgement of QF developers and utility officials when that judgement reflects specific, updated information about a project's status. It does not necessarily follow that because a project has somewhat optimistic. Assuming that initial operations do begin in September, it is reasonable to anticipate a longer delay (beyond October 1) for testing before commercial operations begin. At the same time, however, there are indications that the project is now progressing to completion, and that the previous delays may no longer be factors in the current projections. Staff's witness acknowledged that in evaluating the earlier delays, he was not aware of their being caused by regulatory delays for contract approval. We find it is feasible for the project to commence commercial operations by the contract's termination date of December 1, 1989, and therefore adopt that date for forecast purposes.

2. Capacity Factors

DRA's estimated capacity factors for fourteen QF projects are lower than the utility's estimates in ten cases, the same in three cases, and higher in one case. Because most of its capacity factors are lower, DRA's forecast of purchased power from QF's is 43,754 MWh less than SPPC's.

Ten of the QF's are geothermal projects. SPPC initially used a 90% capacity factor for the majority of these, based on data for only two such QF's recorded over short periods of three to six months. In response to DRA concerns over the reliability of this limited amount of data, the company revised its capacity factor estimates for one hydroelectric and nine geothermal projects. SPPC indicates that the revised estimates are based on information derived from project developers, and upon actual operating data for the QF's which are on-line.

Where data from actual operations was available, DRA relied on recorded capacity factors for its projections. For projects without recorded data, DRA generally used an 80% capacity factor as representative of projects with recorded data. When a new project was the same design as an existing project, DRA applied the capacity factor for the existing project. DRA asserts that

4. For the four QF projects scheduled to start operations during the forecast period, the COD's projected by the parties are as follows:

Project	SPPC	DRA
K-Far West II	12/31/88	2/89
L-AMOR IV	4/01/89	6/89
M-Truckee-Carson Irrigation Dist.	7/01/89	10/89
N-Sierra Pacific Industries	10/01/89	1/90

5. Contracts with each of the developers of the four projects at issue contain termination clauses providing construction milestones and dates for commercial operation to begin. If commercial operations are not established by the contracted date, the project will no longer qualify for higher long-term QF rates.

6. The closer a QF project is to completion, the more precise and reliable estimates of a completion date can be.

7. The QF developers and financiers have significant economic incentives to complete the projects on or before the termination dates, yet delays can and do occur.

8. Extensive testing at Project K, required before firm commercial operations can be established, was not expected to be completed until late January 1989.

9. The developer of Project L planned to spin eight of the twelve units by December 31 in order to receive a $3 million energy tax credit. The developer was faced with a significant incentive to initiate some operations by December 31, and it was feasible to do so.

10. The contract termination date of the Project M hydroelectric project is July 15, 1989, and the developer has an additional incentive to complete the project on schedule because the facility's operations are effectively limited to the irrigation season.

54. SPPC's recommendation to use the System Average Percentage Change methodology for revenue allocation and rate design is undisputed.

55. The Commission determined that SPPC's residential baseline rate should be set at 87% of system average rate in D.88-10-062.

Conclusions of Law

1. Sales and resource forecasts reflecting the following QF commercial operating dates should be adopted:

Project	COD
K-Far West II	2/01/88
L-AMOR IV	4/01/89
M-Truckee-Carson Irrigation Dist.	7/01/89
N-Sierra Pacific Industries	12/01/89

2. DRA's estimated capacity factors for the fourteen QF projects in the resource forecast should be adopted.

3. Fuel oil prices and economy energy prices forecasted by DRA and accepted by SPPC should be adopted.

4. It is appropriate to use the PROMOD production simulation model to forecast resource mix and energy costs without the contribution of combustion turbines to spinning reserve and with a 4.0% efficiency gain for oil burns.

5. DRA's recommended diesel oil inventory level of 4,477 barrels should be adopted.

6. DRA's recommended disallowances for transmission outages and for heat rate increases at the Valmy coal plant should not be adopted.

7. SPPC should be authorized to file the ECAC and AER rate increases set forth in Appendix A.

8. SPPC should be authorized to file the ERAM rate decreases set forth in Appendix A.

9. SPPC should be ordered to submit reports addressing the status of efforts to remedy transmission outages, the feasibility