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Decision 90 09 059 SEP 12 1990

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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| In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) for a Certificate that the Present and Future Public Convenience and Necessity Requires or Will Require Edison to Construct and Operate a 220 kV Double-Circuit Transmission Line Between the Kramer Substation and the Victor Substation in San Bernardino County, California. | Application 89-03-026 (Filed March 20, 1989) |

Richard K. Durant, Carol B. Henningson, James M. Lehrer, Carol A. Schmid-Frazee, and Michael D. Mackness, Attorneys at Law, for Southern California Edison Company, applicant.
Messrs. Jackson, Tufts, Cole & Black, by William H. Booth, Joseph S. Faber, and Evelyn K. Elsesser, Attorneys at Law, for Luz Partnership Management, Inc. and Luz International, Limited; Messrs. Baker & McKenzie, by John R. Shiner and Gordon F. Dickson, Attorneys at Law, for California Energy Company, Inc.; Dick Ratliff, by David Mundstock, Attorneys at Law, Gary C. Heath and Al McCuen, for the California Energy Commission; Messrs. Roberts and Kerner by Douglas K. Kerner, Attorney at Law, for Independent Energy Producers' Association; and Roger Peters, Douglas A. Oglesby, Kathleen B. Welsh, Attorneys at Law, and Gary G. Gauthier, for Pacific Gas and Electric Company; interested parties.
Jason Zeller, Attorney at Law, for the Division of Ratepayer Advocates and Jo Anna Bullock, for the Commission Advisory and Compliance Division.

# I N D E X

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# O P I N I O N

## I. Summary

In this decision, we grant a Certificate of Public Convenience and Necessity (CPCN) to the Southern California Edison Company (SCE or Edison) for the construction of a new, double circuit, 220 kilovolt (kV) electric transmission line connecting SCE's Kramer Substation with its Victor Substation in the Mojave Desert. The CPCN also includes related facilities at the Kramer, Victor, and Lugo Substations needed to handle the power to be transmitted over the new line.

The line is needed to facilitate the delivery into the SCE load center of electricity from two types of small qualifying facilities (QFs) located in the Mojave Desert: geothermal power plants developed by California Energy Company, Inc. (Cal Energy), and solar thermal power plants developed by Luz International Limited (Luz). Under state and federal law, SCE is required to provide for the interconnection of these generating units with the SCE electric system and to pay the QFs for the power they produce under the terms of standard contracts offered by SCE and agreed to by the QFs.

In this decision, we also determine how the costs of the proposed project will be allocated. Luz's cost obligations will be governed by an agreement which it has undertaken with SCE, under which Luz will be responsible for 44.8% of the project cost. Cal Energy will be required to pay for 21% of the cost of the project. The remaining 34.2% of the cost will be borne by SCE's ratepayers.

As a condition for the receipt of the CPCN, SCE will be required to undertake numerous mitigation measures, designed to limit the impact of otherwise significant and potentially significant effects which would stem from the construction and operation of the new facility. In keeping with recent Commission practice, SCE will be required to pay for a third-party mitigation monitoring program to be managed by the Commission's Advisory and Compliance Division (CACD). The mitigation monitoring staff will oversee SCE's implementation of the mitigation measures and other activities required in this decision.

## II. Procedural History

SCE filed its application for a CPCN and the accompanying Proponent's Environmental Assessment (PEA) on March 20, 1989. The scheduled operating date for the proposed project is September 1, 1992, with construction planned to begin September 1, 1991.[1] The application was accepted for filing on April 20, 1990.

A meeting was held in the City of Adelanto on July 26, 1989, to determine public concerns related to the scope of the Environmental Impact Report (EIR). The alternative transmission route proposed for this project travel through and around the City of Adelanto. On August 3, 1989, a prehearing conference was held in San Francisco. The Draft EIR was distributed to interested parties and places of public access in the vicinity of the project on November 30, 1989. The Draft EIR indicated that written comments could be filed no later than January 17, 1990. On that date, a Public Participation Hearing was held in the City of Adelanto. The second prehearing conference was held in Adelanto on that date as well.

In the meantime, other events had occurred which affected the scope of this proceeding. On November 17, 1989, SCE and Luz signed an agreement (SCE/Luz Agreement), which is discussed in

1 Pursuant to the SCE/Luz Agreement signed after the filing of this application and discussed below, Luz would construct the transmission line with the goal of having it in operation before the end of 1991.

greater detail below. Generally, the agreement allocates between Luz and SCE's ratepayers costs related to the proposed 220 kV line and other interconnection and integration facilities. Specifically, Luz agrees to pay 44.8% of the cost of the proposed project. Cal Energy, the other QF developer seeking use of the proposed 220 kV line, has not entered into a cost sharing agreement with SCE, although negotiations continued while this case was pending. SCE asked that the Commission approve the agreement with Luz as part of its review of the application for a CPC&N. Both SCE and Luz filed testimony in support of the agreement.

Division of Ratepayer Advocates' (DRA) testimony, released on December 19, 1989, included a recommendation that the SCE/Luz Agreement be rejected. The essence of DRA's position was that there are no apparent system benefits to be derived from this line and that under such circumstances the full cost of the line should be borne by the QFs. On January 8, 1990, SCE and Luz filed a joint motion asking the Commission to declare that it could approve the SCE/Luz Agreement without considering the system benefits issue. The California Energy Commission (CEC) filed a Staff Prehearing Conference Statement on January 18, 1990, which included comments in support of the motion. DRA responded to the motion on January 19, 1990 and Luz filed an additional response on January 22, 1990.

Under the Permit Streamlining Act (Government Code Section 65950) the Commission has one year from the date that the application was filed to approve or disapprove the project. If the Commission fails to act within that time frame, the project could be deemed approved (Government Code Section 65956(b)). The one-year deadline for this project was April 20, 1990. Since the evidentiary hearings were scheduled to begin on January 22, 1990, SCE and Luz acknowledged that the pendency of the joint motion might delay resolution of the application. This is because SCE and Luz expressed a desire to file rebuttal testimony on the issue of system benefits, if the motion were to be denied. Government Code Section 65957 allows for one extension of the approval/disapproval deadline for a period of up to 90 days with the consent of the public agency and the applicant. Since it was likoly that any necessary rebuttal hearings could not be held until March, SCE requested a 90-day extension. We concur with this request, which results in a final decision deadline of July 20, 1990.

At the hearing held January 22, 1990, the assigned administrative law judge (ALJ) denied the joint motion. Hearings to consider evidence relevant to the issue of system benefits were set to begin March 5, 1990. Luz was given a deadline of February 6, 1990 for the filing of rebuttal testimony on the subject of system benefits. SCE and DRA were given until March 20, 1990 to file their rebuttal on that subject. In addition, SCE and Cal Energy were instructed to notify the Commission by February 6, 1990 as to whether or not a cost allocation agreement between those parties had been achieved. On that date, the parties reported that no agreement had been reached. The parties were directed to file, by February 20, 1990, testimony proposing the appropriate allocation of transmission line costs among SCE and Cal Energy.

On February 20, 1990, in addition to distributing its written testimony, Cal Energy filed a motion which, in effect, sought summary judgment on the issues of system benefits and cost allocation. On February 26, 1990, the CEC filed a Motion for Declaration of Applicable Law which complemented the Cal Energy motion. Subsequently, SCE and DRA responded to the motions in writing.

In addition, Luz raised a discovery matter concerning the timeliness of SCE's responses to Luz data requests related to the system benefits issue. In a telephone conference, the parties agreed to a schedule for the completion of discovery. Luz indicated that the timing of discovery would make it unable to prepare for cross-examination in the further hearings set to begin on March 5, 1990 and requested a delay of the evidentiary hearings. As a result, hearings on March 5, 1990 were limited to oral argument of the pending Cal Energy and CEC motions. On March 5, 1990, both motions were denied. Cal Energy requested that the March 5 rulings be certified to the full Commission for interim appeal. On March 19, 1990, that request was denied. Evidentiary hearings were held on March 19, 20, 21, 22, 26, 27, and 28, 1990. On the last day of hearings, the proceeding was submitted, pending receipt of late-filed Exhibit 48 (addressing business relationships between Luz and SCE and between Cal Energy and SCE other than those stemming from the standard offer agreements) and final briefs. The ALJ issued a ruling on April 18, 1990 which, among other things, admitted Exhibit 48 into evidence. The exhibit is comprised of copies of four contracts signed by SCE and its affiliates and by either Cal Energy or Luz with certain portions redacted by SCE under a claim of confidentiality. On April 20, 1990, DRA filed a motion requesting that all of the redacted portions of the contracts be admitted into evidence and that Exhibit 48 be supplemented with selected materials from Exhibit 87 in Application (A.) 88-02-016. Concurrent opening briefs were filed on April 16, 1990 and reply briefs were filed on May 1, 1990.

Comments on the Proposed Decision were filed by SCE, DRA, Luz, Cal Energy, and IEP. Some changes have been made to this decision in response to comments. The CEC moved for acceptance of a late filing of its Opening Comments. According to the motion, the CEC inadvertently neglected to file the comments, although they were mailed in a timely manner to all parties. DRA opposes the motion not only because the comments were not filed in a timely manner, but because they substantially exceeded the prescribed page limit and consisted largely of reargument, instead of focusing on factual and legal error. The motion is denied, primarily due to the CEC's failure to comply with Rule 77.3 of the Commission's

Rules of Practice and Procedure which limits the scope of comments to a proposed decision.

## III. The CPCN/CEQA Process

Two different regulatory schemes define this Commission's responsibilities in reviewing requests for the approval of new electric transmission projects. Public Utilities (PU) Code Section 1001, et seq. states that a utility must receive a CPCN from the Commission before it can begin the construction of a new line. Public Resources (PR) Code Section 21000 et seq. (CEQA) requires that the CPUC, as lead agency for this type of project, prepare an EIR assessing the environmental implications of the proposed project for its use in considering the request for a CPCN.

The CPCN requirements go beyond a determination that a new project is necessary. Before granting a CPCN, the Commission must consider an analysis of the financial impacts of the proposed project on the utility's ratepayers and shareholders. The Commission must review the expected cost of the project and for those projects estimated to cost more than $50 million, it must set a cap, or maximum amount which can be spent by the utility on the project without seeking further Commission approval. In addition, the Commission has a statutory obligation, even in the absence of CEQA, to give consideration to the following factors as a basis for granting any CPCN:

1. Community values.
2. Recreational and park areas.
3. Historical and aesthetic values.
4. Influence on the environment.

CEQA requires the preparation of an EIR where there is substantial evidence that a project may have a significant effect on the environment. The determination as to whether or not an EIR must be prepared is to be made by the lead agency, which is also responsible for the preparation and certification of the EIR. The lead agency is the governmental body with primary authority over the proposed project. For transmission lines that would carry power from a thermal generating facility to the first point of interconnection with the utility system, the CEC is the lead agency. For all other transmission lines, such as the one proposed here, this commission is the lead agency.[2]

In preparing the EIR, the lead agency must consider the full range of alternatives to the proposed project, including the alternative that there be no new project at all. The lead agency must identify all significant and potentially significant impacts of the proposed project, identify the mitigation measures available to lessen those impacts, and determine whether those measures would reduce the impacts to an insignificant level. If it is determined that the project will still have a significant impact on the environment even after all reasonable mitigation measures are applied, the CPCN must be accompanied by a statement of overriding consideration explaining why the project should still be approved. In any event, the lead agency cannot approve the CPCN until it has certified that the Final EIR is complete. The permit that is finally issued must be conditioned on completion of the adopted mitigation measures.

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2 Although the Commission's statutory jurisdiction includes all transmission lines that are part of the integrated utility system, the CPUC has chosen to limit its review to those lines that are designed for immediate or eventual operation at any voltage in excess of 200 kV. See General Order 131-C.

## IV. The Need for a New Transmission Line

Cal Energy has constructed its BLM and Navy 2 facilities at China Lake in the Mojave Desert. They have a combined net capacity of 150 megawatts (MW). These units are located approximately 43 miles north of the Kramer Substation. Cal Energy contracted with an SCE affiliate for the construction of a 220 kV line to SCE's Inyokern Substation where the conductor loops around the substation and is strung on the formerly vacant side of a series of SCE towers which carry the line down to the Kramer Substation.

Luz has constructed and brought on line its Solar Energy Generating Station (SEGS) Unit VIII at its Harper Lake facility in the Mojave Desert. Each SEGS unit at Harper Lake is designed to have an installed generating capacity of 80 MW. Luz plans to bring SEGS IX on-line in September, 1990 and another unit on-line by the end of each year from 1991 through 1993. In an agreement with SCE to be discussed in more detail later, Luz has also committed to sell to the utility another 20 MW of output from one of its Harper Lake units. Altogether, the SEGS generation from Harper Lake is expected to have a maximum capacity of 480 MW. While the other units are all under contract for sales to SCE, the last unit, SEGS XIII, is under contract to San Diego Gas and Electric Company (SDG&E). Power from SEGS XIII would be wheeled across SCE lines for delivery to the SDG&E service territory if the merger between SCE and SDG&E, which is the subject of A.88-12-035, is not approved.[3] Luz has constructed a 12-mile 220 kV transmission line to deliver power from Harper Lake to the Kramer Substation.

3 As of the date of submission of this case, SCE and Luz had not entered into an agreement governing the transmission of power from SEGS XIII.

No one disputes the fact that SCE is required under the federal Public Utilities Regulatory Policies Act (PURPA)[4] to interconnect with and purchase power from the QFs developed by Cal Energy and Luz.[5] In addition, all parties appear to agree that SCE needs to add additional 220 kV transmission capacity in order to move all of the power from these QFs as far south as the Victor Substation. It is agreed that if the QF generation is to be delivered to the Kramer Substation, it will be necessary for the additional 220 kV transmission line to interconnect at Kramer.

Figure 1 is a map indicating the location of transmission lines and substations related to this project.

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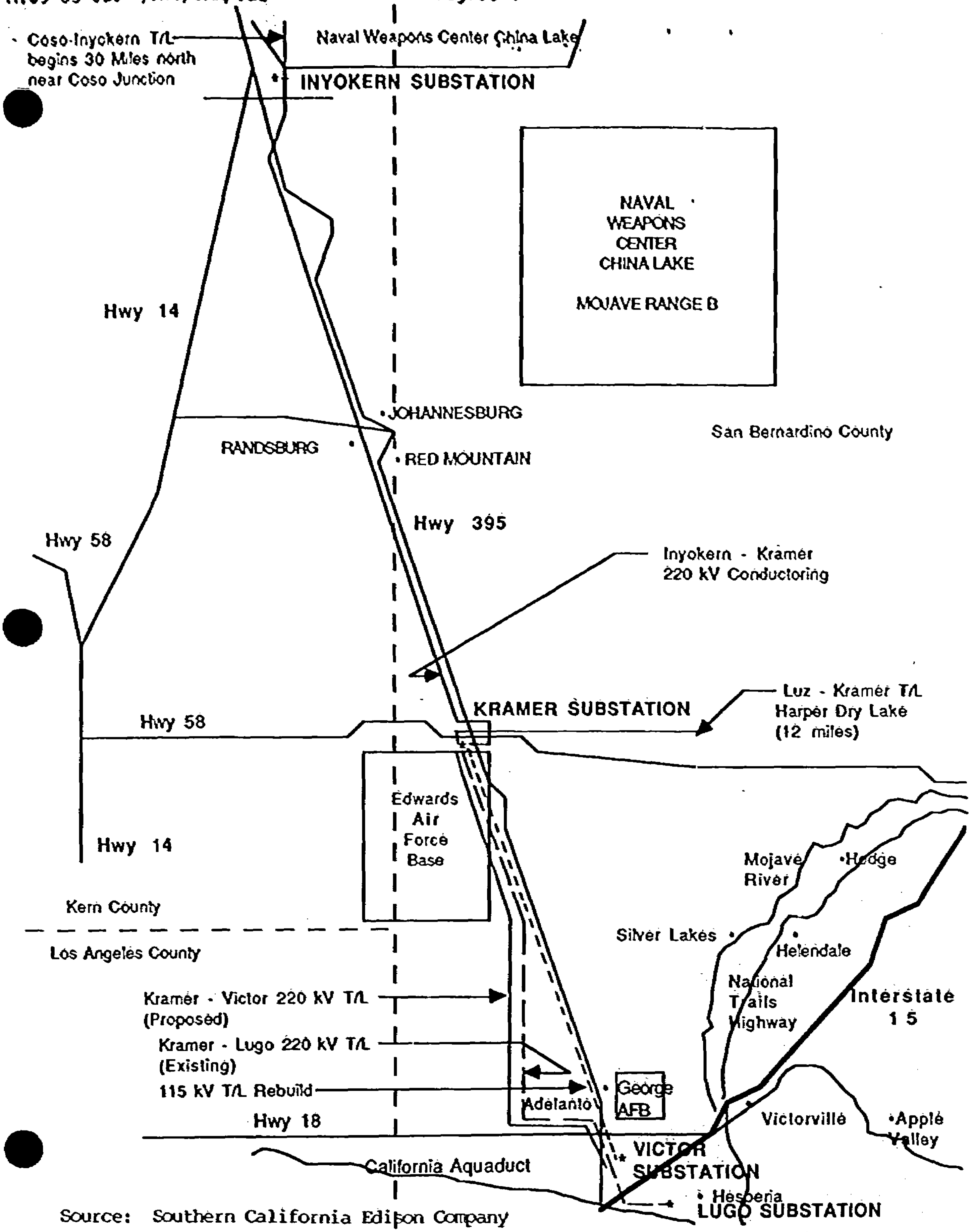
4 16 U.S.C. § 824a-3; 18 CFR § 292.303

5 Throughout this discussion, it should be remembered that SCE is not under contract to purchase power from SEGS XIII. Nor has it been specifically asserted that SCE is under any obligation to interconnect with SEGS XIII. However, since only one point of interconnection will allow for the transfer of the power anticipated to be delivered by all units IIIV-XIII, we will not repeatedly allude to this distinction. In addition, no one has argued that the need for new transmission facilities would be in any way different if SEGS XIII was not part of the consideration.

Figure 1




Source: Southern California Edison Company

Power moving from the Kramer Substation toward the SCE load center is delivered to the Lugo Substation, from which it can be routed on existing 500 kV lines. The Victor Substation is between Kramer and Lugo. SCE has two 220 kV lines which currently carry power directly from Kramer to Lugo. James G. Kritikson, SCE's Transmission Planning Manager, testified that these two circuits and the related transformers will be fully loaded when all existing and previously committed SCE and QF generation resources come on line. Kritikson's load flow diagrams indicate that power is currently imported to Victor from Lugo. SCE will be able to serve load in the Victor area with power heading south from Kramer by interconnecting additional transmission capacity at Victor. The remaining power will continue to flow from Victor toward Lugo on existing lines.

Kritikson calculates that if all of the generating sources which are already committed to use the existing Kramer to Lugo lines were to operate at full strength, they would fill those lines to 102% of their capacity. It is evident that the existing Kramer to Lugo lines cannot be committed to carry the output of any more generating facilities.

The record indicates that while it is possible to carry more than 100% of capacity on a given line, it is not advisable to do so. Line losses would be great and the conductors would be in danger of accelerated deterioration. However, Kritikson testifies that, without the addition of the Cal Energy and Luz facilities, there is very little danger of ever taxing the existing lines to this extent. First, to do so would require that all the facilities which are to rely on these lines be in operation at full strength at the same time. This is unlikely. Second, as demand grows in the Kramer area, more power will be diverted to serve local load, leaving less power to be transmitted to Lugo. At the same time, all parties appear to agree that there is a need to add more transmission capacity if additional generating sources are to deliver power through Kramer.

Even if the power from the Cal Energy and Luz facilities that are the subject of this proceeding was to be delivered not to the Kramer Substation but directly to Victor or Lugo, there seems to be agreement among the parties that new transmission lines would be needed. As will be discussed below, the only other technically feasible means of delivering this power to the SCE grid reflected in the record would involve building radial lines from the China Lake and Harper Lake areas directly to Victor or Luz. Regardless of the merits of that approach, it clearly would not obviate the necessity of adding new transmission facilities.

## V. Description of the Proposed Project

SCE proposes to construct a new, 38-mile long, double-circuit[6] 220 kV transmission line connected in the north to the Kramer Substation, located at the small community of Kramer Junction at the intersection of U.S. Highway 395 and State Highway 58. The proposed route would be parallel to Highway 395 for the first 22.2 miles. SCE seeks to build this portion of the line immediately west of two existing transmission lines that are also roughly parallel to Highway 395. As proposed, the line would continue to run parallel to one set of existing lines or another all the way to its southern terminus at the Victor Substation, which is located on the south side of State Highway 18 near Abode Corners. Along the way, the proposed route is diverted to avoid

6 A double circuit line is one which allows for the stringing of two sets of one circuit conductors on the same towers. One circuit is a set of 3-phase conductors.

running through the small commercial and civic center which hugs Highway 395 in the town of Adelanto.

As explained in the EIR, to accommodate the new line, the existing right-of-way between the Kramer and Victor substations would need to be increased by 75-100 feet, depending on the specific locations of the transmission towers. Most of the proposed project would be constructed on conventional double-circuit lattice steel towers. In two areas, however, different towers would be used. One instance would be where four single circuit towers would be used to enable the line to cross under an existing 500 kV line owned by the Los Angeles Department of Water and Power. The other instance is where single-pole tubular steel towers would be used to enable the new line to pass within an existing 150 foot right-of-way through an industrial park in Adelanto. SCE proposes buying and moving two existing homes which sit in the proposed right-of-way on the northwest side of Adelanto.

The proposed project also includes certain modifications and additions to the Kramer, Victor, and Lugo substations. At the Kramer Substation those changes include:

1. the construction of two additional positions in the existing 220 kV switchyard to terminate the new circuits,

2. the installation of one 115 kV capacitor bank, and

3. the installation of necessary protection equipment.

At Victor, those changes include:

1. the construction of four new 220 kV line positions in a new 220 kV switchrack which will form the termination of the new transmission line and the two existing Lugo-Victor 220 kV circuits,

2. the installation of two 220 kV bank positions,

3. the installation of two 220 kV capacitor banks, and

4. the installation of necessary protection equipment.

Finally, additional protection equipment will be required at the Lugo Substation as a result of increased loading caused by the proposed project.

## VI. Cost Caps and Cost Estimates for the Proposed Project

In compliance with PU Code Section 1003(C), SCE included in its application in this proceeding "an appropriate cost estimate" for the project. The Commission is required by PU Code Section 1005(b) to specify the estimated cost in the certificate which it issues for the project. Further, for facilities estimated to cost more than $50 million, PU Code Section 1005.5 requires that the Commission specify, in the certificate, a maximum cost determined to be reasonable and prudent for the facility. This cost cap can be increased by the Commission after the certificate is issued if the utility applies for an increase and if the Commission finds both that the project will actually cost more than was initially anticipated and that the project is necessary and convenient even at the higher cost.

DRA argues that a limit, or cap should be placed on the amount that SCE can spend on this project on behalf of its ratepayers without seeking further Commission approval. SCE opposes this proposal. In addition, SCE and DRA disagree as to how much the proposed project should be expected to cost.

### A. Project Cost Estimates

Table 1 provides a comparison of the SCE and DRA cost estimates:

Table 1

Project Cost Estimates
(in $million)

| | SCE | DRA |
|---|---|---|
| Transmission Line | 32.225 | 30 |
| Substation Improvements | 18.155 | 13 |
| Total Project Cost | 50.38 | 43 |

DRA's transmission cost expert, Ray Valaitis, prepared DRA's cost estimate for the new transmission line by using the Bonneville Power Administration's (BPA) generic cost-per-mile estimates. SCE's expert, Alexander Mateuchev, tried to develop a more project-specific forecast by estimating labor and material needs and applying current costs.

SCE argues that the DRA approach is too imprecise and does not take into account various peculiarities of the proposed project. For instance, Mateuchev points out that Valaitis did not add costs related to the replacement of 3/4 mile of existing steel lattice towers with steel poles through the Adelanto Industrial Park. He estimates that process to add another $1.3 million to the project cost.[7] In addition, SCE's estimate for permitting and regulatory expenses exceeds that of DRA by $644,000. According to Mateuchev, these regulatory costs include support of the CPCN process, CPUC application fees, preparation of environmental studies and reports, and BLM and Edwards Air Force Base approval. Mateuchev argues that the DRA estimate, which is based on BPA costs, does not reflect the difference between regulatory practices in BPA country (Washington and Oregon) and those in California.

7 The EIR indicates that SCE subsequently proposed to double the length of the segment that will consist of steel poles. This presumably would increase the project cost in a manner not reflected in the SCE estimate.

Finally, Mateuchev argues that DRA neglected to include sales tax which would be paid for the construction materials. He estimates those taxes to total $690,000.

DRA argues that the proposed line is very simple to construct, the terrain in the area is flat and open, and anticipated mitigation expenses are relatively low. DRA argues that SCE has provided virtually no justification as to why costs for this line should exceed the average. Valaitis acknowledges that SCE's cost estimating approach "has the inherent capability of being more precise than the one the I prepared," but that SCE's approach does not always represent the only reality. DRA agrees that its estimate did not include the sales tax figures or the added costs resulting from the removal of 3/4 mile of lattice work towers and their replacement with steel poles. However, DRA argues that its $2 million contingency provides the cushion necessary to cover these costs. DRA also points out that SCE may have been able to avoid the need to replace lattice towers if it had bought a wider right-of-way through the Adelanto Industrial Park at an earlier date. As for the estimate of regulatory expenses, DRA argues that SCE has not demonstrated the existence of any difference between California regulatory requirements and those in the Pacific Northwest which would make it more expensive to license a facility in this state. Finally, DRA argues that SCE was unreasonable in assuming that overheads would add another 30% to the project costs. DRA says that, since most of the project will be built by Luz and since Luz is a smaller organization, it is more realistic to expect that overheads would add only 20% to the project cost.

In its rebuttal testimony, SCE takes exception to several aspects of DRA's estimate of the costs of substation improvements. In preparing its estimate of Kramer Substation costs, DRA used 1978 cost data which was then escalated to 1991 value. SCE argued that DRA should have started 1987 cost data and should have made allowance for the added cost of making changes on an energized substation such as Kramer. SCE says that these changed assumptions would have added $1 million to DRA's cost estimate. SCE argued that, in considering Victor Substation costs, DRA failed to use updated 220 kV circuit breaker costs, failed to include the cost of overhauling and refurbishing eight system breakers, and omitted the added cost of station grounding, site grading, relay equipment, station light and power, crushed rock, and line and bank conductoring. According to SCE, these factors account for $5 million in additional expenses. Finally, SCE argues that DRA did not include $245,000 for specific protection improvements for the Lugo Substation, plans for which were finished after the application for this matter was filed.

DRA did not respond to each of these concerns, but instead emphasized that its estimate included a $2 million dollar contingency figure and that SCE used a very high factor for overheads.

We will adopt SCE's estimate of project costs. While the provision of a detailed cost estimate does not guarantee accuracy, it appears that SCE has used a reasonable approach to assembling its prediction of project costs. We assume that when DRA added a $2 million contingency amount to its original estimate, it intended for that amount to be applied to unexpected expenses, not to be absorbed as a means of covering predictable expenses that DRA failed to identify. According to SCE, the sales taxes and lattice tower replacement costs total about $2 million. If the contingency amount is considered to include these figures, then there is no contingency left to cover unexpected costs.

The parties simply disagree about the expected regulatory costs and overheads. SCE has offered us little guidance as to how it arrived at its estimate of regulatory costs. The DRA has provided an estimate that can more easily be explained, since it relies on a cost estimate methodology that is used by tho BPA. We are nonetheless for the reasons discussed below, willing to adopt SCE's estimate for these expenses.

Neither SCE nor DRA has adequately explained its estimate of overhead expenses. Both parties applied a 30% rate. Nonetheless, DRA argued that a lower rate is more applicable to a smaller firm such as Luz, which is expected to construct most of the project. Unfortunately, DRA offered little support for its assertion that smaller firms face lower overhead costs.

While the proposed project is relatively straightforward, we are imposing mitigation requirements and other permit conditions which may not have been anticipated when SCE made its estimate. The mitigation monitoring program and other conditions placed on the construction of the project may add to regulatory and other costs.

At the same time, DRA's cost estimate demonstrates that SCE has taken a very conservative approach in developing its estimate. SCE should be able to complete the project within its projected budget.

In adopting a cost estimate, it should be remembered that this figure is used for placing the application in a financial context and does not give SCE license to pass any particular amount of money on to ratepayers. As is true with all capital additions, SCE will be required to demonstrate the reasonableness of all of its expenditures related to this project before ratepayers will bear these costs.

B. Cost Cap

PU Code Section 1005.5(a) states:

> "Whenever the commission issues to an electrical or gas corporation a certificate authorizing the new construction...of the corporation's plant estimated to cost greater than fifty million dollars, the commission shall specify in the certificate a maximum cost determined to be reasonable and prudent for the facility..."

If the project later proves to cost more than the amount specified in the certificate, the utility is required to ask the Commission to increase the maximum cost (cost cap).

When the Commission considers whether or not to issue a certificate, it normally must compare the estimated cost of the facility with the expected benefits and with the cost of other feasible project alternatives. The cost cap process set forth in PU Section 1005.5 allows the Commission to ensure that a project which appeared to be cost-effective when it was certified does not move forward unchecked if subsequent cost escalation makes completion of the project economically unwise. The fact that the Commission is required to establish a cost cap for projects expected to cost more than $50 million assures that, at a minimum, cost caps will be applied to all new major projects.

The estimated cost of this project is slightly more than $50 million. DRA proposes that a cost cap be established, regardless of estimated cost. SCE argues that since the ratepayers' share of the cost is likely to be far less than $50 million, the cost cap provision of Section 1005.5 does not apply. DRA responds that Section 1005.5, in establishing the cost cap requirement, is blind to cost allocation. It simply requires that a cost cap be set whenever the cost of the project as a whole is expected to exceed $50 million. We agree. By adopting the highest estimate of project cost, we have helped to assure that the project can be completed within the limits of the cost cap. In addition, this is a short duration project (to be completed before the end of 1991) which is, therefore, less vulnerable than other projects to severe inflation or other unexpected cost effects.

In its comments on the Proposed Decision, SCE argues that the conditions placed on the certificate, outlined below, may add to the cost of the project. SCE asked for permission to file an updated cost cap estimate within 90 days of the date at which this decision becomes final. SCE proposes that its revised estimate then become the cost cap. The request is denied. Section 1005.5 says that the utility can apply for an increase in the cost cap at any time after the application is approved. This is approach that SCE should follow if it determines at any point tho the cost of the project will exceed $50.3 million. Following this approach will help to assure that SCE properly justifies any request for an increase in the cap.

## VII. Ratepayer Cost Responsibilities

Traditionally, utilities apply for CPCN for new projects which will be placed into the utility's rate base, allowing the utility to earn a rate of return on its investment and to depreciate its capital investment over a reasonable period of time. It is the ratepayers who usually pay these costs. The provisions of the PU Code related to CPCN require the Commission to consider the cost-effectiveness of a proposed project as a means of meeting a perceived need before saddling ratepayers with the economic burden of new investments. PU Code Section 1003(d) requires that the applicant for a CPCN demonstrate, among other things, the financial impact of the new project on the company's ratepayers. In order to understand the ratepayer impacts, it is necessary to estimate how much ratepayers will be asked to spend for the project. This requirement applies regardless of the reasons that the project is needed. Section 1005(b) states that the certificate granted by the Commission must specify all of the characteristics of the plant set forth for the applicant to address in Section 1003. Thus, in order to grant a certificate for a proposed project, we must determine, among other things, the portion of the project cost which will be borne by ratepayers.

In November 1988, SCE signed integration and interconnection facilities agreements with Luz and Cal Energy. The agreements called for the construction of the proposed project. As an interim means of carrying Luz and Cal Energy power between Kramer and Victor, the parties agreed to the rebuilding of an existing 115 kV line. This strategy was pursued because the 115 kV project could be accomplished without coming to this Commission for a CPCN. It was agreed that Luz and Cal Energy would split the cost of the rebuild of the 115kV line. Further, it was agreed that Luz, Cal Energy, and SCE would evenly share the cost of the proposed project pending our determination of the proper cost responsibility for each party.

When it filed its application in March of 1989, SCE indicated that it was negotiating separately with Luz and Cal Energy in an effort to agree on a final proposed allocation of the cost of the proposed project among Luz, Cal Energy, and SCE's ratepayers. On November 17, 1989, SCE and Luz signed an agreement allocating costs for the proposed project and other related facilities between Luz' and SCE's ratepayers. SCE has asked us to approve the SCE/Luz agreement in this application. Initially, DRA opposed this agreement. It has since removed it opposition and no one is currently arguing against adoption of the agreement.

SCE and Cal Energy apparently continued to work toward an allocation agreement until well into this proceeding, but failed to come to terms. At one point, counsel for Cal Energy asserted that his client had no interest in negotiating an allocation of the project costs. SCE has proposed that all project costs not allocated to Luz under the terms of their agreement be allocated to Cal Energy. Cal Energy argued that all such costs should be borne by ratepayers. The CEC supported Cal Energy's position. The DRA proposed a hybrid approach to cost allocation. Before considering issues related to Cal Energy's share of the project costs, we will look in more detail at the SCE/Luz Agreement.

## A. <u>The SCE/Luz Agreement</u>

SCE has asked the Commission to approve its agreement with Luz under which Luz would bear the following costs:

1. 44.8% of the cost of the proposed project.

2. 100% of the cost of the 220 kV transmission line from Harper Lake (site of the SEGS VIII-XIII units) to the Kramer Substation and the cost of the line's termination at the Kramer Substation.

3. All operation and maintenance (O&M) costs related to the Kramer Substation termination facilities for the Luz 220 kV line.

4. 52% of the cost of the Kramer-Victor 115 kV transmission line rebuild which provides an interim means for transmitting Luz and Cal Energy power.

5. 100% of the cost of metering and telemetering equipment.

The two parties further agreed that while SCE would engineer, design, and provide equipment specifications for the proposed 220 kV line, Luz would procure the needed equipment and construct the line for a fixed cost. Under this arrangement, Luz and SCE expect that the line can be built as much as a year earlier than was previously planned. That is because Luz is willing to bear the risk of planning and procurement costs while the CPCN is pending. Luz would deed ownership of the line to SCE. SCE would be fully responsible for planning and constructing the other facilities included in the proposed project. SCE agreed to pay all of the cost of upgrading the Lugo substation and all O&M costs for facilities south of the Kramer Substation.

B. <u>Proposals for Allocating the Remainder of the Project Cost</u>

If the SCE/Luz Agreement were to be approved, it would still be necessary to determine what portion, if any, of the remaining 55.2% of the project cost should be borne by Cal Energy. SCE argues that since the new line is being built exclusively to serve the new QFs, all costs for the project not paid by Luz should be paid by Cal Energy. Cal Energy, on the other hands, says that ratepayers should pay all of the remaining project costs. The CEC agrees with Cal Energy. The DRA proposes that Cal Energy be required to pay the same amount as Luz (44.8%) and that the remainder (10.4%) be paid by SCE's ratepayers. In support of its position that all remaining costs should be borne by ratepayers, Cal Energy has relied almost exclusively on its interpretation of a 1985 decision by this Commission. Because of the weight given this decision by Cal Energy, we will now explore the decision and the arguments related to it.

C. D.85-09-058 and Its Significance

In early 1984, the Commission was approached by Pacific Gas and Electric Company (PG&E) and various QFs about limitations in the near-term availability of transmission capacity in portions of Northern California. As more and more QF developers sought to enter into standard offer agreements with PG&E for the sale of power, it was becoming evident that transmission limitations could constrain PG&E's ability to bring new facilities on line. On April 18, 1984, the Commission issued Order Instituting Investigation (I.) 84-04-077 to examine these alleged transmission constraints. The Commission also wanted to assess the extent of any limitations in other utilities' transmission systems which would affect QF development.

The respondent utilities filed statements of anticipated limitations on their transmission systems over the following ten years which might affect QF development. In those statements, only PG&E predicted that it would have significant constraints in its northern transmission system.

After submission of the utilities' statements, the Public Staff Division (now DRA) held several workshops in which an interim solution was developed to address the PG&E constraints specifically. In addition, in the workshops, parties formulated a milestone procedure for tracking the development of individual QF projects and discussed various approaches for allocating costs related to new transmission projects. Hearings were held in April, 1985, on three subjects, which included the utilities' transmission constraints and cost allocation approaches.

In September of that year, the Commission issued D.85-09-058 which addressed these issues. That decision contained the following language, which has been carefully dissected and analyzed by all of the parties to the current proceeding:

> "QF deliveries are a significant part of each utility's resource plan. Accordingly, utilities must plan for and otherwise enable QF facilities to interconnect with their transmission systems in an expeditious manner. We recognize that both the diversity and the number of emerging QFs in PG&E's system have created new problems for the company's transmission planners. However, PG&E along with the other utilities must learn to facilitate the addition of QF power as it already has learned to accept power deliveries from all other resources.
>
> "The parties have agreed among themselves that QFs should not be responsible for the cost of transmission facilities which serve multiple purposes. The parties find since the ratepayers in the past have paid for these transmission facilities, the ratepayers should continue to absorb the cost as long as the transmission facility has system-wide benefits. A QF is responsible only for interconnection and other facilities that have no system-wide benefits and are solely beneficial to the QF. This approach eliminates the need for a difficult cost allocation among the various users of a transmission facility.
>
> "System-wide benefits can mean many things as shown in SDG&E's list of factors affecting its transmission planning. Thus, we believe that nearly all transmission facilities arguably may have some system-wide benefits. Bulk transmission lines by definition have system-wide benefits. And nearly all area lines probably have some system-wide benefits. Thus, QFs will assume cost responsibility only on the

rare occasion that an area line lacks any perceptible system-wide benefit.

"On occasion, a transmission facility's cost may outweigh its system-wide benefits. In this event, the QF perhaps should be responsible for any excessive cost caused by the interconnection of its facility to the utility's system. A rigorous cost-benefit analysis, however, touches upon many as yet undefined criteria. We have yet to determine a long-run avoided cost methodology for QFs. We have not yet adopted consistent energy reliability criteria for all utilities. The cost of transmission service is just one piece to the puzzle of properly valuing QF power. Thus, for the moment, we will allow utilities to follow the general principle that as long as a transmission facility has system-wide benefits, the utility's ratepayers are responsible for the prudent and reasonable cost. The QF is responsible only for interconnection cost and other special facilities which have no system-wide benefits. Refinement of this principle must wait for our determination in the long-run avoided cost proceedings."

Cal Energy has argued that the above language is clear on its face, that, as a matter of definition under D.85-09-058, the proposed project has system-wide benefits, that the Commission is bound by law to adhere to the principles set forth in that decision and that Cal Energy relied on its interpretation of the decision while developing its projects. Cal Energy further argues that a detailed analysis of the proposed project would demonstrate that the new line would provide substantial system benefits. For that reason as well, Cal Energy asserts that we are bound by law to absolve the QF from all cost responsibility for this project. The CEC and Luz agree with Cal Energy's position. SCE argues that the 1985 decision allows for a case-by-case examination of the system-wide benefits question, that the Commission is not bound by law to adhere to the 1985 decision in any event, and that a detailed analysis demonstrates that the proposed project has no system-wide benefits. SCE also argues that Cal Energy's claimed reliance on its interpretation of the 1985 decision was unjustified, was not genuine, and does not prevent the Commission from reinterpreting the decision. In all significant respects, DRA agrees with SCE. We will now address each of these arguments in greater detail.

1. <u>Is the Decision Clear on its Face?</u>

The 1985 decision cited above established a Commission policy which favors having ratepayers bear the cost of new transmission lines which serve beneficial purposes other than allowing for the interconnection of QFs. This policy is set forth clearly in the Conclusions of Law and Ordering Paragraphs of the decision. The 1985 decision provides far less clarity as to how to determine whether or not those other beneficial purposes exist in a given instance. Cal Energy and the CEC argue that the 1985 decision provides no room for misinterpretation; the discussion section contains the statement that "Bulk transmission lines, by definition, have system-wide benefits." This statement is repeated as a Finding of Fact in the decision. SCE appropriately points out that this finding is not an element of any of the conclusions which follow.

The statement about "bulk lines" leaves us little to go on. The decision does not define the term.[8] Cal Energy and CEC suggest that any line of 220 kV or higher voltage is a bulk line and, therefore, that any line of such a size produces system-wide benefits by definition. However, it is not logical to suggest that

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8 Cal Energy argues to the contrary by referring to mimeo pp. 7 and 8 of the decision. However, those pages merely set forth data supplied by parties to the case and provide little guidance as to how the Commission intended to use the term "bulk power." Simply because some 220 kV or 230 kV lines were referred to as bulk lines doesn't mean that all such lines are "bulk" by definition.

size alone produces system-wide benefits. For instance, Cal Energy's witness Lewis stated that, in his opinion not all radial lines produce system-wide benefits, for reasons that don't necessarily relate to the size of the conductors. He drew a distinction between the line strung by Cal Energy on existing SCE towers which could at least produce future system-wide benefits if it was interconnected at the Inyokern Substation, and a more typical radial line. A more typical radial line cannot usually add to system reliability since it does not contribute redundancy to the transmission system and usually does not provide excess capacity, since it is likely to be sized appropriately to carry the anticipated load.

Lewis suggests that the latter type of line does not produce system-wide benefits. The 220 kV line built by Luz to carry power from Harper Lake to the Kramer Substation seems to fit the latter description. No party has argued that this line produces system-wide benefits. To the contrary, as part of its agreement with SCE, Luz has agreed to pay for the full cost of that line. Either some 220 kV lines are not bulk lines as the Commission used that term in 1985, or it simply is not true that all bulk lines have system-wide benefits. In either event, the 1985 decision is not as clear as some have argued. Cal Energy argues that all parties to Commission proceedings understand that all lines over 200 kV are bulk lines. Cal Energy cites a prior SCE statement in an earlier proceeding as proof. However, PG&E adds that bulk lines can be distinguished by a number of characteristics other than voltage rating. In its opening brief, PG&E argues:

> "For example, the specific proposed upgrades discussed by the Commission in D.85-09-058 can be distinguished by their function. These proposed upgrades had a generalized function of supporting power transmission throughout the utility electric system. In contrast despite their voltage rating, the primary function of the lines that are the subject of Edison's

application is to gather output from remote QF projects.

"The developers of these QF projects had their own reasons for siting them in locations remote from Edison's load center. Edison's ratepayers should not automatically be responsible for all costs of system upgrades necessary to accept this power merely because 220 kV lines and associated equipment are involved."

Finally, SCE offers evidence that the Commission had a broader definition in mind when it issued its decisions addressing the allocation of bulk transmission line costs. SCE points out that D.84-08-031 states that it modified D.83-10-093 to conform to PG&E's position, and then argues that PG&E does not distinguish between bulk and area lines on the basis of voltage. D.84-03-092 (issued in the same proceeding as D.83-10-093) quotes a letter from PG&E's attorney in which 230 kV lines areas are described as both bulk and area lines: "Bulk transmission capacity limitations occur on PG&E's 230 and 500 kV transmission system, and area transmission limitations occur on PG&E's 230, 115 and 60 kV system." (D.84-03-092, p. 61.) We are left without clear guidance from prior Commission decisions as to what constitutes a bulk line. This is a matter which should be resolved in a generic proceeding, not in a certification forum with limited parties.

As will be discussed further below, the 1985 decision also fails to set forth criteria for judging the existence of system-wide benefits. It refers to a list of factors used by SDG&E to assess the benefits of a proposed line, but does not assess the merits of that list, or suggest that it sets forth the appropriate criteria for SCE or any other utility to employ. For this reason as well, the 1985 decision does not lend itself to ministerial application.

2. Is the Decision Binding?

a. Positions of the Parties

Cal Energy asserts that D.85-09-058 constitutes the definitive approach to cost allocation, that the Commission is bound by law to follow that approach in subsequent proceedings, and that the Commission is reduced in the current application to the ministerial task of applying the findings from the 1985 decision.

Cal Energy argues that the Commission cannot alter or rescind the 1985 decision in this application, because to do so would violate the notice and hearing requirements of PU Code Section 1708 and the Fourteenth Amendment of the U.S. Constitution. Section 1708 says that the Commission may rescind, alter, or amend any order or decision upon notice to the parties and with opportunity to be heard. In support of this argument, Cal Energy cites California Trucking Association v. PUC, (1977) 19 Cal. 3d 240, a case in which the California Supreme Court held that this Commission cannot issue an ex parte decision in a matter for which a formal protest has been filed requesting hearing. SCE responds that there was an adequate opportunity for the affected parties in this case (Luz and Cal Energy) to be heard and that the Commission is not restricted in its ability to depart from the policy set forth in earlier decisions at least so far as it would affect these parties. Independent Energy Producers argued that a limited proceeding such as this should not be used as the forum for changing the cost allocation policy as it applies to all utilities and QFs.

Cal Energy also argues that because of the existence of D.85-09-058, the Commission has no interpretative discretion as to how costs should be allocated in this proceeding. Instead, Cal Energy claims, the Commission is bound by a ministerial duty to simply enforce and apply the law. In support of this point, Cal Energy cites Great Western Savings and Loan Assn. v. City of Los Angeles, (1973) 31 Cal. App. 3d 403, 413, a case in which a state appeals court said that a local agency must approve a tract map if it conforms to state statutes and local ordinances. SCE argues that there is no such ministerial duty here.

Cal Energy argues that if the Commission applied any interpretive discretion to D.85-09-058, it would necessarily have to produce inconsistent findings that would render any resulting order subject to annulment. In support of this assertion, Cal Energy cites Cal. Portland Cement Company v. PUC, (1957) 49 Cal. 2d 171, 176, a case which said that the Commission cannot issue a valid decision which contains internally inconsistent findings of fact which go to the principal issue involved in the case. SCE points out that, in Cal. Portland, the Commission was held to be at fault for having looked at precisely the same facts and reached two opposite conclusions within the same decision. SCE argues that there is no relevant similarity between that fact pattern and the situation faced in this case.

Finally, Cal Energy argues that while D.85-09-058 was the result of a quasi-legislative proceeding, a CPCN is a quasi-judicial proceeding and that the Commission cannot do anything in a quasi-judicial proceeding which is inconsistent with findings in an earlier quasi-legislative proceeding.

In its Reply Brief, the CEC emphasized its support of the quasi-legislative/quasi-judicial argument and analogized the findings in D.85-09-058 to statutes which an administrative agency is compelled to uphold. The CEC cited Comite de Padres de Familia, (1987) 192 Cal. App. 3d 528, 535 in which the State Department of Education and Board of Education inappropriately failed to comply with a statutory mandate; and County of Orange v. Flournoy, (1974) 42 Cal. App. 3d 908, 912, in which an agency was found at fault for assuming an effective date for new legislation which was inconsistent with the effective date found applicable as a result of a plain reading of provisions in the state constitution.

While arguing for the sanctity of D.85-09-058, Luz did not offer an opinion as to whether or not we are bound in any way by that earlier decision.

SCE argued that, since no Commission can bind a future Commission, this Commission is not bound to adhere to the findings in D.85-09-058. The CEC responded that, while it is true that a later Commission can alter or reverse the course of an earlier Commission, it must follow the rules of notice and opportunity to be heard before doing so. The implication is that the findings in the 1985 decision cannot be altered without prior notice to all the parties to the underlying proceeding, perhaps with hearings held under the prior docket. SCE responds that it is sufficient that the parties to the current proceeding have notice that their rights might be affected in a manner inconsistent with the earlier order. SCE also points out that the finding of fact in the 1985 decision referring to bulk transmission lines was not essential to the conclusions of law or ordering paragraphs which followed, and therefore is fair game for reconsideration in any subsequent proceeding.

DRA argues that it is valid for the Commission to determine how or if it will apply the findings of D.85-09-058 in this proceeding. DRA cites the testimony of SCE's witness Ronald Luxa that in 1986, the amount of potential QF resources that had signed contracts to deliver power in the Kramer-Victor area was more than double that which had been forecasted in the proceeding underlying the 1985 decision. DRA argues that in the field of administrative law, the doctrine of changed circumstances has long been applicable, in recognition of the fact that regulatory agencies with continual jurisdiction are free to change course and policies as circumstances change. DRA quoted our D.89-04-081, in the QF complaint case of <u>Colmac Energy v. SCE</u> in which we said, "our decisions typically rely more on policy concerns, fairness, and common sense than on a detailed study of pertinent legal precedent."

b. Discussion

We have no intention of altering, modifying, or rescinding D.85-09-058 in this decision. While it may be appropriate to reexamine some of the assumptions behind that decision or to explore in more detail how it should be implemented, those questions should be addressed in a broader proceeding, with more expansive notice to affected parties.[9] Here, we must decide how the cost of one proposed transmission project should be allocated among those who serve to benefit from its construction. Consideration of the cost allocation of electric transmission facilities, generically, is beyond the scope of this instant CPCN proceeding. Any cost allocation which is determined to be reasonable in this case is based on the facts and circumstances specific to the parties and testimony in this proceeding and have no further reaching application.

This appears to be the first time we have been asked to examine the policy set forth by the Commission in D.85-09-058 in the context of a specific application for CPCN. That decision said that utilities should have their ratepayers pay for new transmission lines that are built to carry QF power and at the same time provide other system benefits.[10] What that decision did not explain is how those benefits should be measured. The arguments outlined above were shaped largely by the debate generated when Cal

9 The Commission will address transmission line cost allocation in a new, generic investigation on QF transmission issues. This new investigation will be closely coordinated with the ongoing Biennial Resource Plan Update (BRPU) proceeding.

10 D.85-09-058 also included the proviso that at some future time, a means might be developed to limit ratepayer contributions in a way which reflects the benefits being received.

Energy filed a motion which, in effect, sought summary judgment on the questions of system benefits and cost allocation. Cal Energy asserted that we are bound as a matter of law, by language in the decision to relieve Cal Energy of all cost responsibility. The ALJ denied that motion and stated that it was for the full Commission to determine how, if at all, the 1985 decision should be applied to the facts at hand. We agree with the ALJ.

Cal Energy's arguments were dependent on the assumption that a 220 kV line can be nothing but a bulk line. As discussed earlier, the language concerning bulk lines provides little assistance to us because it is ambiguous.

Even if the 1985 decision set forth a clear recipe for determining who should pay for the proposed project, we would not be legally bound by that order in this proceeding. None of the authority cited by the participants in this case stands for the proposition that this Commission is precluded from reconsidering its earlier policy positions, so long as adequate notice and opportunity to be heard is provided to those who will be affected. Thus, we are free to determine that the policy set forth in the 1985 decision is no longer appropriate as it affects the parties in this case.

The California Supreme Court's decision in California Trucking, cited by Cal Energy, does not apply to the current situation. In that case, the Commission had denied a hearing to a party that filed a formal protest and requested a hearing. The Supreme Court held that it was a denial of due process for the Commission to reach a decision in the absence of the requested hearing. In the current application, the QFs who will be affected by our decision had adequate notice and opportunity to be heard. In Great Western Savings decision, which was also cited by Cal Energy, an appellate court held that a local agency exceeded its discretion when it disapproved a tract map which complied with state statutes and local ordinances. There would be no violation of applicable state laws if this Commission determined that the cost of the proposed transmission line should be allocated in a manner not addressed in D.85-09-058 as long as adequate notice and opportunity to be heard was provided.

In Cal. Portland Cement, a Commission decision was annulled because it contained conflicting findings that went to a principal issue in the case. Cal Energy has attempted to suggest that this decision would preclude the Commission from issuing apparently conflicting findings in any two cases. In a regulatory environment where realities are constantly shifting, it would be unrealistic to hold the Commission to such a standard.

The effort by Cal Energy and the CEC to sort our proceedings and responsibilities into quasi-legislative and quasi-judicial cubby-holes is similarly nonpersuasive. Virtually every matter before the Commission is quasi-legislative to the extent to which it requires commissioners to draw upon a generalized understanding of the subtleties of regulation and of the industries that we regulate. With the exception of complaint proceedings, every matter is quasi-legislative in that each proceeding provides an opportunity to establish or refine Commission policy. At the same time, each proceeding is quasi-judicial to the extent to which it depends on an adjudicatory process (focusing on evidence in a formal record, with sworn witnesses, etc.) and the narrow application of facts to law as the basis for a Commission decision. As such, the legislative/judicial labels do not form a meaningful basis for determining when the Commission must rely on prior decisions and when it can formulate new policy.

The CEC cites two cases in an effort to outline the Commission's quasi-judicial responsibilities (Comite de Padres, and County of Orange). In each instance, an agency decision was overturned because it was inconsistent with statutory law. A decision by this Commission would be similarly vulnerable if it conflicted with provisions of the PU Code. For instance, a decision in a CPCN proceeding might be overturned if it failed to meet the requirements of PU Code Section 1001, et seq. However, neither of these cases suggests that the Commission would have committed legal error if it questioned or interpreted its earlier policy in a subsequent proceeding.

In addition, we are not ready to agree with Cal Energy and the CEC that a CPCN proceeding is "obviously" quasi-judicial in nature. See, for instance, D.93724, a 1981 proceeding that considered the availability of attorney's fees for participation in a CPCN proceeding. After a lengthy discussion of the attributes of various parts of a CPCN proceeding, the Commission concluded:

> "Our decisionmaking process in certification proceedings involves more than a narrow application of facts to law in the classical judicial mode. Once we have made the benchmark quasi-judicial decision that a proposed project conforms to the officially adopted forecast, there remain many facts that are considered on a quasi-legislative basis. These include the cost of the project, its likely impact on rates, operating and reliability factors, safety, and environmental impacts. The range for exercise of our discretion is very broad. There is no fixed framework of narrow factual issues which governs the decision-making process. Our process is quasi-legislative on these questions."

What this language demonstrates is that the Commission does not function with a stoplight that signals the nature of its responsibilities in a given proceeding: green light means one can make legislative determinations, red light means one cannot. Instead, the Commission must constantly make its decisions within the constraints and opportunities provided by the state and federal constitutions and applicable statutory law but with an eye toward setting the course for the future.

The flexibility allowed the Commission for these purposes was set forth in a 1925 California Supreme Court decision with an oddly relevant fact pattern. Postal Telegraph-Cable Company v. Railroad Commission of the State of California, (1925) 197 Cal. 426, involved:

> review of a portion of an order made by the Railroad Commission whereby [Postal Telegraph-Cable Company] was allowed one-half of the cost of relocating a portion of its telegraph line in certain areas in which it is closely paralleled by a high-power transmission line operated by the Pacific Gas and Electric Company, in order to prevent induction interferences to [Postal's] telegraph line which, by reason of its close proximity to the power line of Pacific Gas and Electric Company, renders induction unavoidable.

The Postal telegraph line had been built in 1886. In approximately 1904, PG&E began building a 50 kV transmission line which, in some places, closely paralleled the Postal line. Because surges in the PG&E line interfered with the transmission of telegraph signals, portions of the telegraph line had to be rebuilt or relocated. The proceeding before the Commission was a complaint in which Postal sought to have the full cost of the changes borne by PG&E.

Up to that time, it was Commission policy to levy all such charges against the owner of the second line to arrive in the corridor (in this case, PG&E's). However, in the Postal complaint, the Commission said:

> "The evidence in this proceeding shows that both the power and communication circuits have been in operation for many years and long before the question of inductive intereference was given serious consideration. Since that time changes have been made by both utilities in their circuits. In view of the history of the lines involved in this matter, it does not appear that the question of priority of construction should be given material weight in determining the responsibility of payment of costs resulting in the mitigation of interference."

On appeal, Postal asked the Court to nullify the Commission decision because it was inconsistent with established policy. The Court said (at p. 436):

> "The departure by the Commission from its own precedent or its failure to observe a rule ordinarily respected by it is made the subject of criticism, but our reply is that this is not a matter under the control of this court. We do not perceive that such a matter either tends to show that the Commission had not regularly pursued its authority, or that said departure violated any right of the petitioner guaranteed by the state or federal constitution. Circumstances peculiar to a given situation may justify such a departure."

The need for the Commission to be able to adapt its ordinarily applicable rules to the peculiarities of a given situation is just as great today as it was 65 years ago. This is one of the reasons that the Commission cannot be legally bound to apply the 1985 decision to the facts at hand. Later, we will explore some of the peculiar circumstances which would justify a departure from the 1985 rule in this case.

3. <u>Cal Energy's Claims of Reliance on the Decision</u>

Regardless of the Commission's legal responsibility to adhere to precedent, there are strong reasons for the Commission to avoid arbitrary departure from established policy. In no area is this more true than in the QF market. Those considering the development of a QF need assurance that their investment decisions are made with reasonable knowledge of the conditions which will apply when the power is brought to market.

Cal Energy presented General Donald M. O'Shei to testify that the company relied on its interpretation of D.85-09-58. That decision was issued in September, 1985. Cal Energy signed its power purchase agreements with SCE the preceding February. O'Shei says that Cal Energy relied on what he felt to be the plain meaning of D.85-09-058 and assumed that Cal Energy would face no cost related to the improvement of SCE's transmission system in order to receive power. He said that it is with this understanding that Cal Energy secured financing for its projects. O'Shei says that when Cal Energy was informed by SCE that the utility expected Cal Energy to pay for the additional transmission costs it was "like a bolt out of the blue."

SCE argues that the facts do not support Cal Energy's claims of reliance on the September, 1985 decision. First, the decision to site the plants at China Lake was made in 1981. Second, the power purchase contracts were signed before the 1985 decision was issued. SCE argues that the 1985 decision could not have affected the choice of plant location. It only could have affected the decision to proceed with the projects at the sites previously selected. However, SCE argues that the facts do not support a claim that financing decisions were related to D.85-09-058 at all. Table 2 presents SCE's chronology of significant events related to the financing decision.

Table 2

| Decision or Activity | Date |
|---|---|
| Cal Energy decides to locate at China Lake | 1981 (O'Shei, Tr. 8/526) |
| PPAs signed specifying location at China Lake | Feb. - June, 1985 (O'Shei, Tr. 8/525 and 8/539) |
| First Method of Service (MOS) provided to Cal Energy for 115 kV lines | Nov., 1985 (Luxa, Tr. 10/815) |
| Cal Energy commits "substantial funds" for BLM ($25 M[2]) | Mid-1986 (O'Shei, Tr. 8/529-530) |
| Cal Energy commits "substantial funds" for Navy II ($25 M[2]) | Mid-1987 (O'Shei, Tr. 8/529-530) |
| Second MOS to Cal Energy for two 115 kV lines | Aug., 1987 (Luxa, Tr. 10/815) |
| First discussion between Edison and Cal Energy about interconnection at 220 kV | Oct., 1987 (Luxa, Tr. 10/813, 815-816) |
| Edison told Cal Energy 220 kV upgrades south of Kramer would be needed to accept Cal Energy power at 220 kV and they would be responsible for costs | Oct., 1987 (Luxa, Tr. 10/816) |
| Edison agrees to investigate 220 kV interconnection; told Cal Energy they would be responsible for costs of any facilities solely beneficial to QFs | Dec., 1987 (Luxa, Tr. 10/813-814) |
| MOS proposed by Edison for Proposed Project at QF's expense | April, 1988 (Ex. 1, pp. 10-11) |
| Execution of IIFAs providing for BLM and Navy II interconnection at 220 kV<br>- $30-35[2] committed to Navy 2<br>- $150 M[2] committed to BLM | Dec., 1988 (Luxa, Tr. 10/814) (O'Shei, Tr. 8/535) |
| Navy II and BLM projects on-line Total investment = $380 million | Dec., 1989 (O'Shei, Tr. 8/531) |

SCE argues that this chronology shows that prior to October, 1987, SCE had offered Cal Energy Methods of Service (MOS) which contemplated interconnection and integration using 115 kV lines. SCE asserts that until October, 1987, Cal Energy had no basis for even anticipating that it would interconnect and integrate its facilities at 220 kV levels. Thus, SCE concludes, Cal Energy could not have been relying upon its belief that D.85-09-058 would require all bulk line upgrades to be paid for by ratepayers in making any decision to commit substantial funds before that date. SCE says that when it learned that Cal Energy wanted to interconnect at 220 kV, it informed Cal Energy that a 220 kV upgrade south of Kramer Substation would be needed and that Cal Energy would be responsible for those costs. SCE says that by the time a contractual agreement to interconnect was signed in December, 1988, Cal Energy had already spent approximately $180 million on the two projects.

It is SCE's position that only one conclusion can be drawn from this course of conduct. Cal Energy proceeded with construction of the BLM and Navy II plants regardless of what the ultimate interconnection and integration costs would be. SCE argues that Cal Energy purely and simply assumed the risk for those costs, and they must now accept that risk.

Cal Energy responded by saying that it not only expected that ratepayers would pay for all new bulk lines, but that they would pay for all but the most rare area lines as well. Thus, from Cal Energy's perspective, it did not matter what size a new transmission line might be. The company expected that ratepayers would pay for it.

O'Shei was asked to explain the significance of any reliance Cal Energy might have placed on its interpretation of the 1985 decision. He said that that reliance affected the structure of the financing for the project and that any subsequent assignment of transmission costs to Cal Energy would reduce the profitability of the projects in a manner which the company did not anticipate. Then, he added:

> "I suppose, without getting philosophical, that the Commission would also be interested in the reliance that the citizenry in general places on its orders and when its orders are issued, and if the Commission attempts, and in this case succeeded in an unusual fashion to make those orders crisp and clear, and the folks rely upon those orders, I would think that the Utility Commission would take a responsibility for the outcome of that reliance."

We could not agree more with General O'Shei's assertion that the Commission should carefully communicate its policies and attempt to develop in the marketplace reasonable expectations as to the conditions which will apply when projects are brought on line. However, for several reasons, we are not swayed by Cal Energy's claims of reliance on the 1985 decision. First, as SCE has demonstrated, the need and responsibility for transmission additions to serve these projects was sufficiently ambiguous at the crucial decision-making points to make it unlikely that Cal Energy could have reasonably relied on any particular transmission cost allocation in deciding to go forward. Second, as discussed above, we cannot agree that the 1985 decision provided the clear and crisp allocation method that Cal Energy perceived. Finally, Cal Energy had no reasonable basis for relying on its assumption that the ratepayers would pay for the transmission addition regardless of whether it was a bulk or area line.

Fourteen months prior to the time when Cal Energy signed its power purchase agreement, the Commission issued D.83-10-93, which discussed the terms applicable to standard offer contracts for the purchase of electricity from QFs. In that decision, the Commission voiced many of the same concerns expressed by General O'Shei about the need for a solid basis upon which a QF developer can make its investment decisions. In that decision, the Commission stated:

"The staff has suggested that the applicable tariff rules in effect at the time the contract is executed should be included in the standard offer so that the agreement will not be affected by future Commission-approved revisions of those tariffs with the exception of costs of facilities ownership charges. The reason for this recommendation is clear--to provide maximum contract certainty and to define from the outset the QFs and the utility's responsibilities for interconnection costs throughout the life of the contract. This certainty could prove vital to a QF's obtaining financing. While recognizing that such a requirement could impose an administrative burden on the utility due to the number of QFs which might sign standard offers over the years, we believe that such a step should be undertaken to preserve the sanctity and certainty of each contract. We will therefore direct all of the utilities to append to each standard offer the applicable tariff rules governing interconnection costs, cost-sharing and refunds, in the form existing at the time the contract is signed. By doing so, both the QF and utility will have reference to the exact rules which will govern their transaction."

Ordering Paragraph 12 in D.83-10-93, which addressed the then-applicable approach to new transmission cost allocation, contained the following language:

"12. The utilities' tariff rules and standard offer provisions governing interconnection costs and special facilities agreements shall require the following:

"a. The QF shall pay for new or additional line capacity if the upgrade is necessary for the utility to receive the QF's power.

"b. The cost of any line upgrade undertaken to serve additional customers or QFs shall be borne by the utility.

> "c. For two or more QFs seeking to use an existing line, a first come first served approach shall be used... If two QFs establish the right of first-in-time simultaneously, the two QFs shall share the costs of any additional line upgrade necessary to facilitate their cumulative capacity requirements. Costs shall be shared based on the relative proportion of capacity each QF will add to the line."

On January 13, 1984, SCE filed with the Commission its revision to its Rule 21, which mirrors the language contained in the ordering paragraph cited above. The revised Rule 21 went into effect on February 12, 1984 and was still in effect when Cal Energy's power purchase agreements were signed the following February.

Ten months later, the Commission issued D.84-08-031, which resolved an Order to Show Cause which had been issued to PG&E. Although other utilities and QFs were not parties to the proceeding that led to the 1984 decision, the Commission took the opportunity offered by the issuance of that decision to modify Ordering Paragraph 12(a) of D.83-10-093 to read as follows:

> "The QF shall pay for new or additional area distribution or transmission line capacity if the upgrade is necessary for the utility to receive the QF's power."

This modification reaffirmed the notion that ratepayers would pay for bulk line additions but also left the clear signal that area line additions prompted by the QFs would be paid for by the QFs. Whether Cal Energy was paying attention to SCE's Rule 21 or to the modification of the 1983 decision in D.84-08-031, it should have expected to be held responsible for the cost of any new area lines prompted by its transmission needs. Since it could not have formed a final opinion as to whether the added line would be a bulk or area line until after it had formed a strong financial commitment to completing the project, Cal Energy could not reasonably have relied on an expectation that ratepayers would have borne all of the expense of any needed transmission additions.

4. <u>Should D.85-09-058 Be Applied In This Case?</u>

Although we are not legally bound to apply D.85-09-058 in determining Cal Energy's cost responsibilities, we are left with the question of whether it nonetheless should form the basis for our decision. The simple answer is yes. The 1985 decision has served us well, because it has provided balance to the negotiating stance of QFs and utilities who are attempting to resolve transmission cost allocation issues. Prior to the current application, parties have largely been able to work out their differences at the bargaining table. The universal application of D.85-09-058 and subsequent decisions which interpret that order is the best way to preserve that balance.

D. <u>System-Wide Benefits</u>

Because the bulk/area line ambiguity does not provide us with a very simple way of resolving the cost allocation question, we have carefully examined issues related to system-wide benefits. We have encountered two major difficulties. First, D.85-09-058 in its current form remains ambiguous as to what criteria should be applied to define the parameters of system-wide benefits. Second, even if the criteria offered by parties to the proceeding are assumed applicable, the record does not clearly demonstrate that the line would create system-wide benefits.

1. <u>The Lack of Clear Criteria</u>

The lack of established criteria for analyzing system-wide benefits caused the parties in this proceeding to argue as much about definition as about the nature of the proposed project. In D.85-09-058, the Commission referred to a set of criteria on which SDG&E said it relies in assessing the potential benefits of a new project. However, the Commission did not adopt these criteria, or comment on their merits. With few specific parameters or criteria available to sharpen the focus, the parties in this proceeding attempted to apply the SDG&E criteria. However, it is not clear that all of the SDG&E criteria are applicable to the matter of cost allocation. It is also unclear as to what some of the criteria may entail.

2. Lowering Line Losses

In its opening brief, the CEC stated:

> "The proposed 220 kV line is adding substantial new transmission capacity to a system that is constrained and subject to increasingly heavy loads. All of the energy carried on this system, whether QF or utility generated, is being transmitted to serve SCE load. Line losses, currently high, will continue to increase as new QF generation is added. Adding the new 220 kV line will unquestionably greatly reduce SCE's line losses, with the result that SCE will receive at its load center significantly more capacity and energy than if it did not build the line. This may seem simple, but it is also irrefutable common sense. Logic provides this conclusion without computer analyses and expert witnesses.
>
> "Simple logic and common sense are, of course, the first casualties when lawyers and engineers meet in administrative hearings to argue about who should pay. So we leave logic at the door and enter the arcane world of transmission planning and computer modeling."

While CEC's argument may be appealing and while we share CEC's instinct that logic apply, we are not convinced that the new line will "unquestionably greatly reduce" SCE's line losses. It would be extremely useful for someone to present the simple calculations which would support this logic. However, none of the analysts, including CEC's, has taken such a straightforward approach.[11]

In considering whether the proposed line decreases system transmission losses, as with other possible systemwide benefits, we must separate the effects of the line from the effects of the QFs. For example, the additional QF generation may offset oil and gas generation in the LA Basin, which could reduce NOx emissions in the Basin. This is the type of societal benefit which justifies the existence of PURPA and the entire QF program. It is part of the reason that QFs can receive full avoided cost payments. Nonetheless, it is irrelevant to a determination of the benefits created by adding the new line to transport the QF power.

Major studies of line losses were performed by Luz's witness, Rupp, and Edison's witness Kritikson. In Rupp's Surrebuttal Testimony, Exhibit 20, he describes an analysis of the reduced losses from the proposed line based on Edison's response to DRA Data Request # 2. At DRA's request, Edison had analyzed the effects of adding another 220 kV line from Kramer to Lugo, in lieu of the proposed project. Edison's response indicated that the line would reduce losses in the area at a present value of $42 million. (Ex. 20 pp. 10-12.)

Rupp stated that Edison's response to Luz's Data Request #5 showed that the losses on the existing system should be 129.3 MW, not the 118.9 MW used in Edison's response to DRA Data Request #2. (Ex. 20 p. 11.) However, Kritikson testified that Edison sent

11 In their Opening Comments, both Luz and Cal Energy claimed that their respective experts offered this calculation. However, the record does not provide assurance that either witness provided the simple calculation which we describe. Rupp, testifying for Luz, offered an estimate of line loss savings in the Kramer-Victor area, but did not explain what comprises that area, or specify its other underlying assumptions. Lewis, testifying for Cal Energy, assumed 530 MW of QF capacity (instead of 630 MW) and assumed an average load condition, instead of considering the maximum expected line losses.

a correction to its response to Luz's Data Request, explaining that 118.9 MW was the correct figure. (Tr. p. 737.) Rupp later states that the correct amount of losses on the existing system is 132.1 MW. (Ex. 20 p. 15.) Kritikson testified that Rupp appeared to have derived this amount by linear extrapolation which would be inaccurate because line losses vary exponentially. (Tr. p. 741.)

Rupp also believed that Edison improperly modeled the generation at the Coolwater facility. He claimed that Edison improperly increased Coolwater's generation after the addition of the proposed project and QF generation. (Ex. 20 p. 17.) Kritikson argued that if QF production increased, other production would logically decrease. Kritikson responded that Edison wanted an equitable comparison of losses in the area. (Tr. p. 745.) Edison used a 22-24% capacity factor for Coolwater in its models. (Tr. p. 746.)

Rupp also stated that Edison used "unreasonably low" Coolwater capacity factors in analyzing both the existing and proposed cases. (Ex. 20 p. 18.) Rupp modeled the Coolwater facilities at 32% capacity, which Kritikson believes is improperly based on data for another proceeding which did not include the additional Luz and Cal Energy generation. (Tr. p. 744.) Kritikson also noted that the Coolwater capacity for the years 1985 through 1988 had been 7%, less than 2%, 7%, and 27%. (Tr. p. 746.)

Rupp also found fault with Edison's analysis of reactive power support. He says that Edison shows Coolwater providing reactive power even during periods it is not generating power. (Ex. 20 p. 19.) Edison's Kritikson explained that this representation is a feature of the modeling technique and does not imply that Coolwater generates reactive power when off-line. (Tr. p. 747.)

Rupp analyzed two types of loss savings attributable to the new line. The first is capacity loss savings, which he defines as the savings created by the reduction in capacity needed due to reduced losses at peak load. (Ex. 19 p. 7.) He calculated the capacity loss savings by adding the 11 MW reduction in losses in Kramer-Victor area indicated by Edison in its response to DRA's Data Request #11.4 and imputing an additional 5 MW for the rest of the Edison territory. (Ex. 19 p. 8.) In Rupp's surrebuttal testimony he raised the total from 16 to 16.4 MW based on the flaws he found in Edison's analysis. (Ex. 20 p. 24.)

According to Rupp, the second loss savings are avoided energy losses, i.e. energy that is saved because the system has fewer losses. Again, based on his corrections to Edison's modeling, Rupp arrived at annual savings of 92.4 gigawatt-hours (gWh). He translates the total (energy and capacity savings) into a present value of $69.3 million. (Ex. 20 p. 24.)

Kritikson disagreed with Rupp about the proper way to evaluate capacity losses. He believed they should be evaluated over the entire peak period. Thus, while at the instantaneous peak there may be a savings of 11 MW, over the entire peak period, the losses would actually increase, at a value of $7.1 million. (Ex. 38 p. 7, as corrected at Tr. p. 715.)

Cal Energy's witness Lewis testified that the savings would be approximately 80,000 MWh (90 gWh) per year, using Edison's 1990 base case generation and loads. (Ex. 23 p. 11.) This was performed with loads at 80% of peak. The Energy Commission's witness McCuen testified that the line appears to offer significant benefits with respect to reducing line losses. However, he believed that Edison improperly calculated losses on the proposed project with the additional generation from Cal Energy and Luz, which causes line losses to "appear" to increase. (Ex. 35 p. 8.)

Finally, DRA's witness Flores stated that she could not determine whether the line would decrease system losses. (Tr. p. 623.) She noted the sensitivity of the power flow program to the input assumptions, such as those for Coolwater. (Tr. p. 625.)

The parties disagreed as to whether change in losses should be measured across the entire SCE network, or on a basis which is isolated to the Kramer-Victor area. They disagreed as to whether the analysis should be done with the new QF generation included or not included. In addition, they disagreed as to whether or not the line loss credits included in utility payments to QFs should influence the analysis in any way.

Some preliminary conclusions can be drawn. It is not logical to measure the change in losses in the absence of the new QFs. The construction of the new line has been prompted by the need to transport electricity generated by the QFs into the system and is a natural part of the expanded transmission system. Neither should the change in losses because of the QF generation displacing generation closer to Edison's load center be considered: this is not a result of the proposed line. It appears that the relevant question is: How will line losses between Kramer and Lugo be affected by the addition of the new line and 630 MW of QF power? Since the existing lines from Kramer to Lugo are heavily loaded, it appears logical that a new line will cause some of the power on the Kramer-Lugo lines to flow on the new Kramer-Victor line instead. That should lower losses on the existing lines, but increase the losses on the new line. What is the net change? No one has offered that relatively simple calculation.

Finally, SCE's argument that the line loss credit included in QF payments may offset some or all of the perceived line loss benefit must be seriously considered. It might entail double counting if line loss savings for which QFs are already given credit are included in an assessment of system-wide benefit of the new line.

3. <u>Providing for Future Growth</u>

SCE states that the existing transmission system in the Kramer-Victor area is adequate for the next 20 years. (Ex. 38 p. 5.) Luz believes that the load growth predicted in the

Proponent's Environmental Assessment (PEA)[12] for the area will leave SCE with a load of 400 MW or more which would not be served if the existing Victor-Lugo line should fail. Luz claims, "the new line ensures that future load growth will be accommodated within the guidelines of Edison's reliability criteria." Edison counters that Luz has neglected to consider an important element of SCE's transmission planning criteria, which states that a major load cannot be unserved for a "protracted" period. Edison submits that because of Luz's omission and the lack of testimony on its Major Load Criteria there is no support for Luz's statement.

The CEC argues that the line is needed to carry electricity from new generating plants it believes will be built in the Mojave area. McCuen states "It is highly probable that there will eventually be new generation sources developed by Luz International in the Mojave. It is also possible, or even likely, that more geothermal generation will be developed at the Coso Naval Weapons Center." However, the SCE's Electricity Report 7 (ER7) does not project any additional QF or other new generation in this area.

This discussion seems to assume that the proposed project could serve future growth by carrying electricity beyond the 630 MW that is already planned. While the lines would be physically capable of carrying more power, SCE and Cal Energy seem to agree that it would be inappropriate to plan for the line to carry substantial additional generation. In addition, even if the new line is considered capable of carrying additional power, there is no benefit unless it is likely to to be used. The CEC's own planning documents seem to conflict with McCuen's prediction that

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12 The PEA is the environmental documentation which an applicant is required to submit with a request for a CPCN pursuant to Rule 17.1 of the Commissions Rules of Practice and Procedure.

more Luz and geothermal facilities are likely to be built. Both Luz and Cal Energy offered witnesses who could have easily provided that information if it were true. While it is perfectly conceivable that more plants will be built in the Mojave, the evidence must be more solid than that before the ratepayers should be asked to pay for the line.

4. <u>System Security and Reliability</u>

An addition to a electric transmission system makes that system more reliable if it enhances the likelihood that the system will be able to meet the demand of all of its customers. Parties agree that the new line adds N-1 capability to the Kramer Lugo transmission path. N-1 capability is the ability to continue operations when one line fails. SCE argues that it doesn't require the N-1 capability along the Kramer-Lugo path because it has a generation tripping scheme in place. In the current transmission configuration, without a tripping scheme in place, an outage along one of the Kramer-Lugo lines would cause a severe overload on the remaining line, causing it to go out of service as well. By tripping generation to prevent overloading the lines, SCE says that it can currently serve all its load under N-1 conditions. (Ex. 38 p. 7.) SCE states that the proper way to evaluate the reliability of a transmission system is in terms of service to the load: "The ratepayers are not benefited by uninterrupted transmission of the output from any given generator as long as load continues to be served." (Edison Reply Brief p. 44.) Edison's witness Kritikson said that if Edison required N-1 capability for serving every generation sources then Luz and Cal Energy would have been required to build two new lines to Kramer. (Tr. 756.)

DRA agrees with SCE. Because Kramer is a net generation area, DRA finds the N-1 capability supplied by the line to be insignificant. (DRA Reply Brief pp. 12-13.)

Luz asserts that the N-1 capability is "obviously" a system benefit. (Luz Reply Brief p. 12.) In his testimony, Rupp stated that "dropping generation to ensure overloads will be avoided is not an acceptable measure for dealing with an N-1 outage. It simply does not make sense to invest large amounts of money in generation resources which would be dropped for ordinary N-1 transmission system failures." (Ex. 20 p. 5.)

Cal Energy's witness, Lewis, said that the N-1 capability provided by the line would improve the firm transfer of energy from the area. (Ex. 23 p. 12.) However, he also testified that Edison's generation tripping scheme is "a perfectly classical way" of protecting the area. (Tr. p. 474.)

The CEC argues that neither SCE's transmission reliability criteria nor any other utilities' make a distinction for "net generation areas." (Ex. 35 pp. 6-7.) The CEC maintains that, although one can legitimately argue about its value, the N-1 capability is desirable and creates a better, more reliable system than one which relies on generation tripping. (CEC Reply Brief pp. 6-7.)

Just as was the case when considering the line loss question, there is an attractive logic which applies here. SCE's overall electric system should be more reliable whenever it adds a new transmission line which connects generating sources to the load center. However, an increase in reliability does not necessarily provide a tangible benefit. Is there a tangible benefit to providing N-1 reliability in a net generating area when the absence of N-1 capability does not appear to threaten the utility's ability to meet its load? In D.84-10-034, in which the Commission issued CPCNs for the Devers-Valley, Serrano-Valley, and Serrano-Villa Park transmission lines, the Commission discussed SCE's reliability criteria:

> "Edison's transmission reliability criteria basically require that the outage of a single transmission or substation component will not

> interrupt service to customers nor load components in excess of their normal thermal ratings.
>
> "It also requires ('N-2' standard) that outage of two transmission lines will not (1) cause a protracted interruption of major load which is defined as 400 MW or more, (2) cause lino loadings on other system components in oxcess of their emergency thermal ratings, nor (3) cause uncontrolled cascading outages of additional electrical facilities." (16 CPUC 2d 310, 324.)

This language suggests that SCE does consistently measure its system reliability in terms of its ability to meet load. While the addition of the proposed project would provide N-1 reliability to Kramer, it is a "benefit" that is invisible to the ratepayers, who would be no better served during an N-1 outage than they are now.

5. Emergency Support

SCE's witness defines emergency support as reserve support provided from other utilities. Because the proposed line does not connect with another utility, SCE argues that it does not provide any emergency support. (Tr. p. 785.) The CEC appears to suggest that a project provides benefit to the electric system if if it improves the utility's ability to serve load. Based on the testimony of SCE's Kritikson, the CEC claims that if the San Onofre Nuclear Generating Station (SONGS) and Kramer had simultaneous failures, Edison could have problems serving load. (Reply Brief p. 5.) However, in the testimony cited by the CEC, Kritikson says that Edison would have less margin if it lost Kramer, as indeed it would during any N-1 contingency. The CEC's own witness did not submit testimony on this issue.

Cal Energy's witness, Lewis, states that QF generation is very well suited to supplying emergency support. The proposed project would allow all of the Kramer area generation to be available for an emergency that affected generation in the LA Basin. (Ex. 23 p. 13.)

The definition of emergency support apparently relied upon by the CEC and Cal Energy seems to make the concept of emergency support virtually indistinguishable from system reliability. If emergency support comprises a separate potential system-wide benefit, then it must be somehow distinguishable. Based on the record before us, we are not in a position to either agree that this criterion is applicable, or to define it. However, it is worth noting that Cal Energy's position on this issue emphasizes the benefits of the QF power to be carried on the new line as opposed to the benefits stemming from the line itself. Since QF benefits are captured in the avoided cost payment, it would be inappropriate to consider them when determining how to allocate transmission costs.

6. <u>Transfer Capability</u>

SCE defines transfer capability as the ability to allow for economy energy transactions or other support between utilities. Since the Kramer-Lugo system is not interconnected with other utilities, the proposed project does not enhance transfer capability of the type described by SCE. Cal Energy claims that Edison's definition is too narrow, that one should properly consider the benefits from intra-utility support, e.g. during a gas curtailment when nongas generation is increased, as well. (Cal Energy Reply Brief p. 64.) For example during a recent natural gas curtailment, Edison asked Kramer QFs to go to maximum generation. (Tr. p. 382.)

DRA's position is that transmission lines inherently increase transfer capability and therefore that transfer capability should not be characterized as a system benefit. (Tr. p. 665.) Cal Energy says that DRA's argument fails to recognize that there will be capacity on the new line that will not be used by the currently planned QFs. (Cal Energy Reply Brief p. 65.) DRA responds: "Given the lack of surplus capacity on the Kramer-Victor line once the additional QF generation has been added, it is evident that the proposed project will not 'by its very nature' improve the transfer capability of SCE's Kramer-area transmission network." (DRA Reply Brief p. 40.)

CEC says that the proposed line will increase power transfer capability from the Mojave area, which it characterizes as the "area with the greatest generation growth within the SCE system." (Ex. 35 p. 9.) McCuen believes DRA was incorrect to say that the transfer capability of the project is not a system benefit because it is a "purpose of a transmission line." He believes the transfer capability provided by the line is a system benefit because the project was built pursuant to a standard offer, the CEC determined the generation resource was needed and because DRA, SCE, and the CEC agreed that the increased transfer capability is necessary to reliably transmit the QF power. (Ex. 35 p. 10.)

With this suggested criterion, as with others, experts disagree as to what the term means, let alone whether or not a line which enhances transfer capability would be creating a system-wide benefit for that reason. Clearly, the proposed project will not enhance transfers between utilities and will not enhance access to economy energy. Beyond that, the evidence is insufficient for us to find the existence of a system-wide benefit related to this criterion.

7. <u>Firm Resources at System Peak Conditions</u>

Whether the line provides additional firm resources depends on one's definition. SCE states: "Firm generation is merely generation that is counted toward meeting Edison's load and spinning reserve requirements. Under contingency conditions, generation that is lost is replaced by spinning reserves. This does not mean that any generation which can be lost as a result of an N-1 cannot be counted as firm." (Edison Reply Brief p. 47; cf Tr. 759.) The CEC's witness, McCuen, defines firm generation as that having a reasonably reliability, usually N-1. (Ex. 35 p. 11.)

Cal Energy's Lewis witness describes firm resources as those that are available with "100 percent reliability." (Ex. 23 p. 14.) He goes on to explain that "the implication is that there is no constraint on maximum generation resources being applied to meet a system peak condition as a consequence of the loss of a transmission circuit, (i.e., an N-1 transmission contingency)." Therefore, he finds that the line provides a benefit by increasing the firm transfer capability from 500 MW to 1000 MW. (Ex. 23. pp. 14-15.)

The discussion appears to treat this issue as a question of system reliability. As such, it is not clear that this criterion adds to the earlier analysis of reliability.

8. Cost-Effectiveness

SCE argues that any analysis of cost-effectiveness must logically include cost-benefit studies. (Edison Reply Brief pp. 58-59.) Because SCE believes that losses will increase, it does not find the line cost-effective. Edison's witness Kritikson testified that Edison typically requires a 2:1 benefit to cost ratio for a loss reduction project. (Tr. 736, 868.) Kritikson found Luz's witness Rupp's calculations of benefit-cost ratios to be incorrect, because Rupp used a project cost of $27 million instead of $50 million. This reduces the benefit cost ratio from 2.56:1 to 1.39:1, assuming $69 million in loss savings. (Tr. 750.)

While basically this issue hinges on whether one believes the line will decrease system losses, it is worth noting that even given savings of $70 million, the benefit cost ratio is far from Edison's 2:1 criteria.

Using a different definition of cost-effectiveness, CEC's witness McCuen finds the line to be cost-effective because it would be more expensive if the QFs had to build lines to Edison's' loads.

McCuen also states that the settlement agreement also adds to the cost-effectiveness of the line. (Ex. 35 p.11.)

9. <u>QF Generation and Better Air Quality</u>

Some parties argued that QF generation is intrinsically "better" than utility generation and that any transmission line which delivers QF generation to the load must therefore have system-wide benefits. For example Cal Energy notes that "the availability and the cost of fossil fuels are uncertain, whereas with solar and geothermal steam resources there are no such uncertainties, and utilization is environmentally benign." (Cal Energy Opening Brief p.37.) DRA counters that the Commission should be technology neutral, as it has been in the past. (DRA Opening Brief pp. 19-20.) DRA believes the environmental benefits of the QFs are irrelevant. (DRA Reply Brief p. 7.)

Cal Energy argues that the line is a benefit because geothermal production has lower incremental cost than conventional thermal generation. Therefore the line enhances operating economies. (Cal Energy Opening Brief p.37; cf Tr. pp. 418-419.)

DRA replies that if it is appropriate to consider QF technology a benefit, then one should also consider the higher cost of QF power. (DRA Reply Brief p. 22.) SCE offers a comparison of the utility's marginal cost calculated in SO 1 rates to the higher SO2 and SO 4 rates Luz and Cal Energy will be paid and notes that the ratepayers are paying more for the QF generation than they would for Edison's. (Edison Opening Brief p. 63.)

In terms of environmental benefits, Cal Energy states that the new line will improve air quality by providing clean energy to displace fossil generation in LA Basin. (Ex. 23 p. 15.) The new line will also reduce losses, also improving air quality. (Ex. 19 pp. 12-13.) The CEC also finds that the reduction in line losses means less fossil fired generation which means better air quality, which is a significant benefit. (CEC Reply Brief pp. 11-12.) The CEC witness also stated that Luz and Cal Energy generation has significant air quality benefits. (Ex. 22, pp. 9-13.) Kritikson agreed that generation imported to the LA Basin reduces emissions from plants within the Basin. (Tr. 911.)

Some parties (e.g. Rupp Ex. 19 p. 12) found that the reduction in line losses means less generation and therefore less air pollution. Because Edison does not believe there is a loss reduction, it does not believe there is an associated air quality benefit. (Ex. 38 p. 9.)

As we have mentioned in response to earlier system-wide benefits arguments, for the purpose of allocating transmission costs, benefits inherent in the QFs themselves should not be considered. The Commission certainly encourages the development of QFs which use renewable energy sources and reduce pollution. That encouragement is in the form of avoided cost payments. In the Biennial Resource Plan Update (BRPU) proceeding (I.89-07-004) we are considering whether or not environmental benefits of potential QFs should be given weight in the bidding process. However, the question before us here is entirely different. Obviously, the new line is needed to transmit QF power. The question affecting cost allocation is whether or not the new line itself provides system-wide benefits that go beyond the fact that the power being delivered is generated by QFs.

Air quality benefits from the line itself might be significant. If the new line reduces overall transmission losses, then less generation will be needed and less fossil fuel will be burned. Unfortunately, the line loss analysis provided in this record is inconclusive. Thus, we cannot find that this line will produce system-wide benefits in the form of air quality improvements.

10. Conclusions to be Drawn About System Benefits

We are left with only a small number of firm conclusions. First, there is no clear answer as to whether the new line creates system-wide benefits. Second, the policy set forth in D.85-09-058 may be in need of clarification in a generic proceeding.

There are aspects of this project which militate against a clear finding of system-wide benefits. First, the cumulative size of the QFs being developed by these operators is too great to allow us to simply fall back on a generalized notion of cost responsibility. We are not faced, here, with a single facility which will occupy a small fraction of the useful capacity of a transmission line which can serve many other purposes. These projects are large enough to need their own 220 kV transmission system. Although the new line might prove useful to the SCE system in other ways, those uses are clearly subordinate to the need to transmit as much as 630 MW of QF generation. SCE claims, and Cal Energy seems to agree, that there will be very little, if any, room for other users on the new line.

Second, the remoteness of the QFs from the SCE load center takes much of the system-wide benefits analysis alluded to in the 1985 decision into the realm of conjecture. Will a more substantial localized demand ever develop in the Mojave Desert? Will more firms try to construct additional QFs in the area? Is there any chance that SCE will ever seek to interconnect its northern desert transmission system with other utilities to the east or north? Transmission lines in this area are not easily categorized and there is no tidy formula for measuring potential system-wide benefits.

Finally, SCE does not have an arm's length relationship with Cal Energy, a fact which clouds the cost allocation issue.

Steven S. Rupp, testifying for Luz, stated that he is not certain that SCE has chosen the best means for transmitting the QF power into the load center. Kritiksen, testifying for SCE, said that the utility would have preferred that the QFs construct radial lines to the Victor Substation.

SCE argued that a radial line built to deliver the QF power to Victor would clearly have lacked system-wide benefits. According to SCE, since the radial line approach was abandoned solely because it would not meet the time constraints faced by the QFs, it is inappropriate to place the project cost on the shoulders of the ratepayers.

The QFs and the CEC responded to this point by arguing that the radial line issue is irrelevant, since SCE has not asked to build one and that a radial line was never a practical option since it would have required cutting a new right-of-way through the desert at great environmental expense.[13]

While the proposed project is a perfectly acceptable means of transmitting the power, the question remains as to why SCE is proposing a project which it does not prefer. SCE says it has little choice, if it is to be responsive to the need of the QF developers to complete the line as soon as possible. However, since a radial line could be build in the same corridor in a manner which would presumably take no additional time, it remains unclear as to why SCE felt compelled to propose the project it did.

An SCE subsidiary built the Cal Energy generating facilities at China Lake as well as a transmission line bringing the QF power to the Inyokern area. The contracts for those projects contained a performance incentive, increasing the payments to the SCE subsidiary if the projects were synchronized with the SCE grid by a certain date, and assessing penalties if they were not. We do not know if the close relationship between Cal Energy and SCE had any effect on SCE's decision to pursue the proposed

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13 SCE rebutted this point by saying that the radial line could have used the same right-of-way as the proposed project and, therefore, would have been no more expensive or difficult to site. The QFs and CEC did not respond to this SCE rebuttal.

project. All that is clear is that it would be inappropriate to automatically place the burden of the transmission line costs on ratepayers when the record suggests that alternatives to the proposed project may not have been given full weight in the planning process.

As noted earlier (footnote 9, p. 33), the Commission intends to begin a generic proceeding to consider QF transmission issues. This proceeding will be closely coordinated with the ongoing BRPU and will consider the issue of nondiscriminatory transmission access for QFs originally identified for consideration in Phase III of the BRPU. In addition to the issue of nondiscriminatory transmission access, we will allow all interested parties to propose changes or clarifications to the cost allocation rules raised in D.85-09-058. Within the context of the new generic proceeding, all interested parties will be afforded the opportunity to address transmission line cost allocation issues.

E. Allocation of Project Costs

Since the issuance of D.85-09-058, the atmosphere surrounding the allocation of transmission costs between QFs and ratepayers has been one of negotiation. The SCE/Luz Agreement is a manifestation of that spirit of negotiation. As Luz is quick to point out, the agreement reflects the type of real-life, business settlement that we want to encourage in the QF marketplace. Pursuant to the agreement, Luz takes full responsibility for the cost of facilities that are clearly tied to their projects--the transmission lines that carry the QF output to the Kramer Substation, and the substation improvements and added O&M needed to receive the power. Logically, costs incurred as the power moves closer to the load center are to be borne by ratepayers.

The agreement allocates more than half of the cost of the 115 kV transmission line upgrade to Luz. The record indicates that this line was built as an interim measure to meet the QFs' immediate needs and that the QFs agreed to pay for it. In approving this portion of the negotiated package, we are not agreeing that any of the cost of the 115 kV rebuild should be borne by ratepayers.

Luz has also agreed to pay 44.8% of the cost of the proposed project. While there is apparently nothing scientific about this figure, we find it reasonable in light of the fact that Luz has presented colorable arguments about the existence of system-wide benefits stemming from the proposed project. In addition to assuring that a large portion of the project cost will not be the responsibility of ratepayers, Luz has agreed to absorb the risk of all precertification expenses and will undertake the responsibility for building the transmission line itself. Further, had the CPCN proceeding not become entangled in the controversy surrounding the allocation of project costs to Cal Energy, the role played by the SCE/Luz Agreement in simplifying the regulatory process would have been evident. All of the parties to the proceeding support the agreement.

The benefits of negotiated cost allocation have not been brought to bear on the issue of Cal Energy's share of the cost. We are disappointed at the failure of SCE and Cal Energy to come to terms. In addition, our application of D.85-09-058 in its current form has not persuaded us that Cal Energy should be relieved of all cost responsibility for the proposed project.

The parties were asked to file testimony suggesting the appropriate allocation of costs to Cal Energy. SCE proposed that all costs not borne by Luz be paid by Cal Energy. DRA proposed that Cal Energy be required to pay a portion of the project cost equal to that paid by Luz (44.8%), leaving the remainder to ratepayers. Cal Energy simply restated its position that it has the right to avoid any cost allocation under D.85-09-058. SCE supported its proposal by asserting that the proposed project is devoid of system benefits and should, therefore, be paid for by the QFs. DRA supported its proposal by arguing that, although the Luz projects have a much larger aggregate nameplate capacity than those of Cal Energy, both QFs will generate a roughly equivalent number of gigawatt-hours on an annual basis.

Both the SCE and DRA proposals would result in an arbitrary allocation of costs to Cal Energy. In the SCE proposal, Cal Energy would pay for 55.2% of the project cost, simply because Luz only agreed to pay for 44.8%. In the DRA proposal, Cal Energy would pay 44.8% of the cost for the same reason. In a situation such as this where two QFs have equivalent transmission priority status, it is more equitable to base cost allocation on the relative use of the new line. Since the project design is dictated by the maximum capacity needs, not the number of gigawatt-hours produced, it makes more sense to use the relative capacity needs of the two QFs who will be the dominant users of the new line as a basis for determining their cost responsibilities. The record in this proceeding indicates that Luz and Cal Energy have equal transmission priority status. Because Cal Energy will contribute an estimated 150 MW of the 630 MW expected to be carried on the new line, it should be responsible for 150/630, or 23.8% of the QF share of the project cost.

However, there is one aspect of the proposed project which should clearly be incorporated at the expense of ratepayers. Although SCE does not currently anticipate needing additional transmission capacity in this corridor, the utility has proposed to "overbuild" the towers for the new line so that they would be capable of supporting an extra set of conductors on each circuit. It is hoped that this alteration to the project design will enable SCE to meet any unanticipated future need without constructing additional towers or further taxing an already crowded transmission corridor.

The QFs have argued that this overbuilding comprises a system benefit, in that it allows for the accommodation of future growth. We do not agree that this step creates a system benefit, since no one has predicted that it will be needed. In addition, since the overbuilding of the towers is not necessary in order to transmit the QF power, it does not seem appropriate to suggest that the project needed to carry the QF power creates system benefits. Nonetheless, SCE's decision to overbuild the towers for the proposed transmission line is a prudent one because it adds flexibility and the potential for future new transmission capacity at a cost that would be much less than an entirely new transmission system. Since any advantage from this added flexibility would be likely to enure to ratepayers, the incremental cost of this feature should be absorbed by ratepayers.

The record indicates that approximately $6 million of the currently estimated $50.3 million project cost is the result of the tower overbuilding. QFs should not be responsible for that cost. Thus, the overall QF share of the project cost should be calculated as follows:

$$\frac{\$50.3 \text{ million} - \$6 \text{ million}}{\$50.3 \text{ million}} = 88.07\%$$

Cal Energy's allocated share of the overall project cost should be 21%, which is 23.8% of the 88.07% generally allocated to the QFs.

Under this approach, Luz would pay more than twice as much of the project cost as Cal Energy. Nonetheless, Cal Energy argues that this allocation is unfairly discriminatory. Since Luz is responsible for 76% of the capacity of the new QFs and is only required to pay for 44.8% of the project cost, Cal Energy argues that it is unfair to require Cal Energy to pay 21% of the cost, which is more closely related to its relative share of the new QF capacity. Cal Energy's argument fails to take into account that the Luz cost allocation is part of a comprehensive package under which Luz accepts cost responsibility for other ancillary facilities. It is fair to limit Luz' responsibility to a 44.8% share of the project cost because that figure is the product of negotiation and included in a broader agreement which is reasonable when taken as a whole. Just as the Luz agreement should not be used to increase Cal Energy's cost liability (as suggested by SCE and DRA), it should not be used to reduce Cal Energy's cost liability (as suggested by Cal Energy).

Finally, in its Opening Comments, Cal Energy has offered a new cost allocation approach which would reduce its share by assuming that the capacity of the new line would be expanded at some unspecified future date. Cal Energy was strongly encouraged to offer alternative allocation proposals during the evidentiary hearings. It declined to do so, and it would be inappropriate to entertain such new evidence as the result of comments filed after the record was closed. In addition, the record does not support an assumption that the transmission capacity will need to be expanded. For both of these reasons, the latest Cal Energy proposal will not be adopted.

F. <u>Cal Energy's Obligation to Pay its Share</u>

In a conference attended by all parties, Cal Energy responded to a question from the ALJ by asserting that even if the Commission were to allocate a portion of the project cost to Cal Energy, the QF would be under no legal obligation to pay it. Because of this assertion, the ALJ asked all parties to address, in their briefs, the issue of Cal Energy's legal obligation to pay its share of the costs as determined by the Commission.

Cal Energy refused to brief the issue, choosing instead to adhere to its position that it should not be required to pay any portion of the line cost. Having refused to address the issue as requested by the ALJ, Cal Energy then sought to reserve its right to address the issue "in the appropriate manner." Cal Energy has been given ample opportunity to address this legal issue and chosen not to do so. We will now review the positions of the other parties.

SCE, DRA, and Luz all argue that the Commission has ample means for enforcing an obligation on the part of Cal Energy to pay its share of the project costs. It is the PURPA which requires the utility to provide interconnections for QFs. SCE and Luz argue that PURPA also empowers this Commission to require QFs to pay all reasonable interconnection costs. Both cite a portion of PURPA (16 U.S.C. Section 292.306(a) as follows:

> "Each qualifying facility shall be obligated to pay any interconnection costs which tho state regulatory authority (with respect to any electric utility over which it has ratemaking authority)...may assess against the qualifying facility on a non-discriminatory basis with respect to other customers with similar load characteristics."

Luz further argues that the Commission is virtually assured that both Luz and Cal Energy will meet their payment obligations. In its opening brief, Luz states:

> "...these QFs have SO2 and SO4 contracts, pursuant to which Edison will pay the project owners millions of dollars each year. These payments could, if necessary, be offset against for recovery of monies owed for the transmission line. There is thus a guaranteed means of recovering the QF's share of the costs.
>
> "[In addition], Edison controls the breaker switch which permits the QF power to flow into the system. It therefore can control the ability of these QFs to continue to interconnect if they refuse to meet their obligations. Luz respectfully suggests that the risk of QF nonpayment is extremely small and, to the extent any such risk is present, it is mitigated by the above factors."

We agree. Cal Energy is obligated to pay its share of the interconnection costs as determined by this Commission. We further find that the potential for nonpayment of Cal Energy's share of the project costs does not pose a significant risk to SCE or its ratepayers.

## VIII. Environmental Considerations

### A. Preparation of the EIR

When SCE submitted its application in this matter, it was accompanied by the PEA, which sets forth the applicant's understanding of areas of potential environmental concern. The task of analyzing the PEA, determining the scope of the Draft EIR (DEIR), and overseeing the work of the environmental consultant selected to prepare the DEIR was undertaken by the Environmental and Special Projects Section of the Commission's Advisory and Compliance Division (CACD). An Environmental Scoping Meeting was held in Adelanto on July 26, 1989 and the DEIR was released for comment on November 30, 1989. Comments on the DEIR were received until January 7, 1990, which is also the date on which a hearing was held in Adelanto to receive oral comments on the DEIR.

Comments on the DEIR were received from several property owners in the vicinity of the proposed project, SCE, the Department of the Air Force, the California Office of Planning and Research, the California Department of Transportation, the CEC, the City of Adelanto, and the City of Victorville. The comments from each of these parties was addressed in the Final EIR which was distributed in June, 1990.

### B. Project Alternatives

The EIR addresses six alternatives to the proposed project. Two of these are variations of the "no project" alternative. Those two alternatives are as follows:

1. Neither the proposed project nor any of the associated projects (e.g. Coso-Kramer 220 kV T/L conductoring, 115 kV Kramer-Victor rebuild, and Lugo transformer upgrade) are built, or

2. The proposed project is not built, but the associated projects are completed.

Since the existing transmission in the project area is fully committed and cannot safely accommodate the new QF generation, SCE is required under PURPA to identify and develop alternative transmission service as soon as possible. Selection of either variation of the "no project" alternative would result in at least some of the Luz and Cal Energy projects not being interconnected to the regional distribution system. This is not a viable solution to SCE's obligation to interconnect and integrate the QF projects. Under the second variation, approximately 300 MW of the new generation could be transmitted on the existing lines, but line losses would be prohibitively high.

The other four project alternatives explored in the EIR were as follows:

1. 500 kV and greater high voltage direct current (HVDC) transmission line,

2. 500 kV alternating current (HVAC) transmission line,

3. Underground high voltage transmission line, and

4. An alternative 115 kV Method of Service.

These alternative systems were determined to either have greater environmental impacts than the proposed project, significant electrical inefficiencies or both. The HVDC and 500 kV HVAC systems would require the construction of additional facilities, such as converter stations and substations, which would substantially increase the amount of ground disturbance required for the project. These alternatives would also have a significant potential to adversely affect visual resources and create land use conflicts due to the large additional structures that would be required for each respective system.

Undergrounding of a 220 kV line was rejected due to the significant amount of ground disturbance that would occur in an environmentally sensitive area. None of these three alternatives were found to be environmentally preferable to the construction of a conventional 220 kV transmission line.

The fourth alternative, a new 115 kV Method of Service, would have involved the construction of a new 85-mile, double-circuit steel pole line directly from the BLM and Navy 2 facilities to Victor Substation, two new 40-mile, double circuit 115 kV lines from Harper Lake directly to Victor Substation, and reconstruction work at the Victor Substation. While this is technically feasible, this alternative was rejected since it would have higher line losses than the preferred 220 kV system and would create significantly higher environmental impacts due to the greater length of transmission line needed and the need for new access roads. This approach was also found to be more costly than the proposed project.

C. <u>Alternative Corridors</u>

Four alternative corridors were selected for study in the EIR. Alternative I consisted of a route directly paralleling the existing Kramer-Victor 115 kV line between the two substations. This line would run generally parallel to Highway 395 and would pass directly through the center of Adelanto. Alternative II is similar to the preferred route except that its southern portion passes farther west of the Adelanto area. Alternatives IV and V run east from Kramer Junction generally parallel to Highway 58 for approximately 10 miles, then turn south-southeast along a subroute that eventually crosses over the mountains northeast of Victorville. Near Victorville, these routes would turn west along existing utility corridors and continue into the substation. Alternatives IV and V would have slightly different subroutes and would provide corridor options along the eastern side of the study area.

Alternative III is the preferred corridor. This is the corridor than runs mostly parallel to the existing SCE 220 kV line. It was selected as the preferred corridor because it had the lowest overall environmental impacts.

D. Environmental Impacts

The following is a summary of the potentially significant effects of the project as set forth in the EIR. Mitigation measures, where recommended, are also summarized.

1. General

The project is not expected to have any significant effect on the environment because the line would be constructed adjacent to an existing similar line, existing access roads and construction-related storage sites are already available to serve the project, and few sensitive resources are located in the preferred corridor.

2. Biological Resources

The project area includes the habitat of sensitive plant and wildlife resources such as desert tortoise (an endangered species), Mojave ground squirrel (a State-listed threatened species), Mojave spineflower, desert cymopterus, and Western Mojave saltbush assemblage. However, construction of the proposed line in the preferred route is not expected to have a significant impact on these resources because of the location of the selected alignment and the mitigation measures proposed for incorporation into the project.

While there are reported low to moderate densities of desert tortoise in the general vicinity of the preferred route, site surveys for this project indicate that densities are very low in areas directly adjacent to Highway 395 and in the preferred corridor. Because of the low amount of ground surface contact of transmission line structures, the proposed project would only result in the permanent loss of approximately two acres of habitat.

Since existing access roads can be used, only approximately one mile of new spur roads would be needed to complete the project.

The occurrences of the other sensitive biological resources in the project areas are also very low in comparison to other parts of the study area. For example, only a few Mojave ground squirrels have been recorded in the entire route and the sensitive plants are limited to a few known sites.

In addition to selecting a route that has low occurrences of sensitive species, the following measures will be undertaken to prevent direct or indirect impacts to such resources. Sensitive plant species will either be avoided or damage will be limited to very small areas. Appropriately timed spring surveys will be conducted by qualified personnel to confirm the presence or absence of sensitive species. Transmission line facilities will be located so as to avoid such resources as is practical. All resources to be avoided will be flagged prior to initiation of construction activities.

Wildlife resources, especially desert tortoise and Mojave ground squirrel, will be protected by preconstruction surveys. Flagging of burrows and dens, spanning or relocation of facilities to avoid sensitive areas, removal of tortoises out of the construction areas, and implementation of construction crew environmental education programs. All work will be monitored by qualified environmental personnel to assure continued protection of desert tortoise and Mojave ground squirrels during the construction period.

3. Land Use

The preferred corridor traverses a variety of open space, rural, and developed land uses. The route avoids conflicts with existing military facilities, such as Edwards Air Force Base, and it is located in an approved U. S. Bureau of Land Management utility corridor. Placement of the new line directly adjacent to an existing line minimizes potential land use conflicts in contract to routing away from existing utility corridors.

In the Adelanto area the proposed transmission line would potentially conflict with two existing residential structure and a proposed business park. Without mitigation, acquisition of the right-of-way necessary for the new line would conflict with established lots in a business park being developed by the City of Adelanto.

To eliminate potential land use impacts, SCE intends to acquire and relocate two homes within the new right-of-way. To eliminate potential land use impacts to the business park, SCE has proposed to use tubular steel towers for both the existing and proposed line where it passes east of this development. The double row of tubular steel towers will fit within the existing right-of-way in that area.

The proposed new line could potentially conflict with some existing mining areas and a communications facility in the Kramer Hills. SCE will avoid this potential impact by coordinating the placement of towers in these areas with the adjacent landowners.

The project will not have a significant land use impact if these measures are implemented.

4. Visual Resources

The project would result in the construction of a new 220 kV transmission line that will cross the project area. Because of the open qualities of the desert terrain and the proximity of the line to urban uses, it will result in a change to the existing visual resources. However, if the line is placed in the preferred route, impacts to visual resources should not be significant.

The proposed line would be placed in close proximity to an existing, very similar, 220 kV transmission line for its entire length. SCE should align the new towers with the existing towers where feasible to reduce the visual disharmony that would otherwise result. While the line will be visible, it should not result in a significant deterioration of the existing visual resources of the project area.

5. Cultural Resources

The project area has been generally surveyed for archaeological and historical resources. These studies indicate the preferred corridor should avoid most regionally significant cultural resources. However, additional focused preconstruction cultural resource surveys will be needed in all areas that may be disturbed by the project. SCE shall either avoid or excavate and record reported cultural resource sites in the preferred corridor.

6. Paleontological Resources

The northern portion of the preferred route has the potential to contain subsurface paleontological resources that may be significant. While the project will only involve limited subsurface disturbance (tower footings), the soil removed from foundation excavations shall be sampled and surveyed by a qualified paleontologist retained by SCE. The results of these surveys shall be placed in the appropriate local library.

7. Other Resources

The project is not expected to have any significant effects on other resources such as noise, air quality, socioeconomics, traffic and transportation, radio interference, or public health and safety. Except as otherwise noted in this decision, the EIR found that standard design and construction procedures typically implemented by SCE are adequate to prevent any significant effects on such resources.

8. Comparison to Alternative Corridors

The four alternative corridors evaluated in this EIR and the SCE background studies would potentially generate greater environmental impacts than would the preferred route.

Alternative I would result in significant land use and visual changes since the new transmission line would be extended through a relatively dense urban area, downtown Adelanto. Acquisition of additional right-of-way would affect many properties and the new towers would be visually intrusive in this type of setting. These impacts could probably not be reduced to a level of insignificance. This alternative would only incrementally reduce the potential impacts to biological resources.

Alternative II would increase impacts to visual and biological resources since it would traverse an open, generally undeveloped, portion of desert to the west of Adelanto. The sub-route farther to the west of Adelanto than the preferred route would slightly reduce potential land use conflicts, however, those impacts have been completely mitigated in the latter route.

Alternative IV and V would comparatively increase the amount of high value, undisturbed desert habitat that is crossed by the transmission line, it would increase public access to such areas, and it would increase visual impacts in comparison to the preferred route. Alternative VI is slightly better than V since it partially follows an existing utility corridor.

None of the alternative corridors, even with mitigation, is environmentally preferable to Alternative III, the proposed corridor.

E. <u>Comments on the DEIR</u>

Many significant points were raised in the comments to the DEIR and all of them have been addressed in the EIR. Two, however, are worthy of extra discussion. The first is a comment made by Robert L. Therkelsen, the Chief of the Energy Facility and Environmental Protection Division of the CEC.

When certifying the location for a new transmission project, this Commission does not determine where each footing for each tower will be placed. There are at least two practical reasons for this. First, taking this project as an example, over

150 miles of corridors were explored to determine the preferred place to site a 38 mile line. The expense and time required to take a magnifying glass to every foot of each alternative location would be prohibitive. Often, detailed studies can be completed only after the list of potential locations has been narrowed down. Second, we need to balance our responsibilities to thoroughly assess and minimize environmental impacts with the need to leave the constructing utility with the flexibility to get the project done. As a result, instead of approving a precise route, we approve a corridor in which the project must be sited. In most locations, the study corridors for this project are two miles wide. In addition, we specify a series of mitigation measures and other conditions which must be applied in determining where the towers will be placed. Thus, although the utility maintains some discretion, it also carries prescribed responsibilities which must be carried out to adequately protect the environment.

Therkelsen has discovered an apparent anomaly in this process. He points out that, because of the expanse of the study corridors, the EIR has used sensitivity analysis and sampling techniques to assess potential impacts instead of performing detailed studies. He agrees that this is the appropriate approach to use before a final route is selected. However, he says that the EIR nonetheless speaks in terms of a specific preferred route and seems to gear its mitigation measures accordingly. He says that since this is the case, the studies of impacts in that corridor included in the DEIR should have been much more specific.

The response to this issue contained in the EIR says that SCE has decided to undertake more detailed archaeological and biological studies even before project approval in order to expedite the completion of the project. SCE chose to undertake the more detailed studies only along its preferred route alignment. The EIR states that even small differences between the alignment studied and the project as it is finally approved could cause the expedited construction schedule to slip.

While SCE was free to undertake more detailed studies wherever it wanted to, it limited the location of the detailed study area at its own risk. The CEQA project review and CPCN process would be meaningless unless the lead agency could assert its judgment as to the environmentally preferred location for the project. Regardless of the detailed archaeological and biological studies undertaken to date, we will require that SCE meet a high standard of care in undertaking the mitigation measures prescribed in this order as well as in meeting other licensing conditions. Only after the full range of mitigation measures and other conditions are satisfied will SCE be able to specifically site each tower. As part of the mitigation monitoring program to be discussed below, SCE must demonstrate both that all of the detailed studies adequately address the specific locations where the line will be placed and that impacts to the specific resources discovered as a result of those detailed studies are adequately mitigated.

The second comment which we will specifically address was echoed by a number of property owners from the vicinity of the preferred corridor. Each commenting property owner expressed the concern that the DEIR was insufficient in addressing the potential health hazard for people residing adjacent to electrical power lines of the type that will be built here. In response to these comments, extensive additional discussion of this issue was added to the EIR.

As reported in the EIR, studies to date allow one to reach virtually any conclusion as to whether the electromagnetic fields emanating from transmission lines pose hazards to health. On the cellular level, laboratory studies have demonstrated several different types of physiological responses to the presence of power frequency fields. While any of these different effects could create a health hazard, none has yet been shown to pose a hazard. Some epidemiological studies have shown a statistically significant relationship between exposure to above-average electromagnetic fields and the risk of contracting childhood cancer. Some such studies have not found a statistically significant relationship. All that is certain is that we do not know enough to dismiss the issue entirely.

Is the potential of a health risk stemming from exposure to higher than normal electromagnetic fields sufficiently certain to require us to find the introduction of such fields to be a significant environmental effect under CEQA? The EIR finds the potential risk to be too speculative to be categorized as significant. This may be an appropriate response, given both the uncertainties involved and the limited range of designations provided under CEQA.

However, our responsibility to respond to the health, safety and environmental concerns of those exposed to utility facilities is not limited to CEQA. As cited above, PU Code Section 1002 provides us with responsibility independent of CEQA to include environmental influences and community values in our consideration of a request for a CPCN.

Several states have responded to the electromagnetic field issue by establishing maximum exposure levels to be allowed at the edge of a transmission right-of-way. We feel that the information currently available is insufficient to allow for this type of regulation. Other jurisdictions and agencies have concluded that, while the jury is out on the question of transmission line-related health risks, the prudent response is to avoid unnecessary new exposure to electromagnetic fields. Thus, if it is ever determined that a health risk does exist, government will have acted rationally to avoid unnecessary exposure to that risk.

We are no more able than any other governmental entity to make a final judgment based on current information about the potential for health risk stemming from exposure to electromagnetic fields. However, until the scientific findings are more definitive, we will require SCE to take responsible, low-cost steps to avoid unnecessarily exposing people to these fields. Whatever remedies will be applied must be determined within the constraints of each new construction project. This should not be construed as requiring that any action be taken to change field exposure levels along existing transmission lines. Because of the continuing scientific uncertainty, remedies should be fashioned so as to minimize impact on over-all project cost. Since no one has identified any particular exposure level as safe or unsafe, the chosen remedy must strive to maintain the status quo. As a first step, those living and working near a proposed new line should be enabled to make informed judgment about the potential for health risk with continuous exposure. In addition, wherever economically feasible, a new line should not increase the electromagnetic field levels to residents and workers along the right-of-way. In a project such as this, which will run parallel to an existing transmission corridor, the goal is not to eliminate electromagnetic field effects, but to situate the line so that, wherever feasible, those living and working along the corridor will be exposed to no more than the field strengths already in place.

Toward that end, we will place two additional conditions on the CPCN to be granted today:

1. SCE shall provide to those living, playing and working in close proximity to the final transmission line route balanced written information about the existing controversy in the scientific community concerning the potential for health effects stemming from prolonged exposure to electromagnetic fields emanating from electric transmission lines.

2. SCE shall measure existing electromagnetic field levels at the edge of the proposed right-of-way along the preferred route and shall take reasonable steps to place the new line within the study corridor in such a way as to minimize any increase in field exposure levels to those living in planned and existing residences, working or playing near the edge of the right-of-way.

The goal of these actions is to minimize the risks that would exist if increased exposures do pose a health problem, by taking steps that do not significantly increase the over-all project cost. Although these steps do not comprise mitigation measures under CEQA, SCE's implementation of these requirements shall be coordinated with the mitigation monitoring program set forth below.

In its Opening Comments, SCE suggested alternative approaches to each of the additional conditions. First, instead of providing written information to affected individuals, SCE would provide "notice" in the project area. This proposal is too vague to assure that potentially affected individuals will have an opportunity to be informed about the controversy. Second, SCE proposes that it only be required to adjust the tower alignment within the preferred right-of-way. Because that corridor is so relatively narrow, confining line adjustments to that area would make it less likely that realignment would produce beneficial results. SCE's proposed changes are rejected.

F. <u>Mitigation and Mitigation Monitoring</u>

The Commission is required to evaluate this application in conformance with the provisions of CEQA. The significance of that requirement goes far beyond the mere preparation of an EIR as one of the regulatory steps in processing the application. It is the purpose of the EIR to identify the significant environmental effects of the proposed project, identify project alternatives and indicate how the significant effects can be mitigated or avoided.

Under CEQA, the Commission is required to give preference to environmentally preferred alternatives. However, CEQA does not require the mandatory choice of the environmentally preferred alternative. Other considerations such as economic, legal, social and technological factors may make the environmentally superior alternatives unacceptable. The applicant's proposal can be approved once its significant adverse environmental effects have been reduced to an acceptable level by mitigation measures.

The EIR contains an extensive list of measures designed to mitigate the adverse environmental impacts of the proposed project. All of the mitigation measures should be adopted as more fully described in the EIR. In addition, we will adopt a mitigation monitoring program, as described in the EIR, which is similar to that which was adopted for SDG&E's Eastern Interconnection System, SCE's Devers-Palo Verde 1 and SCE's Devers-Palo Verde 2 projects.[14] The goal of the program will be to assure that the mitigation programs outlined in the EIR are fully implemented and that additional mitigation takes place consistent with the results of further studies undertaken after engineering plans and construction methods are finalized. All costs of the mitigation monitoring program will be borne by SCE and the other project participants as part of the project costs.

We conclude, based on the EIR and other comments, that the recommended mitigation measures reduce the environmental impacts of the project to an insignificant level.

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14 D.93785, issued December 1, 1981 in A.59755; D.84-10-034, issued October 3, 1984 in A.59982; and D.88-12-030, issued December 9, 1988 in A.85-12-012.

## IX. Pending Motions

Three motions were filed subsequent to the submission of the proceeding:

### A. Motion of DRA to Admit Additional Evidence Related to Exhibit 48

Exhibit 48 is a late-filed exhibit containing copies of three contracts between companies affiliated with Cal Energy and companies affiliated with SCE related to the construction of power plants and transmission lines in the China Lake area. Portions of each contract were redacted by SCE. In accepting the exhibit, the ALJ indicated that parties would have an opportunity to protest the omission of the redacted portions. The exhibit also contained a copy of one contract between Luz and SCE.

DRA sought to expand the exhibit by restoring all of the redacted portions of the contracts in the exhibit and appending to Exhibit 48 limited excerpts from testimony prepared by DRA for presentation in another proceeding. The latter excerpts pertain directly to the Luz contract which was already included in the exhibit. Responses opposing the motion were filed by SCE and by its affiliate, Mission Power Engineering Company.

The motion is denied. However, in denying this motion, we wish to make it clear that we are not ruling on the merits of the SCE/Mission Power claim that the redacted portions of Exhibit 48 should be protected. We are simply are not persuaded that the information withheld from Exhibit 48 could in any way change the outcome of this proceeding. At the same time, the complete, unredacted version of the contracts in Exhibit 48 is fully discoverable by DRA. SCE shall provide copies to DRA no later than ten days after the issuance of this decision. The prepared testimony belatedly offered by DRA will also not be received. There is no apparent reason that DRA could not have offered a witness to sponsor this and any other related testimony during the proceeding.

B. Motion Re Supplemental Brief of Luz International Limited

Luz requested extra time to file a supplemental brief on issues related to interconnection requirements. The brief was filed May 4, 1990. The motion is granted.

C. Motion of SCE to Establish Phase II of A.89-03-026 to Determine Cost Allocation of Interconnection and Integration Facilities Not Subject to CPCN

The agreement between Luz and SCE resolved issues related not only to Luz's share of the cost of the proposed project, but also Luz's share of expenses related to certain other facilities which cost approximately $50 million. Those other facilities include the 115 kV rebuild from Kramer to Victor, Lugo Substation upgrades, termination of the Luz 220 kV line at the Kramer Substation, and the cost of portion of the Coso-Kramer 220 kV line and termination. Since no such agreement was reached between Cal Energy and SCE, Cal Energy's share of these costs is left unresolved. SCE says that $38.3 million of that cost will remain unresolved after this issuance of this decision. SCE claims an agreement between SCE and Cal Energy covering costs is unlikely.

SCE moves for the creation of a second phase in this proceeding to allow for prompt allocation of these costs. DRA supports this motion and requests that, in Phase II, the Commmission examine all of the costs stemming from the construction of the ancillary facilities, including those addressed in the Luz/SCE agreement. The effect of following DRA's suggestion is that the final decision as to whether to SCE/Luz agreement should be approved would then be postponed until the end of Phase II.

Luz supports the creation of a second phase under this docket, but strongly opposes DRA's request that certain aspects of the SCE/Luz Agreement be examined in that phase. Luz describes

DRA's proposal as one coming forth "out of the blue", and argues that it is "entirely unfair". Luz describes the granting of DRA's request as "a potentially lethal blow to Luz's ability to meet a development schedule that will satisfy its obligations to Edison under its Standard Offer 2 contracts, as well as a potentially lethal blow to Luz's financial viability in constructing power plants."

The passionate nature of Luz's objection is a bit curious in light of the fact that Luz, itself, had made an earlier request that the reasonableness of its agreement with SCE be deferred to a separate and later phase of the case. That earlier request was denied for the same reason that DRA's request will now be denied. Because we must understand the nature of costs to be borne by ratepayers prior to granting a CPCN, we must examine the SCE/Luz agreement and the merits of the CPCN in the same phase of the proceeding. No part of the agreement becomes effective unless the document is approved in its entirety. Thus, the portions of the agreement related to allocation of the cost of the proposed project cannot affect the issuance of the CPCN unless we approve or reject the entire agreement now. During the proceeding, DRA supported approval of the whole agreement. The evidence overwhelmingly supports that approval.

We will establish a second phase of this proceeding for the sole purpose of addressing the unresolved cost issues related to the 115 kV rebuild, Lugo Substation upgrades, and the Coso-Kramer 220 kV line and termination. The ALJ shall schedule a prehearing conference at an early date to schedule the presentation of evidence in Phase II. At the same time, we continue to encourage SCE and Cal Energy to attempt to resolve their differences through negotiation.

Findings of Fact

1. SCE filed its application for a CPCN and the accompanying PEA on March 20, 1989.

2. SCE proposes to construct a new, 38-milo long, double-circuit 220 kV transmission line connected in tho north to the Kramer Substation, located at the small community of Kramer Junction at the intersection of U.S. Highway 395 and State Highway 58.

3. The proposed line is needed to facilitate the delivery into the SCE load center of power from two types of small power facilities (QFs) located in the Mojave Desert: geothermal power plants developed by Cal Energy, and solar thermal power plants developed by Luz.

4. The project is currently scheduled to go into operation in December 1991.

5. On November 17, 1989, SCE and Luz signed an agreement which allocates among Luz and SCE's ratepayers costs related to the proposed 220 kV line and other interconnection and integration facilities.

6. Luz agrees to pay 44.8% of the cost of the proposed 220 kV line. Cal Energy, the other QF developer seeking use of the proposed 220 kV line, has not entered into a cost sharing agreement with SCE.

7. DRA's testimony, released on December 19, 1989, included a recommendation that the SCE/Luz Agreement be rejected.

8. SCE requested a 90-day extension. We concur with this request, which results in a final decision deadline of July 20, 1990.

9. The CPCN requirements go beyond a determination that a new project is necessary. Before granting a CPCN, the Commission must consider an analysis of the financial impacts of the proposed project on the utility's ratepayers and shareholders. The Commission must review the expected cost of the project and for

those projects estimated to cost more than $50 million, it must set a cap, or maximum amount which can be spent by the utility on the project without seeking further Commission approval.

10. The Commission has a statutory obligation, even in the absence of CEQA, to give consideration to the following factors as a basis for granting any CPCN:

a. Community values.
b. Recreational and park areas.
c. Historical and aesthetic values.
d. Influence on the environment.

11. CEQA requires the preparation of an EIR where there is substantial evidence that a project may have a significant effect on the environment.

12. In preparing the EIR, the lead agency must consider the full range of alternatives to the proposed project, including the alternative that there be no new project at all.

13. Cal Energy has constructed its BLM and Navy 2 facilities at China Lake in the Mojave Desert. They have a combined net capacity of 150 MW.

14. Cal Energy procured the construction of a 220 kV line to SCE's Inyokern Substation where the conductor loops around the substation and is strung on the formerly vacant side of a series of SCE towers which carry the line down to the Kramer Substation.

15. Luz has constructed and brought on line its SEGS Unit VIII at its Harper Lake facility in the Mojave Desert.

16. Each SEGS unit at Harper Lake is designed to have an installed generating capacity of 80 MW.

17. Luz plans to bring SEGS IX on line in September, 1990 and another unit on line by the end of each year from 1991 through 1993.

18. In its agreement with SCE, Luz has committed to sell to the utility additional 20 MW of output from one of its Harper Lake units.

19. Altogether, the SEGS generation from Harper Lake is expected to have a maximum capacity of 480 MW.

20. SEGS XIII is under contract to SDG&E.

21. Power from SEGS XIII would be wheeled across SCE lines for delivery to the SDG&E service territory if the merger between SCE and SDG&E, which is the subject of A.88-12-035, is not approved.

22. Luz has constructed a 12 mile 220 kV transmission line to deliver power from Harper Lake to the Kramer Substation.

23. SCE is required under the federal PURPA to interconnect with and purchase power from the QFs developed by Cal Energy and Luz.

24. SCE needs to add additional 220 kV transmission capacity in order to move all of the power from these QFs as far south as the Victor Substation.

25. If the QF generation is to be delivered to the Kramer Substation, it will be necessary for the additional 220 kV transmission capacity to interconnect at Kramer.

26. Power moving from the Kramer Substation toward the SCE load center is delivered to the Lugo Substation, from which it can be routed on existing 500 kV lines.

27. SCE has two 220 kV lines which currently carry power directly from Kramer to Lugo.

28. These two existing Kramer to Lugo circuits and the related transformers will be fully loaded when all existing and previously committed SCE and QF generation resources come on line.

29. Power is currently imported to Victor from Lugo.

30. SCE will be able to serve load in the Victor area with power heading south from Kramer by interconnecting additional transmission capacity at Victor.

31. If all of the generating sources which are already committed to use the existing Kramer to Lugo lines were to operate at full strength, they would fill the existing lines to 102% of their capacity.

32. While it is possible to carry more than 100% of capacity on a given line, it is not advisable to do so. Line losses would be great and the conductors would be in danger of accelerated deterioration.

33. Without the addition of the Cal Energy and Luz facilities, there is very little danger of ever taxing the existing lines to this extent.

34. Another technically feasible means of delivering this power to the SCE grid reflected in the record would involve building radial lines from the China Lake and Harper Lake areas directly to Victor or Luz.

35. To accommodate the new line, the existing right-of-way between the Kramer and Victor substations would need to be increased by 75-100 feet, depending on the specific locations of the transmission towers.

36. The proposed project also includes certain modifications and additions to the Kramer, Victor and Lugo substations. At the Kramer Substation those changes include:

a. the construction of two additional positions in the existing 220 kV switchyard to terminate the new circuits,

b. the installation of one 115 kV capacitor bank, and

c. the installation of necessary protection equipment.

At Victor, those changes include:

a. the construction of four new 220 kV line positions in a new 220 kV switchrack which will form the termination of the new transmission line and the two existing Lugo-Victor 220 kV circuits,

b. the installation of two 220 kV bank positions,

c. the installation of two 220 kV capacitor banks, and

d. the installation of necessary protection equipment.

Finally, additional protection equipment will be required at the Lugo Substation as a result of increased loading caused by the proposed project.

37. The Commission is required by PU Code Section 1005(b) to specify the estimated cost in the certificate which it issues for the project. Further, for facilities estimated to cost more than $50 million, PU Code Section 1005.5 requires that the Commission specify, in the certificate, a maximum cost determined to be reasonable and prudent for the facility.

38. SCE estimates the proposed transmission line to cost $32.225 million and the proposed substation improvements to cost $18.155 million.

39. DRA estimates the proposed transmission line to cost $30 million and the proposed substation improvements to cost $13 million.

40. SCE's project cost estimate was prepared in a reasonable manner.

41. The cost cap process set forth in PU Section 1005.5 allows the Commission to ensure that a project which appeared to be cost-effective when it was certified does not move forward unchecked if subsequent cost escalation makes completion of the project economically unwise.

42. The estimated cost of this project is slightly more than $50 million.

43. PU Code Section 1003(d) requires that the applicant for a CPCN demonstrate, among other things, the financial impact of the new project on the company's ratepayers.

44. In order to understand the ratepayer impacts, it is necessary to estimate how much ratepayers will be asked to spend for the project.

45. As an interim means of carrying Luz and Cal Energy power between Kramer and Victor, the parties agreed to the rebuilding of an existing 115 kV line.

46. No one is currently opposing approval of the SCE/Luz agreement.

47. SCE has asked the Commission to approve its agreement with Luz under which Luz would bear the following costs:

a. 44.8% of the cost of the proposed project.

b. 100% of the cost of the 220 kV transmission line from Harper Lake (site of the SEGS VIII-XIII units) to the Kramer Substation and the cost of the line's termination at the Kramer Substation.

c. All operation and maintenance (O&M) costs related to the Kramer Substation termination facilities for the Luz 220 kV line.

d. 52% of the cost of the Kramer-Victor 115 kV transmission line rebuild which provides an interim means for transmitting Luz and Cal Energy power.

e. 100% of the cost of metering and telemetering equipment.

48. The two parties further agreed that while SCE would engineer, design and provide equipment specifications for the proposed 220 kV line, Luz would procure the needed equipment and construct the line for a fixed cost.

49. Under the SCE/Luz agreement, Luz and SCE expect that the line can be built as much as a year earlier than was previously planned.

50. Pursuant to the SCE/Luz agreement, Luz would deed ownership of the line to SCE.

51. Pursuant to the SCE/Luz agreement, SCE would be fully responsible for planning and constructing the other facilities included in the proposed project.

52. SCE agreed to pay all of the cost of upgrading the Lugo substation and all O&M costs for facilities south of the Kramer Substation.

53. If the SCE/Luz Agreement were to be approved, it would still be necessary to determine what portion, if any, of the remaining 55.2% of the project cost should be borne by Cal Energy.

54. Decision (D.) 85-09-058, a 1985 decision, established a Commission policy which favors having ratepayers bear the cost of new transmission lines which serve beneficial purposes other than allowing for the interconnection of QFs.

55. The 1985 decision does not clearly prescribe how to determine whether or not other beneficial purposes exist in a given instance.

56. The typical radial line cannot add to system reliability since it does not contribute redundancy to the transmission system and usually does not provide excess capacity, since it is likely to be sized appropriately to carry the anticipated load.

57. The 1985 decision also fails to set forth criteria for judging the existence of system-wide benefits.

58. Cal Energy presented General Donald M. O'Shei to testify about the company's reliance on its interpretation of D.85-09-58.

59. The need and responsibility for transmission additions to serve these projects was sufficiently ambiguous at the crucial decision-making points to make it unlikely that Cal Energy could have reasonably relied on any particular transmission cost allocation in deciding to go forward.

60. Since a radial line could be built in the same corridor in a manner which would presumably take no additional time, it remains unclear as to why SCE felt compelled to propose the project it did.

61. An SCE subsidiary built the Cal Energy generating facilities at China Lake as well as a transmission line bringing the QF power to the Inyokern area.

62. The contracts for those projects contained a performance incentive, increasing the payments to the SCE subsidiary if the projects were synchronized with the SCE grid by a cortain date, and assessing penalties if they were not.

63. It would be inappropriate to automatically place the burden of the transmission line costs on ratepayers when the record suggests that alternatives to the proposed project may not have been given full weight in the planning process.

64. The lack of established criteria for analyzing system-wide benefits caused the parties in this proceeding to argue as much about definition as about the nature of the proposed project.

65. We are not convinced that the new line will reduce SCE's line losses.

66. It would entail double counting if line loss savings for which QFs are already given credit are included in an assessment of system-wide benefit of the new line.

67. While the proposed lines would be physically capable of carrying more power than is currently expected from the QFs, SCE, and Cal Energy seem to agree that it would be inappropriate to plan for the line to carry substantial additional generation.

68. While SCE's overall electric system should be more reliable whenever it adds a new transmission line which connects generating sources to the load center, an increase in reliability does not necessarily provide a tangible benefit.

69. While the addition of the proposed project would provide N-1 reliability to Kramer, it is a "benefit" that is invisible to the ratepayers, who would be no better served during an N-1 outage than they are now.

70. Since QF benefits are captured in the avoided cost payment, it would be inappropriate to consider them when determining how to allocate transmission costs.

71. The proposed project will not enhance transfers between utilities and will not enhance access to economy energy. Beyond that, the evidence is insufficient for us to find the existence of a system-wide benefit related to this criterion.

72. The line loss analysis provided in this record is inconclusive.

73. Because the Kramer-Victor area is a net generation area, SCE does not need more capacity to serve its customers.

74. The line is not being built for the purpose of receiving power from yet to be identified QFs.

75. The utility has proposed to "overbuild" the towers for the new line so that they would be capable of supporting an extra set of conductors on each circuit.

76. Approximately $6 million of the currently estimated $50.3 million project cost is the result of the tower overbuilding.

77. The EIR addresses six alternatives to the proposed project. Two of these are variations of the "no project" alternative. Those two alternatives are as follows:

a. Neither the proposed project nor any of the associated projects (e.g. Coso-Kramer 220 kV T/L conductoring, 115 kV Kramer-Victor rebuild, and Lugo transformer upgrade) are built, or

b. The proposed project is not built, but the associate projects are completed.

78. Selection of either variation of the "no project" alternative would result in at least some of the Luz and Cal Energy projects not being interconnected to the regional distribution system.

79. The other four project alternatives explored in the EIR were as follows:

a. 500 kV and greater high voltage direct current (HVDC) transmission line,

b. 500 kV alternating current (HVAC) transmission line,

c. Underground high voltage transmission line, and

d. An alternative 115 kV Method of Service.

80. The HVDC and 500 kV HVAC systems would require the construction of additional facilities, such as converter stations and substations, which would substantially increase the amount of ground disturbance required for the project.

81. These alternatives would also have a significant potential to adversely effect visual resources and create land use conflicts due to the large additional structures that would be required for each respective system.

82. Undergrounding of a 220 kV line would result in a significant amount of ground disturbance in an environmentally sensitive area.

83. None of the alternatives was found to be environmentally preferable to the construction of a conventional 220 kV transmission line.

84. A new 115 kV Method of Service would have involved the construction of a new 85 mile, double-circuit steel pole line directly from the BLM 1 and Navy 2 facilities to Victor Substation, two new 40 mile, double circuit 115 kV lines from Harper Lake directly to Victor Substation, and reconstruction work at the Victor Substation.

85. While this is technically feasible, this alternative was rejected since it would have higher line losses than the preferred 220 kV system and would create significantly higher environmental impacts due to the greater length of transmission line needed and the need for new access roads.

86. This approach was also found to be more costly than the proposed project.

87. The corridor that runs mostly parallel to the existing SCE 220 kV line was selected as the preferred corridor because it had the lowest overall environmental impacts.

88. While there are reported low to moderate densities of desert tortoise in the general vicinity of the proferred route, site surveys for this project indicate that densities are very low in areas directly adjacent to Highway 395 and in the preferred corridor. The proposed project would only result in the permanent loss of approximately two acres of habitat.

89. To eliminate potential land use impacts, SCE intends to acquire and relocate two homes within the new right-of-way.

90. To eliminate potential land use impacts to a business park, SCE has proposed to use tubular steel towers for both the existing and proposed line where it passes east of this development.

91. The project will not have a significant land use impact if the measures discussed in the EIR are implemented.

92. Wildlife resources, especially desert tortoise and Mojave ground squirrel, will be protected by preconstruction surveys.

93. While the line will be visible, it should not result in a significant deterioration of the existing visual resources of the project area.

94. The project area has been generally surveyed for archaeological and historical resources. These studies indicate the preferred corridor should avoid most regionally significant cultural resources.

95. Additional focused preconstruction cultural resource surveys will be needed in all areas that may be disturbed by the project.

96. The northern portion of the preferred route has the potential to contain subsurface paleontological resources that may be significant.

97. While the project will only involve limited subsurface disturbance (tower footings), the soil removed from foundation excavations shall be sampled and surveyed by a qualified paleontologist retained by SCE.

98. The project is not expected to have any significant effects on other resources such as noise, air quality, socioeconomics, traffic and transportation, radio interference, or public health and safety.

99. The four alternative corridors evaluated in this EIR and the SCE background studies would potentially generate greater environmental impacts than would the preferred route.

100. When certifying the location for a new transmission project, this Commission does not determine where each footing for each tower will be placed.

101. Instead of approving a precise route, we approve a corridor in which the project must be sited.

102. In most locations, the study corridors for this project are two miles wide.

103. Laboratory studies have demonstrated several different types of physiological responses to the presence of power frequency fields.

104. While any of these different effects could create a health hazard, none has yet been shown to pose a hazard.

105. Some epidemiological studies have shown a statistically significant relationship between exposure to above-average electromagnetic fields and the risk of contracting childhood cancer. Some such studies have not found a statistically significant relationship.

106. We do not know enough to entirely dismiss the issue of health effects stemming from exposure to above-average electromagnetic fields.

107. The EIR finds the potential risk to be too speculative to be categorized as significant.

108. Our responsibilities to respond to the health, safety and environmental concerns of those exposed to utility facilities is not limited to CEQA.

109. Several states have responded to the electromagnetic field issue by establishing maximum exposure levels to be allowed at the edge of a transmission right-of-way.

110. Those living and working near a proposed new line should be enabled to make informed judgment about the potential for health risk with continuous exposure.

111. The EIR contains an extensive list of measures designed to mitigate the adverse environmental impacts of the proposed project.

112. The overbuilding of the towers to facilitate future additional conductors, estimated to cost $6 million, is a prudent addition to the project which should be completed at ratepayer expense.

<u>Conclusions of Law</u>

1. For transmission lines that would carry power from a thermal generating facility to the first point of interconnection with the utility system, the California Energy Commission (CEC) is the lead agency. For all other transmission lines, such as the one proposed here, this commission is the lead agency.

2. We should adopt SCE's estimate of project costs.

3. We will place a cost cap of $50.3 million on this project.

4. In order to grant a certificate for a proposed project, we must determine, among other things, the portion of the project cost which will be borne by ratepayers.

5. We have no intention of altering, modifying or rescinding D.85-09-058 in this decision.

6. While it may be necessary to reexamine some of the assumptions behind D.85-09-058 or to explore in more detail how it should be implemented, those questions should be addressed in a broader proceeding, with more expansive notice to affected parties.

7. The comments in D.85-09-058 about bulk lines do not provide this Commission with a basis for resolving the cost allocation dispute in this proceeding because the term is not adequately defined.

8. Even if D.85-09-058 set forth a clear recipe for determining who should pay for the proposed project, we would not be legally bound by that order in this proceeding.

9. There would be no violation of applicable state laws if this Commission determined that the cost of the proposed transmission line should be allocated in a manner not addressed in D.85-09-058 as long as adequate notice and opportunity to be heard was provided.

10. Cal Energy had no reasonable basis for relying on its interpretation of the D.85-09-058 to conclude that it could not be found liable for any costs related to the transmission improvements needed to serve its China Lake projects.

11. D.85-09-058 should be applied to determine cost responsibilities related to the proposed project.

12. The record does not clearly demonstrate that the proposed project will provide system-wide benefits.

13. The SCE/Luz agreement is reasonable and should be approved.

14. Because Cal Energy will contribute an estimated 150 MW of the 630 MW expected to be carried on the new line, it should be responsible for 150/630, or 23.8% of the share of the project cost.

15. SCE's decision to overbuild the towers for the proposed transmission line is a prudent one because it adds flexibility and the potential for future new transmission capacity at a cost that would be much less expensive than an entirely new transmission system.

16. QFs should not be responsible for that cost. Thus, the overall QF share of the project cost should be calculated as follows:

$$\frac{\$50.3 \text{ million} - \$6 \text{ million}}{\$50.3 \text{ million}} = 88.07\%$$

Cal Energy's allocated share of the overall project cost should be 21%, which is 23.8% of the 88.07% generally allocated to the QFs.

17. Cal Energy is obligated to pay its share of the interconnection costs as determined by this Commission.

18. The project should not have any significant effect on the environment because the line would be constructed adjacent to an existing similar line, existing access roads and construction-related storage sites are already available to serve the project, and few sensitive resources are located in the preferred corridor.

19. Regardless of the detailed archaeological and biological studies undertaken to date, we should require that SCE meet a high standard of care in undertaking the mitigation measures prescribed in this order as well as in meeting other licensing conditions.

20. As part of the mitigation monitoring program to be discussed below, SCE must demonstrate both that all of the detailed studies adequately address the specific locations where the line will be placed and that impacts to the specific resources discovered as a result of those detailed studies are adequately mitigated.

21. While the question of transmission line-related health risks has yet to be settled, the prudent response is to avoid unnecessary new exposure to electromagnetic fields.

22. Until the scientific findings are more definitive, we should require SCE to take responsible, low-cost steps to avoid unnecessarily exposing people to these fields.

23. Since no one has identified any particular exposure level as safe or unsafe, any chosen remedy must strive to maintain the status quo.

24. Wherever economically feasible, a new line should not increase the electromagnetic field levels to residents and workers along the right-of-way.

25. All of the mitigation measures should be adopted as more fully described in the EIR.

26. We should adopt a mitigation monitoring program, as described in the EIR, which is similar to that which was adopted for SDG&E's Eastern Interconnection System, SCE's Devers-Palo Verde 1 and SCE's Devers-Palo Verde 2 projects.

27. Luz requested extra time to file a supplemental brief on issues related to interconnection requirements. The brief was filed May 4, 1990. The motion should be granted.

28. We should establish a second phase of this proceeding for the sole purpose of addressing the allocation of cost to Cal Energy stemming from the construction of ancillary facilities that were not the subject of this proceeding.

29. The certificate of public convenience and necessity should be granted.

30. The proposed transmission corridor should be approved.

31. The EIR should be approved.

# ORDER

IT IS ORDERED that:

1. A certificate of public convenience and necessity (CPCN) is granted, subject to the conditions set forth in this order, to Southern California Edison Company (SCE) to construct and operate a 220 kilovolt (kV) transmission line between its Kramer Substation and its Victor Substation in the Mojave Desert and to make related improvements to the Kramer, Victor, and Lugo substations.

2. The agreement between SCE and Luz International (Luz) allocating a portion of the cost of the proposed project to Luz is approved.

3. California Energy Company (Cal Energy) shall pay for 21% of the cost of the proposed project.

4. The maximum reasonable cost of the proposed project pursuant to Public Utilities Code Section 1005.5 shall be $50.3 million.

5. During construction SCE shall file quarterly reports for the project with the Formal Files office with one copy to go to the Energy Branch of CACD to review for compliance with this order. These reports shall contain:

(a) A period cost report reflecting:

1. Monthly budgeted expenses
2. Actual monthly expenses
3. Budgeted total cost to date
4. Actual total cost to date
5. Total committed costs to date
6. Total budgeted costs for the project at completion
7. Forecasted total costs for the project at completion

(b) S-curve graphs showing budgeted and actual project costs by month, and year-to-date.

(c) An exhibit showing the major milestones of scheduling for each major phase of the project.

(d) A narrative explanation of the major accomplishments and problems occurring since the last report with special emphasis on any variance from budgeted expenses or construction schedules, and a description of SCE's progress toward the major milestone including an estimate of whether those milestone will be achieved within budgeted costs and on schedule.

6. SCE shall provide to those living, playing and working in close proximity to the final transmission line route balanced written information about the existing controversy in the scientific community concerning the potential for health effects stemming from prolonged exposure to electromagnetic fields emanating from electric transmission lines.

7. SCE shall measure existing electromagnetic field levels at the edge of the proposed right-of-way along the preferred route and shall take reasonable steps to place the new line within the study corridor in such a way as to minimize any increase in field exposure levels to those living in planned and existing residences, working or playing near the edge of the right-of-way.

8. The Executive Director of the Commission shall file a Notice of Determination for the project, as set forth in Appendix A to this decision, with the Secretary of Resources.

9. Interested parties shall be provided the opportunity to propose changes or clarifications of the cost allocation issues raised in D.85-09-058 in the context of an upcoming generic investigation on QF transmission issues.

10. The ALJ assigned to this proceeding shall schedule a prehearing conference for Phase II in this proceeding, in which we will address the allocation of cost to Cal Energy stemming from the construction of ancillary facilities.

11. A mitigation monitoring program, as set forth in the EIR, shall be established to assure satisfactory compliance with the environmental mitigation measures and other environmental conditions required by this order.

This order is effective today.

Dated SEP 12 1990, at San Francisco, California.

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

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

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

Neal J. Shulman

NEAL J. SHULMAN, Executive Director

pb

STATE OF CALIFORNIA

GEORGE DEUKMEJIAN, Governor

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

APPENDIX A
NOTICE OF DETERMINATION

TO: ___Office of Planning and Research
1400 Tenth Street, Room 121
Sacramento, CA 95814

FROM: California Public Utilities Commission

___County Clerk
County of ____________

SUBJECT: Filing of Notice of Determination in compliance with Section 21108 or 21152 of the Public Resources Code.

Project Title
Kramer-Victor No. 1 and 2 22 kv Transmission Line Project

State Clearinghouse Number (If Submitted to Clearinghouse): SCH # 89071710
Contact Person: Jo Anna Bullock
Area Code/Number/Ext.: (415) 557-1808

Project Location

Mohave Desert, parallel to Highway 395

Project Description

37 mile 220 kv transmission line

This is to advise that the California Public Utilities Commission (Lead Agency or Responsible Agency)

has approved the above described project on ___________ (Date) and has made the following determinations regarding the above described project:

1. The project ____will, X will not have a significent effect on the environment.
2. X An Environmental Impact Report was prepared for this project to the provisions of CEQA.
   ____A Negative Declaration was prepared for this project pursuant to the provisions of CEQA.
3. Mitigation measures X were, _____were not made a condition of the approval of the project.
4. A statement of Overriding Considerations____was,____was not adopted for this project.

This is to certify that the final EIR with comments and responses and of project aproval is available to the General Public at:

CPUC, 505 Van Ness Avenue, San Francisco, CA 94102

Date Received for Filing and Posting at OPR ____________

Signature (Public Agency) Title