APPENDIX 15

OCT 18 1979

Docket Nos. 50-361
50-362

Mr. James H. Drake
Vice President
Southern California Edison Company
P. O. Box 800
2244 Walnut Grove Avenue
Rosemead, CA 91770

Dear Mr. Drake:

SAN ONOFRE NUCLEAR GENERATING STATION, UNITS 2 & 3

Your counsel furnished by transmittal letter of August 10, 1979 answers to questions we had asked with respect to the operating license antitrust review for the captioned nuclear units. We thank you for your clear and complete response. We have now reviewed the answers you supplied and references you referred to. Based on this review, we would appreciate it if you could now furnish us with some additional material and clarify some of our questions as follows:

1. Please furnish copies of Edison's generation projections, for as many years as they were projected, for each year projections were made beginning in 1973 and ending with the latest projection.

2. Please furnish a copy of the Settlement Agreement and associated coordination or power sales agreements which Edison entered into with the Anza Electric Cooperative, Inc.

3. In the August 10, 1979 response to our questions, counsel for Edison stated that the Anaheim and Riverside Integrated Operation Agreements (IOAs) had been accepted for filing by FERC. Are the FERC proceedings with respect to these IOAs concluded? If so, was there a final Order or Statement made by FERC which you could supply us with? If not concluded, please summarize the events and schedules which are yet to take place. Has Riverside or Anaheim taken any services under the IOAs? If so, please describe briefly what has taken place.

4. Have any further significant actions taken place with respect to IOAs between Edison and other California cities? If so, please describe briefly and supply relevant documents.

8110508C 262

5. Mr. R. L. [illegible] in his testimony before FERC in [illegible] [illegible] that at the time the Sundesert Project was shelved, the Sundesert participants [illegible] were [illegible] agreement on a coordinated transmission plan. Please describe the arrangements anticipated and furnish any substantiating documents.

6. Under Section 12.2 of the Anaheim or Riverside IOA, reserves are calculated as a percent of annual peak combined firm loads of the parties. This percentage figure is then applied to the City's capacity (rather than load) to determine the City's responsibility. Is its Edison's opinion that this is a proper determination when a City's capacity resources exceed its peak annual load? Is it anticipated that this section of the IOA would be amended if and when the City's capacity exceeds its peak annual load? Does Edison consider that this method of reserve responsibility calculation may have the effect of discouraging a City from becoming self-sufficient in generation?

7. Under Section 5.5 of the IOA a City's installed reserve obligatic are subtracted from its capacity resources to obtain its capacity credit. Then, under Section 15.1.1 of the IOA, Capacity Credit is used in establishing City's demand and energy requirements under the partial requirement rate schedule. This method of demand and energy requirement appears to have two effects:

(1) A City's spinning reserve requirement would be equal to its full installed reserve requirement and,

(2) energy associated with the reserve portion of a base load unit would not be credited to City.

This latter effect would be particularly significant for nuclear units which would normally be base loaded. For example, if the installed reserve requirement were 20%, it appears that a City would only get credit for 80% of the energy from its portion of a nuclear unit. Furthermore, under economic dispatch principles, it appears that Edison could utilize energy from the City's other 20% of the nuclear unit and provide spinning reserves from other less efficient units. Please explain the rationale for the method used in the IOA for crediting a City's capacity resource. What was the origination of the method used in this determination?

8. Under Section 10.2 of the IOA, Edison supplies Contract Energy to replace energy from City resources which Edison does not

[illegible]

[illegible] based on either of two methods:

(1) Edison's Contract Energy Cost, or

(2) City Incremental Cost

Edison's Contract Energy Cost is based on the cost of Edison's conventional oil-fired, combustion turbine and combined-cycle generation, i.e., the cost of intermediate and peaking generation which would presumably have considerably higher energy costs than Edison's base load generation. Thus, during light load conditions when Edison is operating its base load generation and through economic dispatch principles possibly be replacing City's base load generation which may have only slightly higher costs than Edison's, the City would be charged at Edison's intermediate and peaking generation cost. For example, assume that during an off-peak load condition, Edison Contract Energy cost is 35 mills, Edison's incremental energy cost is 20 mills and City's incremental cost is 22 mills. Under economic dispatch principles, Edison would dispatch its 20 mill generation in place of City's 22 mill generation. On a split-the-savings basis, City would be charged 21 mills. However, under the IOA, City would be charged at 35 mills. Please explain the rationale for the use of Contract Energy Cost instead of a split-the-savings basis.

We understand that under the IOA a City may choose another method of paying for Contract Energy rather than the one just described, i.e., one based on the City Incremental Cost rather than Edison's Contract Energy Cost. However, it appears that this option is not appropriate for a City with only partial generation. For example, at a slightly higher load level than the illustration given above, City's incremental cost could jump quite rapidly because with partial generation the City would be into its very high cost peaking generation whereas Edison would still be using its base load generation. As an illustration, when Edison's incremental cost is 21 mills City's incremental cost could be 45 mills and Edison would be making a 24 mill profit under the IOA. Without the IOA arrangement City would buy partial requirement power instead of dispatching its high cost peaking units. The only time City would dispatch such peaking units if under City's control would be during extreme peak load periods in order to reduce the demand charges under the partial requirement rate schedule.

In summary, it would appear that ... City's peaking units ... use the ... during off-peak would not actually be ... load periods, City would nevertheless have to pay Edison ... they had been dispatched. Please explain the rationale and appropriateness of this type of pricing for a partial requirement purchaser. From what books or operating principles did the two pricing methods, i.e., Edison's Contract Energy Cost or alternatively City's Incremental Cost originate? Please furnish the separate components (FC, HR, OC and 100/(100-L) of Edison's Contract Energy Cost for the latest month for which it is available.

9. With respect to the Anaheim and Riverside requests for transmission from the Palo Verde Nuclear Plant, Edison responded that the capacity of the Palo Verde to Devers 500 kv transmission line would be utilized by Edison over a period of time for Palo Verde Units 1, 2, and 3, for additional units in Arizona, for acquiring a portion of the Salt River Projects interest in Palo Verde and for participation in the second D.C. tie to the Northwest.

If Edison declines to furnish firm transmission services outside of its retail service area on the basis that sometime in the future its transmission facilities may become loaded,

Mr. James Under what conditions, if any, would it offer firm transmission services outside its service area?

We note that Mr. R. L. Mitchell in his testimony in the FERC Docket E-7777 states:

> "The basic reason for Edison's inability to offer long-term firm transmission service or co-ownership in this line was its need to transmit 1370 MW of power from its share of Palo Verde Units 1, 2 and 3, and its planned shares for participation in Palo Verde Units 4 and 5. In fact, Edison's planned participation in Palo Verde Units 4 and 5 of 790 MW, plus its 580 MW participation in Palo Verde Units 1, 2 and 3 will exceed the transfer capability of the Palo Verde-Devers line, and will require construction of additional transmission facilities from Palo Verde to Southern California."

Did Edison recognize at the time of its initial response to the cities that it would require more than one 500 kv line to carry out the functions which it itemized? Is it Edison's

... that the transmission [illegible] from [illegible] have been designed to accommodate the cities' [illegible] to [illegible] of participation [illegible]

Under the IOAs with Anaheim and Riverside, would the transmission requirements from Palo Verde be any different if Riverside and Anaheim had acquired a portion of Salt River Project's interest in Palo Verde instead of Edison? Please explain. Is it Edison's view that the cities could have and should have built their own transmission facilities, separate from those of Edison to obtain Palo Verde Participation?

10. Mr. R. L. Hitchell in his testimony before FERC in Docket No. E-7777 indicated that Edison had not as of then received right-of-way rights from the Bureau of Land Management for transmission lines from Palo Verde. Has Edison received such rights yet? If so, were there any conditions attached regarding transmission rights of others?

Please respond to the above questions and requests at your earliest opportunity so that we can continue our review in an expedited manner.

Sincerely,

/s/ A. L. Toalston

Argil Toalston, Chief
Power Supply Analysis Section
Antitrust & Indemnity Group
Office of Nuclear Reactor Regulation

Distribution:
Docket Files
PDR
LPDR
AIG R/F
JRutberg
JSaltzman
AToalston Reading
AIG Subject

NRR:AIG	NRR:AIG	OELD
AToalston:na	JSaltzman	JRutberg

APPENDIX 16

Southern California Edison Company

P.O. BOX 800
2244 WALNUT GROVE AVENUE
ROSEMEAD, CALIFORNIA 91770

LAW DEPARTMENT

DAVID N. BARRY III
ASSISTANT GENERAL COUNSEL

TELEPHONE
(213) 572-1920

February 4, 1980

U. S. Nuclear Regulatory Commission
Washington
D. C. 20555

Attention: Argil Toalston, Chief
Power Supply Analysis Section
Antitrust & Indemnity Group
Office of Nuclear Reactor Regulation

Gentlemen:

Re: Docket Nos. 50-361 and 50-362

In reply to your letter of October 18, 1979, I enclose Southern California Edison Company's response to your ten questions.

Please let me know if you wish any amplification or additional information. I look forward to hearing from you.

Very truly yours,

[signature]

DNB:feh
Encl.

cc: Mr. Jack Goldberg

Z999
SE
1/1

dupe of 323

A 8002070

RESPONSE OF SOUTHERN CALIFORNIA EDISON COMPANY
TO OCTOBER 18, 1979 QUESTIONS OF
UNITED STATES REGULATORY COMMISSION,
DOCKET NOS. 50-361 AND 50-362

Response to Question 1:

We are furnishing copies of Edison's description of future generation resource programs for the 1973 through 1979 period. The attachment includes the latest projection.

Response to Question 2:

We are furnishing copies of Edison's Settlement Agreements with Anza Electric Cooperative, Inc. dated February 2, 1973, and June 8, 1978, respectively. These Agreements were dealt with in Opinion No. 654 of the Federal Power Commission issued March 19, 1973 and Order Approving Settlement and Allowing Withdrawal in Docket No. E-7777 (Phase II) and Docket No. E-7796 of the Federal Energy Regulatory Commission issued February 23, 1979. Copies of these Orders are attached.

Response to Question 3:

Attached are copies of FERC's June 7 and June 25, 1979 letters notifying Edison of the acceptance for filing of the Integrated Operations Agreements with Riverside and Anaheim. Anaheim and Riverside have not yet taken any services under the IOA's. However, as described in p. 12 of Mr. R. L. Mitchell's E-7777 testimony, Edison did integrate non-firm energy which Riverside and Anaheim purchased from Nevada Power Company, and did provide interruptible transmission service to the Cities for this non-firm energy. These arrangements preceded the

execution of the IOA's. All interruptible transmission service arrangements provided by Edison to these Cities are outside the scope of the IOA's (see IOA Section 18.6).

Response to Question 4:

This answer supplements our August 10, 1979 response to your Request No. 6. No further significant actions have taken place with respect to IOA's between Edison and other California cities. Edison is still waiting for comments respecting the IOA on behalf of the other California cities (Azusa, Banning and Colton). Edison has not received a reply from Mr. George Spiegel to Mr. John R. Bury's July 27, 1979 letter to Mr. Spiegel. There have been some informal and generalized discussions concerning the IOA's with representatives of the Cities. These discussions arose out of proposals by each of the Cities to acquire resources. Banning considered and abandoned a proposed power purchase from Western Area Power Administration. Colton is a proposed participant in the California Coal Project. Azusa is considering the purchase of power from a methane gas generation project initiated by Azusa Land Reclamation Company. All of the Cities indicated that Mr. Spiegel would be their spokesperson concerning IOA matters.

Response to Question 5:

The anticipated transmission arrangements are clearly summarized and set forth in the attached negotiations summary prepared by San Diego Gas & Electric Company following the

negotiating meeting immediately preceding termination of the Sundesert Project.

Response to Question 6:

The substance of Section 12.2 of the IOA's, involving the method for calculating a City's contribution to installed reserves for Edison's electrical control area, was agreed upon in the 1972 Settlement Agreement with Anaheim, Riverside and Banning. The method agreed to is the use of a five-year rolling average percentage of the reserve margins of the combined systems and applying this percentage to the rated capability of a City's capacity resources. Unless a City becomes grossly over-resourced, we see the effect of this approach to be the same when capacity resources are less than or are exceeding a City's annual peak load. Therefore, we do not anticipate any amendment to Section 12.2.

We are not sure what the NRC means by "discouraging" the development of generation by a City. Edison and the Cities have agreed to Section 12.2, and Cities are, in fact, proceeding to obtain generation with a view toward becoming self-sufficient. At such time as Cities feel disadvantaged by the IOA they have the option of seeking modification in accordance with Section 206 of the Federal Power Act, in the event they are unable to reach agreement with Edison. The Cities will be "encouraged" or "discouraged" by many events, such as, for example, the prices of fuel.

Response to Question 7:

First of all, we are at a loss to understand the reason for this inquiry. Cities have not complained to Edison; indeed these arrangements (and their origination) are the results of negotiations with these Cities. Are we to assume that contracts, reached through arms length negotiations with the Cities, and accepted for filing by the FERC, following intervention by the Cities in support of the filings, are nevertheless to be dissected by the staff of the NRC in pursuit of some other interest? Moreover, your Question No. 7 appears to indicate a misinterpretation of Sections 5.5 and 15.1.1 of the IOA's. The IOA's are silent with respect to a City's obligation to provide spinning reserves from an integrated City Capacity Resource. Once a City integrates a Capacity Resource into the Edison system and contributes its proportionate share of installed reserves, Edison operates its system as if that resource were owned by Edison. (See IOA Section 10.2.1.) Neither the IOA's nor any other City-Edison agreement requires that a City provide spinning reserves as you state in Item No. 1 of Question 7. Item No. 2 of Question 7 is in error in that if Edison were to operate a City Capacity Resource at 100% of its rated capability, the City would receive credit against the energy portion of its monthly billing for all of the energy associated with the Rated Capability.

Response to Question 8:

Please explain the rationale for use of Contract Energy Cost instead of a split-the-savings basis.

All energy sold by Edison to a City under an Integrated Operations Agreement is on a firm basis. Edison has never utilized a split-the-savings approach to the pricing of firm energy. We believe this is consistent with all utility practices. It should be recognized that Edison must be prepared to furnish Contract Energy to a City (in addition to partial requirements energy above the Capacity Credit Line) at any and all times, including times when a City's own integrated capacity resources are not available to the combined City-Edison systems.

In general, to the extent that the Cities acquire and integrate City Capacity Resources to meet all or a portion of their electrical requirements, the Cities are treated as generating agencies. In general, the Cities are considered regular resale customers to the extent that they have not acquired and integrated City Capacity Resources, and purchase that portion of their capacity and energy required (above the Capacity Credit Line) from Edison under the general filed partial requirements resale rate. Edison's basic approach to the pricing of energy is that when a retail customer or a regular resale customer pays a demand charge and thus supports Edison's investment costs, such customer is entitled to pay for energy on an average cost basis. This approach is utilized in the pricing of partial resale requirements energy above the Capacity

Credit Line and of retail energy subject to California PUC jurisdiction.

On the other hand, when the purchaser of energy does not pay a demand charge, energy is priced on the basis of the incremental cost of generating such energy. Under the IOA's, for instance, a City does not pay a demand charge for capacity associated with energy purchased below the Capacity Credit Line. Incremental costing has long been the basis for pricing energy sold by Edison to generating agencies such as Los Angeles Department of Water and Power and Pacific Gas and Electric Company. In the IOA's this incremental costing approach was used for energy sales below the Capacity Credit Line to partial requirements Cities like Anaheim and Riverside.

Edison has utilized a split-the-savings approach to energy sales only for sales of non-firm or economy energy, consistent with normal industry custom and practice.

Please describe the rationale and appropriateness of this type of pricing (City Incremental Cost or Edison's Contract Energy Cost) for a partial requirement purchaser.

The question suggests the possibility that a City would acquire and integrate a generating resource such as a peaking unit, but that the peaking unit would not be dispatched most of the time. For an integrated peaking unit, a City would pay for energy not scheduled from the "capacity credit" for the unscheduled peaking unit at the incremental energy cost of the

peaking unit or Edison's Contract Energy Cost, depending on the City's designation under IOA Section 16.2.1.1.

The rationale for this type of pricing is that a City is regarded and treated as a fully resourced generating agency (not as a conventional resale customer) for its energy purchases below the Capacity Credit Line. Knowing it will be regarded as a generating agency, in evaluating a prospective resource, a City should compare and estimate the likely capacity factor for the resource, its incremental energy cost, the value of its capacity credit and Edison's estimated contract energy cost. All of these factors will be compared with the estimated levelized demand and energy charges under Edison's partial requirements rate. If a City chooses to acquire and integrate a low capital cost, high energy cost, and low capacity factor peaking unit, a City must expect to pay Edison contract energy cost (presumably lower than the unit's incremental energy cost) for energy associated with that unit's capacity credit, under the IOA Section 10.2 criteria, when the unit is available but not scheduled by Edison. This approach is certainly equitable and fair to all of Edison's regular customers. If a City could acquire and integrate a peaking unit solely for the purpose of reducing its demand charges, and at the same time pay Edison's average energy costs for energy associated with the capacity credit for the unscheduled unit, cost burdens would be unfairly shifted from such City to Edison's other customers.

We believe that the IOA Section 16.2.1.1 approach to pricing will result in City's acquisition and integration of resources most beneficial to the overall interests of the City's own customers and Edison's other retail and regular resale customers. We repeat that the Cities agreed to this provision.

As your question recognizes, the suggestion that a "City would dispatch peaking units if under a City's control...during extreme peak load periods in order to reduce demand charges under the partial requirements rate schedule" is inconsistent with the integration and capacity credit process under the IOA. A City will receive the same capacity credit for any integrated capacity resource. No distinction is made between a base load, intermediate load or peaking load resource.

From what books or operating principles did the two pricing methods, i.e., Edison's Contract Energy Cost or alternatively City's Incremental Cost originate?

The contract energy cost pricing method was negotiated as an alternative to utilizing Edison's incremental energy cost as shown each hour on Edison's system operation computer. Edison and the Cities preferred this approach because the price would only be changed on a monthly basis, and because of its ease of administration. In fact, contract energy cost was expected to be lower overall than the recorded incremental cost of generation with oil and gas as the fuel source.

In accordance with your request that Edison furnish the separate components (FC, HR, OC and 100/100-L) of Edison's

Contract Energy Cost for the latest month available, we are attaching our calculation of this cost as of November and December, 1978.

Response to Question 9:

A distinction must be made between firm transmission service offered over new transmission facilities constructed to deliver power from new sources of generation, and transmission service offered over existing transmission facilities constructed for a different purpose.

New Transmission Facilities. As part of the development and long-range planning of a proposed new jointly-owned generation project participated in by Edison (e. g., San Joaquin or Kaiparowits), which project requires the construction of new transmission facilities, the project participants would jointly plan the construction of the optimum new transmission facilities without regard to which participants would own such new facilities. The goal of such planning would be to deliver the output of the new project to the participants, to interconnect the new facilities with the affected existing transmission facilities, and to minimize adverse environmental impacts from the new construction. It may be assumed the project participants would agree upon which participants would own and which participants would receive transmission service from the new facilities. Edison would coordinate its planning with the needs of other participants in the

new project when and if it planned and developed new transmission facilities relating to its participation share in the project. Satisfactory transmission arrangements for all participants would be as essential to the consummation of the generation project as would be acquisition and installation of a turbine-generator for the project. In this situation, the new transmission facilities are built from the outset to deliver the project's output to the systems of the project participants. If the use of Edison's pre-existing transmission facilities would also be required to deliver the output to other project participants, the necessary long-term arrangements would have to be worked out as a part of the establishment of the overall feasibility of the project. The important point is that sufficient lead times would exist to work out plans for the necessary increment of transmission capacity to handle the output of the project. Edison would of course comply with the transmission service provisions of its San Onofre Units 2 and 3 licenses, its Settlement Agreements and Integrated Operations Agreements.

Existing Transmission Facilities Outside Edison's Service Area. Edison's undertakings in the San Onofre licenses, Settlement Agreements and IOA's are to use its "best efforts" to provide firm transmission services over then existing transmission facilities outside its service area.

These undertakings do not obligate Edison to construct new transmission facilities if such are required to furnish the necessary transmission service. (While not obligated to do so, Edison has offered to construct such new facilities in projects such as San Joaquin.) Because each new proposal for Edison to provide firm transmission service involves different facilities, conditions and parameters, the determination of the circumstances when "best efforts" will obligate Edison to furnish firm transmission service over existing facilities will of necessity be made on a case-by-case basis. As in the case of "rule of reason" determinations, universal and all-encompassing "conditions" cannot be quantified. Experience to date indicates certain circumstances when Edison has offered such services. Edison has provided firm transmission service using transmission capability in its existing facilities that was determined to be surplus to its needs to transmit firm or non-firm energy to serve its customers or to meet prior firm transmission service commitments. An example is Edison's offer to provide firm transmission service over the proposed No. 1 Palo Verde-Devers 500 kV transmission line to various delivery points or interconnection points on Edison's system, beginning January 1, 1982 and terminating May 1, 1986. This is described in the E-7777 testimony of Mr. R. L. Mitchell at pages 18-19. Another example was Edison's offer to

provide long-term firm transmission service to Pacific Gas and Electric Company for the output of its share of the proposed Harry Allen-Warner Valley Project, and to California Department of Water Resources for the output of its share of the Reid-Gardner Project in Nevada. Subject to negotiation of a mutually satisfactory agreement, Edison was also willing to provide such long-term service to Anaheim and Riverside if they participated in the San Joaquin Project or in a Cholla unit of Arizona Public Service Company.

When Edison constructs new transmission facilities to serve the needs of its customers, such facilities become dedicated under its public utility obligations to serve Edison's retail and regular resale customers on a first priority basis. Under present fuel and energy supply conditions facing Edison, in addition to its firm transmission usages, Edison would reserve some capacity for delivery of economy and other non-firm energy purchased by it from other systems. To the extent that such capacity is reserved but not needed by Edison, it would be available to provide interruptible transmission service to other systems.

Edison recognized at the time of its initial response to Anaheim and Riverside that the No. 1 Palo Verde-Devers 500 kV transmission line would be inadequate to transmit the output of its proposed participation share in Palo Verde Units 4 and 5, in addition to its firm 580 MW participation share of Palo

Verde Units 1-3, and therefore that more than one 500 kV line would be required to carry out the functions which Edison itemized. All of the proposed California participants in Palo Verde Units 4 and 5 recognized that new transmission arrangements and facilities would be required if they participated in this project. In fact, the California parties were embarking on such a study. As in the case of projects such as Kaiparowits and San Joaquin, for which Edison contemplated constructing some new facilities and providing transmission services over them to other participants, the optimum approach may have been for Edison or one of the other California participants alone to construct and own a No. 2 Palo Verde-Devers transmission line. The owning participant would have been expected to assist in the long-term transmission service needs of other California participants for their output from the Palo Verde Units 4-5 project, utilizing capacity in the No. 1 and No. 2 Palo Verde-Devers lines, if the transmission studies indicated that the construction of such second line was the optimum facility to be built for the Units 4 and 5 project.

We do not understand your next question, because Edison did not acquire any interest of Salt River Project in Palo Verde Units 1-3. This interest in the Palo Verde Units 1-3 will be acquired by Los Angeles Department of Water and Power from Salt River Project.

Finally, it is Edison's view that Anaheim and Riverside could not have and should not have built their own transmission

facilities solely to transmit their 2.5% share of the 2444 MW Palo Verde Units 4 and 5 project (unless the facilities were also to be utilized by other parties). Consistent with its earlier discussion of the construction of new transmission facilities, Edison is confident that mutually satisfactory transmission arrangements, with the least possible adverse environmental impact, would have been agreed upon by all of the California participants (including Anaheim and Riverside) in this project.

Response to Question 10:

The latest action by the Bureau of Land Management is reflected in the attached notification letter from BLM dated January 2, 1980.

DAVID BARRY
Assistant General Counsel
February 4, 1980

PACIFIC INTERTIE UPRATING TASK FORCE
FINAL REPORT
January 25, 1977

INTRODUCTION

In 1975 a group of Western utilities agreed that a review of possible methods of upgrading the Pacific Intertie was in order. In September of that year an originating Committee (later named Coordinating Committee--Third 500 kV AC Line), comprising representatives of utilities with a direct interest in the proposed upgrading study, formed a task force to determine in approximate terms certain benefits and costs that would result from various levels of Intertie upgrading. This task force in turn formed the Pacific Intertie Uprating Task Force and delegated to this new group that part of their assignment dealing with the cost of various levels and methods of upgrading so that they might concentrate their efforts on developing the corresponding benefits attributable to reserve sharing.

The Pacific Intertie Uprating Task Force was to include in their analysis both the AC and DC intertie segments and the capacity increases were to be based on the system configuration anticipated in the early 1980 time frame.

It is intended that the results of these two committees be analyzed by the originating committee in regard to the overall cost/benefits of the various plans. The end result would be a recommendation of upgrading techniques that, from the preliminary analyses, appear economically justifiable and practical.

The Pacific Intertie Uprating Task Force comprises representatives from Bonneville Power Administration, Los Angeles Department of Water and Power, Pacific Gas and Electric Company, San Diego Gas and Electric Company and the Southern California Edison Company.

RESULTS

In general, some of the possible methods of upgrading the Intertie are to devise new operating procedures, improve the reinsertion performance of the capacitors, improve the current carrying capability of the AC network components, increase the operating voltage of the DC line, increase the current capability of the valve groups in the DC terminals, add another 500 kV line or convert the two three-phase AC lines to three bipolar DC lines.

[illegible] in visualizing these alternatives, Figure 1 is included which shows the geographical location of the Pacific Intertie lines and substations as well as the line mileages between intertie buses.

a) <u>Use of Remedial Action</u>

At the initiation of this study the AC portion of the Pacific Intertie was rated at 2100 MW at Malin and the DC portion at 1440 MW at Celilo for north to south transfers. The AC stability limit for heavy load conditions has now been increased to a maximum of 2500 MW at Malin with the use of special procedures incorporating various remedial actions. The procedures and remedial actions can be summarized in the following manner.

In The Northwest:

1. Drop 600 MW at Chief Joseph for loss of any line between John Day and Round Mountain.

2. Eliminate switching of the additional 25% Northwest Compensation for faults between Grizzly and Round Mountain.

In California:

1. Reset the relays in the GE capacitors at Round Mountain on the lines to Malin so that the capacitors will not attempt to reinsert unless the current is below 1900 amperes. They were set for 3000 amperes. (This will delay reinsertion of these capacitors following a fault in the parallel line. If these capacitors do not initially try to reinsert, the post-insertion current is significantly lower, and the Westinghouse capacitors at the Malin end of the line should reinsert reliably. Reinsertion of about one-third of the capacitors is required.)

2. Use jumpers to bypass one-half of the capacitor banks at the Table Mountain end of the Round Mountain-Table Mountain line. (This should reduce post-insertion current to below 2700 amperes in the remaining line for faults between Round Mountain and Table Mountain.)

3. Send a signal to the Northwest to insert the Chief Joe braking resistor for multiphase faults between Round Mountain and Table Mountain.

Although the Pacific Intertie rating has not officially been changed to 2500 MW, the above procedure to achieve the 2500 MW limit has been implemented and will likely remain in affect until future system changes result in a change in the rating.

b) Capacitor Upgrade

The first level of facility upgrade considered consists of increasing the capacitor ratings to the rating of the conductor in the AC lines, i.e., the overload capability of the capacitors would be compatible with the short-time emergency rating of the conductor. This results in a 2700 MW rating on the AC lines north of Table Mountain. The capital cost in 1976 dollars for upgrading the series capacitors from John Day to Tesla is estimated to be $67 million. This assumes a 70 percent compensation level. If six percent losses are assumed, the incremental cost of the delivered power at Tesla is calculated to be $358/kW using the 2500 MW rating (see Table I). It is important to note that the relatively large cost per kilowatt figure developed using the 2500 MW base does not reflect the significant improvement in reliability realized by upgrading the capacitors. The 2500 MW rating requires a number of additional remedial actions not required at the 2100 MW level. These were outlined in Part (A) of this section. The capacitor upgrade to 2700 MW eliminates most of the remedial actions.

c) Addition of a Third AC Line

To increase the AC Intertie rating a significant amount above the 2700 MW level would require a third AC line. The addition of a third line would increase the Intertie rating to 4500 MW. The 1976 capital cost of a third line and associated terminal equipment from John Day to Tesla is $301 million. This cost figure assumes a 70 percent series compensation level and includes 585 miles of 500 kV construction with intermediate terminals at Grizzly, Malin, Round Mountain and Vaca-Dixon. The incremental cost of the delivered power at Tesla is $160/kW for the 2500 MW base rating (See Table I). These costs assume a 4500 MW intertie rating and six percent transmission losses.

d) DC Line Upgrades

An alternative to increasing the capacity of the AC portion of the intertie is to upgrade the DC line from its present level of 1440 MW at the sending end when operating at ± 400 kV. Rough estimates have been made for increasing the DC capacity by increasing the operating voltage or by increasing the current rating.

DC Voltage Increase

If the operating voltage is increased from ± 400 kV to ± 533 kV, the sending end capacity is increased from 1440 MW to 1920 MW, a 480 MW improvement. The voltage increase would require a capital expenditure of $64 million (1976 dollars) and results in an incremental cost of $137/kW for power delivered at Sylmar. The cost figure for increasing the voltage assumes that the existing conductor would not have to be replaced. Before this plan receives further consideration, an investigation should be made to determine the maximum voltage possible for uprating without substantial modifications to the existing line equipment.

DC Current Increases

The capacity of existing conductors will permit increasing the existing current rating without significant sag related tower modifications. Replacement of all existing valves with thyristor or LMP valves and replacement of converter transformers with a higher current rating would be required.

Three levels of current increases were examined. The current increases considered in this evaluation upgraded the DC line 360, 565 and 760 MW respectively. The 1976 capital costs for these upgrades are $103, $145 and $157 million respectively. Corresponding incremental costs of power delivered at Sylmar are $366, $310 and $274 per kW (See Table 1). The 565 MW increase corresponds to the same 467 MW of delivered power as in the case of the voltage upgrade but note that the incremental cost for that case was only $137/kW.

The above costs do not include several factors, the most important being the downtime costs incurred during the installation and modification of facilities. The downtime is expected to be more significant for the current increase modifications than the voltage increase modifications.

The voltage increase concept appears to be less expensive and easier to implement than the current increase concept. Of the two, it is seen that it would be more beneficial to investigate the voltage increase opportunities in greater depth if the anticipated benefits of upgrading the DC line warrant further study.

e) Conversion of AC Lines to DC

Another alternative for increasing the Intertie capability is the conversion of the two 500 kV AC Intertie lines to three bipolar DC lines.

A large increase in capacity can be achieved by this conversion. In addition, an asynchronous tie would have loop flow benefits and with proper control might assist in system stability.

John Day was selected as the northern terminus of the DC lines since it is near major generating sources and Tesla was selected as the southern terminus since it is near the load center in northern California.

Three levels of upgrade were considered for this AC to DC conversion. The total three DC line system was assumed to be rated 4000, 5000 or 7500 MW corresponding to the three levels of upgrades. The 1976 capital costs for these various levels of upgrades are given in Table I as \$400, \$488, and \$663 million respectively. The incremental costs of the delivered power for these same three levels were calculated as \$291, \$217 and \$153 per kW, respectively for the 2500 MW base rating.

It was stated previously that the conversion would be implemented between John Day and Tesla. Whether DC lines with these terminals would be feasible is uncertain. The intermediate stations between John Day and Tesla on the present AC system have significant blocks of power transferred to or from the 500 kV Intertie system. In some areas, substantial changes to the existing 230 kV network would have to be made if the 500 kV AC lines were converted to DC. Alternatively, it would be necessary to establish large AC/DC conversion stations at these locations. In either case, the conversion costs could be substantial and thus the actual cost of this conversion would be higher than indicated here. On the other hand, there is some cost associated with the control or accommodation of loop flow. The elimination of loop flow as a result of the AC to DC conversion should yield a cost savings which could be deducted from the net cost of the plan. Any credit for loop flow control would not be expected to alter the comparative economic position of the conversion plan.

SUMMARY

The various methods and levels of upgrades and their respective costs are summarized in Table I.

From Table I it is seen that, in regard to upgrading the DC line, the methods which increase the current carrying capacity are the most expensive when compared with other alternatives. It should be noted that some loss adjustment should be made to the DC upgrade cost evaluation to account for the fact that the power is delivered further south at Sylmar instead of Tesla. The conversion of the two AC lines

to three DC bipolar lines is also [illegible] unjustifiable unless the [illegible] MW capacity alternative is realistically required.

Except for the cost of capacitor upgrades from the 2500 MW rating, the remaining plans are within the same range of cost per kilowatt of incremental increase but differ in the amount of capacity increase. Therefore, if the capacity increase that can be justified is within the 400-2000 MW range, the DC voltage increase and third line alternative should be given detailed consideration.

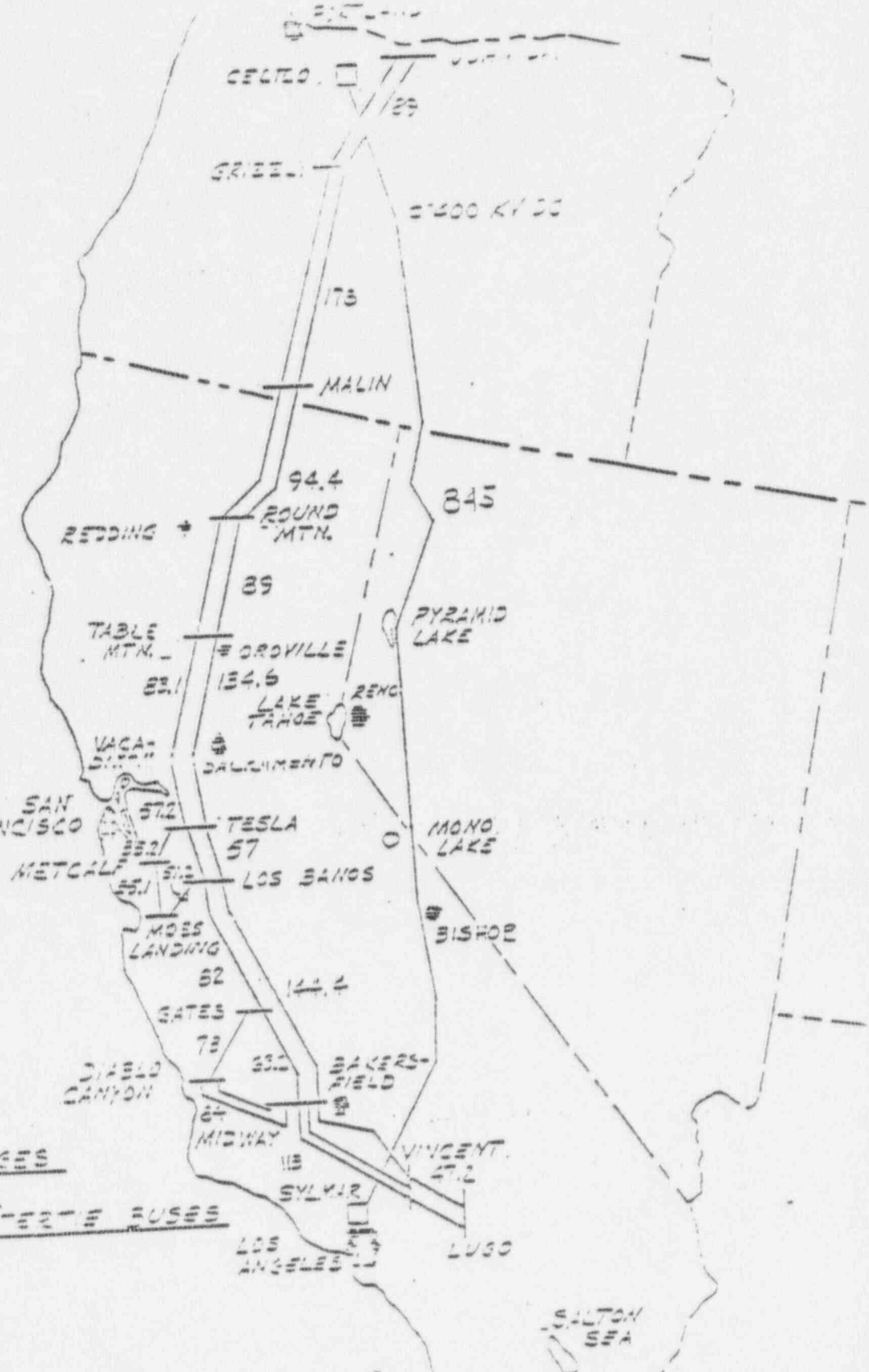

FIGURE I
LINE MILEAGES
BETWEEN
PACIFIC INTERTIE BUSES

TABLE I

SUMMARY OF METHODS OF UPGRADING INTERTIE

Method Of Upgrading	Total AC Or DC Intertie Capacity MW	Amount Of Upgrading 2500 Base MW	Additional Delivered Power 2500 Base MW	Cost Of Upgrading $ x 10^6	1976 Capital Cost Per kW Of Additional Power Delivered 2500 Base MW	Deliv[ery] Point
Capacitor	2700	200	188	67	358	TESLA
Third AC Line	4500	2000	1880	301	160	TESLA
DC Voltage Increase	1920	480	467	64	137	SYL[illegible]
DC Current Increase #1	1800	360	202	103	366	SYL[illegible]
DC Current Increase #2	2005	565	467	145	310	SYL[illegible]
DC Current Increase #3	2200	760	574	157	274	SYL[illegible]
Conversion Of AC to DC Plan #1	4000	1500	1375	400	291	[illegible]
Conversion Of AC to DC Plan #2	5000	2500	2250	488	217	[illegible]
Conversion Of AC to DC Plan #3	7500	5000	4325	663	153	[illegible]

APPENDIX 18

BONNEVILLE POWER ADMINISTRATION
P.O. Box 3621, PORTLAND, OREGON

To Those Indicated on the Attached List:

Gentlemen:

Attached are a copy of my notes on the August 10, 1976, meeting held in San Francisco relative to construction of a third 500-kV a-c Pacific Northwest-Pacific Southwest intertie; an attendance list; and copies of data discussed at the meeting.

As indicated in the notes, the group concluded that it should become the Coordinating Committee--Third 500-kV A-C Line. All interested parties are invited to name a representative to the committee and/or attend all committee meetings.

The next meeting was set for 9 a.m., on September 16 in room 464 of the BPA office in Portland.

Sincerely yours,

Hector J. Durocher
Assistant Administrator
for Power Management

6 Enclosures:
Meeting Notes
Attendance List
Assumptions for Econ. Eval. of 3rd A-C Line
to California (Preliminary) 8/5/76
Charts 1-4
Principles for Exchange of Forced-Outage
Reserve Capacity (Preliminary) 8/9/76
Proposed Principles for Reserve Sharing
Between the PNW and California

AMERICAN REVOLUTION BICENTENNIAL 1776-1976

NOTES OF AUGUST 10, 1976, MEETING REGARDING FEASIBILITY OF A THIRD [illegible] PACIFIC NORTHWEST-CALIFORNIA INTERTIE

The Committee convened at 10:45 a.m. at the office of Pacific Gas & Electric Company in San Francisco. An attendance list is attached.

Mr. Durocher summarized ongoing studies in the Pacific Northwest to analyze the capability of the hydro system to produce sustained peaking operations during the summer months. Most of the available data relates to instantaneous or hourly peaking capability. The summer-winter diversity-capacity exchanges both with Arizona and Nevada utilities and with California utilities assume supply of peaking capacity 8 hours per day, 5 days per week. More careful study and evaluation is needed of the ability to sustain such operations, the effect on daily and weekly pond and tailwater fluctuations and of seasonal drawdown of reservoirs.

Because of concerns for seasonal reservoir drawdown and because seasonal load shapes in the Pacific Northwest and Pacific Southwest seem to peak for 3 to 5 months, it appears that maximum diversity-capacity exchanges should be limited to 3 months (June through August and December through February) with exchanges in adjacent months limited to about 50 percent of the maximum (see Chart 4 of Attachment 2). The Pacific Northwest also would want a right to obtain return within 1 week of the energy supplied if water conditions are such that storage reservoirs are being drafted excessively in any season. In such years, the Pacific Northwest would need to purchase winter energy in order to obtain return of the diversity capacity.

The Economic Evaluation Task Force prepared a benefit-cost analysis of the third A-C line assuming that line capacity not required for reserves pooling would be used to effect diversity-capacity exchanges. It indicates a benefit-cost ratio of more than two to one. The diversity-capacity exchange appears to be the most probable use of both existing and future intertie lines for firm transactions, since it seems improbable that BPA will be able to renew its capacity-energy exchange contracts when they expire.

Mr. Shackelford said that load management may have significant future impacts on the relationship of summer-winter loads in California. This will need further evaluation in considering the benefits of future seasonal diversity-capacity exchanges.

Mr. Blood reviewed the preliminary benefit-cost analysis, Attachment 1, and the underlying assumptions. Mr. Perry questioned the line capacity used, indicating it should be about 2,000 megawatts. He also said the California reserves savings through pooling reserves should be at least 700 megawatts. There were other comments on capacity available

for surplus energy transactions. The committee agreed, however, that based on the study assumptions, which need verification, the third A-C intertie appears to be feasible.

[illegible] reviewed the graphs, Attachment 2, Charts 1-4. He pointed out that surplus capacity shown for California [illegible] before deduction for reserves while that shown for the Pacific Northwest was after reserves.

Messrs. Gjelde and DuBois reviewed draft principles for reserves sharing, Attachments 3 and 4, respectively. Several comments were received that will be considered in subsequent redrafts.

Mr. Perry suggested that the committee and task forces working on the third A-C intertie studies should be more formalized. He pointed out that a steering committee had been formed to guide the work related to the existing interties and this committee may be appropriate for a similar assignment on the third A-C line. After extended discussions including some discussion of combining with committees working on the second D-C line, it was concluded that this committee should become the Coordinating Committee, Third 500-kV A-C Line. It will assign, coordinate, and review work of involved task forces. All interested parties are invited to name representatives to the committee and/or attend all committee meetings. Minutes will be widely distributed. Mr. Durocher was elected chairman.

The following task forces are analyzing various aspects of the third A-C line:

<u>Resource Analysis and Economic Evaluation Task Force</u>

Forrest Blood, BPA, Chairman
E. F. Timme, ICP
Curt DuBois, SCE
Jack Craig, LADWP
Jerry Garman, Seattle City Light
W. C. Lester, PG&E

<u>Functions</u>: Evaluate resources, loads, load diversities, maintenance requirements, probable transactions over and economic benefits of the third A-C line. The resources available in each region for intertie transactions and uses that will be made of existing lines as present contracts terminate will be considered first. Proposed transactions should be determined for the years 1984-85, 1989-90, and 1995-96.

<u>Reserves Pooling Task Force</u>

S. E. Moody, SCE, Chairman
G. J. Bellenger, PG&E
G. L. Nesbitt, SDG&E
D. A. Reddie, LADWP
A. D. Hanson, Power Pool
Mark Crisson, Tacoma City Light
Bob Wilson, PP&L
Diana Jones, BPA

<u>Functions</u>: Review results of currently available studies and study capacity savings probable through pooling reserves in the Pacific Northwest and California in 1989-90 and 1995-96.

<u>Technical Studies Task Force</u>

C. C. Young, PG&E, Chairman
M. D. Whyte, SCE
D. Hopkins, SDG&E
F. G. Schaufelberger, BPA
D. E. Martin, PP&L
A. A. Armstrong, PG&E
D. Gray, Seattle City Light

<u>Functions</u>: Analyze system additions required, their operations in the WSCC systems, and costs of facilities to be added.

The next meeting was set for 9:00 a.m. on September 16, 1976, in Room 464 of the BPA office in Portland. The chairman of each task force will report to the committee on the current status of task force assignments.

[illegible]

Mr. B. W. Shackelford
Vice President & General Counsel
Pacific Gas & Electric Company
77 Beale Street
San Francisco, California 94106

Mr. W. C. Travis
Pacific Gas & Electric Company
77 Beale Street
San Francisco, California 94106

Mr. W. C. Lester
Pacific Gas & Electric Company
77 Beale Street
San Francisco, California 94106

Mr. H. R. Perry
Chief Planning Engineer
Pacific Gas & Electric Company
77 Beale Street
San Francisco, California 94106

Mr. E. F. Kaprielian
Manager, Power Control Department
Pacific Gas & Electric Company
77 Beale Street
San Francisco, California 94106

Mr. James L. Mulloy
Chief Electrical Engineer and
Assistant Manager
Los Angeles Department of Water & Power
P.O. Box 111
Los Angeles, California 90051

Mr. Jack A. Craig
Los Angeles Department of Water & Power
P.O. Box 111
Los Angeles, California 90051

Mr. R. L. Mitchell
Manager, Power Contracts
Southern California Edison Company
P.O. Box 800
Rosemead, California 91770

Mr. Curt DuBois
Senior Power Contracts Engineer
Southern California Edison Company
P.O. Box 800
Rosemead, California 91770

Mr. James M. Henderson
Vice President--Elec. [illegible]
[illegible]
P.O. Box 1831
San Diego, California [illegible]

Mr. James C. Holcombe
Supt.--Electric [illegible]
San Diego Gas & Electric Company
P.O. Box 1831
San Diego, California 92112

Mr. R. B. Lisbakken
Vice President—Power Resources
Pacific Power & Light Company
920 SW. 6th Avenue
Portland, Oregon 97204

Mr. Ralph Deesen
Pacific Power & Light Company
920 SW. 6th Avenue
Portland, Oregon 97204

Mr. D. E. Martin
Pacific Power & Light Company
920 SW. 6th Avenue
Portland, Oregon 97204

Mr. D. H. Knight
Vice President
Puget Sound Power & Light Company
P.O. Box 868
Bellevue, Washington 98009

Mr. G. E. Bredemeier
Vice President
Portland General Electric Company
621 SW. Alder Street
Portland, Oregon 97205

Mr. Larry A. Soderquist
Portland General Electric Company
621 SW. Alder Street
Portland, Oregon 97205

Mr. E. W. Harding
Vice President--Power Supply
The Washington Water Power Company
P.O. Box 3727
Spokane, Washington 99220

[illegible]
The Washington Water Power Company
P.O. Box 3727
[illegible]

Mr. E. F. Timme
Intercompany Pool
P.O. Box 3727
Spokane, Washington [illegible]

Mr. A. J. Benedetti
Director
Tacoma City Light
P.O. Box 11007
Tacoma, Washington 98411

Mr. Don Caha
Tacoma City Light
P.O. Box 11007
Tacoma, Washington 98411

Mr. G. F. Vickery
Superintendent
Seattle City Light
1015 Third Avenue
Seattle, Washington 98104

Mr. Fred Dyer
Power Manager
Seattle City Light
1015 Third Avenue
Seattle, Washington 98104

Mr. Jerry Garman
Seattle City Light
1015 Third Avenue
Seattle, Washington 98104

Mr. Lyman Harris
Northwest Area Power Manager
Aluminum Company of America
P.O. Box 120
Vancouver, Washington 98660

Mr. Robert Ferrie
President
Intalco Aluminum Corporation
P.O. Box 937
Ferndale, Washington 98248

Mr. Bernard Goldhammer
Consultant
700 NE Multnomah, Suite 310
Portland, Oregon 97232

Mr. Hank Curtis
General Manager
[illegible] Public Power [illegible]
[illegible]
Vancouver, [illegible]

Mr. [illegible] Billington
Executive Director
Washington Public Utility
Districts' Association
1601 Tower Building
Seattle, Washington 98101

Mr. R. Ken Dyar
Manager
Public Power Council
P.O. Box 1307
Vancouver, Washington 98660

Mr. Larry D. Peterson, Manager
Grant County PUD
Box 878
Ephrata, Washington 98823

Mr. R. O. Ingebrigtson
Grant County PUD
Box 878
Ephrata, Washington 98823

Mr. Howard C. Elmore, Manager
Chelan County PUD
327 N. Wenatchee Avenue, Box 1231
Wenatchee, Washington 98801

Mr. Howard Schoffen
Chelan County PUD
327 N. Wenatchee Avenue, Box 1231
Wenatchee, Washington 98801

Mr. Fred W. Leiberg, Manager
Douglas County PUD
1151 N. Main Street
East Wenatchee, Washington 98801

Mr. Gordon Estes
U.S. Bureau of Reclamation
Mid-Pacific Region
2800 Cottage Way
Sacramento, California 95825

Mr. Wayne Schafer
Electrical Engineering Associate
Burbank Public Service Department
164 W. Magnolia Blvd.
Burbank, California 91503

[illegible] L. Young
[illegible] Public Service Department
119 N. Glendale Avenue
[illegible], California [illegible]

Mr. Jerry [illegible] Lohr
Power System [illegible]
[illegible] Municipal Water & Power Dept.
[illegible] N. Garfield Avenue
[illegible], California 91109

Mr. Bob Gillette
CH2M-Hill
1500-114th Avenue, SE.
Bellevue, Washington 98004

Mr. Hal Mozer
CH2M-Hill
1500-114th Avenue, SE.
Bellevue, Washington 98004

Mr. Bob Mooney
CH2M-Hill
1600 Western Blvd.
Corvallis, Oregon 97330

Mr. Bob Gallup
R. W. Beck & Associates
200 Tower Building
Seattle, Washington 98101

Mr. John Mangan
Regional Project Develop. Engr.
U.S. Bureau of Reclamation
Pacific Northwest Region
Box 043, 550 W. Fort Street
Boise, Idaho 83724

Mr. Merrill J. Martz
Regional Supervisor of Power
U.S. Bureau of Reclamation
Pacific Northwest Region
Box 043, 550 W. Fort Street
Boise, Idaho 83724

Mr. J. J. Stein
Managing Director
Washington Public Power Supply System
P.O. Box 968
Richland, Washington 99352

Mr. Phillip L. Cole
Chief, Engineering Division
U.S. Army Corps of Engineers
North Pacific Division
210 Custom House
Portland, Oregon 97209

[illegible]
Department of Water [illegible]
State of [illegible]
P.O. Box 388
Sacramento, California [illegible]

Mr. Ed. Terhaar
Department of Water Resources
State of California
P.O. Box 388
Sacramento, California [illegible]

Mr. R. O. Olson
U.S. Bureau of Reclamation
Lower Colorado Region
P.O. Box 247
Boulder City, Nevada 89005

Mr. R. J. McMullin
General Manager
Salt River Project
P.O. Box 1980
Phoenix, Arizona 85001

Mr. Leroy Michael, Jr.
Assistant General Manager
Salt River Project
P.O. Box 1980
Phoenix, Arizona 85001

Mr. R. W. Mason
Manager, Power Resource Development
Salt River Project Agricultural
Improvement and Power District
P.O. Box 1980
Phoenix, Arizona 85001

Mr. A. J. Pfister
Deputy General Manager - Power
Salt River Project
P.O. Box 1980
Phoenix, Arizona 85001

Mr. A. E. Pearson
President
Nevada Power Company
P.O. Box 230
Las Vegas, Nevada 89151

Mr. John C. Gibbs
Executive Vice President
Nevada Power Company
P.O. Box 230
Las Vegas, Nevada 89151

[illegible]
[illegible]
Nevada Power Company
P.O. Box [illegible]
[illegible] 89151

Mr. Einar Greve
Senior Vice President
Tucson Gas & Electric Company
P.O. Box 711
Tucson, Arizona 85702

Mr. Norman Johnson
Tucson Gas & Electric Company
P.O. Box 711
Tucson, Arizona 85702

Mr. A. R. Williamson
Consultant
Arizona Public Service Company
P.O. Box 21666
Phoenix, Arizona 85036

Mr. K. L. Turley, President
and Chief Executive Officer
Arizona Public Service Company
P.O. Box 21666
Phoenix, Arizona 85036

Mr. Herbert H. Hunt
Director, Operations and Engineering
Eugene Water & Electric Board
P.O. Box 10148
Eugene, Oregon 97401

Mr. Robert L. McKinney
General Manager
Cowlitz County PUD
960 Commerce
Longview, Washington 98632

Mr. Merrill Schultz
Northwest Power Pool
Coordinating Group
1210 Public Service Building
Portland, Oregon 97204

Mr. Gordon D. Jorgensen
R. W. Beck & Associates
Suite 1507 First Federal
Savings Building
Phoenix, Arizona 85012

[illegible]
Route 1, Box [illegible]
[illegible], Washington [illegible]

Mr. Robert D. [illegible]
[illegible]
1016 Old National Bank Bldg.
Spokane, Washington [illegible]

Mr. S. H. Moody
Southern California Edison Company
P.O. Box 800
Rosemead, California 91770

Mr. G. J. Bellenger
Pacific Gas & Electric Company
77 Beale Street
San Francisco, California 94106

Mr. G. L. Nesbitt
San Diego Gas & Electric Company
P.O. Box 1831
San Diego, California 92112

Mr. D. A. Reddie
Los Angeles Dept. of Water & Power
P.O. Box 111
Los Angeles, California 90051

Mr. A. D. Hanson
Northwest Power Pool
Coordinating Group
1210 Public Service Building
Portland, Oregon 97204

Mr. Mark Crisson
Tacoma City Light
P.O. Box 11007
Tacoma, Washington 98411

Mr. Bob Wilson
Pacific Power & Light Company
920 SW. 6th Avenue
Portland, Oregon 97204

Mr. C. C. Young
Pacific Gas & Electric Company
77 Beale Street
San Francisco, California 94106

Mr. M. D. Whyte
Southern California Edison Compan
P.O. Box 800
Rosemead, California 91770

[illegible]
San Diego Gas & Electric Company
P.O. Box 1831
[illegible]

Mr. A. A. Armstrong
Pacific Gas & Electric Company
77 Beale Street
San Francisco, California 94106

Mr. Dennis Gray
Seattle City Light
1015 Third Avenue
Seattle, Washington 98104

Third A-C Intertie Meeting
[illegible]
August 1[illegible], 19[illegible]

ATTENDANCE

Name	Organization
Hec Durocher	Bonneville Power Administration
Lyman Harris	Alcoa
Curt DuBois	So. California Edison
Jerry Lohr	City of Pasadena
E. F. Timme	Intercompany Pool
Bob Mason	Salt River Project
Earl Gjelde	Bonneville Power Administration
Jack Craig	LA Dept. of Water & Power
Hal Worcester	Eugene Water & Electric Board
D. E. Martin	Pacific Power & Light Company
Lloyd Harvego	Calif. Dept. of Water Resources
Dick Ferreira	Calif. Dept. of Water Resources
Forrest C. Blood	Bonneville Power Administration
Jerry Garman	Seattle City Light
Glen E. Bredemeier	Portland General Electric Co.
H. P. Braun	Pacific Gas and Electric Co.
W. C. Lester	Pacific Gas and Electric Co.
T. S. Swearingen	Pacific Gas and Electric Co.
H. R. Perry	Pacific Gas and Electric Co.
B. W. Shackelford	Pacific Gas and Electric Co.

APPENDIX 19

RESOURCES PLANNING
ADMINISTRATION

JUL 24 1978

RECEIVED

...artment of Energy
...eville Power Administration
... Box 3621
...tland, Oregon 97208

July 21, 1978

To Interested Parties - Proposed Celilo-Mead-Phoenix D-C Intertie

Gentlemen:

The attached copy of a memorandum from Sterling Munro and Robert L. McPhail to Assistant Secretary George S. McIsaac, Department of Energy, summarizes conclusions reached at our meeting on July 18 regarding the proposed Celilo-Mead-Phoenix d-c line. Both Pacific Northwest and Pacific Southwest representatives agreed that additional studies are needed and the earliest the line could be completed is the late 1980s.

A number of additional study needs were identified at the April 25, 1978, meeting in Las Vegas:

For the Pacific Southwest--

1. Evaluate PSW maintenance schedules. Can PSW maintenance be done outside of the summer period and, if so, how long? Quantify the benefits of uniforming maintenance schedules.

2. Evaluate the amount of new plant capacity that could be deferred with 6-hour and 10-hour capacity available from the PNW at the 1985, 1990, and 1995 levels of development for both Arizona-Nevada and Arizona-Nevada-Southern California.

3. Determine value of PSW capacity deferrals.

4. Verify the 162-MW average annual energy delivered offpeak to the PNW in 1 year out of 5. Can the amount be greater?

For the Pacific Northwest--

1. If increased fall drafts of reservoirs are acceptable, identify and quantify the dollar benefits associated with not drawing them down.

2. Study various combinations of 6 to 10 hours peaking.

3. Quantify the benefits associated with uniforming thermal maintenance schedules.

4. Reevaluate the cost of PNW capacity.

5. Determine if the interest rates used in the study for WAPA and BPA are accurate considering the shift to the Department of Energy.

Desirability of pursuing these studies was confirmed at the July 18 meeting. However, the study years should be 1988, 1993, and 1998. Cliff Watkins, Chief of our Branch of Power Resources, will coordinate Pacific Northwest study efforts and will contact Pacific Southwest task force representatives from time-to-time as studies progress.

An attendance list for the July 18 meeting is attached, together with a copy of our mailing list of interested entities.

3 Enclosures:
Memo dtd. 7/15/78
Attendance List
Mailing List

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208

OFFICE OF THE ADMINISTRATOR

JUL 18 1978

In reply refer to: RA/BPA - P

MEMORANDUM FOR GEORGE S. McISAAC
ASSISTANT SECRETARY
RESOURCE APPLICATIONS

FROM: STERLING MUNRO
ADMINISTRATOR
BONNEVILLE POWER ADMINISTRATION

Sterling Munro

FOR ROBERT L. McPHAIL
ADMINISTRATOR
WESTERN AREA POWER ADMINISTRATION

Thomas S. Weaver

SUBJECT: PROPOSED CELILO-MEAD-PHOENIX D-C LINE

Representatives of Bonneville Power Administration, the Western Area Power Administration, and private and public utilities in both the Pacific Southwest and Pacific Northwest areas met in Portland, Oregon, on July 18, 1978, to discuss the proposed Celilo-Mead-Phoenix d-c intertie. The proposed intertie, a 1000-kilovolt direct-current transmission line would transmit power more than a thousand miles to permit seasonal exchanges of capacity and energy. The Southwest would use Northwest resources during the summer months and, conversely, during the winter months power generated by Southwest entities would be sent back along the same d-c line to the Northwest to help meet their peak demands. Such exchanges would reduce the need for installing peaking plants in both regions.

Significant changes in the resource and load pictures in both the Pacific Northwest and Pacific Southwest areas of the country indicated that additional studies would be required in order to determine if there is a matching of one region's resources to the other region's loads. Additional studies on loads and resources, which are estimated to take approximately 12 months, will mean an in-service date of the intertie not earlier than the late 1980's. Representatives of utilities in each region will reanalyze their needs and capabilities. Another joint meeting is tentatively planned for early in 1979 in order to determine future course of action.

Meeting on Califor... Bonneville Power Administration Building
July 18, 9:00 a.m., ...

NAME	AGENCY	LOCATION
Lyman Harris	Alcoa	Vancouver, WA
Bob Krohn	Corps of Engineers	Portland
Fred Schaufelberger	BPA	Portland
Howard Schoffen	Chelan Co. P.U.D.	Wenatchee, W.
Bill Murphy	Arizona Public Service	Phoenix
Byron L. Miller	Nevada Power Co	Las Vegas,
Leroy Michael	Salt River Project	Phoenix,
John F. Sullivan	Salt River Project	Phoenix
Howard Farrington	BPA	The Dal
Peter O. Hergesty	Corps of Engrs	Port
Tom Hicks	BPA	Por.
Jeff Watkins	"	
Russ Mitchell	So. Cal. Edison	Los A
Ralph F. Dessen	Pacific Power & Light Co	A
Nicholas Dodge	Corps of Engrs, NPD	
Robert A. Olson	Western Area Power Admin.	
Thomas L. Weaver	Western Area Power Admin.	
John G. Rogers	L.A. Dept. of Water & Power	
Hal Mozer	CH2M Hill for Public Power	
Ken Durocher	GFA	
Charles Bayd	Ariz Public Servi	

Mr. David E. Piper
Manager
Public Power Council
P.O. Box 1307
Vancouver, WA 98660

Mr. Larry D. Peterson, Manager
Grant County PUD
Box 878
Ephrata, WA 98823

Mr. Howard C. Elmore, Manager
Chelan County PUD
Box 1231
Wenatchee, WA 98801

Mr. Fred W. Lieberg, Manager
Douglas County PUD
1151 N. Main Street
East Wenatchee, WA 98801

Mr. Hal Moser
CH2M-Hill
1500 - 114th Avenue, S.E.
Bellevue, WA 98004

Mr. Bob Gallup
R.W. Beck & Associates
200 Tower Building
Seattle, WA 98101

Mr. Phillip L. Cole
Chief, Engineering Division
Corps of Engineers, NPD
P.O. Box 2870
Portland, OR 97209

Mr. Ronald B. Robie, Director
Department of Water Resources
State of California
P.O. Box 388
Sacramento, CA 95802

Mr. Leroy Michael, Jr.
Assistant General Manager
Salt River Project
P.O. Box 1980
Phoenix, AZ 85001

Mr. Les Ormsby
Arizona Power Authority
P.O. Box 6694
Phoenix, AZ 85005

Mr. M. K. Curtis
Arizona Power Pooling Association
Route 1, P.O. Box 63
Coolidge, AZ 85228

Mr. A. J. Pfister
General Manager
Salt River Project
P.O. Box 1980
Phoenix, AZ 85001

Mr. John C. Gibbs
Executive Vice President
Nevada Power Company
P.O. Box 230
Las Vegas, NV 89151

Mr. Einar Greve
Senior Vice President
Tucson Gas & Electric Company
P.O. Box 711
Tucson, AZ 85702

Mr. R. D. Hulse
Vice President Resource Planning
Arizona Public Service Company
P.O. Box 21666
Phoenix, AZ 85036

Mr. Merrill Schultz
NW Power Pool Coordinating Group
1210 Public Service Building
Portland, OR 97204

Mr. Everett C. Ross
Public Utilities Director
City of Riverside
3900 Main Street
Riverside, CA 92501

Mr. Gordon W. Hoyt
Utilities Director
City of Anaheim
P.O. Box 3222
Anaheim, CA 92803

Mr. Robert McPhail
Administrator
Western Area Power Administration
P.O. Box 3402
Golden, CO 80401

Mr. [illegible] Shackelford
Vice President & General Counsel
Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94106

Mr. James L. Mulloy
Chief Electrical Engineer
& Assistant Manager
Los Angeles Dept. of Water & Power
P.O. Box 111
Los Angeles, CA 90051

Mr. Al Arenal
Vice President
Southern California Edison Company
P.O. Box 800
Rosemead, CA 91770

Mr. R. L. Mitchell
Manager, Power Contracts
Southern California Edison Company
P.O. Box 800
Rosemead, CA 91770

Mr. James M. Henderson
Vice President, Elec. Power Supply
San Diego Gas & Electric Company
P.O. Box 1831
San Diego, CA 92112

Mr. R. B. Lisbakken
Vice President - Power Resources
Pacific Power & Light Company
920 SW 6th Avenue
Portland, OR 97204

Mr. D. H. Knight
Vice President
Puget Sound Power & Light Company
P.O. Box 868
Bellevue, WA 98009

Mr. G. E. Dredemeier
Vice President
Portland General Electric Company
121 SW. Salmon Street
Portland, OR 97205

Mr. R. O. Olsen, Area Manager
Western Area Power Administration
P.O. Box 200
Boulder City, NV 89005

Mr. [illegible] Harding
Vice President - Power Supply
The Washington Water Power Company
P.O. Box [illegible]
Spokane, WA 99220

Mr. E. F. Timme
Intercompany Pool
P.O. Box 3727
Spokane, WA 99220

Mr. A. J. Benedetti
Director
Tacoma City Light
P.O. Box 11007
Tacoma, WA 98411

Mr. G. F. Vickery
Superintendent
Seattle City Light
1015 Third Avenue
Seattle, WA 98104

Mr. Lyman Harris
NW Area Power Manager
Aluminum Company of America
P.O. Box 120
Vancouver, WA

Mr. Norman C. Jacox
General Manager
Northwest Public Power Association
P.O. Box 1307
Vancouver, WA 98660

Mr. Ken Billington
Executive Director
Washington Public Util. Districts Assoc.
1601 Tower Building
Seattle, WA 98101

Mr. Karl A. Johnson
City Manager
City of Pasadena
100 N. Garfield Avenue
Pasadena, CA 91109

Mr. E. B. Stolle
State of Nevada
Div. of Colorado Resources
P.O. Box 19090
Las Vegas, NV 89119

APPENDIX 21

CITY OF Riverside PUBLIC UTILITIES DE[illegible] Riverside Ca[illegible]

January 2, 1980

EVERETT C. ROSS
Public Utilities Director

Mr. Argil Toalston, Chief
Power Supply Analysis Section
Antitrust and Indemnity Group
Office of Nuclear Reactor Regulation
Nuclear Regulatory Commission
Washington, D.C. 20555

Re: San Onofre Nuclear Generating Station, Units 2 and 3

Dear Mr. Toalston:

You have requested that the City of Riverside answer specific questions in connection with your review of the operating license applications for San Onofre Nuclear Generating Station, Units 2 and 3. Our answers to those questions are as stated below.

The City of Riverside, along with the City of Anaheim, is a prospective participant in the San Onofre Nuclear Generating Station, Units 2 and 3. Both cities are concerned that the operating license for both units be issued as quickly as possible. While there are certain matters at issue between each of the Cities and Southern California Edison Company (Edison), the predominant participant in the San Onofre plant, these matters are currently the subject matter of ongoing litigation between the Cities and Edison at either the Federal Energy Regulatory Commission, or in the Federal District Court. The Cities urge that the NRC Staff take all steps necessary to complete its review as quickly as possible and grant the operating licenses for the San Onofre Nuclear Generating Station, Units 2 and 3.

Question 1: On January 21, 1977, you wrote to Mr. Robert L. Myers of the Southern California Edison Company expressing an interest in participating in the Palo Verde Nuclear Plants and inquiring of Edison as to the availability of transmission from the plant. Were any transmission alternatives considered other than the one with Edison? If so, what was considered? If not, why not? What are the reasons that Riverside did not ultimately choose to participate in the Palo Verde Plant? Under what conditions, if any, would Riverside have chosen to participate in the nuclear plant? Under what conditions, if any, would the Arizona Public Service Company have permitted Riverside to participate in the plant?

DUPE OF
8001100466

M

At the time of my [illegible] ers of the Southern California Edison Company, the City of Riverside was considering an arrangement with the Salt River Project (SRP) wherein Riverside might acquire a portion of SRP's ownership interest in Units 1, 2 and 3 at Palo Verde. Riverside was also, at that time, a proposed participant in the Sundesert Nuclear Generating Station. It had been suggested that Edison's transmission line from the Palo Verde project be looped in to the Sundesert Project. Moreover, Edison was the only Palo Verde participant, at that time, with a need to bring power to California. Thus, Edison's proposed transmission line appeared to be the only viable proposal for transmission from Palo Verde to California. Since Riverside was contemplating possible ownership in both Sundesert and Palo Verde, it appeared appropriate for Riverside to acquire an ownership interest in transmission lines from both projects bringing power to Riverside. Riverside's ownership interest in both of the projects was not sufficient to have permitted Riverside to construct transmission lines except on a joint participation basis with other participants in those projects. Riverside would have considered any transmission scheme which provided for (1) Riverside's rights to firm transmission over the system; and (2) Riverside's cost would be based upon cost of the transmission system. Riverside ultimately was not able to participate in Units 1, 2 and 3 at Palo Verde because SRP entered into arrangements with the Department of Water and Power of the City of Los Angeles wherein SRP sold a portion of its ownership interest in the Coronado Generating Station to Los Angeles with the proviso that when the Palo Verde 1, 2 and 3 Units came on line Los Angeles' ownership interest would transfer from Coronado to Palo Verde. There were no other ownership interests in the Palo Verde Units which Riverside could acquire. If an ownership interest in Palo Verde had been available, Riverside would have attempted to acquire such ownership interest. We do not know under what conditions, if any, Arizona Public Service Company would have permitted Riverside to participate in Palo Verde 1, 2 and 3 Units. I was aware that Anaheim had communicated with Arizona Public Service Company regarding possible acquisition of an ownership interest and that Anaheim was told that no ownership interest from Arizona Public Service Company was available from Palo Verde 1, 2 and 3.

Question 2: Has Riverside taken any services under its Integrated Operations Agreement (IOA) and associated agreements with Edison? If not, why not? If so, has Riverside experienced any particular difficulties? Did any outside engineering or economic consultants assist Riverside in working out the terms and conditions of the IOA and related agreements? Have the terms and conditions of the IOA and related agreements been interpreted as Riverside initially understood them? If not, what changes in the interpretation have occurred?

[illegible] the integrated [illegible] with Edison on November 1, 1977. Prior to that date, Riverside entered into an agreement with Nevada Power Company to purchase non-firm energy. Edison agreed to provide interruptible transmission for that energy from the Nevada-Edison Interconnection Point to the City of Riverside. That energy was integrated by Edison in accordance with the terms of an Agreement of Integration and Transmission of Non-Firm Energy with Riverside. That Agreement was entered into prior to the conclusion of negotiations between Riverside and Edison for the Integrated Operations Agreement. However, it was agreed that the parties would operate in accordance with Exhibit A of the Settlement Agreement between Riverside and Edison and others, which Exhibit A contained the principles which served as the basis for the negotiations of the Integrated Operations Agreement.

Edison and Riverside have had a dispute concerning Edison's obligations to provide Riverside interruptible transmission service under the 1972 Settlement Agreement and subsequently the Integrated Operations Agreement. It is Riverside's position that Edison is required by the terms of the Settlement Agreement to use its best efforts to provide interruptible transmission service over Edison's facilities for the City of Riverside. Edison contends that interruptible transmission was not one of the services which it agreed to provide under the terms of the 1972 Settlement Agreement and, therefore, has refused to incorporate the provisions for interruptible transmission service as one of the services offered under the Integrated Operations Agreement. This is of particular importance since Edison is required under the Integrated Operations Agreement to schedule and dispatch all of Riverside's integrated resources as if they were owned by Edison. As Edison contends that interruptible transmission is not one of the services that it is required to provide under the Integrated Operations Agreement, it has applied a different standard concerning the provision of interruptible transmission service. Edison's position is that interruptible transmission service for Riverside is subject to interruption by Edison for any reason, whether justified or not. Riverside's energy from Nevada Power Company is not treated by Edison in the same manner as if it were Edison's owner energy. It is treated as "second class" by Edison, and if Edison, for whatever reason, wishes to interrupt the transmission of that energy, it does so. The City of Riverside thus has suffered numerous interruptions with respect to the transmission of energy from Nevada Power Company to the City of Riverside. The unavailability of transmission has meant that Riverside has been required to purchase higher price energy from Edison rather than take advantage of the lower cost energy available from Nevada Power Company.

[illegible]

[illegible] arbitration of disputes which arise between Edison and [illegible]erside. In addition, it would be the [illegible] of Riverside that to the extent that the Integrated Operations Agreement is subject to the jurisdiction of the Federal Energy Regulatory Commission, disputes under the IOA could be brought before that Commission for resolution.

<u>Questions 3</u>: Are there any other matters that you are aware of that you think the NRC Staff should consider in its review as to whether antitrust related significant changes have occurred in Edison's activities?

<u>Answer 3</u>: As indicated in the beginning of this letter, there are a number of issues in dispute between Riverside and Edison. With respect to the wholesale rates which Edison charges Riverside and its other wholesale customers, Riverside, along with the Cities of Anaheim, Colton, Banning and Azusa, California, have alleged before the Federal Energy Regulatory Commission in Docket Nos. E-8570, ER 76-205 and ER 79-150 that Edison's rates as filed create a "price squeeze" situation when compared with Edison's similar retail rates, and that this "price squeeze" results in price discrimination which is illegal under the Federal Power Act. The five Cities have also brought a trebel damage antitrust suit in Federal District Court, (Central District of California), alleging, among other things, that the price squeeze created by Edison's wholesale rates is illegal under the antitrust laws of the United States.

Riverside, along with the other Cities, in their antitrust action against Edison in Federal District Court have alleged that Edison's foreclosure of the bulk power supply market is in violation of the antitrust laws of the United States.

The Cities are also involved in litigation with Edison concerning Edison's activities to foreclose the Cities from access to alternative bulk power supplies. This litigation includes Docket No. E-7777 (Phase II) and Docket No. E-7796 before the Federal Energy Regulatory Commission. These proceedings concern investigation by the FERC of the California Power Pool, and Pacific Intertie Arrangements, which are those arrangements concerning the transmission facilities between the Pacific Northwest and California. The Cities have alleged that Edison alone, and in conspiracy with the California Power Pool Companies, have acted to foreclose the Cities, as well as other municipal systems in California from access to available energy in the Pacific Northwest. Cities also alleged that Edison, alone and in conspiracy with the other California Power Pool Companies, have agreed to divide the California bulk power supply market so as to insure that municipals located within the service area of the systems such as that of Southern California Edison Company, will not obtain power on an economic basis from other private utilities in California.

[illegible]
January 4, 1980

[illegible] Edison's [illegible] raised [illegible] significant [illegible] questions. It is the position of Riverside that these issues are being fully [illegible] and [illegible] gated before other agencies, including the Federal Energy Regulatory Commission and in the Federal District Court. We would again urge that action be taken by the NRC Staff to complete its review and grant the operating license applications for the San Onofre Nuclear Generating Station Units 2 and 3.

Very truly yours,

CITY OF RIVERSIDE

Everett C. Ross
Public Utilities Director

ECR:ns

APPENDIX 22

ANAHEIM PUBLIC UTILITIES DEPARTMENT

January 8, 1980

Mr. Argil Toalston, Chief
Power Supply Analysis Section
Antitrust and Indemnity Group
Office of Nuclear Reactor Regulation
Nuclear Regulatory Commission
Washington, D. C. 20555

Re: San Onofre Nuclear Generating Station, Units 2 and 3

Dear Mr. Toalston:

You have requested that the City of Anaheim answer specific questions in connection with your review of the operating license applications for San Onofre Nuclear Generating Station, Units 2 and 3. Our answers to those questions are as stated below.

The City of Anaheim, along with the City of Riverside, is a prospective participant in the San Onofre Nuclear Generating Station, Units 2 and 3. Both Cities are concerned that the operating license for both units be issued as quickly as possible. While there are certain matters at issue between each of the Cities and Southern California Edison Company (Edison), the predominant participant in the San Onofre plant, these matters are currently the subject matter of ongoing litigation between the Cities and Edison at either the Federal Energy Regulatory Commission, or in the Federal District Court. The Cities urge that the NRC staff take all steps necessary to complete its review as quickly as possible and grant the operating licenses for the San Onofre Nuclear Generating Station, Units 2 and 3.

Question 1:

In your March 24, 1978 letter to Mr. R. L. Myers of Southern California Edison Company, you stated that the California Energy Resources Conservation and Development Commission in reporting to the Legislature had suggested that the participants in the proposed Sundesert Nuclear Project purchase from Edison an interest in the Lucerne Valley Project. Please provide any documentation or other basis that would have suggested to the Energy Commission that Edison would offer or allow participation in Lucerne.

Z999 Add: Ltr Encl
OELD
5/1 AIG

8001210245

DUPE OF
8001210245

Answer 1:

Anaheim has no information or documentation that would suggest that Edison would have allowed participation in its proposed combined cycle plant to be constructed in Lucerne Valley. Nor are we aware of any documentation which the Energy Commission had that suggested that Edison would offer or allow participation in that plant. In fact, pursuant to a letter from Robert L. Myers, dated May 1, 1978, (a copy of which is attached) Southern California Edison stated that it would not offer participation in the Lucerne Valley plant to Anaheim.

Question 2:

In October, 1976, you wrote to Mr. K. L. Turley, President of Arizona Public Service Company, expressing an interest to participate in an amount of 50 mw in each of the Palo Verde Nuclear Units 1, 2 and 3, together with the related transmission lines to California. What response did Anaheim receive? What transmission alternatives did Anaheim consider other than joint ownership with Southern California Edison? What are the reasons that Anaheim did not ultimately choose to participate in the Palo Verde Units? Under what conditions, if any, would Anaheim have chosen to participate in the Units? Under what conditions, if any, would Arizona Public Service Company have permitted Anaheim to participate in the Units? Do you know why LADWP chose to participate in the Units, whereas Anaheim did not? Do you know LADWP's arrangements for transmission from Palo Verde to California?

Answer 2:

Attached hereto is a copy of a letter from Thomas G. Woods, Jr., Executive Vice President, Arizona Public Service Company, dated October 28, 1976, stating that Arizona Public Service Company was unable to offer the City of Anaheim any of its ownership interest in the Palo Verde Nuclear Generating Station, Units 1, 2 or 3. Moreover, this letter indicates that Arizona Public Service Company did not have authority to dispose of the ownership rights of any other participant in the Palo Verde Nuclear Generating Station, Units 1, 2 and 3. At the time of the October, 1976 letter which I wrote to Mr. K. L. Turley of Arizona Public Service Company, it had been suggested that a transmission line from the Palo Verde Nuclear Generating Station would be looped in to the Sundesert Nuclear Project in which Anaheim was a proposed participant. Thus, it was contemplated that Anaheim could obtain joint ownership in the transmission lines from both of these projects. Anaheim would have considered any transmission scheme which provided for (1) Anaheim's rights to firm transmission over the system; and 2)

Anaheim's cost would be based upon the cost of the transmission system. It should be noted, however, that Edison was, at that time, the only Palo Verde participant with a need to bring power west to California. Thus, Edison's proposed transmission line appeared to be the only viable proposal for transmission from Palo Verde. Anaheim was told that there was no available ownership participation to be acquired in the Palo Verde 1, 2 and 3 units. Anaheim would have participated in those units if ownership rights had been available. We do not know under what conditions, if any, Arizona Public Service would have permitted Anaheim to participate in the Palo Verde 1, 2 and 3 units. It is our understanding that the Los Angeles Department of Water and Power (LADWP) acquired from the Salt River Project (SRP) ownership rights in SRP's Coronado Generating Station. That arrangement provides that when the Palo Verde 1, 2 and 3 units become available that the ownership interest of LADWP in the Coronado units will transfer to the Palo Verde 1, 2 and 3 units. We are not familiar with LADWP's arrangements for transmission from Palo Verde to California.

Question 3:

Has Anaheim taken any services under its Integrated Operations Agreement ("IOA") and associated agreements with Edison? If not, why not? If so, has Anaheim experienced any particular difficulties? Did any outside engineering or economic consultants assist Anaheim in working out the terms and conditions of the IOA and related agreements? Have the terms and conditions of the IOA and related agreements been interpreted as Anaheim initially understood them? If not, what changes in the interpretation have occurred?

Answer 3:

Anaheim entered into the Integrated Operations Agreement with Edison on November 29, 1977. Prior to that date, Anaheim entered into an agreement with Nevada Power Company to purchase non-firm energy. Edison agreed to provide interruptible transmission for that energy from the Nevada-Edison interconnection point to the City of Anaheim. That energy was integrated by Edison in accordance with the terms of an Agreement of Integration and Transmission of Non-firm Energy with Anaheim. That Agreement was entered into prior to the conclusion of negotiations between Anaheim and Edison for the Integrated Operations Agreement. However, it was agreed that the parties would operate in accordance with Exhibit A of the Settlement Agreement between Anaheim and Edison and others, which Exhibit A contained the principles which served as the basis for the

[illegible] of the Integrated Operations Agreement.

[illegible] Anaheim have had a dispute concerning Edison's [illegible] to provide Anaheim interruptible transmission service under the 1972 Settlement Agreement and subsequently the Integrated Operations Agreement. It is Anaheim's position that Edison is required by the terms of the Settlement Agreement to use its best efforts to provide interruptible transmission service over Edison's facilities for the City of Anaheim. Edison contends that interruptible transmission was not one of the services which it agreed to provide under the terms of the 1972 Settlement Agreement and, therefore, has refused to incorporate the provisions for interruptible transmission service as one of the services offered under the Integrated Operations Agreement. This is of particular importance since Edison is required under the Integrated Operations Agreement to schedule and dispatch all of Anaheim's integrated resources as if they were owned by Edison. As Edison contends that interruptible transmission is not one of the services that it is required to provide under the Integrated Operations Agreement, it has applied a different standard concerning the provision of interruptible transmission service. Edison's position is that interruptible transmission service for Anaheim is subject to interruption by Edison for any reason whether justified or not. Anaheim's energy from Nevada Power Company is not treated by Edison in the same manner as if it were Edison's own energy. It is treated as "second class" by Edison, and if Edison, for whatever reason, wishes to interrupt the transmission of that energy, it does so. The City of Anaheim thus has suffered numerous interruptions with respect to the transmission of energy from Nevada Power Company to the City of Anaheim. The unavailability of transmission has meant that Anaheim has been required to purchase higher price energy from Edison rather than take advantage of the lower cost energy available from Nevada Power Company.

The Integrated Operations Agreement contains a provision for the arbitration of disputes which arise between Edison and Anaheim. In addition, it would be the position of Anaheim that to the extent that the Integrated Operations Agreement is subject to the jurisdiction of the Federal Energy Regulatory Commission, disputes under the IOA could be brought before that Commission for resolution.

Question 4:

Are there any other matters that you are aware of that you think that the NRC staff should consider in its review as to whether antitrust related significant changes have occurred

in Edison's activities?

Answer 4:

As indicated in the beginning of this letter, there are a number of issues in dispute between Anaheim and Edison. With respect to the wholesale rates which Edison charges Anaheim and its other wholesale customers, Anaheim, along with the Cities of Riverside, Colton, Banning and Azusa, California, have alleged before the Federal Energy Regulatory Commission in Docket Nos. E-8570, ER 76-205 and ER 79-150 that Edison's rates as filed create a "price squeeze" situation when compared with Edison's similar retail rates, and that this "price squeeze" results in price discrimination which is illegal under the Federal Power Act. The five Cities have also brought a treble damage antitrust suit in Federal District Court (Central District of California) alleging, among other things, that the price squeeze created by Edison's wholesale rates is illegal under the antitrust laws of the United States.

Anaheim, along with the other Cities, in their antitrust action against Edison in Federal District Court, have alleged that Edison's foreclosure of the bulk power supply market is in violation of the antitrust laws of the United States.

The Cities are also involved in litigation with Edison concerning Edison's activities to foreclose the Cities from access to alternative bulk power supplies. This litigation includes Docket No. E-7777 (Phase II) and Docket No. E-7796 before the Federal Energy Regulatory Commission. These proceedings concern investigation by the FERC of the California Power Pool, and Pacific Intertie arrangements, which are those arrangements concerning the transmission facilities between the Pacific Northwest and California. The Cities have alleged that Edison alone and in conspiracy with the California Power Pool companies have acted to foreclose the Cities, as well as other municipal systems in California, from access to available energy in the Pacific Northwest. Cities also alleged that Edison, alone and in conspiracy with the other California Power Pool companies, have agreed to divide the California bulk power supply market so as to insure that municipals located within the service area of one of the systems such as that of Southern California Edison Company, will not obtain power on an economic basis from other private utilities in California.

Thus, whi. Edison's activities with respect to Anaheim raises a number of significant antitrust questions, it is the position

of Anaheim that these issues are being fully aired and litigated before other agencies including the Federal Energy Regulatory Commission and in the District Court.

We would again urge that action be taken by the NRC staff to complete its review and grant the operating license applications for the San Onofre Nuclear Generating Station, Units 2 and 3.

Very truly yours,

Gordon W. Hoyt
General Manager