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 RECIP. NAME RECIPIENT AFFILIATION
 TOALSTON, A. Antitrust & Indemnity Group

SUBJECT: Forwards response to NRC 791018 questions re future generation re search programs, integrated operations agreements, use of contract energy cost & transmission svc.

(See reports)

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Southern California Edison Company



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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,

David Barry

DNB:feh
Encl.

cc: Mr. Jack Goldberg

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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

February 21, 1979
FUTURE GENERATION RESOURCE PROGRAM

1979-1998
PRINCIPAL CHANGES FROM THE FEBRUARY 7, 1978
FUTURE GENERATION RESOURCE PROGRAM

1. This program is based on the December, 1978 System Forecasts. In comparison with the previous forecast, the Edison Net Main System peak demand forecast was decreased by 80 MW in 1980, 30 MW in 1987, and 810 MW in 1997. This forecast includes the expected load management impacts approved on May 11, 1978. The study period was extended by one year to 1998.
2. Cool Water Combined Cycle Units 3 and 4 were released for firm operation on May 31 and August 31, 1978, respectively, at a capacity of 180 MW each. It is expected that both units will be rerated to a firm capacity of 234 MW each on June 1, 1979.
3. Long Beach Combined Cycle Units 8 and 9 Summer/Winter capacity rerate of 31/38 MW and 22/27 MW, (53/65 MW total) respectively, was delayed from June 1, 1978, to June 1, 1979.
4. An exchange with Portland General Electric has been executed, where Edison provided 225 MW of capacity to PGE during October 15, 1978 - January 15, 1979, and PGE will provide 225 MW to SCE during the summer of 1981.
5. The 22 MW Axis Combustion Turbine previously scheduled for firm operation on April 1, 1979, to serve the isolated Blythe load was released for firm operation on December 28, 1978. Interconnection with the main system is anticipated in 1981.
6. Firm cogeneration capacity of 36 MW in 1980, increasing to a total of 111 MW in 1998 has been added to the resource program. This is in addition to the non-firm cogeneration which was deducted from the load forecast after adjusting for diversity.
7. The 1979, 3 MW wind demonstration unit is scheduled as firm capacity of 1 MW starting in 1983 dependent upon successful operation during the demonstration period. Total wind capacity in 1983 - 1998 is increased from 100 MW to 203 MW.

8. Geothermal pilot and demonstration units of 9 MW in 1980, and 9 MW and 45 MW in 1982 are scheduled as firm capacity in 1982 and 1986 respectively dependent upon successful operation during the demonstration period.
9. The 1500 MW California Coal Project (3-500 MW units, Edison's share 50%) was added in 1987, 1988 and 1989.
10. The 2-unit San Joaquin Nuclear Project scheduled for 1988/1990 (Edison's share, 572 MW; and resale cities of Anaheim and Riverside's share 104 MW) was canceled.
11. The planned 990 MW of Combustion Turbine capacity added after 1986 has been increased to 1980 MW
12. Coal capacity additions in the 1991-1998 period have been reduced from 2250 MW to 1250 MW.
13. Nuclear capacity additions in the 1992-1998 period have been reduced from 2340 MW to 1350 MW.
14. The resource plan was extended to include the additional year of 1998 with 100 MW of Solar, 135 MW of geothermal, 20 MW of wind, 250 MW of coal capacity, 275 MW of combustion turbines, and 5 MW of co-generation capacity.

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GEN2:PAL102.A

February 21, 1979
FUTURE GENERATION RESOURCE PROGRAM
1979-1998

Definition of Column Headings

Date

Firm operating date of unit or contractual agreement.

Resources

Resource identification. Often includes supplemental information about capacity, particularly when the identification refers to a unit which is undergoing rerate, has associated off-system losses, or is a participation unit.

Net Capacity Added

Effective operating capacity ratings of resources. These have been adjusted for losses incurred outside the Edison Main System where applicable.

Total Capacity

Summer total capacity includes resources installed as of July 1 of that year; winter includes all capacity added in that year. Summer capacity shown for 1978 includes resources installed as of September 25, 1978.

Area Peak Demand

Includes Edison Net Main System peak demand plus firm on-peak sales to other utilities, CDWR and Metropolitan Water District on-peak pumping demands, and demands for formerly isolated Edison loads commencing when they are interconnected with the Main System.

Area Margin

Megawatt margin is the difference between total installed capacity and area peak demand. Percent margin is the megawatt margin divided by area peak demand and multiplied by 100.

Area Reliability Index

The reliability index represents the likelihood that a particular year's specified resources will be sufficient to serve forecast loads for each hour of the year, allowing for planned generation maintenance and forced outages without requiring delivery of capacity via Edison's interconnections in excess of firm deliveries plus 300 MW from 1978 through 1984, and firm deliveries plus 600 MW after 1984.

Edison Net Peak Demand

Edison Net Main System peak demand is based on the System Forecasts prepared by the System Development Department in December, 1978. This peak demand forecast includes reductions for load management and conservation.

Annual Load Increase

Percent by which Edison net peak demand increases over the previous year's net peak demand.

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FEBRUARY 21, 1979
 FUTURE GENERATION RESOURCE PROGRAM
 1979-1998

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
12-31-78	AGGREGATE RATED CAPACITY REDUCED FOR "DRY YEAR HYDRO" CONDITIONS. 213 MW FOR SUMMER AND 264 MW FOR WINTER		14753	14608 (1)						
6- 1-79	COOL WATER 3 RERATE (234/249)	54/ 69								
6- 1-79	COOL WATER 4 RERATE (234/249)	54/ 69								
6- 1-79	WIND 1 - DEMO (3 MW)	(2)								
6- 1-79	LONG BEACH 8 COMBINED CYCLE RERATE	31/ 38 (3)								
6- 1-79	LONG BEACH 9 COMBINED CYCLE RERATE	22/ 27 (3)								
6- 1-79	CO-GENERATION (12 MW EXISTING)	(4)								
7- 1-79	RECONDITION LONG BEACH 11	56 (5)								
	TOTAL CAPACITY ADDED	217/ 259								
	LOADS AND RESOURCES FOR SUMMER 1979		14970		12393	2577	20.8	.99	12130	1.1
	LOADS AND RESOURCES FOR WINTER 1979			14867	10425	4442	42.6			
1- 1-80	INCREASE SALE TO APPA 2MW	-2 (6)								
1-15-80	GEOTHERMAL 1 - BRAWLEY 9 MW DEMONSTRATION	(7)								
3- 1-80	BIG CREEK 3 UNIT 5	31								
4- 1-80	DECREASE NAVAJO LAYOFF (4.3 MW TOTAL)	-4 (8)								
6- 1-80	DECREASE SALE TO APPA 1MW	1 (6)								
6- 1-80	CO-GENERATION (36 MW TOTAL)	24 (4)								
7- 1-80	DECREASE NAVAJO LAYOFF (7.7 MW TOTAL)	-3 (8)								
10- 1-80	DECREASE NAVAJO LAYOFF (21.4 MW TOTAL)	-14 (8)								
10- 1-80	SAN ONOFRE 2 (220/176 MW)	176 (9)								
	TOTAL CAPACITY ADDED	209								
	LOADS AND RESOURCES FOR SUMMER 1980		15017		12671	2346	18.5	.99	12400	2.2
	LOADS AND RESOURCES FOR WINTER 1980			15076	10663	4413	41.4			

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW) (%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)	
1- 1-81	DECREASE NAVAJO LAYOFF (28.3 MW TOTAL)	-6 (8)								
4- 1-81	DECREASE SALE TO APPA 1MW	1 (6)								
4- 1-81	DECREASE NAVAJO LAYOFF (40.5 MW TOTAL)	-12 (8)								
4- 1-81	EDWARDS AFB EXCHANGE	18/ 15 (10)								
4- 1-81	INTERCONNECT AXIS GENERATION WITH MAIN SYSTEM (75/25MW STEAM + 22MW CT)	47 (11)								
6- 1-81	CO-GENERATION (40 MW TOTAL)	4 (4)								
6- 1-81	PGE EXCHANGE (225 MW)	212 (12)								
7- 1-81	DECREASE NAVAJO LAYOFF (54.8 MW TOTAL)	-14 (8)								
10- 1-81	DECREASE NAVAJO LAYOFF (57.4 MW TOTAL)	-3 (8)								
10- 1-81	SOLAR - DEMO (10 MW)	(13)								
10- 1-81	RERATE SAN ONOFRE 2 (220/176 TO 1100/860 MW)	704 (9)								
10- 1-81	TERMINATE PGE EXCHANGE	-212 (12)								
	TOTAL CAPACITY ADDED	739/ 736								
	LOADS AND RESOURCES FOR SUMMER 1981		15429		13180	2249	17.1	.99	12870	3.8
	LOADS AND RESOURCES FOR WINTER 1981			15812	11085	4727	42.6			

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW) (%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)	
1- 1-82	INCREASE SALE TO APPA 17MW	-16 (6)								
1- 1-82	SAN ONOFRE 3 (220/176 MW)	176 (9)								
5- 1-82	PALO VERDE NUCLEAR 1 (1222/193 MW)	187 (14)								
6- 1-82	DERATE FOUR CORNERS 4 (800/384 TO 785/377 MW)	-7 (15)								
6- 1-82	DERATE FOUR CORNERS 5 (800/384 TO 785/377 MW)	-7 (15)								
6- 1-82	CO-GENERATION (44 MW TOTAL)	4 (4)								
7- 1-82	GEOHERMAL 2 - NILAND 9 MW DEMONSTRATION	(7)								
10- 1-82	GEOHERMAL 3 - HEBER 45 MW DEMONSTRATION	(7)								
	TOTAL CAPACITY ADDED	----- 337								
	LOADS AND RESOURCES FOR SUMMER 1982		16255		13716	2539	18.5	.97	13350	3.7
	LOADS AND RESOURCES FOR WINTER 1982			16149	11548	4601	39.8			
1- 1-83	RERATE SAN ONOFRE 3 (220/176 TO 1100/880 MW)	704 (9)								
4- 1-83	TERMINATE OROVILLE-THERMALITO (340 MW)	-326 (16)								
4- 1-83	ADJUST DRY-YEAR HYDRO DERATE TO 193MW/225MW TO REMOVE OROVILLE	20/ 39 (16)								
6- 1-83	WIND 1 - COMMERCIAL (3 MW)	1 (2)								
6- 1-83	CO-GENERATION (49 MW TOTAL)	5 (4)								
7- 1-83	FUEL CELL 1	26 (17)								
	TOTAL CAPACITY ADDED	----- 430/ 449								
	LOADS AND RESOURCES FOR SUMMER 1983		16685		14091	2594	18.4	.99	13860	3.8
	LOADS AND RESOURCES FOR WINTER 1983			16598	11843	4755	40.2			

7

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
5- 1-84	BEGIN DIVERSITY EXCHANGE WITH NORTHWEST (275MW NW TO SCE FROM MAY THRU OCT)	259/ 0	(18)							
5- 1-84	PALO VERDE NUCLEAR 2 (1222/193 MW)	187	(14)							
6- 1-84	GEOTHERMAL 1 - COMMERCIALIZE BRAWLEY 9 MW DEMONSTRATION	9	(7)							
6- 1-84	CO-GENERATION (53 MW TOTAL)	4	(4)							
11- 1-84	ANNUAL WINTER EXCH 275MW TO NORTHWEST		(18)							
	TOTAL CAPACITY ADDED	459/ 200								
	LOADS AND RESOURCES FOR SUMMER 1984		17144		14621	2523	17.3	.99	14390	3.8
	LOADS AND RESOURCES FOR WINTER 1984			16798	12542	4256	33.9			
1- 1-85	END SALE TO APPA 34MW	32	(6)							
1- 1-85	TERMINATE NAVAJO LAYOFF (270 MW)	-263	(8)							
6- 1-85	COMBINED CYCLE PROJECT (CT'S)	540/549	(19)							
6- 1-85	BALSAM MEADOW HYDRO	140	(20)							
6- 1-85	CO-GENERATION (57 MW TOTAL)	4	(4)							
	TOTAL CAPACITY ADDED	453/ 462								
	LOADS AND RESOURCES FOR SUMMER 1985		17597		15071	2526	16.8	.98	14840	3.1
	LOADS AND RESOURCES FOR WINTER 1985			17260	12922	4338	33.6			

(A) COMBUSTION TURBINES ARE ALTERNATIVES TO THE
 COMBINED CYCLE PROJECT

NOTE: HARRY ALLEN - WARNER VALLEY PROJECT RESOURCES IN THE 1984-1988
 TIME FRAME COULD POTENTIALLY REPLACE PLANNED CAPACITY ADDITIONS (21)

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN		AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)		(MW)	(%)			
3-31-86	TERMINATE EDWARDS AFB EXCHANGE	-18/-15	(10)							
5- 1-86	FUEL CELLS 2 & 3	52	(17)							
5- 1-86	PALO VERDE NUCLEAR 3 (1222/193 MW)	188	(14)							
6- 1-86	WIND 2 (6 MW)	2	(2)							
(A)6- 1-86	COMBINED CYCLE PROJECT (CT'S)	180/183	(19)							
(A)6- 1-86	COMBINED CYCLE PROJECT (STM)	130/133	(19)							
6- 1-86	GEOTHERMAL 2 - COMMERCIALIZE NILAND 9 MW DEMONSTRATION	9	(7)							
6- 1-86	GEOTHERMAL 3 - COMMERCIALIZE HEBER 45 MW DEMONSTRATION	45	(7)							
6- 1-86	CO-GENERATION (61 MW TOTAL)	4	(4)							
	TOTAL CAPACITY ADDED	592/ 601								
	LOADS AND RESOURCES FOR SUMMER 1986		18189		15551	2638	17.0	.99	15320	3.2
	LOADS AND RESOURCES FOR WINTER 1986			17861	13322	4539	34.1			

(A) COMBUSTION TURBINES ARE ALTERNATIVES TO THE
 COMBINED CYCLE PROJECT

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
5- 1-87	FUEL CELLS 4 & 5	52 (17)								
6- 1-87	WIND 3 (15 MW)	5 (2)								
6- 1-87	TERMINATE HOOVER	-331 (22)								
6- 1-87	ADJUST DRY-YEAR HYDRO DERATE TO 139MW/171MW TO REMOVE HOOVER	54 (22)								
(A)6- 1-87	COMBINED CYCLE PROJECT (CT'S)	180/183 (19)								
(A)6- 1-87	COMBINED CYCLE PROJECT (STM)	260/266 (19)								
6- 1-87	CALIF COAL 1 (500/250 MW)	250 (23)								
6- 1-87	COMBUSTION TURBINE (2 UNITS)	110 (24)								
6- 1-87	GEO THERMAL 4	45 (7)								
6- 1-87	CO-GENERATION (65 MW TOTAL)	4 (4)								
8- 1-87	BEGIN DIVERSITY EXCHANGE WITH NORTHWEST (550MW NW TO SCE FROM MAY THRU OCT)	517/ 0 (18)								
8- 1-87	TERMINATE BPA EXCHANGE	-517 (18)								
11- 1-87	ANNUAL WINTER EXCH 550MW TO NORTHWEST	(18)								
	TOTAL CAPACITY ADDED	629/ 121								
	LOADS AND RESOURCES FOR SUMMER 1987		18818		16051	2767	17.2	.98	15820	3.3
	LOADS AND RESOURCES FOR WINTER 1987			17982	14334	3648	25.4			
5- 1-88	FUEL CELLS 6 - 9	104 (17)								
5- 1-88	PALO VERDE NUCLEAR 4 (1222/425 MW)	412 (25)								
6- 1-88	WIND 4 (30 MW)	10 (2)								
6- 1-88	CALIF COAL 2 (500/250 MW)	250 (23)								
6- 1-88	CO-GENERATION (69 MW TOTAL)	4 (4)								
	TOTAL CAPACITY ADDED	780								
	LOADS AND RESOURCES FOR SUMMER 1988		19598		16515	3083	18.7	.97	16320	3.2
	LOADS AND RESOURCES FOR WINTER 1988			18762	14744	4018	27.3			

10

(A) COMBUSTION TURBINES ARE ALTERNATIVES TO THE
 COMBINED CYCLE PROJECT

NOTE: RESALE CITIES' CAPACITY RESOURCES IN THE 1987-1998 TIME FRAME
 COULD POTENTIALLY REPLACE PLANNED CAPACITY (26)

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW) (%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
5- 1-89	FUEL CELLS 10 - 15	156 (17)							
6- 1-89	WIND 5 (30 MW)	10 (2)							
6- 1-89	CALIF COAL 3 (500/250 MW)	250 (23)							
6- 1-89	CO-GENERATION (73 MW TOTAL)	4 (4)							
	TOTAL CAPACITY ADDED	420							
	LOADS AND RESOURCES FOR SUMMER 1989		20018		17025	2993	17.6	16830	3.1
	LOADS AND RESOURCES FOR WINTER 1989			19182	15174	4008	26.4		
5- 1-90	PALO VERDE NUCLEAR 5 (1222/425 MW)	413 (25)							
6- 1-90	WIND 6 (45 MW)	15 (2)							
6- 1-90	COMBUSTION TURBINE (1 UNIT)	55 (24)							
6- 1-90	GEOHERMAL 5	90 (7)							
6- 1-90	CO-GENERATION (77 MW TOTAL)	4 (4)							
	TOTAL CAPACITY ADDED	577							
	LOADS AND RESOURCES FOR SUMMER 1990		20595		17509	3086	17.6	17350	3.1
	LOADS AND RESOURCES FOR WINTER 1990			19759	15604	4155	26.6		
6- 1-91	WIND 7 (60 MW)	20 (2)							
6- 1-91	EAST COAL 1 (1000/263 MW)	250 (27)							
6- 1-91	COMBUSTION TURBINE (5 UNITS)	275 (24)							
6- 1-91	CO-GENERATION (81 MW TOTAL)	4 (4)							
	TOTAL CAPACITY ADDED	549							
	LOADS AND RESOURCES FOR SUMMER 1991		21144		18069	3075	17.0	17910	3.2
	LOADS AND RESOURCES FOR WINTER 1991			20308	16074	4234	26.3		

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
6- 1-92	COMBUSTION TURBINE (7 UNITS)	385 (24)								
6- 1-92	WIND 8 (60 MW)	20 (2)								
6- 1-92	EAST COAL 2 (1000/263 MW)	250 (27)								
6- 1-92	CO-GENERATION (85 MW TOTAL)	4 (4)								
	TOTAL CAPACITY ADDED	659								
	LOADS AND RESOURCES FOR SUMMER 1992		21803		18639	3164	17.0	.96	18480	3.2
	LOADS AND RESOURCES FOR WINTER 1992			20967	16554	4413	26.7			
6- 1-93	COMBUSTION TURBINE (2 UNITS)	110 (24)								
6- 1-93	WIND 9 (60 MW)	20 (2)								
6- 1-93	GEO THERMAL 6	135 (7)								
6- 1-93	NUCLEAR 1 (1000/450 MW)	450 (28)								
6- 1-93	CO-GENERATION (90 MW TOTAL)	5 (4)								
	TOTAL CAPACITY ADDED	720								
	LOADS AND RESOURCES FOR SUMMER 1993		22523		19219	3304	17.2	.97	19060	3.1
	LOADS AND RESOURCES FOR WINTER 1993			21687	17034	4653	27.3			
1- 1-94	RETIRE LONG BEACH 10 & 11	-212								
5- 1-94	SOLAR 1	100 (13)								
6- 1-94	WIND 10 (60 MW)	20 (2)								
6- 1-94	COMBUSTION TURBINE (6 UNITS)	330 (24)								
6- 1-94	NUCLEAR 2 (1000/450 MW)	450 (28)								
6- 1-94	CO-GENERATION (94 MW TOTAL)	4 (4)								
	TOTAL CAPACITY ADDED	692								
	LOADS AND RESOURCES FOR SUMMER 1994		23215		19809	3406	17.2	.97	19650	3.1
	LOADS AND RESOURCES FOR WINTER 1994			22379	17534	4845	27.6			

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN		AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
			SUMMER (MW)	WINTER (MW)		(MW)	(%)			
1- 1-95	EAST COAL 3 (1000/263 MW)	250 (27)								
5- 1-95	SOLAR 2	100 (13)								
6- 1-95	COMBUSTION TURBINE (2 UNITS)	110 (24)								
6- 1-95	WIND 11 (60 MW)	20 (2)								
6- 1-95	GEO THERMAL 7	135 (7)								
6- 1-95	CO-GENERATION (98 MW TOTAL)	4 (4)								
	TOTAL CAPACITY ADDED	619								
	LOADS AND RESOURCES FOR SUMMER 1995		23834		20389	3445	16.9	.98	20230	3.0
	LOADS AND RESOURCES FOR WINTER 1995			22998	18014	4984	27.7			
5- 1-96	SOLAR 3	100 (13)								
6- 1-96	WIND 12 (60 MW)	20 (2)								
6- 1-96	COMBUSTION TURBINE (4 UNITS)	220 (24)								
6- 1-96	GEO THERMAL 8	135 (7)								
6- 1-96	EAST COAL 4 (1000/263 MW)	250 (27)								
6- 1-96	CO-GENERATION (102 MW TOTAL)	4 (4)								
	TOTAL CAPACITY ADDED	729								
	LOADS AND RESOURCES FOR SUMMER 1996		24563		20979	3584	17.1	.99	20820	2.9
	LOADS AND RESOURCES FOR WINTER 1996			23727	18514	5213	28.2			

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
5- 1-97	SOLAR 4	100 (13)								
6- 1-97	WIND 13 (60 MW)	20 (2)								
6- 1-97	COMBUSTION TURBINE (2 UNITS)	110 (24)								
6- 1-97	CO-GENERATION (106 MW TOTAL)	4 (4)								
6- 1-97	NUCLEAR 3 (1000/450 MW)	450 (28)								
	TOTAL CAPACITY ADDED	684								
	LOADS AND RESOURCES FOR SUMMER 1997		25247		21589	3658	16.9	.99	21430	2.9
	LOADS AND RESOURCES FOR WINTER 1997			24411	19024	5387	28.3			
5- 1-98	SOLAR 5	100 (13)								
6- 1-98	WIND 14 (60 MW)	20 (2)								
6- 1-98	COMBUSTION TURBINE (5 UNITS)	275 (24)								
6- 1-98	EAST COAL 5 (1000/263 MW)	250 (27)								
6- 1-98	GEO THERMAL 9	135 (7)								
6- 1-98	CO-GENERATION (111 MW TOTAL)	5 (4)								
	TOTAL CAPACITY ADDED	785								
	LOADS AND RESOURCES FOR SUMMER 1998		26032		22219	3813	17.2	.98	22060	2.9
	LOADS AND RESOURCES FOR WINTER 1998			25196	19544	5652	28.9			

DEVELOPMENT OF PERTINENT DATA

- 1) RECONCILIATION OF THE 12-31-1978 AGGREGATE RATED CAPACITY WITH THE JANUARY 1, 1979 REVISION OF THE "GENERATOR RATINGS AND EFFECTIVE OPERATING CAPACITY OF RESOURCES".

	SUMMER (MW)	WINTER (MW)
NET MAIN SYSTEM RESOURCES	13102	13102
TOTAL FIRM PURCHASES	+1632	+1532
HYD CAPACITY	+315	+315
HYDRO DERATE	-213	-264
TOTAL OFF SYSTEM LOSSES	-83	-77
12-31-78 AGGREGATE RATED CAPACITY	14753	14608

2) SUMMARY OF AREA PEAK DEMANDS (1979-1998)

	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
SUMMER										
EDISON NET PEAK DEMAND *	12130	12400	12870	13350	13860	14390	14840	15320	15820	16320
MWD LOAD	231	231	231	231	231	231	231	231	231	195
STATE WATER PROJECT **	32	40	79	135	-	-	-	-	-	-
AREA PEAK DEMAND	12393	12671	13180	13716	14091	14621	15071	15551	16051	16515
INTERRUPTIBLE LOAD ***	60	85	89	93	97	101	105	109	113	118
WINTER										
EDISON NET PEAK DEMAND *	10140	10370	10760	11160	11590	12030	12410	12810	13230	13640
MWD LOAD	159	159	159	159	159	159	159	159	123	123
STATE WATER PROJECT **	32	40	72	135	-	-	-	-	-	-
DIV EXCHANGE PORTLAND GE	94	94	94	94	94	94	94	94	106	106
DIV EXCHANGE NORTH-WEST	-	-	-	-	-	259	259	259	292	292
DIV EXCHANGE BPA	-	-	-	-	-	-	-	-	583	583
AREA PEAK DEMAND	10425	10663	11085	11548	11843	12542	12922	13322	14334	14744
INTERRUPTIBLE LOAD ***	60	75	79	83	87	91	95	99	103	107
1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	
SUMMER										
EDISON NET PEAK DEMAND *	16830	17350	17910	18480	19060	19650	20230	20820	21430	22060
MWD LOAD	195	159	159	159	159	159	159	159	159	159
AREA PEAK DEMAND	17025	17509	18069	18639	19219	19809	20389	20979	21589	22219
INTERRUPTIBLE LOAD ***	122	126	130	134	139	143	147	151	155	160
WINTER										
EDISON NET PEAK DEMAND *	14070	14500	14970	15450	15930	16430	16910	17410	17920	18440
MWD LOAD	123	123	123	123	123	123	123	123	123	123
DIV EXCHANGE PORTLAND GE	106	106	106	106	106	106	106	106	106	106
DIV EXCHANGE NORTH-WEST	292	292	292	292	292	292	292	292	292	292
DIV EXCHANGE BPA	583	583	583	583	583	583	583	583	583	583
AREA PEAK DEMAND	15174	15604	16074	16554	17034	17534	18014	18514	19024	19544
INTERRUPTIBLE LOAD ***	111	115	119	123	127	131	135	139	143	147

* BLYTHE LOAD IS INCLUDED IN THE EDISON NET PEAK DEMAND STARTING IN 1981
 ** WITH THE CONTRACT TERMINATION OF OROVILLE-THERMALITO IN 1983, IT HAS BEEN
 ASSUMED THAT THE STATE WATER PROJECT WILL SERVE ITS OWN ON-PEAK LOADS
 *** EDISON NET PEAK DEMAND HAS BEEN REDUCED FOR INTERRUPTIBLE LOAD,
 WHICH IN SUMMER INCLUDES INTERRUPTIBLE AIR CONDITIONING

February 21, 1979
FUTURE GENERATION RESOURCE PROGRAM
1979-1998

Notes

1. Aggregate rated capacity is in accord with the January 1, 1979, revision of "Generator Ratings and Effective Operating Capacity of Resources," adjusted to include MWD's capacity of 315 MW (261 MW at Hoover, 54 MW at Parker), and reduced by Edison, Hoover and Oroville-Thermalito dry year hydro derates.
2. A 3 MW demonstration wind unit is scheduled for June 1, 1979, near Devers Substation for testing. The rated capacity is based on a 40 mph wind speed with the firm capacity value of the unit estimated to be 1 MW. Contingent upon a successful demonstration, this unit is scheduled for firm commercial operation on June 1, 1983. All wind units are expected to yield a firm capacity value of 1/3 of their nameplate ratings. Construction of units in 1986-1998 is contingent upon successful research and development and competitive costs.
3. Long Beach 8 and 9 Combined Cycle units are currently rated at 280 MW and 210 MW, respectively. Dependent upon field performance tests, on June 1, 1979 they are expected to be rerated at 311 MW and 232 MW, respectively (total = 543 MW), which is an additional 31 MW and 22 MW increase for Units 8 and 9, respectively.
4. Firm co-generation capacity as estimated in the May, 1978, Load Management Forecast has been added during the 1980-1998 time period. For planning purposes, integration with the system is shown to commence on June 1 of each year. Existing cogeneration (12 MW) is shown in 1979. In addition, non-firm cogeneration, adjusted for diversity, has been deducted from the load forecast.
5. Prior to completion of reconditioning in 1979, Long Beach Unit 11 has been derated from 106 to 50 MW.
6. The Arizona Power Pooling Association (APPA) has executed an agreement with Edison, Arizona Public Service, Nevada Power and Tucson Gas and Electric to sell capacity and associated energy to APPA based on the availability and cost of Navajo Power from March 1, 1978, until termination of Navajo layoff to Edison. Edison's share of the capacity sale will range from 16.5 MW in 1978 to 33.4 MW in 1982.

7. Geothermal additions are scheduled as follows: a 9 MW demonstration unit located at Brawley in 1980; a 9 MW demonstration unit located at Niland in 1982; and a 45 MW commercial unit located at Heber in 1982. Assuming successful testing, these units will be released for firm operation after four years, and will contribute 9 MW of firm capacity in 1984, and 9 MW and 45 MW of firm capacity in 1986, respectively. Addition of future commercial geothermal units shown in the resource plan is contingent upon successful research and development and competitive costs.
8. A contract has been executed with the Western Area Power Authority (WAPA) (formerly the U.S. Bureau of Reclamation) for layoff of power from the Navajo Project. At such time as WAPA needs this power for the Central Arizona Project, WAPA has the right to terminate this layoff, effective on or after January 1, 1980, upon at least five years' advance written notice. Such notice has not been given; however, it is currently anticipated that the layoff will terminate in 1985. Edison has been notified, however, that the layoff will be decreased to provide power for WAPA's desalination project (contingent upon execution of a letter agreement providing for staged withdrawal of layoff power) as follows:

<u>Date</u>	<u>Total Withdrawal</u>
4-1-80	4.3 MW
7-1-80	7.7 MW
10-1-80	21.4 MW
1-1-81	28.3 MW
4-1-81	40.5 MW
7-1-81	54.8 MW
10-1-81	57.4 MW

9. For planning reporting purposes, San Onofre Units 2 and 3 are considered a firm capacity resource at 20% of their full power rating (880 MW total SCE share each unit) starting one year prior to their respective full power firm operating dates of October 1, 1981, and January 1, 1983. The capacity shown is 80% of the Project, which includes Edison's share and the resale cities' potential share (Anaheim - 1.66% or 36.5 MW and Riverside - 1.79% or 39.4 MW of the total project).

10. Edwards Air Force Base exchange capacity is available to Edison in the amount of 18.5 MW from March 1 to September 30, and 14.95 MW from October 1 to February 28, annually until March 31, 1986. The capacity is added to the Edison Main System in 1981 with the interconnection of the Blythe System.
11. The 22 MW Axis combustion turbine was released for firm operation on December 28, 1978, to serve the Blythe area load. Loads and resources of the Blythe Isolated System are interconnected with the Edison Main System in 1981.
12. A firm capacity exchange agreement was executed with Portland General Electric in October, 1978. Under this agreement, Edison provided 225 MW of firm capacity to PGE during the period October 15, 1978 through January 15, 1979. In exchange, during the period June 1, 1981 through September 30, 1981, PGE will provide 225 MW (212 MW after losses) of firm capacity to Edison.
13. A 10 MW solar-thermal demonstration unit is scheduled for operation on October 1, 1981. Because this is a jointly-owned, prototype unit with uncertain commercial operation, no firm capacity addition is assumed at any future date. Solar Units 1-5 in the 1994 to 1998 period (100 MW each) are contingent upon successful research and development and competitive costs.
14. Edison is participating in the three-unit, 3666 MW Palo Verde Nuclear Project in Arizona with a 15.8% share (562 MW after off-system losses). Firm operating dates are scheduled for May 1, 1982; May 1, 1984; and May 1, 1986.

The project is allocated as follows:

	<u>Participation Percentage</u>
Arizona Public Service Company	29.1
Salt River Project	23.4*
El Paso Electric Company	15.8
Southern California Edison Company	15.8
Public Service Company of New Mexico	10.2
Los Angeles Department of Water & Power	<u>5.7*</u>
TOTAL	100.0

*SRP's current share is 29.1%. Upon the date of commercial operation of Palo Verde Unit 1, 5.7% of SRP's entitlement will be transferred to LADWP in exchange for LADWP's share of Coronado Units 1 and 2.

15. Additional air pollution control equipment is required for Four Corners Units 4 and 5 by January 1, 1983, to comply with the November, 1977, ruling of the Environment Improvement Board of the State of New Mexico. This is expected to result in a capacity reduction of approximately 15 MW per unit (SCE's share is 7 MW per unit). For planning purposes, these reductions are shown to commence on June 1, 1982.
16. Edison has been notified by the California Department of Water Resources (CDWR) that, on April 1, 1983, the contractual provisions for energy and capacity assigned to Edison from the Oroville-Thermalito facility will be terminated. The Edison capacity allocation of 340 MW is adjusted to 326 MW for losses and further reduced by 20 MW/39 MW to reflect dry year summer/winter hydro conditions. Concurrent with the termination of the capacity assignment, it is assumed that Edison's load obligation to CDWR may terminate.
17. In March, 1973, Edison joined a group of investor-owned utilities to fund an electric utility fuel cell program in conjunction with United Technologies Corporation. Final commitments to purchase 15 units at 26 MW each (390 MW total capacity) for delivery in 1983-1989 is contingent upon both competitive costs with other peaking capacity and successful validation of a demonstrator unit.
18. A seasonal diversity exchange of 275 MW capacity commencing on May 1, 1984, is being discussed with the Pacific Northwest. To replace the 550 MW capacity/energy exchange with Bonneville Power Authority, which terminates on August 1, 1987, an additional seasonal diversity exchange is also being discussed. The effect of these seasonal diversity exchanges on Edison's resources is equivalent to a capacity purchase in the summer (May 1 through October 31) and a capacity sale in the winter. Exchange amounts have been adjusted for Edison's net loss obligations.
19. The capacities shown are for the proposed 1290 MW Combined Cycle Project (Lucerne Valley site assumed for evaluation). Combustion turbines are installed prior to integrated combined cycle operation, which will commence as soon as respective steam turbine components are in service. Combustion turbines are alternatives to the combined cycle units.

20. It is planned to construct a new 140 MW hydro facility at Balsam Meadow (in the Big Creek area) in 1985.
21. Edison is evaluating participation in the proposed 2500 MW Harry Allen-Warner Valley Project. Edison could receive up to 1045 MW of firm capacity from the project in the 1984-88 period. Participation in this project could potentially replace other planned capacity additions in this period.
22. Edison's present 50-year Hoover contract for energy and capacity (331 MW) with the U.S. Department of Interior, expires on June 1, 1987. Dry year hydro derate reduces the above capacity by 54 MW. MWD's Hoover capacity (261 MW) is assumed to continue.
23. Edison is planning to construct the 3-500 MW unit California Coal Project in Southern California (Edison share 50%). Five potential sites have been identified. Participation in the project is currently being determined.
24. Specific sites for 1980 MW of combustion turbines in the 1987-1998 time frame have not been determined.
25. Edison is a 32.3% (765.7 MW after off-system losses) participant in the Palo Verde Nuclear Units 4 and 5, which replicate the Palo Verde Nuclear Units 1-3.

Anticipated project allocation is as follows:

	<u>Participation Percentage</u>
Arizona Public Service	39.1
Southern California Edison	32.3
L.A. Department of Water & Power	11.7
San Diego Gas and Electric	5.2
El Paso Electric Company	4.0
Nevada Power Company	2.2
City of Anaheim	1.5
City of Burbank	1.0
City of Glendale	1.0
City of Pasadena	1.0
City of Riverside	<u>1.0</u>
TOTAL	100.0

Included in Edison's future generation resource plan are the capacity allocations of this project for Edison's resale cities of Anaheim (35.6 MW after off-system losses) and Riverside (23.7 MW total after off-system losses).

26. Edison has been informed that the resale cities of Anaheim and Riverside are evaluating participation in the Intermountain Project Units 1 to 4, scheduled for 1987-1990, in the following amounts:

	<u>Intermountain</u>
Anaheim	307 MW
Riverside	<u>204 MW</u>
TOTAL	511 MW

27. Sites for coal capacity scheduled for 1991 and beyond have not been determined.
28. Sites for nuclear capacity scheduled for 1993 and beyond have not been determined.

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FEBRUARY 7, 1978
FUTURE GENERATION RESOURCE PROGRAM
1978-1997
PRINCIPAL CHANGES FROM THE MAY 3, 1977 FUTURE
GENERATION RESOURCE PROGRAM

1. This program is based on the System Forecasts prepared in January 1978. In comparison with the previous forecast, the Edison Net Main System peak demand increased by 90 MW in 1980, but decreased by 80 MW in 1985 and 180 MW in 1990.
2. Reconditioning of Long Beach unit 10 was completed on 6-1-77, which restored its rating to 106 MW.
3. An agreement has been executed with Arizona Power Pooling Association (APPA) whereby Edison and other Navajo participants will provide capacity and energy to APPA based on the availability and costs of the Navajo project. Edison's obligation will vary from 16.5 MW to 33.4 MW over the period February 15, 1978 to January 1, 1985.
4. The firm operating date of Cool Water Combined Cycle unit 3 was delayed from 4-1-78 to 6-1-78.
5. The Long Beach Combined Cycle units 8 and 9 Summer/Winter capacity rerate of 31/38 MW and 22/27 MW, (53/65 MW total) respectively was delayed from 12-1-77 to 6-1-78.
6. The decrease in lay off power from the Navajo project has been revised from 22 MW to 20 MW in 1980 and from 40 MW to 32 MW in 1981 to reflect a decrease in required capacity for USBR's planned desalination project.
7. To comply with the regulation of the Environment Improvement Board of the State of New Mexico, SCE's share of Four Corners units 4 and 5 have been derated by 7 MW each due to installation of air pollution control equipment effective 6-1-82.
8. Palo Verde nuclear units 1 to 3 have been rerated from 1235 MW to 1222 MW due to an increase in auxiliary power requirements. Accordingly Edison's 15.8% share was reduced from 195 MW to 193 MW per unit.

9. The fifteen 26 MW (390 MW total) fuel cells were delayed by one year from 1982-1988 to the 1983-1989 time frame.
10. Edison was notified by the California Department of Water Resources (CDWR) that termination of the Oroville-Thermalito power sale contract of 340 MW will be advanced from 1-1-85 to 4-1-83. It is assumed for the purposes of capacity planning that Edison's obligation to serve the CDWR on-peak loads will terminate concurrently.
11. The seasonal diversity exchange of 275 MW with the Northwest has been advanced by one year from 5-1-85 to 5-1-84.
12. 140 MW of Hydro capacity was advanced from 6-1-87 to 6-1-85.
13. The Combined Cycle project (Lucerne Valley site assumed) schedule has been revised as follows:

YEAR	May 3, 1977 Resource Plan Schedule (MW)	Feb 7, 1978 Resource Plan Schedule (MW)
_____	_____	_____
1985	1030	540
1986	260	310
1987	-	440
Total	1290	1290

14. Edison's projected participation in the Palo Verde 4 and 5 nuclear project (scheduled for 1988 and 1990) has been increased from 15.8% (193 MW per unit) to 32.3% (395 MW per unit). The resale cities shares of 1.5% (18.3 MW each unit) and 1.0% (12.2 MW each unit) for Anaheim and Riverside respectively, have been included in the resource plan.
15. The San Joaquin Nuclear Project was reduced from four units to two units and delayed from 1987/89 to 1988/90 and the unit size was increased from 1270 MW to 1300 MW. Edison's share was reduced from 1118 MW to 572 MW, total and Anaheim's and Riverside's share was reduced from a total of 203 MW to 104 MW.
16. The planned 1485 MW of Combustion Turbine capacity in the 1987-1996 time frame has been reduced to 990 MW.
17. The resource plan was extended to include the additional year of 1997 with 780 MW of Nuclear and 100 MW of Solar capacity being shown in that year.

3

FEBRUARY 7, 1978
FUTURE GENERATION RESOURCE PROGRAM
1978-1997

DEFINITION OF COLUMN HEADINGS

Date

Firm operating date of unit or contractual agreement.

Resource

Resource identification. Often includes supplemental information about capacity, particularly when the identification refers to a unit which is undergoing rerate, has associated off-system losses, or is a participation unit.

Net Capacity Added

Effective operating capacity ratings of resources. These have been adjusted for losses incurred outside the Edison Main System where applicable.

Total Capacity

Summer total capacity includes resources installed as of July 1 of that year; winter includes all capacity added in that year.

Area Peak Demand

Includes Edison Net Main System peak demand plus firm on-peak sales to other utilities, CDWR and Metropolitan Water District on-peak pumping demands, and demands for formerly isolated Edison loads commencing when they are interconnected with the Main System.

Area Margin

Megawatt margin is the difference between total installed capacity and area peak demand. Percent margin is the megawatt margin divided by area peak demand and multiplied by 100.

Area Reliability Index

The reliability index represents the likelihood that a particular year's specified resources will be sufficient to serve forecast loads for each hour of the year, allowing for planned generation maintenance and forced outages without requiring delivery of capacity via Edison's interconnections in excess of firm deliveries plus 300 MW from 1978 through 1984, and firm deliveries plus 600 MW after 1984.

Edison Net Peak Demand

Edison Net Main System peak demand is based on the System Forecasts prepared by the System Development Department in January, 1978. This peak demand forecast includes reductions for load management and conservation.

Annual Load Increase

Percent by which Edison net peak demand increases over the previous year's net peak demand.

FEBRUARY 7, 1978
 FUTURE GENERATION RESOURCE PROGRAM
 1978-1997

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DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
12-31-77	AGGREGATE RATED CAPACITY REDUCED FOR "DRY YEAR HYDPC" CONDITIONS, 213 MW FOR SUMMER AND 264 MW FOR WINTER		14410	14265 (1)						
2-15-78	SALE TO APPA 17MW	-16 (2)								
6- 1-78	COOL WATER 3	234/249								
6- 1-78	LONG BEACH 8 COMBINED CYCLE RERATE	31/ 38 (3)								
6- 1-78	LONG BEACH 9 COMBINED CYCLE RERATE	22/ 27 (3)								
8- 1-78	COOL WATER 4	234/249								
	TOTAL CAPACITY ADDED	505/ 547								
	LOADS AND RESOURCES FOR SUMMER 1978		14681		12142	2539	20.9	.99	11800	4.9
	LOADS AND RESOURCES FOR WINTER 1978			14812	10136	4676	46.1			
1- 1-79	RECONDITION LONG BEACH 11	56 (4)								
4- 1-79	AXIS COMBUSTION TURBINE (22 MW)	(5)								
	TOTAL CAPACITY ADDED	56								
	LOADS AND RESOURCES FOR SUMMER 1979		14971		12533	2438	19.5	.99	12270	4.0
	LOADS AND RESOURCES FOR WINTER 1979			14868	10375	4493	43.3			
1- 1-80	INCREASE SALE TO APPA 2MW	-2 (2)								
3- 1-80	BIG CREEK 3 UNIT 5	31								
6- 1-80	DECREASE SALE TO APPA 1MW	1 (2)								
6- 1-80	DECREASE NAVAJO LAYOFF (20 MW)	-20 (6)								
10- 1-80	SAN ONOFRE 2 (220/176 MW)	176 (7)								
	TOTAL CAPACITY ADDED	185								
	LOADS AND RESOURCES FOR SUMMER 1980		14981		12747	2234	17.5	.99	12480	1.7
	LOADS AND RESOURCES FOR WINTER 1980			15054	10719	4335	40.4			

FEBRUARY 7, 1978
 FUTURE GENERATION RESOURCE PROGRAM
 1978-1997

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
4- 1-81	DECREASE NAVAJO LAYOFF (32 MW)	-31 (6)								
4- 1-81	DECREASE SALE TO APPA 1MW	1 (2)								
4- 1-81	EDWARDS AFB EXCHANGE	18/ 15 (8)								
4- 1-81	INTERCONNECT AXIS GENERATION WITH MAIN SYSTEM (75/25MW STEAM + 22MW CT)	47 (5)								
6- 1-81	PURCHASE	300 (9)								
0- 1-81	RERATE SAN ONOFRE 2 (220/176 TO 1100/680 MW)	704 (7)								
0- 1-81	TERMINATE PURCHASE.....	-300 (9)								
	TOTAL CAPACITY ADDED	739/ 736								
	LOADS AND RESOURCES FOR SUMMER 1981		15492		13213	2279	17.2	.99	12910	3.4
	LOADS AND RESOURCES FOR WINTER 1981			15790	11115	4675	42.1			
4- 1-82	INCREASE SALE TO APPA 17MW	-16 (2)								
1- 1-82	SAN ONOFRE 3 (220/176 MW)	176 (7)								
5- 1-82	PALO VERDE NUCLEAR 1 (1222/193 MW)	187 (10)								
6- 1-82	DERATE FOUR CORNERS 4 (800/384 TO 785/377 MW)	-7 (11)								
6- 1-82	DERATE FOUR CORNERS 5 (800/354 TO 785/377 MW)	-7 (11)								
	TOTAL CAPACITY ADDED	333								
	LOADS AND RESOURCES FOR SUMMER 1982		16229		13726	2503	18.2	.98	13360	3.5
	LOADS AND RESOURCES FOR WINTER 1982			16123	11558	4565	39.5			

FEBRUARY 7, 1978
 FUTURE GENERATION RESOURCE PROGRAM
 1978-1997

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
1- 1-83	REPERE SAN ONOFRE 3 (220/176 TO 1100/850 MW)	704 (7)								
4- 1-83	TERMINATE OROVILLE-THERMALITO (340 MW)	-326 (12)								
4- 1-83	ADJUST DRY-YEAR HYDRO DERATE TO 193MW/225MW TO REMOVE OROVILLE	20/ 39 (12)								
7- 1-85	FUEL CELL 1	26 (13)								
	TOTAL CAPACITY ADDED	424/ 443								
	LOADS AND RESOURCES FOR SUMMER 1983		16653		14051	2602	18.5	.99	13820	3.4
	LOADS AND RESOURCES FOR WINTER 1983			16566	11803	4763	40.4			
5- 1-84	BEGIN DIVERSITY EXCHANGE WITH NORTHWEST (275MW NW TO SCE FROM MAY THRU OCT)	259/ 0 (14)								
5- 1-84	PALO VERDE NUCLEAR 2 (1222/193 MW)	187 (10)								
11- 1-84	ANNUAL WINTER EXCH 275MW TO NORTHWEST	(14)								
	TOTAL CAPACITY ADDED	446/ 187								
	LOADS AND RESOURCES FOR SUMMER 1984		17099		14541	2558	17.6	.99	14310	3.5
	LOADS AND RESOURCES FOR WINTER 1984			16753	12472	4281	34.3			
1- 1-85	END SALE TO APPA 34MW	32 (2)								
1- 1-85	TERMINATE NAVAJO LAYOFF (276 MW)	-268 (6)								
6- 1-85	COMBINED CYCLE PROJECT (CT'S)	540/549 (15)								
6- 1-85	HYDRO	140 (16)								
	TOTAL CAPACITY ADDED	444/ 453								
	LOADS AND RESOURCES FOR SUMMER 1985		17543		15031	2512	16.7	.99	14300	3.4
	LOADS AND RESOURCES FOR WINTER 1985			17206	12832	4324	33.6			

FEBRUARY 17, 1978
 FUTURE GENERATION RESOURCE PROGRAM
 1978-1997

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
1- 1-86	WIND 1	4								
3-31-86	TERMINATE EDWARDS AFB EXCHANGE	-18/-15								
5- 1-86	PALO VERDE NUCLEAR 3 (1222/193 MW)	188								
5- 1-86	FUEL CELLS 2&3	52								
6- 1-86	COMBINED CYCLE PROJECT (STM)	130/133								
6- 1-86	COMBINED CYCLE PROJECT (CT'S)	180/183								
6- 1-86	GEOTHERMAL	100								
	TOTAL CAPACITY ADDED	636/ 645								
	LOADS AND RESOURCES FOR SUMMER 1986		18179		15551	2628	16.9	.98	15320	3.5
	LOADS AND RESOURCES FOR WINTER 1986			17851	13322	4529	34.0			
1- 1-87	WIND 2	6								
1- 1-87	FUEL CELLS 4&5	52								
6- 1-87	TERMINATE HOOVER	-331								
6- 1-87	COMBINED CYCLE PROJECT (STM)	260/266								
6- 1-87	COMBINED CYCLE PROJECT (CT'S)	180/183								
6- 1-87	ADJUST DRY-YEAR HYDRO DERATE TO 139MW/171MW TO REMOVE HOOVER	54								
6- 1-87	COMBUSTION TURBINE (7 UNITS)	385								
8- 1-87	TERMINATE BPA EXCHANGE	-517								
8- 1-87	BEGIN DIVERSITY EXCHANGE WITH NORTHWEST (550MW NW TO SCE FROM MAY THRU OCT)	517/ 0								
11- 1-87	ANNUAL WINTER EXCH 550MW TO NORTHWEST									
	TOTAL CAPACITY ADDED	606/ 93								
	LOADS AND RESOURCES FOR SUMMER 1987		18785		16081	2704	16.8	.99	15850	3.5
	LOADS AND RESOURCES FOR WINTER 1987			17949	14354	3595	25.0			

(A) RESALE CITIES' CAPACITY RESOURCES IN THE 1987-1993 TIME FRAME
 COULD POTENTIALLY REPLACE PLANNED CAPACITY (20)

FEBRU 7, 1978
 FUTURE GENERATION RESOURCE PROGRAM
 1978-1997

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
1- 1-91	WIND 6	30 (17)								
6- 1-91	EAST COAL 1 (1000/526 MW)	500 (23)								
	TOTAL CAPACITY ADDED	530								
	LOADS AND RESOURCES FOR SUMMER 1991		21511		18349	3162	17.2	.98	18190	3.5
	LOADS AND RESOURCES FOR WINTER 1991			20675	16314	4361	26.7			
6- 1-92	NUCLEAR 1 (1000/780 MW)	780 (24)								
	TOTAL CAPACITY ADDED	780								
	LOADS AND RESOURCES FOR SUMMER 1992		22291		18969	3322	17.5	.97	18310	3.4
	LOADS AND RESOURCES FOR WINTER 1992			21455	16834	4621	27.5			
6- 1-93	GEOTHERMAL	150 (17)								
6- 1-93	COMBUSTION TURBINE (6 UNITS)	330 (19)								
6- 1-93	EAST COAL 2 (1000/526 MW)	500 (23)								
	TOTAL CAPACITY ADDED	980								
	LOADS AND RESOURCES FOR SUMMER 1993		23271		19619	3652	18.6	.96	19460	3.5
	LOADS AND RESOURCES FOR WINTER 1993			22435	17374	5061	29.1			
1- 1-94	RETIRE LONG BEACH 10 & 11	-212								
5- 1-94	SOLAR 1	100 (17)								
6- 1-94	NUCLEAR 2 (1000/780 MW)	780 (24)								
	TOTAL CAPACITY ADDED	668								
	LOADS AND RESOURCES FOR SUMMER 1994		23939		20299 ^o	3640	17.9	.96	20140	3.5
	LOADS AND RESOURCES FOR WINTER 1994			23103	17944	5159	28.8			

FEBRUARY 7, 1978
 FUTURE GENERATION RESOURCE PROGRAM
 1978-1997

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
1- 1-88	WIND 3	10 (17)								
1- 1-88	FUEL CELLS 6&7	52 (13)								
3- 1-88	FUEL CELLS 2&9	52 (13)								
5- 1-88	PALO VERDE NUCLEAR 4 (1222/425 MW)	412 (21)								
6- 1-88	COMBUSTION TURBINE (5 UNITS)	275 (19)								
11- 1-88	SAN JOAQUIN NUC 1 (1300/338 MW)	338 (22)								
	TOTAL CAPACITY ADDED	1139								
	LOADS AND RESOURCES FOR SUMMER 1988		19586		16605	2981	18.0	.98	16410	3.5
	LOADS AND RESOURCES FOR WINTER 1988			19088	14824	4264	28.8			
1- 1-89	WIND 4	20 (17)								
3- 1-89	FUEL CELLS 10-15	156 (13)								
	TOTAL CAPACITY ADDED	176								
	LOADS AND RESOURCES FOR SUMMER 1989		20100		17185	2915	17.0	.99	16990	3.5
	LOADS AND RESOURCES FOR WINTER 1989			19264	15304	3960	25.9			
1- 1-90	WIND 5	30 (17)								
5- 1-90	PALO VERDE NUCLEAR 5 (1222/425 MW)	413 (21)								
5- 1-90	SAN JOAQUIN NUC 2 (1300/338 MW)	338 (22)								
6- 1-90	GEO THERMAL	100 (17)								
	TOTAL CAPACITY ADDED	881								
	LOADS AND RESOURCES FOR SUMMER 1990		20981		17739	3242	18.3	.98	17580	3.5
	LOADS AND RESOURCES FOR WINTER 1990			20145	15804	4341	27.5			

FEBRUARY 7, 1978
 FUTURE GENERATION RESOURCE PROGRAM
 1978-1997

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
1- 1-95	EAST COAL 3 (1000/526 MW)	500 (23)								
5- 1-95	SOLAR 2	100 (17)								
6- 1-95	GEOHERMAL	150 (17)								
	TOTAL CAPACITY ADDED	750								
	LOADS AND RESOURCES FOR SUMMER 1995		24689		20939	3700	17.6	.97	20830	3.4
	LOADS AND RESOURCES FOR WINTER 1995			23853	18514	5339	28.8			
5- 1-96	SOLAR 3	100 (17)								
6- 1-96	GEOHERMAL	150 (17)								
6- 1-96	EAST COAL 4 (1000/526 MW)	500 (23)								
	TOTAL CAPACITY ADDED	750								
	LOADS AND RESOURCES FOR SUMMER 1996		25439		21679	3760	17.3	.98	21520	3.3
	LOADS AND RESOURCES FOR WINTER 1996			24603	19094	5509	28.9			
5- 1-97	SOLAR 4	100 (17)								
6- 1-97	NUCLEAR 3 (1000/780 MW)	780 (24)								
	TOTAL CAPACITY ADDED	860								
	LOADS AND RESOURCES FOR SUMMER 1997		26319		22399	3920	17.5	.98	22240	3.3
	LOADS AND RESOURCES FOR WINTER 1997			25483	19694	5789	29.4			

DEVELOPMENT OF PERTINENT DATA

- 1) RECONCILIATION OF THE 12-31-77 AGGREGATE RATED CAPACITY WITH THE JANUARY 1, 1978 REVISION OF THE "GENERATOR RATINGS AND EFFECTIVE OPERATING CAPACITY OF RESOURCES".

	SUMMER (MW)	WINTER (MW)
	-----	-----
NET MAIN SYSTEM RESOURCES	12742	12742
TOTAL FIRM PURCHASES	+1649	+1549
MWD CAPACITY	+315	+315
HYDRO DERATE	-213	-264
TOTAL OFF SYSTEM LOSSES	-83	-77
	-----	-----
12-31-77 AGGREGATE RATED CAPACITY	14410	14265
	-----	-----

2) SUMMARY OF AREA PEAK DEMANDS (1978-1997)

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
SUMMER										
EDISON NET PEAK DEMAND *	11800	12270	12480	12910	13360	13820	14310	14800	15320	15850
MWD LOAD	317	231	231	231	231	231	231	231	231	231
STATE WATER PROJECT **	25	32	36	72	135	-	-	-	-	-
AREA PEAK DEMAND	12142	12533	12747	13213	13726	14051	14541	15031	15551	16081
INTERRUPTIBLE LOAD ***	-	-	25	32	39	47	54	61	79	97
WINTER										
EDISON NET PEAK DEMAND *	9700	10090	10430	10790	11170	11550	11960	12370	12810	13250
MWD LOAD	317	159	159	159	159	159	159	159	159	123
STATE WATER PROJECT **	25	32	36	72	135	-	-	-	-	-
DIV EXCHANGE PORTLAND GE	94	94	94	94	94	94	94	94	94	106
DIV EXCHANGE NORTH-WEST	-	-	-	-	-	-	259	259	259	292
DIV EXCHANGE BPA	-	-	-	-	-	-	-	-	-	583
AREA PEAK DEMAND	10136	10375	10719	11115	11558	11803	12472	12882	13322	14354
INTERRUPTIBLE LOAD ***	-	-	34	45	56	69	80	90	128	168
SUMMER										
EDISON NET PEAK DEMAND *	16410	16990	17580	18190	18910	19460	20140	20830	21520	22240
MWD LOAD	195	195	159	159	159	159	159	159	159	159
AREA PEAK DEMAND	16605	17185	17739	18349	18969	19619	20299	20989	21679	22399
INTERRUPTIBLE LOAD ***	115	132	150	171	192	212	233	254	268	284
WINTER										
EDISON NET PEAK DEMAND *	13720	14200	14700	15210	15730	16270	16840	17410	17990	18590
MWD LOAD	123	123	123	123	123	123	123	123	123	123
DIV EXCHANGE PORTLAND GE	106	106	106	106	106	106	106	106	106	106
DIV EXCHANGE NORTH-WEST	292	292	292	292	292	292	292	292	292	292
DIV EXCHANGE BPA	583	583	583	583	583	583	583	583	583	583
AREA PEAK DEMAND	14824	15304	15804	16314	16834	17374	17944	18514	19094	19694
INTERRUPTIBLE LOAD ***	206	243	280	323	365	407	450	492	521	553

* BLYTHE LOAD IS INCLUDED IN THE EDISON NET PEAK DEMAND STARTING IN 1981
 ** WITH THE CONTRACT TERMINATION OF CROVILLE-THERMALITO IN 1983, IT HAS BEEN ASSUMED THAT THE STATE WATER PROJECT WILL SERVE ITS OWN ON-PEAK LOADS
 *** INTERRUPTIBLE LOAD HAS BEEN DEDUCTED FROM EDISON NET PEAK DEMAND

FEBRUARY 7, 1978
FUTURE GENERATION RESOURCE PROGRAM
1978-1997

NOTES

1. Aggregate rated capacity is in accord with the January 1, 1978 revision of "Generator Ratings and Effective Operating Capacity of Resources," and MWD's capacity of 315 MW (261 MW at Hoover, 54 MW at Parker), adjusted for Edison, Hoover and Oroville-Thermalito dry year hydro derates.
2. The Arizona Power Pooling Authority (APPA) has executed an agreement with Edison, Arizona Public Service, Nevada Power and Tucson Gas and Electric, to sell capacity and associated energy to APPA based on the availability and cost of Navajo power from 2-15-78 to 1-1-85. Subject to approval by the Federal Energy Regulatory Commission, Edison's share of the capacity sale will range from 16.5 to 33.4 MW.
3. Long Beach 8 and 9 Combined Cycle units are currently rated at 280 MW and 210 MW respectively. Dependent upon field performance tests they are expected to be rated at 311 MW & 232 MW respectively (total = 543 MW), which is an additional 31 MW and 22 MW increase for units 8 and 9 respectively.
4. Prior to completion of reconditioning in 1979, Long Beach Unit 11 has been derated from 106 to 50 MW.
5. The 22 MW Axis combustion turbine is scheduled for firm operation on 4-1-79 to serve the Blythe area load. Loads and resources of the Blythe Isolated System are interconnected with the Edison Main System in 1981.
6. A contract has been executed with the U. S. Bureau of Reclamation for lay-off of power from the Navajo Project. At such time as USBR needs this power for the Central Arizona Project, USBR has the right to terminate this layoff effective on or after January 1, 1980, upon at least five years advance written notice. Such notice has not been given; however, it is currently anticipated that the layoff will terminate in 1985. Edison has been notified, however, that the layoff will be decreased by 20 MW on June 1, 1980 and an additional 32 MW on June 1, 1981 to provide power for USBR's desalination project.

7. For planning and reporting purposes, San Onofre Units 2 and 3 are considered a firm capacity resource at 20% of their full power rating (880 MW total SCE share each unit) starting one year prior to their respective full power firm operating dates of 10-1-81 and 1-1-83. The capacity shown is 80% of the Project, which includes Edison's share and the resale cities' potential shares (Anaheim - 1.66% or 36.5 MW and Riverside - 1.79% or 30.4 MW of the total project).
8. Edwards Air Force Base exchange capacity is available to Edison in the amount of 18.5 MW from March 1 to September 30, and 14.95 MW from October 1 to February 28, annually as of April 1, 1976 and terminating on March 31, 1986. However, the capacity is not added to the Edison Main System until the interconnection of the Blythe System in 1981.
9. A capacity purchase totaling 300 MW commencing on June 1, 1981 and terminating on October 1, 1981 is currently under negotiation.
10. Edison is participating in the three unit, 3666 MW Palo Verde Nuclear Project in Arizona with a 15.8% share (562 MW after off-system losses). Firm operating dates are scheduled for May 1, 1982; May 1, 1984; and May 1, 1986. The project is allocated as follows:

	<u>Participation Percentage</u>
Arizona Public Service Company	29.1
Salt River Project	23.4
El Paso Electric Company	15.8
Southern California Edison Company	15.8
Public Service Company of New Mexico	10.2
Los Angeles Department of Water & Power	<u>5.7</u>
TOTAL	100.0

11. Additional air pollution control equipment is required for Four Corners Units 4 and 5 by 1-1-83, to comply with the November 1977 ruling of the Environment Improvement Board of the State of New Mexico. This is expected to result in a capacity reduction of approximately 15 MW per unit (SCE's share is 7 MW per unit). For planning purposes these reductions are shown to commence on 6-1-82.

12. Edison has been notified by the California Department of Water Resources, (CDWR) that on April 1, 1983, the contractual provisions for energy and capacity assigned to Edison from the Oroville-Thermalito facility will be terminated. The Edison capacity allocation of 340 MW is adjusted to 326 MW for losses and further reduced by 20 MW/39 MW to reflect dry year summer/winter hydro conditions. Concurrent with the termination of the capacity assignment, it is assumed that Edison's load obligation to CDWR will terminate.
13. In March 1973, Edison joined a group of investor-owned utilities to fund an electric utility fuel cell program in conjunction with United Technologies Corporation. Final commitments to purchase 15 units at 26 MW each (390 MW total capacity) for delivery in 1983-1989 is contingent upon both competitive costs and successful validation of a test unit in 1978.
14. A seasonal diversity exchange of 275 MW capacity commencing on May 1, 1984, is being discussed with the Pacific Northwest. To replace the 550 MW capacity/energy exchange with Bonneville Power Authority which terminates on August 1, 1987, an additional seasonal diversity exchange is also being discussed. The effect of these seasonal diversity exchanges on Edison's resources is equivalent to a capacity purchase in the summer (May 1 through October 31) and a capacity sale in the winter. Exchange amounts have been adjusted for Edison's net loss obligations.
15. The capacities shown are for the proposed 1290 MW combined cycle project (Lucerne Valley site assumed for evaluation). Combustion turbines are installed prior to integrated combined cycle operation, which will commence as soon as respective steam turbine components are in service.
16. It is tentatively planned to increase the capacity of existing hydro facilities by approximately 140 MW in 1985.
17. Construction of wind, geothermal and solar resources are contingent upon successful research and development and competitive costs of commercial units.
18. Edison's present 50-year Hoover contract for energy and capacity (331 MW) with the U.S. department of Interior, expires on June 1, 1987. Dry year hydro derate reduces the above capacity by 54 MW. MWD's Hoover capacity (261 MW) is assumed to continue.

19. Specific sites for 990 MW of combustion turbines in the 1987-1993 time frame are currently under study.
20. Edison has been informed that the resale cities of Anaheim and Riverside are evaluating participation in the Intermountain and Sundesert Projects in the following amounts:

	<u>Intermountain</u>	<u>Sundesert</u>
Anaheim	450 MW	95 MW
Riverside	148-300 MW	76 MW
TOTAL	598-750 MW	171 MW

21. Edison is a 32.3% (789.4 MW total) participant in the Palo Verde Nuclear units 4 and 5, which replicate the Palo Verde Nuclear units 1-3.

Anticipated project allocation is as follows:

	<u>Participation Percentage</u>
APS	39.1
SCE	32.3
LADWP	11.7
SDG&E	5.2
EPEC	4.0
NPC	2.2
CITY OF ANAHEIM	1.5
CITY OF BURBANK	1.0
CITY OF GLENDALE	1.0
CITY OF PASADENA	1.0
CITY OF RIVERSIDE	1.0
	<u>100.0</u>

Included in Edison's future generation resource plan are the capacity allocations of this project for Edison's resale cities of Anaheim (36.7 MW total) and Riverside (24.4 MW total).

22. Edison is currently a 22% (572 MW total) participant in a two unit 2600 MW nuclear plant scheduled for 1988/90 in the San Joaquin Valley. Preliminary project allocation is as follows:

	<u>Participation Percentage</u>
LADWP	35.5
PG&E	23.0
SCE	22.0
DEPARTMENT OF WATER RESOURCES	10.0
CITY OF ANAHEIM	2.0
CITY OF GLENDALE	2.0
NORTHERN CALIFORNIA POWER AGENCY	2.0
CITY OF RIVERSIDE	2.0
CITY OF PASADENA	<u>1.5</u>
TOTAL	100.0

Edison Resale Cities' capacity allocation from this project (Anaheim 52 MW, Riverside 52 MW), is included in Edison's future generation resource planning.

23. Sites for coal capacity scheduled for 1991 and beyond are presently under study.
24. Assumed 78% allocation to Edison in 1000 MW unit size.

DJF/m

MAY 3, 1977
FUTURE GENERATION RESOURCE PROGRAM
1977-1996
Principal Changes From The July 23, 1976
Future Generation Resource Program

1

1. This program is based on the System Forecasts prepared in March 1977. Reductions of peak demand from the previous forecast are 120 megawatts in 1980, increasing to 590 megawatts by 1985 and 1640 megawatts by 1990.
2. The Long Beach 9 Combined Cycle Unit was delayed from 2-17-77 to 5-1-77. The total Long Beach combined cycle capacity was rerated from 572 megawatts to a 543/555 megawatt summer/winter rating.
3. Interconnection of Axis generation with the Main System was delayed from 1979 to 1981.
4. The 296 megawatt Pacific Northwest Diversity Exchange commencing in 1980 was replaced with a four month 300 megawatt purchase in 1981 and a 275 megawatt capacity exchange commencing in 1985.
5. The initial 120 megawatts of Lucerne Valley capacity was delayed from 1981 to 1985 resulting in a scheduled installation of 1030 megawatts in 1985. The remaining 260 megawatts of the combined cycle project are scheduled for completion in 1986.
6. The first fuel cell unit was delayed one year from 1981 to 1982, and the remaining units were delayed two years from the 1983-1986 period to the 1985-1988 period.
7. The Palo Verde nuclear units were rerated from 1270 megawatts to 1235 megawatts each due to a reassessment of the auxiliary requirements by the Project Manager. This results in a reduction of 5.5 megawatts of SCE's share for each of the three units.
8. The 550 megawatts of combustion turbine capacity in 1985 and 1986 were deferred to 1987.
9. The 936 megawatts of combined cycle capacity scheduled in 1987-1989 were deleted.
10. The BPA capacity/energy exchange (550 megawatts) which terminates in 1987 was replaced with a capacity diversity exchange from the Pacific Northwest (550 megawatts) starting in 1987.
11. A 15.8% share of Palo Verde Nuclear Units 4 and 5 (195 megawatts each unit) was added in 1988-1990.
12. Eastern Desert Nuclear Units 1 and 2 (780 megawatts each) were delayed from 1988-1991 to 1992-1994.
13. The 1560 megawatts of nuclear capacity previously shown in 1994-1995 were deleted.

MAY 3, 1977
FUTURE GENERATION RESOURCE PROGRAM
1977 - 1996

DEFINITION OF COLUMN HEADINGS

Date

Firm operating date of unit or contractual agreement.

Resource

Resource identification. Often includes supplemental information about capacity, particularly when the identification refers to a unit which is undergoing rerate, has associated off-system losses, or is a participation unit.

Net Capacity Added

Effective operating capacity rating of the resource. These have been adjusted for losses incurred outside the Edison Main System where applicable.

Total Capacity

Summer total capacity includes resources installed as of July 1 of that year; winter includes all capacity added in that year.

Area Peak Demand

Includes Edison Net Main System peak demand plus firm on-peak sales to other utilities, CDWR and Metropolitan Water District on-peak pumping demands, and demands for formerly isolated Edison loads commencing when they are interconnected into the Main System.

Area Margin

Megawatt margin is the difference between total installed capacity and area peak demand. Percent margin is the megawatt margin divided by area peak demand and multiplied by 100.

Area Reliability Index

The reliability index represents the probability that a particular year's specified resources will be sufficient to serve forecast loads for each hour of the year, allowing for planned generation maintenance and forced outages without requiring delivery of capacity via Edison's interconnections in excess of firm deliveries plus 300 MW from 1976 through 1984, and firm deliveries plus 600 MW after 1984.

Edison Net Peak Demand

Edison net main system peak demand is based on the System Forecasts prepared by the System Development Department in March, 1977. This peak demand forecast includes reductions for load management and conservation.

Annual Load Increase

Percent by which Edison net peak demand increases over the previous year net peak demand.

MAY 3 1977
 FUTURE GENERATION RESOURCE PROGRAM
 1977-1996

29APR77T1430DJF

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
12-31-76	AGGREGATE RATED CAPACITY REDUCED FOR "DRY YEAR HYDRO" CONDITIONS, 213 MW FOR SUMMER AND 264 MW FOR WINTER		13859	13994 (1)						
	SUMMER CAPACITY INCLUDES ANNUAL CAPACITY EXCHANGE OF 100MW (94MW NET)		(2)							
4- 1-77	RERATE SAN ONOFRE 1	5 (3)								
5- 1-77	LONG BEACH 9 COMBINED CYCLE	210 (4)								
12- 1-77	LONG BEACH 8 COMBINED CYCLE RERATE	31/ 38 (4)								
12- 1-77	LONG BEACH 9 COMBINED CYCLE RERATE	22/ 27 (4)								
	TOTAL CAPACITY ADDED	2087	280							
	LOADS AND RESOURCES FOR SUMMER 1977		14354		11554	2800	24.2	.99	11230	1.3
	LOADS AND RESOURCES FOR WINTER 1977			14274	9908	4366	44.1			
4- 1-78	COOL WATER 3	234/249								
8- 1-78	COOL WATER 4	234/249								
	TOTAL CAPACITY ADDED	4687	498							
	LOADS AND RESOURCES FOR SUMMER 1978		14641		11926	2715	22.8	.99	11670	3.9
	LOADS AND RESOURCES FOR WINTER 1978			14772	10158	4614	45.4			
1- 1-79	RECONDITION LONG BEACH 10 & 11	112 (5)								
4- 1-79	AXIS COMBUSTION TURBINE (22 MW)	(6)								
	TOTAL CAPACITY ADDED	112								
	LOADS AND RESOURCES FOR SUMMER 1979		14987		12393	2594	20.9	.99	12130	3.9
	LOADS AND RESOURCES FOR WINTER 1979			14884	10575	4309	40.7			

MAY 3 1977
 FUTURE GENERATION RESOURCE PROGRAM
 1977-1996

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
3- 1-80	BIG CREEK 3 UNIT 5	31								
6- 1-80	DECREASE NAVAJO LAYOFF (22 MW)	-22 (7)								
10- 1-80	SAN ONOFRE 2 (220/176 MW)	176 (8)								
	TOTAL CAPACITY ADDED	185								
	LOADS AND RESOURCES FOR SUMMER 1980		14996		12657	2339	18.5	.99	12390	2.1
	LOADS AND RESOURCES FOR WINTER 1980			15069	10869	4180	38.4			
4- 1-81	EDWARDS AFH EXCHANGE	18/ 15 (9)								
4- 1-81	INTERCONNECT AXIS GENERATION WITH MAIN SYSTEM (75/25MW STEAM + 22MW CT)	47 (6)								
6- 1-81	DECREASE NAVAJO LAYOFF (40 MW)	-39 (7)								
6- 1-81	PURCHASE	300 (10)								
10- 1-81	RERATE SAN ONOFRE 2 (220/176 TO 1100/860 MW)	704 (8)								
10- 1-81	TERMINATE PURCHASE.....	-300 (10)								
	TOTAL CAPACITY ADDED	730/ 727								
	LOADS AND RESOURCES FOR SUMMER 1981		15498		13193	2305	17.5	.99	12890	4.0
	LOADS AND RESOURCES FOR WINTER 1981			15796	11425	4371	38.3			
1- 1-82	SAN ONOFRE 3 (220/176 MW)	176 (8)								
5- 1-82	PALO VERDE NUCLEAR 1 (1235/195 MW)	189 (11)								
7- 1-82	FUEL CELL 1	26 (12)								
	TOTAL CAPACITY ADDED	391								
	LOADS AND RESOURCES FOR SUMMER 1982		16293		13726	2567	18.7	.99	13360	3.6
	LOADS AND RESOURCES FOR WINTER 1982			16187	11968	4219	35.3			

MAY 3 1977
 FUTURE GENERATION RESOURCE PROGRAM
 1977-1996

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	AREA MARGIN (%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
----	-----	-----	SUMMER (MW)	WINTER (MW)	-----	-----	-----	-----	-----	-----
1- 1-83	RERATE SAN ONOFRE 3 (220/176 TO 1100/880 MW)	704 (8)								
	TOTAL CAPACITY ADDED	704								
	LOADS AND RESOURCES FOR SUMMER 1983		16997		14177	2820	19.9	.99	13830	3.5
	LOADS AND RESOURCES FOR WINTER 1983			16891	12430	4461	35.9			
5- 1-84	PALO VERDE NUCLEAR 2 (1235/195 MW)	190 (11)								
	TOTAL CAPACITY ADDED	190								
	LOADS AND RESOURCES FOR SUMMER 1984		17187		14700	2487	16.9	.98	14350	3.8
	LOADS AND RESOURCES FOR WINTER 1984			17081	12982	4119	31.8			
1- 1-85	TERMINATE OROVILLE-THERMALITO (340 MW)	-326 (13)								
1- 1-85	ADJUST DRY-YEAR HYDRO DERATE TO 193MW/225MW TO REMOVE OROVILLE	20/ 39 (13)								
1- 1-85	TERMINATE NAVAJO LAYOFF (265 MW)	-258 (7)								
5- 1-85	BEGIN DIVERSITY EXCHANGE WITH NORTHWEST (275MW NW TO SCE FROM MAY THRU OCT)	259/ 0 (14)								
5- 1-85	FUEL CELLS 2&3	52 (12)								
6- 1-85	LUCERNE VALLEY STEAM TURBINE	130/133 (15)								
6- 1-85	LUCERNE VALLEY COMBUSTION TURBINES	900/915 (15)								
11- 1-85	ANNUAL WINTER EXCH 275MW TO NORTHWEST	(14)								
	TOTAL CAPACITY ADDED	777/ 555								
	LOADS AND RESOURCES FOR SUMMER 1985		17964		15312	2652	17.3	.99	14880	3.7
	LOADS AND RESOURCES FOR WINTER 1985			17636	13807	3829	27.7			

MAY 3 1977
 FUTURE GENERATION RESOURCE PROGRAM
 1977-1996

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
1- 1-88	WIND 3	10 (16)								
3- 1-88	FUEL CELLS 10-15	156 (12)								
5- 1-88	PALO VERDE NUCLEAR 4 (1235/195 MW)	189 (22)								
	TOTAL CAPACITY ADDED	355								
	LOADS AND RESOURCES FOR SUMMER 1988		19924		16981	2943	17.3	.99	16550	3.5
	LOADS AND RESOURCES FOR WINTER 1988			19088	16084	3004	18.7			
1- 1-89	WIND 4	20 (16)								
4- 1-89	SAN JOAQUIN NUC 2 (1270/330 MW)	330 (21)								
6- 1-89	COMBUSTION TURBINE (5 UNITS)	275 (19)								
	TOTAL CAPACITY ADDED	625								
	LOADS AND RESOURCES FOR SUMMER 1989		20549		17532	3017	17.2	.98	17150	3.6
	LOADS AND RESOURCES FOR WINTER 1989			19713	16581	3132	18.9			
1- 1-90	WIND 5	30 (16)								
5- 1-90	PALO VERDE NUCLEAR 5 (1235/195 MW)	189 (22)								
6- 1-90	GEOTHERMAL	100 (16)								
6- 1-90	COMBUSTION TURBINE (7 UNITS)	385 (19)								
10- 1-90	SAN JOAQUIN NUC 3 (1270/330 MW)	330 (21)								
	TOTAL CAPACITY ADDED	1034								
	LOADS AND RESOURCES FOR SUMMER 1990		21253		18152	3101	17.1	.99	17760	3.6
	LOADS AND RESOURCES FOR WINTER 1990			20747	17158	3589	20.9			
1- 1-91	WIND 6	30 (16)								
6- 1-91	EAST COAL 1 (1000/526 MW)	500 (23)								
	TOTAL CAPACITY ADDED	530								
	LOADS AND RESOURCES FOR SUMMER 1991		22113		18738	3375	18.0	.99	18380	3.5
	LOADS AND RESOURCES FOR WINTER 1991			21277	17711	3566	20.1			

MAY 3 1977
 FUTURE GENERATION RESOURCE PROGRAM
 1977-1996

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
4- 1-92	SAN JOAQUIN NUC 4 (1270/330 MW)	330 (21)								
6- 1-92	NUCLEAR 1 (1000/780 MW)	780 (24)								
	TOTAL CAPACITY ADDED	1110								
	LOADS AND RESOURCES FOR SUMMER 1992		25223		19437	3786	19.5	.99	19050	3.6
	LOADS AND RESOURCES FOR WINTER 1992			22387	18343	4044	22.0			
6- 1-93	GEO THERMAL	150 (16)								
6- 1-93	EAST COAL 2 (1000/526 MW)	500 (23)								
	TOTAL CAPACITY ADDED	650								
	LOADS AND RESOURCES FOR SUMMER 1993		23873		20114	3759	18.7	.99	19730	3.6
	LOADS AND RESOURCES FOR WINTER 1993			23037	18949	4088	21.6			
1- 1-94	RETIRE LONG BEACH 10 & 11	-212								
5- 1-94	SOLAR 1	100 (16)								
6- 1-94	NUCLEAR 2 (1000/780 MW)	780 (24)								
	TOTAL CAPACITY ADDED	668								
	LOADS AND RESOURCES FOR SUMMER 1994		24541		20853	3688	17.7	.98	20440	3.6
	LOADS AND RESOURCES FOR WINTER 1994			23705	19599	4106	21.0			
1- 1-95	EAST COAL 3 (1000/526 MW)	500 (23)								
5- 1-95	SOLAR 2	100 (16)								
6- 1-95	GEO THERMAL	150 (16)								
	TOTAL CAPACITY ADDED	750								
	LOADS AND RESOURCES FOR SUMMER 1995		25291		21593	3698	17.1	.98	21180	3.6
	LOADS AND RESOURCES FOR WINTER 1995			24455	20270	4185	20.6			

MAY 3 1977
 FUTURE GENERATION RESOURCE PROGRAM
 1977-1996

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
5- 1-96	SOLAR 3	100	(16)							
6- 1-96	COMBUSTION TURBINE (2 UNITS)	110	(19)							
6- 1-96	GEO THERMAL	150	(16)							
6- 1-96	EAST COAL 4 (1000/526 MW)	500	(23)							
	TOTAL CAPACITY ADDED	860								
	LOADS AND RESOURCES FOR SUMMER 1996		26151		22352	3799	17.0	.98	21930	3.5
	LOADS AND RESOURCES FOR WINTER 1996			25315	20939	4376	20.9			

MAY 3 1977
FUTURE GENERATION RESOURCE PROGRAM
1977-1996

DEVELOPMENT OF PERTINENT DATA

- 1) RECONCILIATION OF THE 12-31-76 AGGREGATE RATED CAPACITY WITH THE JANUARY 1, 1977 REVISION OF THE "GENERATOR RATINGS AND EFFECTIVE OPERATING CAPACITY OF RESOURCES".

NET MAIN SYSTEM RESOURCES (DECEMBER 31, 1976)	12471
TOTAL FIRM PURCHASES (DECEMBER 31, 1976)	+1549
MWD CAPACITY	+315
WINTER HYDRO DERATE	-264
TOTAL OFF SYSTEM LOSSES	-77
12-31-76 AGGREGATE RATED CAPACITY	----- 13994 -----

2) SUMMARY OF AREA PEAK DEMANDS (1977-1996)

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
SUMMER										
EDISON NET PEAK DEMAND *	11230	11670	12130	12390	12890	13360	13830	14350	14880	15020
MWD LOAD	317	231	231	231	231	231	231	231	268	268
STATE WATER PROJECT	7	25	32	36	72	135	116	119	164	169
AREA PEAK DEMAND	11554	11926	12393	12657	13193	13726	14177	14700	15312	15848
INTERRUPTIBLE LOAD **	-	-	-	120	140	160	180	190	210	220
WINTER										
EDISON NET PEAK DEMAND *	9490	9880	10290	10600	11100	11580	12060	12590	13130	13690
MWD LOAD	317	159	159	159	159	159	159	159	159	159
STATE WATER PROJECT	7	25	32	36	72	135	117	119	165	169
DIV EXCHANGE PORTLAND GE	94	94	94	94	94	94	94	94	94	94
DIV EXCHANGE NORTH-WEST	-	-	-	-	-	-	-	-	259	259
AREA PEAK DEMAND	9908	10158	10575	10869	11425	11968	12430	12962	13807	14362
INTERRUPTIBLE LOAD **	-	-	-	120	140	160	180	190	210	220
SUMMER										
EDISON NET PEAK DEMAND *	15990	16550	17150	17760	18380	19050	19730	20440	21180	21930
MWD LOAD	268	268	231	195	159	159	159	159	159	159
STATE WATER PROJECT	161	163	151	197	199	228	225	254	254	263
AREA PEAK DEMAND	16419	16981	17532	18152	18738	19437	20114	20853	21593	22352
INTERRUPTIBLE LOAD **	230	240	250	260	270	280	290	310	320	330
WINTER										
EDISON NET PEAK DEMAND *	14280	14780	15310	15860	16410	17010	17620	18250	18910	19580
MWD LOAD	159	159	123	123	123	123	123	123	123	123
STATE WATER PROJECT	157	164	167	194	197	229	225	245	256	255
DIV EXCHANGE PORTLAND GE	106	106	106	106	106	106	106	106	106	106
DIV EXCHANGE NORTH-WEST	292	292	292	292	292	292	292	292	292	292
DIV EXCHANGE BPA	583	583	583	583	583	583	583	583	583	583
AREA PEAK DEMAND	15577	16084	16581	17158	17711	18343	18949	19599	20270	20939
INTERRUPTIBLE LOAD **	230	240	250	260	270	280	290	310	320	330

* BLYTHE LOAD IS INCLUDED IN THE EDISON NET PEAK DEMAND STARTING IN 1981
 ** INTERRUPTIBLE LOAD HAS BEEN DEDUCTED FROM EDISON NET PEAK DEMAND

MAY 3, 1977
FUTURE GENERATION RESOURCE PROGRAM
1977-1996

NOTES

1. Aggregate rated capacity in accord with the January 1, 1977 revision of "Generator Ratings and Effective Operating Capacity of Resources," and MWD's capacity of 315 MW (261 MW at Hoover, 54 MW at Parker), adjusted for Edison, Hoover and Oroville-Thermalito dry year hydro derates.
2. An assignment has been negotiated with Pacific Gas and Electric Company and Portland General Electric Company providing for sale and exchange of capacity and energy. The effect on Edison's capacity resources is equivalent to a firm capacity purchase in the summer (from May 16 through October 15) which began in 1975, and a firm capacity sale in the winter, which began in 1976. The exchange amount has been adjusted for Edison's net loss obligation.
3. San Onofre Unit 1 capacity was increased by 6 MW (5 MW SCE's share) to fully utilize the reactor capability following turbine capacity rerating by Westinghouse Corporation.
4. The total capacity of the Long Beach 8 and 9 Combined Cycle units during summer/winter is 543/555 MW. This is a preliminary rating pending completion of field performance tests.
5. Prior to completion of reconditioning in 1979, Long Beach Units 10 and 11 have been derated from 106 to 50 MW each.
6. Loads and resources of the Blythe Isolated System are integrated into the Edison Main System in 1981.
7. A contract has been executed with the U.S. Bureau of Reclamation for layoff of power from the Navajo Project. At such time as USBR needs this power for the Central Arizona Project, USBR has the right to terminate this layoff effective on or after January 1, 1980, upon at least five years advance written notice. Such notice has not been given; however, it is currently anticipated that the layoff will terminate in 1985. Edison has been notified, however, that the layoff will be decreased by 22 MW on June 1, 1980 and 40 MW on June 1, 1981 to provide power for USBR's desalination project.

8. For planning and reporting purposes, San Onofre Units 2 and 3 are considered a firm capacity resource at 20% of their full power rating (1100 MW total each unit) for one year prior to their respective full power firm operating dates of 10-1-81 and 1-1-83. The capacity shown is 80% of the Project, which includes Edison's share and the resale cities' potential shares (Anaheim - 1.66% or 36.5 MW and Riverside - 1.79% or 39.4 MW of total project).
9. Edwards Air Force Base exchange capacity is available to Edison in the amount of 18.5 MW from March 1 to September 30, and 14.95 MW from October 1 to February 28, annually as of April 1, 1976 and terminating on March 31, 1986. However, the capacity is not added to the Edison Main System until the interconnection of the Blythe System in 1981.
10. A capacity purchase totaling 300 MW commencing on June 1, 1981 and terminating on October 1, 1981 is currently under negotiation.
11. Edison is participating in the three unit, 3705 MW Palo Verde Nuclear Project in Arizona with a 15.8% share (568 MW after off-system losses). Firm operating dates are scheduled for May 1, 1982; May 1, 1984; and May 1, 1986. The project is allocated as follows:

	<u>Participation Percentage</u>
Arizona Public Service Company	29.1
Salt River Project	29.1
El Paso Electric Company	15.8
Southern California Edison Company	15.8
Public Service Company of New Mexico	10.2
TOTAL	<u>100.0</u>

12. In March 1973, Edison joined a group of investor-owned utilities to fund an electric utility fuel cell program in conjunction with United States Technologies Corporation. Final commitments to purchase 15 units at 26 MW each (390 MW total capacity) for delivery in 1982-1988 is contingent upon both competitive costs and successful validation of a test unit in 1978.

13. On January 1, 1985, the contractual provisions for energy and capacity assigned to Edison from the Oroville-Thermalito facility will be terminated. The 340 MW Edison capacity allocation was adjusted to 326 MW for losses and further reduced by 20 MW/39 MW to reflect dry year summer/winter hydro conditions.
14. A seasonal diversity of 275 MW capacity commencing on May 1, 1985, is being discussed with the Pacific Northwest. An additional seasonal diversity exchange being discussed is planned to commence on August 1, 1987 to replace the 550 MW capacity/energy exchange with Bonneville Power Authority which terminates on that date. The effect on Edison's resources is equivalent to a capacity purchase in the summer (May 1 through October 31) and a capacity sale in the winter. Exchange amounts have been adjusted for Edison's net loss obligations.
15. The capacities shown are for the Lucerne Valley Combined Cycle Project located in the Upper Johnson Valley. Fifteen combustion turbines (900 MW) are scheduled for completion by June, 1985. The first 130 MW steam turbine is added in 1985 with the remaining two 130 MW steam turbines scheduled for June, 1986, completing the 1290 MW combined cycle project.
16. Construction of wind, geothermal and solar resources are contingent upon successful research and development and competitive costs of commercial units.
17. Edison's present 50-year Hoover contract for energy and capacity (331 MW) with the U.S. Department of Interior, expires on June 1, 1987. Dry year hydro derate reduces the above capacity by 54 MW. MWD's Hoover capacity (261 MW) is assumed to continue.
18. It is tentatively planned to increase the capacity of existing hydro facilities.
19. Specific sites for combustion turbines in the 1987-1996 time frame are currently under study.
20. Edison has been informed that the resale cities of Anaheim and Riverside are evaluating participation in the Inter-mountain and Sundersert Projects in the following amounts:

	<u>Intermountain</u>	<u>Sundesert</u>
Anaheim	300-450 MW	95 MW
Riverside	300 MW	38 MW
TOTAL	600-750 MW	133 MW

21. Edison is currently a 22% (1118 MW) participant in a four unit 5080 MW nuclear development in the San Joaquin Valley. Preliminary project allocation is as follows:

	<u>Participation Percentage</u>
LADWP	35.5
PG&E	23.0
SCE	22.0
Department of Water Resources	10.0
City of Anaheim	2.0
City of Glendale	2.0
Northern California Power Agency	2.0
City of Riverside	2.0
City of Pasadena	1.5
TOTAL	100.0

Edison Resale Cities' capacity allocation from this project (Anaheim 102 MW, Riverside 102 MW), is included in Edison's future generation resource planning.

22. Edison is planning to participate in Palo Verde Nuclear Units 4 and 5 with a 15.8% share (390 MW total) scheduled for firm operation on May 1, 1988 and May 1, 1990. Arizona Public Service, the Project Manager, is currently planning these units which replicate Palo Verde Units 1-3.
23. Coal capacity is presently under study.
24. Assumed 78% allocation to Edison at an Eastern Desert Site.

JULY 23, 1976
FUTURE GENERATION RESOURCE PROGRAM

Principal Changes From The February 3, 1976
Future Generation Resource Program

1. This program is based on the System Forecasts filed with the State Energy Resources Conservation and Development Commission on March 1, 1976. In May 1976 reductions to peak demand due to load management of 210 MW starting in 1980 and increasing to 640 MW in 1995 were included. The detailed breakdown is shown in Attachments 1 and 2.
2. The increase in USBR's Navajo lay-off originally scheduled for April 15, 1976 was delayed to May 1, 1976.
3. The planned derate of Four Corners Unit 5 by 4.5 MW (2 MW SCE share) has been deferred from May 1, 1976 to November 1, 1976.
4. The Axis Combustion Turbine capacity has been reduced from 25 MW to 23 MW to reflect the expected rating.
5. The Lucerne Valley Combined Cycle Project Schedule has been changed as follows:

	<u>Old Schedule</u>	<u>New Schedule</u>
By June 1, 1981	600 MW	120 MW
By December 1, 1984	-	180 MW
By June 1, 1985	300 MW	990 MW
By December 1, 1986	390 MW	-

6. The four unit 3100 MW Kaiparowits Project (1203 MW SCE share) previously scheduled for the 1982-1984 time frame has been cancelled.
7. Beginning in 1980 a 161 MW (after losses) summer/winter capacity exchange with the Pacific Northwest has been added to the previously planned 117 MW exchange scheduled to begin at the same time (total 278 MW).
8. Edison's participation in the Palo Verde Project has been increased from 15.4 to 15.8%, changing the net delivered capacity from 190 to 195 MW for each unit (total SCE share 584 MW net).

9. The approximate 1400 MW of unsited combustion turbine capacity previously shown in the 1987-1994 period has been advanced into the 1985-1990 time frame. Also, a 55 MW unsited combustion turbine unit has been added in each of 1993 and 1995.
10. The San Joaquin Nuclear Project capacity has been delayed from 1985-1990 to 1987-1992 to reflect LADWP's latest project schedule.
11. Nuclear 1 & 2, previously scheduled for 1989 and 1992, have been advanced one year to 1988 and 1991.
12. The 702 MW of combined cycle capacity previously shown in 1987-1988 has been increased to 936 MW in the 1987-1989 time period.
13. East Coal Unit 2 has been delayed one year from 1991 to 1992.

DJF:gm
8/31/76

JULY 23, 1976
FUTURE GENERATION RESOURCE PROGRAM
1976 - 1995

DEFINITION OF COLUMN HEADINGS

Date

Firm operating date of unit or contractual agreement.

Resource

Resource identification. Often includes supplemental information about capacity, particularly when the identification refers to a unit which is undergoing rerate, has associated off-system losses, or is a participation unit.

Net Capacity Added

Effective operating capacity rating of the resource. These have been adjusted for losses incurred outside the Edison Main System where applicable.

Total Capacity

Summer total capacity includes resources installed as of July 1 of that year; winter includes all capacity added in that year.

Area Peak Demand

Includes Edison Net Main System peak demand plus firm on-peak sales to other utilities, CDWR and Metropolitan Water District pumping load, and demands for formerly isolated Edison loads commencing when they are expected to be integrated into the Main System.

Area Margin

Megawatt margin is the difference between total installed capacity and area peak demand. Percent margin is the megawatt margin divided by area peak demand and multiplied by 100.

Area Reliability Index

The reliability index represents the probability that a particular year's specified resources will be sufficient to serve forecast loads for each hour of the year, allowing for planned generation maintenance and forced outages without requiring delivery of capacity via Edison's interconnections in excess of firm deliveries plus 300 MW from 1976 through 1984, and firm deliveries plus 600 MW after 1984.

Edison Net Peak Demand

Edison net peak demand is based on the System Forecasts prepared by the System Development Department and filed with the State Energy Resources Conservation and Development Commission on March 1, 1976. Reductions due to load management were included in May 1976. 1976 summer peak demand is recorded as of July 15, 1976.

Annual Load Increase

Percent by which Edison net peak demand increases over the previous year net peak demand.

DJF:gm
8/31/76

JULY 23, 1976
 FUTURE GENERATION RESOURCE PROGRAM
 1976-1995

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
12-31-75	AGGREGATE RATED CAPACITY REDUCED FOR "DRY YEAR HYDRO" CONDITIONS, 213 MW FOR SUMMER AND 264 MW FOR WINTER		13736	13591 (1)						
	SUMMER CAPACITY INCLUDES ANNUAL CAPACITY EXCHANGE OF 100MW (94MW NET)	(2)								
5- 1-76	INCREASE NAVAJO LAYOFF (126 MW)	123 (3)								
9- 2-76	LONG BEACH 1 (COMBUSTION TURBINE)	63 (4)								
9-30-76	LONG BEACH 2 (COMBUSTION TURBINE)	63 (4)								
10-27-76	LONG BEACH 3 (COMBUSTION TURBINE)	63 (4)								
11- 1-76	BEGIN ANNUAL WINTER PGE EXCHANGE (94 MW SCE TO PGE FROM NOV 1 THRU MAR 31)	(2)								
11- 1-76	DERATE FOUR CORNERS 5 (800/384 TO 795/382 MW)	-2 (5)								
11-24-76	LONG BEACH 4 (COMBUSTION TURBINE)	63 (4)								
11-24-76	LONG BEACH 8R (STEAM)	82 (4)								
12-22-76	LONG BEACH 5 (COMBUSTION TURBINE)	63 (4)								
	TOTAL CAPACITY ADDED	518								
	LOADS AND RESOURCES FOR SUMMER 1976		13859		11292	2567	22.7	.99	11081	8.7
	LOADS AND RESOURCES FOR WINTER 1976			14109	9304	4805	51.6			
1- 1-77	RERATE SAN ONOFRE 1	6 (6)								
1-19-77	LONG BEACH 6 (COMBUSTION TURBINE)	63 (4)								
2-17-77	LONG BEACH 7 (COMBUSTION TURBINE)	63 (4)								
2-17-77	LONG BEACH 9 (STEAM)	49 (4)								
	TOTAL CAPACITY ADDED	181								
	LOADS AND RESOURCES FOR SUMMER 1977		14435		11448	2987	26.1	.99	11219	1.2
	LOADS AND RESOURCES FOR WINTER 1977			14290	9790	4500	46.0			

JULY 23, 1976
 FUTURE GENERATION RESOURCE PROGRAM
 1976-1995

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
4- 1-78	COOLWATER 3	236								
8- 1-78	COOLWATER 4	236								
	TOTAL CAPACITY ADDED	472								
	LOADS AND RESOURCES FOR SUMMER 1978		14671		11946	2725	22.8	.99	11690	4.3
	LOADS AND RESOURCES FOR WINTER 1978			14762	10268	4494	43.8			
1- 1-79	RECONDITION LONG BEACH 10 & 11	112 (7)								
4- 1-79	EDWARDS AFB EXCHANGE	18/ 15 (8)								
4- 1-79	INTEGRATE YUMA-AXIS STEAM GENERATION INTO MAIN SYSTEM (75/25 MW)	25 (9)								
4- 1-79	AXIS COMBUSTION TURBINE	23								
	TOTAL CAPACITY ADDED	178/ 175								
	LOADS AND RESOURCES FOR SUMMER 1979		15085		12450	2635	21.2	.99	12190	4.3
	LOADS AND RESOURCES FOR WINTER 1979			14937	10762	4175	38.8			
3- 1-80	BIG CREEK 3 UNIT 5	31								
5- 1-80	BEGIN ANNUAL EXCHANGE WITH NORTHWEST (296MW NW TO SCE FROM MAY 1 THRU OCT 31)	276/ 0 (10)								
6- 1-80	DECREASE NAVAJO LAYOFF (22 MW)	-22 (3)								
10- 1-80	SAN ONOFRE 2 (220/176 MW)	176 (11)								
11- 1-80	ANNUAL WINTER EXCH 278MW TO NORTHWEST	(10)								
	TOTAL CAPACITY ADDED	463/ 185								
	LOADS AND RESOURCES FOR SUMMER 1980		15372		12777	2595	20.3	.99	12510	2.6
	LOADS AND RESOURCES FOR WINTER 1980			15122	11397	3725	32.7			

JULY 23, 1976
 FUTURE GENERATION RESOURCE PROGRAM
 1976-1995

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
1- 1-84	FUEL CELLS 4&5	52 (13)								
5-15-84	PALO VERDE NUCLEAR 2 (1270/200 MW)	194 (14)								
11- 1-84	LUCERNE VALLEY COMBUSTION TURBINE	60 (12)								
12- 1-84	LUCERNE VALLEY COMBUSTION TURBINES	120 (12)								
	TOTAL CAPACITY ADDED	426								
	LOADS AND RESOURCES FOR SUMMER 1984		17732		15160	2572	17.0	.97	14810	4.5
	LOADS AND RESOURCES FOR WINTER 1984			17486	13800	3686	26.7			
1- 1-85	LUCERNE VALLEY COMBUSTION TURBINES	120 (12)								
1- 1-85	TERMINATE OROVILLE-THERMALITO (340 MW)	-326 (15)								
1- 1-85	ADJUST DRY-YEAR HYDRO DERATE TO 193MW/225MW TO REMOVE OROVILLE	20/ 39 (15)								
1- 1-85	TERMINATE NAVAJO LAYOFF (265 MW)	-258 (3)								
1- 1-85	FUEL CELLS 6&7	52 (13)								
2- 1-85	LUCERNE VALLEY STEAM TURBINE	130 (12)								
2- 1-85	LUCERNE VALLEY COMBUSTION TURBINES	120 (12)								
3- 1-85	LUCERNE VALLEY COMBUSTION TURBINES	120 (12)								
3- 1-85	FUEL CELLS 8&9	52 (13)								
4- 1-85	LUCERNE VALLEY STEAM TURBINE	130 (12)								
4- 1-85	LUCERNE VALLEY COMBUSTION TURBINES	120 (12)								
5- 1-85	LUCERNE VALLEY COMBUSTION TURBINES	120 (12)								
6- 1-85	COMBUSTION TURBINE (3 UNITS)	165 (16)								
6- 1-85	LUCERNE VALLEY STEAM TURBINE	130 (12)								
	TOTAL CAPACITY ADDED	695/ 714								
	LOADS AND RESOURCES FOR SUMMER 1985		18607		15865	2742	17.3	.99	15470	4.5
	LOADS AND RESOURCES FOR WINTER 1985			18200	14516	3684	25.4			

NOTE: SUNDESERT NUCLEAR IS AN ALTERNATIVE TO CAPACITY SHOWN IN 1985-1990

JULY 23, 1976
 FUTURE GENERATION RESOURCE PROGRAM
 1976-1995

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
1- 1-86	WIND 1	4 (17)								
3- 1-86	FUEL CELLS 10-15	156 (13)								
3-31-86	TERMINATE EDWARDS AFB EXCHANGE	-18/-15 (8)								
4- 1-86	GEOHERMAL 1&2	100 (17)								
5-15-86	PALO VERDE NUCLEAR 3 (1270/201 MW)	195 (14)								
6- 1-86	COMBUSTION TURBINE (7 UNITS)	385 (16)								
	TOTAL CAPACITY ADDED	822/ 625								
	LOADS AND RESOURCES FOR SUMMER 1986		19429		16591	2838	17.1	.99	16200	4.7
	LOADS AND RESOURCES FOR WINTER 1986			19025	15187	3836	25.3			
1- 1-87	WIND 2	6 (17)								
6- 1-87	TERMINATE HOOVER	-331 (19)								
6- 1-87	ADJUST DRY-YEAR HYDRO DERATE TO 139MW/171MW TO REMOVE HOOVER	54 (19)								
6- 1-87	HYDRO	140 (20)								
6- 1-87	COMBUSTION TURBINE (10 UNITS)	550 (16)								
6- 1-87	COMBINED CYCLE (2 UNITS)	468 (16)								
10- 1-87	SAN JOAQUIN NUC 1 (1270/330 MW)	330 (18)								
	TOTAL CAPACITY ADDED	1217								
	LOADS AND RESOURCES FOR SUMMER 1987		20316		17352	2964	17.1	.99	16960	4.7
	LOADS AND RESOURCES FOR WINTER 1987			20242	15874	4368	27.5			
1- 1-88	WIND 3	10 (17)								
6- 1-88	NUCLEAR 1 (1000/780 MW)	780 (21)								
	TOTAL CAPACITY ADDED	790								
	LOADS AND RESOURCES FOR SUMMER 1988		21436		18134	3302	18.2	.99	17740	4.0
	LOADS AND RESOURCES FOR WINTER 1988			21032	16545	4487	27.1			

JULY 23, 1976
 FUTURE GENERATION RESOURCE PROGRAM
 1976-1995

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
1- 1-89	WIND 4	20 (17)								
4- 1-89	SAN JOAQUIN NUC 2 (1270/330 MW)	330 (18)								
6- 1-89	COMBINED CYCLE (2 UNITS)	468 (16)								
	TOTAL CAPACITY ADDED	818								
	LOADS AND RESOURCES FOR SUMMER 1989		22254		18952	3302	17.4	.99	18570	4.7
	LOADS AND RESOURCES FOR WINTER 1989			21850	17278	4572	26.5			
1- 1-90	WIND 5	30 (17)								
1- 1-90	EAST COAL 1 (1300/520 MW)	504 (22)								
6- 1-90	COMBUSTION TURBINE (5 UNITS)	275 (16)								
6- 1-90	GEO THERMAL	100 (17)								
10- 1-90	SAN JOAQUIN NUC 3 (1270/330 MW)	330 (18)								
	TOTAL CAPACITY ADDED	1239								
	LOADS AND RESOURCES FOR SUMMER 1990		23163		19792	3371	17.0	.99	19400	4.5
	LOADS AND RESOURCES FOR WINTER 1990			23089	18019	5070	28.1			
1- 1-91	WIND 6	30 (17)								
6- 1-91	GEO THERMAL	150 (17)								
6- 1-91	NUCLEAR 2 (1000/780 MW)	780 (21)								
	TOTAL CAPACITY ADDED	960								
	LOADS AND RESOURCES FOR SUMMER 1991		24453		20598	3855	18.7	.99	20240	4.3
	LOADS AND RESOURCES FOR WINTER 1991			24049	18772	5277	28.1			
4- 1-92	SAN JOAQUIN NUC 4 (1270/330 MW)	330 (18)								
6- 1-92	EAST COAL 2 (1300/520 MW)	504 (22)								
	TOTAL CAPACITY ADDED	834								
	LOADS AND RESOURCES FOR SUMMER 1992		25287		21477	3810	17.7	.99	21090	4.2
	LOADS AND RESOURCES FOR WINTER 1992			24883	19554	5329	27.3			

JULY 23, 1976
 FUTURE GENERATION RESOURCE PROGRAM
 1976-1995

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
1- 1-93	EAST COAL 3 (1300/520 MW)	504 (22)								
5- 1-93	SOLAR 1	100 (17)								
6- 1-93	COMBUSTION TURBINE (1 UNITS)	55 (16)								
6- 1-93	GEOTHERMAL	150 (17)								
	TOTAL CAPACITY ADDED	809								
	LOADS AND RESOURCES FOR SUMMER 1993		26096		22324	3772	16.9	.99	21940	4.0
	LOADS AND RESOURCES FOR WINTER 1993			25692	20300	5392	26.6			
1- 1-94	RETIRE LONG BEACH 10 & 11	-212								
6- 1-94	EAST COAL 4 (1300/520 MW)	504 (22)								
6- 1-94	NUCLEAR 3 (1300/780 MW)	780 (22)								
	TOTAL CAPACITY ADDED	1072								
	LOADS AND RESOURCES FOR SUMMER 1994		27168		23233	3935	16.9	.99	22820	4.0
	LOADS AND RESOURCES FOR WINTER 1994			26764	21110	5654	26.8			
5- 1-95	SOLAR 2	100 (17)								
6- 1-95	COMBUSTION TURBINE (1 UNIT)	55 (16)								
6- 1-95	GEOTHERMAL	150 (17)								
6- 1-95	NUCLEAR 4 (1300/780 MW)	780 (22)								
	TOTAL CAPACITY ADDED	1085								
	LOADS AND RESOURCES FOR SUMMER 1995		28253		24153	4100	17.0	.99	23740	4.0
	LOADS AND RESOURCES FOR WINTER 1995			27849	21941	5908	26.9			

JULY 23, 1976
FUTURE GENERATION RESOURCE PROGRAM
1976-1995

DEVELOPMENT OF PERTINENT DATA

1) RECONCILIATION OF THE 12-31-75 AGGREGATE RATED CAPACITY WITH THE JANUARY 1, 1976 REVISION OF THE "GENERATOR RATINGS AND EFFECTIVE OPERATING CAPACITY OF RESOURCES".

** NET MAIN SYSTEM RESOURCES (DECEMBER 31, 1975)	12191
** TOTAL FIRM PURCHASES (DECEMBER 31, 1975)	+1423
MWD CAPACITY	+315
WINTER HYDRO DERATE	-264
TOTAL OFF SYSTEM LOSSES	-74

12-31-75 AGGREGATE RATED CAPACITY	13591

** CONSISTENT WITH THE MAY 1, 1976 REVISION OF THE "GENERATOR RATINGS AND EFFECTIVE OPERATING CAPACITY OF RESOURCES" EDISON HOOVER CAPACITY IS SHOWN AS A PURCHASE.

2) SUMMARY OF AREA PEAK DEMANDS (1976-1995)

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
SUMMER										
DECT5 NET PEAK FORECAST	11081	11210	11690	12190	12720	13280	13870	14490	15160	15860
LOAD MANAGEMENT MAY76	-	-	-	-	-210	-250	-280	-320	-350	-390
EDISON NET PEAK DEMAND ***	11081	11210	11690	12190	12510	13030	13590	14170	14810	15470
MWD LOAD	211	231	231	231	231	231	231	231	231	231
STATE WATER PROJECT	-	-	25	29	36	72	36	116	119	164
AREA PEAK DEMAND	11292	11448	11946	12450	12777	13333	13857	14517	15160	15865
WINTER										
DECT5 NET PEAK FORECAST	9080	9530	9990	10480	11000	11550	12140	12750	13420	14120
LOAD MANAGEMENT MAY76	-	-	-	-	-170	-200	-220	-250	-270	-300
EDISON NET PEAK DEMAND ***	9080	9530	9990	10480	10830	11350	11920	12500	13150	13820
MWD LOAD	123	159	159	159	159	159	159	159	159	159
STATE WATER PROJECT	7	7	25	29	36	72	36	117	119	165
SALE TO PORTLAND GE	94	94	94	94	94	94	94	94	94	94
SALE TO NORTH-WEST	-	-	-	-	278	278	278	278	278	278
AREA PEAK DEMAND	9304	9790	10268	10762	11397	11953	12487	13148	13800	14516
1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	
SUMMER										
DECT5 NET PEAK FORECAST	16610	17390	18200	19050	19900	20770	21640	22520	23430	24380
LOAD MANAGEMENT MAY76	-410	-430	-460	-480	-500	-530	-550	-580	-610	-640
EDISON NET PEAK DEMAND ***	16200	16960	17740	18570	19400	20240	21090	21940	22820	23740
MWD LOAD	231	231	231	231	195	159	159	159	159	159
STATE WATER PROJECT	160	161	163	151	197	199	228	225	254	254
AREA PEAK DEMAND	16591	17352	18134	18952	19792	20598	21477	22324	23233	24153
WINTER										
DECT5 NET PEAK FORECAST	14780	15480	16200	16950	17710	18490	19260	20040	20850	21700
LOAD MANAGEMENT MAY76	-320	-330	-350	-370	-390	-410	-430	-460	-480	-510
EDISON NET PEAK DEMAND ***	14460	15150	15850	16580	17320	18080	18830	19580	20370	21190
MWD LOAD	195	195	159	159	123	123	123	123	123	123
STATE WATER PROJECT	160	157	164	167	194	197	229	225	245	256
SALE TO PORTLAND GE	94	94	94	94	94	94	94	94	94	94
SALE TO NORTH-WEST	278	278	278	278	278	278	278	278	278	278
AREA PEAK DEMAND	15187	15874	16545	17278	18019	18772	19554	20300	21110	21941

*** BLYTHE LOAD IS INCLUDED IN THE EDISON NET PEAK DEMAND STARTING IN 1979

14

JULY 23, 1976
FUTURE GENERATION RESOURCE PROGRAM
1976 - 1995

NOTES

1. Aggregate rated capacity in accord with the January 1, 1976 revision of "Generator Ratings and Effective Operating Capacity of Resources," and MWD's capacity of 315 MW (261 MW at Hoover, 54 MW at Parker), adjusted for Edison, Hoover and Oroville-Thermalito dry year hydro derates.
2. An assignment has been negotiated with Pacific Gas & Electric Company and Portland General Electric Company providing for sale and exchange of capacity and energy. The effect on Edison's capacity resources is equivalent to a firm capacity purchase in the summer (from May 16 through October 15) beginning in 1975, and a firm capacity sale in the winter, beginning in 1976. The exchange amount has been adjusted for Edison's net loss obligation.
3. A contract has been executed with the U.S. Bureau of Reclamation for layoff of power from the Navajo Project. At such time as USBR needs this power for the Central Arizona Project, USBR has the right to terminate this lay-off effective on or after January 1, 1980, upon at least five years advance written notice. Such notice has not been given; however, it is currently anticipated that the layoff will terminate in 1985. Edison has been notified, however, that the layoff will be decreased by 22 MW on June 1, 1980 and 40 MW on June 1, 1981 to provide power for USBR's desalination project.
4. The capacities shown for the 572 MW Long Beach Combined Cycle Project are for the individual combustion turbine and steam portions which make up the combined cycle units.
5. The exact date and amount of Four Corners Unit 5 capacity derate, reflecting the power requirements for an emission control test module, has not been determined by Arizona Public Service. The anticipated date and amount are shown.
6. It is planned to increase San Onofre Unit 1 capacity by 8 MW (6 MW SCE's share) to fully utilize the reactor capability following turbine capacity rerating by Westinghouse Corporation. Final capacity adjustment will be determined upon completion of validation tests.

7. Prior to completion of reconditioning in 1979, Long Beach Units 10 & 11 have been derated from 106 to 50 MW each.
8. Edwards Air Force Base exchange capacity is available to Edison in the amount of 18.5 MW from March 1 to September 30, and 14.95 MW from October 1 to February 28, annually commencing on April 1, 1976 and terminating on March 31, 1986. However, the capacity is not added to the Edison Main System until the integration of the Blythe System in 1979.
9. Loads and resources of the Blythe Isolated System are integrated into the Edison Main System in 1979.
10. An exchange of capacity and energy commencing on May 1, 1980, is being negotiated with the Pacific Northwest. The effect on Edison's resources is equivalent to a capacity purchase in the summer and a capacity sale in the winter. Exchange amounts are specified at anticipated levels and have been adjusted for Edison's net loss obligations.
11. For planning and reporting purposes, San Onofre Units 2 & 3 are considered a firm capacity resource at 20% of their full power rating (1100 MW each) for one year prior to their respective full power firm operating dates of 10-1-81 and 1-1-83. Edison's share of Units 2 & 3 is 80% in accordance with agreements with San Diego Gas & Electric Company.
12. The capacities are shown for the Lucerne Valley Combined Cycle Project located in the Upper Johnson Valley. In 1981, 120 MW of combustion turbine capacity is scheduled with the remainder of the 900 MW of combustion turbines completed by June 1985. The 390 MW of steam turbines are scheduled for completion by June 1985 completing the 1290 MW combined cycle project. The dates for the Lucerne Valley units may be advanced in the event of unforeseen load growth or delays in other resources scheduled for the 1980 to 1985 period.
13. In March 1973, Edison joined a group of investor-owned utilities to fund an electric utility fuel cell program in conjunction with United Technologies Corporation. Final commitments to purchase 15 units at 26 MW each (390 MW total capacity) for delivery in 1981-1986 is contingent upon both competitive costs and successful validation of a test unit in 1978.
14. Edison is participating in the three unit, 3810 MW Palo Verde Nuclear Project in Arizona with a 15.8% share (584 MW after off-system losses). Firm operating dates

are scheduled for May 15, 1982, May 15, 1984, and May 15, 1986. The project is allocated as follows:

	<u>Participation Percentage</u>
Arizona Public Service Company	29.1
Salt River Project	29.1
El Paso Electric Company	15.8
Southern California Edison Company	15.8
Public Service Company of New Mexico	<u>10.2</u>
Total	100.0

- 15. On January 1, 1985, the contractual provisions for energy and capacity assigned to Edison from the Oroville-Thermalito facility will be terminated. The 340 MW Edison capacity allocation was adjusted to 326 MW for losses and further reduced by 20 MW/39 MW to reflect dry year summer/winter hydro conditions.
- 16. Specific sites for combustion turbines and combined cycle units in the 1985-1995 time frame are currently under study.
- 17. Wind, geothermal and solar resources are contingent upon successful research and development and competitive costs of commercial units.
- 18. Edison is currently a 22% (1118 MW) participant in a four unit 5080 MW nuclear development in the San Joaquin Valley. Preliminary project allocation is as follows:

	<u>Participation Percentage</u>
LADWP	35.5
PG&E	23.0
SCE	22.0
Department of Water Resources	10.0
City of Anaheim	2.0
City of Glendale	2.0
Northern California Power Agency	2.0
City of Riverside	2.0
City of Pasadena	<u>1.5</u>
Total	100.0

Edison Resale Cities' capacity allocation from this project (Anaheim 102 MW, Riverside 102 MW), is included in Edison's future generation resource planning.

19. Edison's present 50-year Hoover contract for energy and capacity (331 MW) with the U.S. Department of the Interior, expires on June 1, 1987. Dry year hydro derate reduces the above capacity by 54 MW.
20. It is tentatively planned to increase the capacity of existing hydro facilities.
21. Assumed 78% allocation to Edison at an Eastern Desert site.
22. Coal and nuclear capacity is presently under study.

DJF:gm
8/31/76

ATTACHMENT 1

REDUCTIONS IN 1980 PEAK DEMAND (MW)

	Customer Class					Total
	<u>Res.</u>	<u>Com.</u>	<u>Ind.</u>	<u>OPA</u>	<u>Resale</u>	
<u>Included in 12/75 Forecast</u>						
Price Elasticity and Conservation (1)	170	330	530	180	170	1380
Mandated Measures (2)	460	230	-	30	30	750
Time-of-use Rates	-	2	-	-	-	2
Subtotal	630	562	530	210	200	2132
<u>Load Management Measures</u>						
Time-of-use Rates	-	-	35*	-	16*	51
Interruptible Rates	-	-	60*	-	-	60
Water-Heater Control	60*	-	-	-	-	60
A/C Limiters	30*	4*	-	-	-	34
Sensible Cooling	-	3*	-	-	-	3
Subtotal (Load Management)	90	7	95	-	16	208
Total	720	569	625	210	216	2340

* Reductions due to load management. These reductions are not included in the December 1975 System Forecast.

(1) Reductions due to price-elasticity impact on kilowatthour sales of each customer class. These reductions are included in the December 1975 System Forecast.

(2) Reductions due to mandatory improvements in the air-conditioner efficiency (50% for room A/C and 20% for central A/C) and building insulation standards (20% for new homes and 10% for existing homes). These reductions are included in the December 1975 System Forecast.

ATTACHMENT 2

REDUCTIONS IN 1985 PEAK DEMAND (MW)

	Customer Class					Total
	Res.	Com.	Ind.	OPA	Resale	
<u>Included in 12/75 Forecast</u>						
Price Elasticity and Conservation (1)	180	640	920	350	300	2390
Mandated Measures (2)	830	570	-	50	50	1500
Time-of-use Rates	-	50	-	-	-	50
Subtotal	1010	1260	920	400	350	3940
<u>Load Management Measures</u>						
Time-of-use Rates	-	-	65*	-	28*	93
Interruptible Rates	-	-	94*	-	-	94
Water-Heater Control	120*	-	-	-	-	120
A/C Limiters	60*	15*	-	-	-	75
Sensible Cooling	4*	4*	-	-	-	8
Subtotal (Load Management)	184	19	159	-	28	390
Total	1194	1279	1079	400	378	4330

* Reductions due to load management. These reductions are not included in the December 1975 System Forecast.

- (1) Reductions due to price-elasticity impact on kilowatthour sales of each customer class. These reductions are included in the December 1975 System Forecast.
- (2) Reductions due to mandatory improvements in the air-conditioner efficiency (50% for room A/C and 20% for central A/C) and building insulation standards (20% for new homes and 10% for existing homes). These reductions are included in the December 1975 System Forecast.

FEBRUARY 3, 1976 FUTURE GENERATION RESOURCE PROGRAM
 PRINCIPAL CHANGES FROM THE SEPTEMBER 3, 1975
 FUTURE GENERATION RESOURCE PROGRAM

1. This program is based on the December, 1975 System Forecasts using lifeline rates.
2. MWD load forecast (formerly 295 MW) has been reduced to a range of 123 MW to 268 MW.
3. Edison's Hoover and MWD's Hoover-Parker capacity has been increased 54 MW and 5 MW respectively with corresponding dry year hydro derates of 54 MW and 39/52 MW (Summer/Winter).
4. Oroville-Thermalito capacity has been increased 7 MW with a corresponding dry year hydro derate of 10 MW.
5. Four Corners units 4 and 5 derates due to scrubbers (56 MW SCE's total share) have been deferred indefinitely except for a derate of Unit 5 (2 MW SCE's share) in 1976.
6. Each unit of the Long Beach Combined Cycle Project has been delayed by 2 months. The project completion date is revised to February 17, 1977.
7. San Onofre Unit 1 capacity is planned to be increased by 8 MW (6 MW SCE's share) to 458 MW effective 1-1-77. Final unit rating will be determined upon completion of validation tests.
8. Coolwater Unit 4, operating date was changed from 6-1-78 to 8-1-78.
9. Lucerne Valley Project schedule has been changed as follows:

	Old Schedule	New Schedule
By 6-1-80 (Combustion Turbines)	720 MW	--
By 6-1-81 (Combustion Turbines)	180 MW	600 MW
By 6-1-85 (Combustion Turbines)	--	300 MW
By 6-1-85 (Steam Turbines)	390 MW	--
By 12-1-86 (Steam Turbines)	--	390 MW

10. Beginning in 1980, a 124 MW (117 MW after losses) Summer/Winter capacity exchange with the Pacific Northwest has been added.

11. The 1981 reduction in Navajo layoff power has changed from -63 MW to -39 MW, due to a reduction in the estimated power requirements for USBR's desalination plant.
12. Each Kaiparowits unit has been delayed one year. Edison's net delivered share has been increased from 291 MW to 301 MW for each unit due to planned use of horizontal rather than vertical scrubbers.
13. The unsited combustion turbine capacity previously shown from 1981-1988, has been deferred to the 1987-1994 time period.
14. The San Joaquin Nuclear Project capacity has been advanced from 1987-1991 to 1985-1990 in accord with LADWP projections.
15. The 200 MW geothermal capacity previously shown in 1985 to 1990 has been increased to 650 MW and deferred to the 1986-1995 period.
16. The 1170 MW of combined cycle capacity previously shown in 1986-1987 has been reduced to 702 MW and delayed to the 1987-1988 time period.
17. Wind and solar resources (300 MW total) presently under research and development have been added from 1986 to 1995.
18. The 517 MW BPA exchange capacity previously terminated on 8-1-87, has been assumed to continue through 1995.
19. 140 MW of hydro capacity previously shown in 1990 has been advanced to 1987.
20. Vidal (1386 MW) and Eastern Desert (1386 MW) HTGR previously shown in 1988 and 1989 have been replaced with two 1000 MW LWR's on 1-1-89 and 6-1-92. Edison's assumed share is 780 MW each.
21. Long Beach units 10 and 11 are retired in place on 1-1-94.
22. Unsited coal and nuclear capacity of 1512 MW and 2340 MW respectively are shown in the 1991-1995 time frame.

FEBRUARY 3, 1976
FUTURE GENERATION RESOURCE PROGRAM
1976 - 1995

DEFINITION OF COLUMN HEADINGS

Date

Firm operating date of unit or contractual agreement.

Resource

Resource identification. Often includes supplemental information about capacity, particularly when the identification refers to a unit which is undergoing rerate, has associated off-system losses, or is a participation unit.

Net Capacity Added

Effective operating capacity rating of the resource. These have been adjusted for losses incurred outside the Edison Main System where applicable.

Total Capacity

Summer total capacity includes resources installed as of July 1 of that year, winter includes all capacity added in that year.

Area Peak Demand

Includes Edison Net Main System peak demand plus firm on-peak sales to other utilities, Metropolitan Water District pumping loads, and demands for isolated Edison loads commencing when they are expected to be integrated into the Main System.

Area Margin

Megawatt margin is the difference between total installed capacity and area peak demand. Percent margin is the megawatt margin divided by area peak demand and multiplied by 100.

Area Reliability Index

The reliability index represents the probability that a particular year's specified resources will be sufficient to serve forecast loads for each hour of the year, allowing for planned generation maintenance and forced outages without requiring delivery of capacity via Edison's interconnections in excess of firm deliveries plus 300 MW from 1976 through 1984, and 600 MW after 1984.

Edison Net Peak Demand

Edison net peak demand for 1976-1995 is based on the 1976-1995 System Forecasts prepared in December, 1975 by the System Development Department.

Annual Load Increase

Percent by which Edison net peak demand increases over the previous year net peak demand.

DJF/mad
1/21/76

FEBRUARY 3, 1976
 FUTURE GENERATION RESOURCE PROGRAM
 1976-1995

DATE	RESOURCE	NFT CAPACITY ADDED (MW)	TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN		AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
			SUMMER (MW)	WINTER (MW)		(MW)	(%)			
12-31-75	AGGREGATE DATED CAPACITY REDUCED FOR "DRY YEAR" HYDRO CONDITIONS. 213 MW FOR SUMMER AND 264 MW FOR WINTER		13772	13591 (1)						
4-15-76	INCREASE NAVAJO LAYOFF (126 MW)	123 (2)								
5- 1-76	DERATE FOUR COPIERS 5 (800/3P4 TO 795/3R2 MW)	-2 (3)								
5-16-76	BEGIN ANNUAL SUMMER PGE EXCHANGE (100 MW PGE TO SCE FROM MAY 16, THRU OCT 15)	94/ 0 (4)								
9- 2-76	LONG BEACH 1 (COMBUSTION TURBINE)	63 (5)								
9-30-76	LONG BEACH 2 (COMBUSTION TURBINE)	63 (5)								
10-27-76	LONG BEACH 3 (COMBUSTION TURBINE)	63 (5)								
11- 1-76	BEGIN ANNUAL WINTER PGE EXCHANGE (94 MW SCE TO PGE FROM NOV 1 THRU MAR 31)	(4)								
11-24-76	LONG BEACH 4 (COMBUSTION TURBINE)	63 (5)								
11-24-76	LONG BEACH RR (STEAM)	82 (5)								
12-22-76	LONG BEACH 5 (COMBUSTION TURBINE)	63 (5)								
	TOTAL CAPACITY ADDED	612/ 518								
	LOADS AND RESOURCES FOR SUMMER 1976		13857		11025	2832	25.7	.99	10750	5.5
	LOADS AND RESOURCES FOR WINTER 1976			14109	9304	4205	51.6			
1- 1-77	DERATE SAN ONOFE 1	6 (6)								
1-14-77	LONG BEACH 6 (COMBUSTION TURBINE)	63 (5)								
2-17-77	LONG BEACH 7 (COMBUSTION TURBINE)	63 (5)								
2-17-77	LONG BEACH 9 (STEAM)	49 (5)								
	TOTAL CAPACITY ADDED	181								
	LOADS AND RESOURCES FOR SUMMER 1977		14435		11448	2987	26.1	.99	11210	4.3
	LOADS AND RESOURCES FOR WINTER 1977			14290	9790	4500	46.0			

FEBRUARY 3, 1979
 FUTURE GENERATION RESOURCE PROGRAM
 1976-1995

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN		AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
			SUMMER (MW)	WINTER (MW)		(MW)	(%)			
4- 1-78	COOL WATER 3	236								
8- 1-78	COOL WATER 4	236								
	TOTAL CAPACITY ADDED	472								
	LOADS AND RESOURCES FOR SUMMER 1978		14671		11946	2725	22.8	.99	11690	4.3
	LOADS AND RESOURCES FOR WINTER 1978			14762	10268	4494	43.8			
1- 1-79	RECONDITION LONG BEACH 10 & 11	112 (7)								
4- 1-79	EDWARD AFB EXCHANGE	18/ 15 (8)								
4- 1-79	INTEGRATE YUMA-AXIS STEAM GENERATION INTO MAIN SYSTEM (75/25 MW)	25 (9)								
4- 1-79	AXIS COMBUSTION TURBINE	25								
	TOTAL CAPACITY ADDED	180/ 177								
	LOADS AND RESOURCES FOR SUMMER 1979		15087		12450	2637	21.2	.99	12190	4.3
	LOADS AND RESOURCES FOR WINTER 1979			14939	10762	4177	38.8			
3- 1-80	PIG CREEK 3 UNIT 5	31								
5- 1-80	BEGIN ANNUAL EXCHANGE WITH NORTHWEST (124MW SCE TO NP FROM MAY 1 THRU OCT 31)	117/ 0 (10)								
6- 1-80	DECREASE NAVAJO (LAYOFF (22 MW)	-22 (2)								
10- 1-80	SAN ONOFRE 2 (220/176 MW)	176 (11)								
11- 1-80	ANNUAL WINTER EXCH 117MW TO NORTHWEST	(10)								
	TOTAL CAPACITY ADDED	302/ 185								
	LOADS AND RESOURCES FOR SUMMER 1980		15213		12987	2226	17.1	.99	12720	4.3
	LOADS AND RESOURCES FOR WINTER 1980			15124	11406	3718	32.6			

FEBRUARY 3, 1974
 FUTURE GENERATION RESOURCE PROGRAM
 1976-1995

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
			SUMMER (MW)	WINTER (MW)						
1- 1-81	LUCERNE VALLEY COMBUSTION TURBINE	60 (12)								
2- 1-81	LUCERNE VALLEY COMBUSTION TURBINE	60 (12)								
3- 1-81	LUCERNE VALLEY COMBUSTION TURBINE	120 (12)								
4- 1-81	LUCERNE VALLEY COMBUSTION TURBINE	120 (12)								
5- 1-81	LUCERNE VALLEY COMBUSTION TURBINE	120 (12)								
6- 1-81	DECREASE NAVAJO LAYOFF (40 MW)	-34 (2)								
6- 1-81	LUCERNE VALLEY COMBUSTION TURBINE	120 (12)								
7- 1-81	FUEL CELL 1	26 (13)								
10- 1-81	PERATE SAN ONOFRE 2 (220/176 TO 1100/880 MW)	704 (11)								
	TOTAL CAPACITY ADDED	1291								
	LOADS AND RESOURCES FOR SUMMER 1981		15976		13583	2393	17.6	.99	13280	4.4
	LOADS AND RESOURCES FOR WINTER 1981			16415	11992	4423	36.9			
1- 1-82	SAN ONOFRE 3 (220/176 MW)	176 (11)								
5-15-82	FALO VERDE NUCLEAR 1 (1270/196 MW)	190 (14)								
5-31-82	FAIRBANKS 1 (775/310 MW)	301 (15)								
	TOTAL CAPACITY ADDED	667								
	LOADS AND RESOURCES FOR SUMMER 1982		17347		14137	3210	22.7	.99	13870	4.4
	LOADS AND RESOURCES FOR WINTER 1982			17082	12546	4536	36.2			
1- 1-83	PERATE SAN ONOFRE 3 (220/176 TO 1100/880 MW)	704 (11)								
5- 1-83	FUEL CELLS 2&3	52 (13)								
5-31-83	FAIRBANKS 2 (775/310 MW)	301 (15)								
	TOTAL CAPACITY ADDED	1057								
	LOADS AND RESOURCES FOR SUMMER 1983		18404		14837	3567	24.0	.99	14490	4.5
	LOADS AND RESOURCES FOR WINTER 1983			18139	13237	4902	37.0			

FEBRUARY 3, 1974
 FUTURE GENERATION RESOURCE PROGRAM
 1974-1990

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN		AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
			SUMMER (MW)	WINTER (MW)		(MW)	(%)			
1- 1-84	FUEL CELLS 465	52 (13)								
3- 1-84	KAIPAROWITS 3 (775/310 MW)	300 (15)								
5-15-84	HALO VERDE NUCLEAR 2 (1270/195 MW)	190 (14)								
12- 1-84	KAIPAROWITS 4 (775/310 MW)	301 (15)								
	TOTAL CAPACITY ADDED	843								
	LOADS AND RESOURCES FOR SUMMER 1984		18946		15510	3436	22.2	.99	15160	4.6
	LOADS AND RESOURCES FOR WINTER 1984			18982	13909	5073	36.5			
1- 1-85	TERMINATE OROVILLE-THERMALITO (340 MW)	-326 (16)								
1- 1-85	ADJUST DRY-YEAR HYDRO DERATE TO 193MW/225MW TO REMOVE OROVILLE	20/ 39 (14)								
1- 1-85	TERMINATE NAVAJO LAYOFF (265 MW)	-258 (2)								
1- 1-85	FUEL CELLS 667	52 (13)								
2- 1-85	LUCERNE VALLEY COMBUSTION TURBINE	60 (12)								
3- 1-85	LUCERNE VALLEY COMBUSTION TURBINE	60 (12)								
3- 1-85	FUEL CELLS 889	52 (13)								
4- 1-85	LUCERNE VALLEY COMBUSTION TURBINE	60 (12)								
5- 1-85	LUCERNE VALLEY COMBUSTION TURBINE	60 (12)								
6- 1-85	LUCERNE VALLEY COMBUSTION TURBINE	60 (12)								
12- 1-85	SAN JOAQUIN NUC 1 (1270/330 MW)	330 (17)								
	TOTAL CAPACITY ADDED	1707/ 189								
	LOADS AND RESOURCES FOR SUMMER 1985		19087		16255	2832	17.4	.99	15860	4.6
	LOADS AND RESOURCES FOR WINTER 1985			19171	14655	4516	30.8			

NOTE: SUNDESERT NUCLEAR IS AN ALTERNATIVE TO CAPACITY SHOWN IN 1985-1990

FEBRUARY 3, 1977
 FUTURE GENERATION RESOURCE PROGRAM
 1976-1995

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)	
			SUMMER (MW)	WINTER (MW)		(%)				
1- 1-86	WIND 1	4 (18)								
3- 1-86	FUEL CELLS 10-15	156 (13)								
3-31-86	TERMINATE EDWARDS AF- EXCHANGE	-18/-15 (8)								
4- 1-86	GEO THERMAL 1&2	100 (18)								
5-15-86	PAJO VERDE NUCLEAR 3 (1270/196 MW)	190 (14)								
6- 1-86	LUCERNE VALLEY STEAM TURBINE	130 (12)								
9- 1-86	LUCERNE VALLEY STEAM TURBINE	130 (12)								
12- 1-86	LUCERNE VALLEY STEAM TURBINE	130 (12)								
	TOTAL CAPACITY ADDED	822/ 825								
	LOADS AND RESOURCES FOR SUMMER 1986		19979		17001	2978	17.5	.99	16610	4.7
	LOADS AND RESOURCES FOR WINTER 1986			19996	15346	4650	30.3			
1- 1-87	WIND 2	6 (18)								
6- 1-87	COMBUSTION TURBINE (2 UNITS)	114 (19)								
6- 1-87	TERMINATE HOOVER	-331 (20)								
6- 1-87	ADJUST DRY-YEAR HYDRO DEPRATE TO 139MW/171MW TO REMOVE HOOVER	54 (20)								
6- 1-87	COMBINED CYCLE (1 UNIT)	234 (19)								
6- 1-87	HYDRO	140 (21)								
6- 1-87	SAN JOAQUIN NUC 2 (1270/330 MW)	330 (17)								
	TOTAL CAPACITY ADDED	547								
	LOADS AND RESOURCES FOR SUMMER 1987		20786		17782	3004	16.9	.99	17390	4.7
	LOADS AND RESOURCES FOR WINTER 1987			20543	16043	4500	28.0			

FEBRUARY 3, 1974
 FUTURE GENERATION RESOURCE PROGRAM
 1974-1995

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN		AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
			SUMMER (MW)	WINTER (MW)		(MW)	(%)			
1- 1-88	WIND 3	10 (18)								
6- 1-88	COMBINED CYCLE (2 UNITS)	468 (19)								
6- 1-88	COMBUSTION TURBINE (10 UNITS)	500 (19)								
12- 1-88	SAN JOAQUIN NUC 3 (1270/330 MW)	330 (17)								
	TOTAL CAPACITY ADDED	1308								
	LOADS AND RESOURCES FOR SUMMER 1988		21764		18594	3170	17.0	.99	18200	4.7
	LOADS AND RESOURCES FOR WINTER 1988			21851	16734	5117	30.6			
1- 1-89	WIND 4	20 (18)								
6- 1-89	NUCLEAR 1 (1000/780 MW)	780 (22)								
	TOTAL CAPACITY ADDED	800								
	LOADS AND RESOURCES FOR SUMMER 1989		22894		19432	3462	17.8	.99	19050	4.7
	LOADS AND RESOURCES FOR WINTER 1989			22651	17487	5164	29.5			
1- 1-90	WIND 5	30 (18)								
1- 1-90	FAST COAL 1 (1300/520 MW)	504 (23)								
6- 1-90	GEO THERMAL	100 (18)								
6- 1-90	SAN JOAQUIN NUC 4 (1270/330 MW)	330 (17)								
	TOTAL CAPACITY ADDED	964								
	LOADS AND RESOURCES FOR SUMMER 1990		23858		20292	3566	17.6	.97	19900	4.5
	LOADS AND RESOURCES FOR WINTER 1990			23615	18238	5377	29.5			

FEBRUARY 3, 1976
 FUTURE GENERATION RESOURCE PROGRAM
 1976-1995

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL-CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN		AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
			SUMMER (MW)	WINTER (MW)		(MW)	(%)			
1- 1-91	WIND 6	30 (18)								
6- 1-91	GEO-THERMAL	150 (18)								
6- 1-91	COMBUSTION TURBINE (4 UNITS)	200 (19)								
6- 1-91	FAST COAL 2 (1300/520 MW)	504 (23)								
	TOTAL CAPACITY ADDED	884								
	LOADS AND RESOURCES FOR SUMMER 1991		24742		21128	3614	17.1	.99	20770	4.4
	LOADS AND RESOURCES FOR WINTER 1991			24499	19021	5478	28.8			
6- 1-92	COMBUSTION TURBINE (5 UNITS)	256 (19)								
6- 1-92	NUCLEAR 2 (1000/780 MW)	780 (22)								
	TOTAL CAPACITY ADDED	1030								
	LOADS AND RESOURCES FOR SUMMER 1992		25772		22027	3745	17.0	.99	21640	4.2
	LOADS AND RESOURCES FOR WINTER 1992			25529	19823	5706	28.8			
1- 1-93	FAST COAL 3 (1300/520 MW)	504 (23)								
5- 1-93	SOLAR 1	100 (18)								
6- 1-93	COMBUSTION TURBINE (5 UNITS)	250 (19)								
6- 1-93	GEO-THERMAL	150 (18)								
	TOTAL CAPACITY ADDED	1004								
	LOADS AND RESOURCES FOR SUMMER 1993		26776		22904	3872	16.9	.99	22520	4.1
	LOADS AND RESOURCES FOR WINTER 1993			26533	20599	5934	28.8			

FEBRUARY 3, 1976
 FUTURE GENERATION RESOURCE PROGRAM
 1976-1995

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN		AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
			SUMMER (MW)	WINTER (MW)		(MW)	(%)			
1- 1-94	RETIRE LONG BEACH 10 & 11	-212								
4- 1-94	COMBUSTION TURBINE (2 UNITS)	100								
6- 1-94	FAST COAL 4 (1300/520 MW)	504								
6- 1-94	NUCLEAR 3 (1300/780 MW)	780								
	TOTAL CAPACITY ADDED	1172								
	LOADS AND RESOURCES FOR SUMMER 1994		27948		23843	4105	17.2	.99	23430	4.0
	LOADS AND RESOURCES FOR WINTER 1994			27705	21429	6276	29.3			
5- 1-95	SOLAR 2	100								
6- 1-95	GEO THERMAL	150								
6- 1-95	NUCLEAR 4 (1300/780 MW)	780								
	TOTAL CAPACITY ADDED	1030								
	LOADS AND RESOURCES FOR SUMMER 1995		28978		24793	4185	16.9	.99	24380	4.1
	LOADS AND RESOURCES FOR WINTER 1995			28735	22290	6445	28.9			

FEBRUARY 3, 1976
FUTURE GENERATION RESOURCE PROGRAM
1976-1995

DEVELOPMENT OF PERTINENT DATA

1) RECONCILIATION OF THE 12-31-75 AGGREGATE RATED CAPACITY WITH THE
JANUARY 1, 1976 REVISION OF THE "GENERATOR RATINGS AND EFFECTIVE
OPERATING CAPACITY OF RESOURCES".

NET MAIN SYSTEM RESOURCES (DECEMBER 31, 1975)	12522
TOTAL FIRM PURCHASES (DECEMBER 31, 1975)	+1092
YWD CAPACITY	+315
WINTER HYDRO DERATE	-264
TOTAL OFF SYSTEM LOSSES	-74
12-31-75 AGGREGATE RATED CAPACITY	<u>13591</u>

2) SUMMARY OF AREA PEAK DEMANDS (1976-1995)

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
SUMMER										
EDISON NET PEAK DEMAND ***	10750	11210	11690	12190	12720	13280	13870	14490	15160	15860
MWD LOAD	268	231	231	231	231	231	231	231	231	231
STATE WATER PROJECT	7	7	25	29	36	72	36	116	119	164
TOTALS	11025	11448	11946	12450	12987	13583	14137	14837	15510	16255
WINTER										
EDISON NET PEAK DEMAND ***	9080	9530	9990	10440	11000	11550	12140	12750	13420	14120
MWD LOAD	123	159	159	159	159	159	159	159	159	159
STATE WATER PROJECT	7	7	25	29	36	72	36	117	119	165
SALE TO PORTLAND GE	94	94	94	94	94	94	94	94	94	94
SALE TO NORTH-WEST	-	-	-	-	117	117	117	117	117	117
TOTALS	9304	9790	10268	10762	11406	11992	12546	13237	13909	14655
1986										
SUMMER										
EDISON NET PEAK DEMAND ***	16610	17390	18200	19050	19900	20770	21640	22520	23430	24380
MWD LOAD	231	231	231	231	195	159	159	159	159	159
STATE WATER PROJECT	160	161	163	151	197	199	228	225	254	254
TOTALS	17001	17782	18594	19432	20292	21128	22027	22904	23843	24793
WINTER										
EDISON NET PEAK DEMAND ***	14780	15480	16200	16950	17710	18490	19260	20040	20850	21700
MWD LOAD	195	195	159	159	123	123	123	123	123	123
STATE WATER PROJECT	160	157	164	167	194	197	229	225	245	256
SALE TO PORTLAND GE	94	94	94	94	94	94	94	94	94	94
SALE TO NORTH-WEST	117	117	117	117	117	117	117	117	117	117
TOTALS	15346	16043	16734	17487	18238	19021	19823	20599	21429	22290

*** MLYTHE LOAD IS INCLUDED IN THE EDISON NET PEAK DEMAND STARTING IN 1979

FEBRUARY 3, 1976
FUTURE GENERATION RESOURCE PROGRAM
1976 - 1995

NOTES

- (1) Aggregate rated capacity in accord with the January 1, 1976 revision of "Generator Ratings and Effective Operating Capacity of Resources," and MWD's capacity of 315 MW (261 MW at Hoover, 54 MW at Parker), adjusted for Edison, Hoover and Oroville-Thermalito dry year hydro derates.
- (2) A contract has been executed with the U. S. Bureau of Reclamation for layoff of power from the Navajo Project. At such time as USBR needs this power for the Central Arizona Project, USBR has the right to terminate this layoff effective on or after January 1, 1980, upon at least five years advance written notice. Such notice has not been given; however, it is currently anticipated that the layoff will terminate in 1985. Edison has been notified, however, that the layoff will be decreased by 22 MW on June 1, 1980 and 40 MW on June 1, 1981 to provide power for USBR's desalination project.
- (3) Arizona Public Service is planning to derate the capacity of Four Corners Unit 5 by 4.6 MW (2 MW SCE's share) on May 1, 1976 to reflect the power requirements for an emission control test module.
- (4) An assignment has been negotiated with Pacific Gas & Electric Company and Portland General Electric Company providing for sale and exchange of capacity and energy. The effect on Edison's capacity resources is equivalent to a firm capacity purchase in the summer and a firm capacity sale in the winter, beginning in the winter of 1976. The exchange amount has been adjusted for Edison's net loss obligation.
- (5) The capacities shown for the 572 MW Long Beach Combined Cycle Project are for the individual combustion turbine and steam portions which make up the combined cycle units.

- (6) It is planned to increase San Onofre Unit 1 capacity by 8 MW (6 MW SCE's share) to fully utilize the reactor capability following turbine capacity rerating by Westinghouse Corporation. Final capacity adjustment will be determined upon completion of validation tests.
- (7) Prior to reconditioning in 1979, Long Beach Units 10 & 11 have been derated from 106 to 50 MW each. Retirement of the units is planned for January 1, 1994.
- (8) Edwards Air Force Base exchange capacity is available to Edison in the amount of 18.5 MW from March 1 to September 30, and 14.95 MW from October 1 to February 28, annually commencing on April 1, 1976 and terminating on March 31, 1986. However, the capacity is not added to the Edison Main System until the integration of the Blythe Isolated System in 1979.
- (9) Loads and resources of the Blythe Isolated System are integrated into the Edison Main System in 1979.
- (10) An exchange of capacity and energy commencing on May 1, 1980, is being negotiated with the Pacific Northwest. The effect on Edison's resources is equivalent to a capacity purchase in the summer and a capacity sale in the winter. Exchange amounts are specified at anticipated levels and have been adjusted for Edison's net loss obligations.
- (11) For planning and reporting purposes, San Onofre Units 2&3 are considered a firm capacity resource at 20% of their Full Power rating (1100 MW each) for one year prior to their respective Full Power firm operating dates of 10-1-81 and 1-1-83. Edison's share of Units 2&3 is 80% in accordance with agreements with San Diego Gas & Electric Company.
- (12) The capacities shown for the Lucerne Valley Combined Cycle Project in 1981 and 1985 are for 900 MW of combustion turbine capacity. The addition of the 390 MW steam turbine portion in 1986 completes the 1290 MW combined cycle project. The dates for the Lucerne Valley units may be advanced in the event of unforeseen load growth or delays in other resources scheduled for the 1980 to 1985 period.

- (13) In March 1973, Edison joined a group of investor-owned utilities to fund an electric utility fuel cell program in conjunction with United Technologies Corporation. Final commitments to purchase 15 units at 26 MW each (390 MW total capacity) for delivery in 1981-1986 is contingent upon both competitive costs and successful validation of a test unit in 1978.
- (14) Edison is participating in the three unit, 3810 MW Palo Verde Nuclear Project in Arizona with a 15.4% share (587 MW). Firm operating dates are scheduled for 5-15-82, 5-15-84, and 5-15-86. The project is allocated as follows:

	<u>Participation Percentage</u>
Arizona Public Service Company	28.1
Salt River Project	28.1
El Paso Electric Company	15.8
Southern California Edison Company	15.4
Public Service Company of New Mexico	10.2
Arizona Electric Power Co-Op	<u>2.4</u>
Total	100.0

- (15) Edison is a 40% (1240 MW) participant in the 3100 MW Kaiparowits coal development in Southern Utah. The allocation of the project to the participants is:

	<u>Percentage</u>
SCE	40.0
APS	18.0
SDG&E	23.4
Uncommitted	<u>18.6</u>
Total	100.0

Capacity available to Edison has been adjusted for losses incurred outside the Edison Main System.

- (16) On January 1, 1985, the contractual provisions for energy and capacity assigned to Edison from the Oroville-Thermalito facility are terminated. The 340 MW Edison capacity allocation was adjusted to 326 MW for losses and further reduced by 20 MW/39 MW to reflect dry year summer/winter hydro conditions.

- (17) Edison is currently a 22% (1118 MW) participant in a 4-unit, 5080 MW nuclear development in the San Joaquin Valley. Preliminary project allocation is as follows:

	<u>Participation Percentage</u>
LADWP	35.5
PG&E	23.0
SCE	22.0
Dept. of Water Resources	10.0
City of Anaheim	2.0
City of Glendale	2.0
Northern Calif. Power Agency	2.0
City of Riverside	2.0
City of Pasadena	<u>1.5</u>
Total	100.0

Edison Resale Cities' capacity allocation from this project (Anaheim 102 MW, Riverside 102 MW) is included in Edison's future generation resource planning.

- (18) Wind, geothermal and solar resources are contingent upon successful research and development and competitive costs of commercial units.
- (19) Specific sites for combustion turbine and combined cycle units in the 1987 to 1994 time frame are currently under study.
- (20) Edison's present 50-year Hoover contract for energy and capacity (331 MW) with the U. S. Department of the Interior, expires on June 1, 1987. Dry year hydro derate reduces the above capacity by 54 MW.
- (21) It is tentatively planned to increase the capacity of existing hydro facilities.
- (22) Assumed 78% allocation to Edison at an Eastern Desert site.
- (23) Coal and nuclear capacity is presently under study.

FEBRUARY 3, 1976 NUC INITIATIVE CASE 1
 FUTURE GENERATION RESOURCE PROGRAM 11FER76DJF
 1976-1996

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW) (%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
12-31-75	AGGREGATE RATED CAPACITY REDUCED FOR "DRY YEAR HYDRO" CONDITIONS. 213 MW FOR SUMMER AND 264 MW FOR WINTER		13772	13591 (1)					
4-15-76	INCREASE NAVAJO LAYOFF (126 MW)	123 (2)							
5- 1-76	DERATE FOUR CORNERS 5 (800/384 TO 795/382 MW)	-2 (3)							
5-16-76	BEGIN ANNUAL SUMMER PGE EXCHANGE (100 MW PGE TO SCE FROM MAY 16, THRU OCT 15)	94/ 0 (4)							
9- 2-76	LONG BEACH 1 (COMBUSTION TURBINE)	63 (5)							
9-30-76	LONG BEACH 2 (COMBUSTION TURBINE)	63 (5)							
10-27-76	LONG BEACH 3 (COMBUSTION TURBINE)	63 (5)							
11- 1-76	BEGIN ANNUAL WINTER PGE EXCHANGE (94 MW SCE TO PGE FROM NOV 1 THRU MAR 31)	(4)							
11-24-76	LONG BEACH 4 (COMBUSTION TURBINE)	63 (5)							
11-24-76	LONG BEACH RP (STEAM)	82 (5)							
12-22-76	LONG BEACH 5 (COMBUSTION TURBINE)	63 (5)							
	TOTAL CAPACITY ADDED	612/ 518							
	LOADS AND RESOURCES FOR SUMMER 1976		13857		11025	2832 25.7		10750	5.5
	LOADS AND RESOURCES FOR WINTER 1976			14109	9304	4805 51.6			
1- 1-77	DERATE SAN ONOFE 1	6 (6)							
1-19-77	LONG BEACH 6 (COMBUSTION TURBINE)	63 (5)							
2-17-77	LONG BEACH 7 (COMBUSTION TURBINE)	63 (5)							
2-17-77	LONG BEACH 9 (STEAM)	49 (5)							
6- 1-77	DERATE SAN ONOFE 1 (350 TO 210)	-140 (6)							
	TOTAL CAPACITY ADDED	41							
	LOADS AND RESOURCES FOR SUMMER 1977		14295		11448	2847 24.9		11210	4.3
	LOADS AND RESOURCES FOR WINTER 1977			14150	9790	4360 44.5			

FEBRUARY 3, 1976 NUC INITIATIVE CASE 1
 FUTURE GENERATION RESOURCE PROGRAM
 1976-1995

11FEB76DJF

PAGE 2

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
4- 1-78	COOL WATER 3	236								
8- 1-78	COOL WATER 4	236								
	TOTAL CAPACITY ADDED	472								
	LOADS AND RESOURCES FOR SUMMER 1978		14531		11946	2585	21.6	.	11690	4.3
	LOADS AND RESOURCES FOR WINTER 1978			14622	10268	4354	42.4			
1- 1-79	RECONDITION LONG BEACH 10 & 11	112 (7)								
4- 1-79	EDWARDS AFB EXCHANGE	18/ 15 (8)								
4- 1-79	INTEGRATE YUMA-AXIS STEAM GENERATION INTO MAIN SYSTEM (75/25 MW)	25 (9)								
4- 1-79	AXIS COMBUSTION TURBINE	25								
	TOTAL CAPACITY ADDED	180/ 177								
	LOADS AND RESOURCES FOR SUMMER 1979		14947		12450	2497	20.1	.	12190	4.3
	LOADS AND RESOURCES FOR WINTER 1979			14799	10762	4037	37.5			
3- 1-80	HIG CREEK 3 UNIT 5	31								
5- 1-80	REGIN ANNUAL EXCHANGE WITH NORTHWEST (124MW SCE TO NW FROM MAY 1 THRU OCT 31)	117/ 0 (10)								
5- 1-80	LUCERNE VALLEY COMBUSTION TURBINE	60 (12)								
6- 1-80	DECREASE NAVAJO LAYOFF (22 MW)	-22 (2)								
6- 1-80	LUCERNE VALLEY COMBUSTION TURBINE	60 (12)								
10- 1-80	LUCERNE VALLEY COMBUSTION TURBINE	60 (12)								
11- 1-80	ANNUAL WINTER EXCH 117MW TO NORTHWEST	(10)								
11- 1-80	LUCERNE VALLEY COMBUSTION TURBINE	60 (12)								
12- 1-80	LUCERNE VALLEY COMBUSTION TURBINE	60 (12)								
	TOTAL CAPACITY ADDED	426/ 309								
	LOADS AND RESOURCES FOR SUMMER 1980		15193		12987	2206	17.0	.	12720	4.3
	LOADS AND RESOURCES FOR WINTER 1980			15108	11406	3702	32.5			

FEBRUARY 3, 1976 NUC INITIATIVE CASE 1
 FUTURE GENERATION RESOURCE PROGRAM
 1976-1995

11FEB76DJF

PAGE 3

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN		AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
			SUMMER (MW)	WINTER (MW)		(MW)	(%)			
1- 1-81	LUCERNE VALLEY COMBUSTION TURBINE	60 (12)								
2- 1-81	LUCERNE VALLEY COMBUSTION TURBINE	60 (12)								
3- 1-81	LUCERNE VALLEY COMBUSTION TURBINE	120 (12)								
4- 1-81	LUCERNE VALLEY COMBUSTION TURBINE	120 (12)								
5- 1-81	LUCERNE VALLEY COMBUSTION TURBINE	120 (12)								
6- 1-81	DECREASE NAVAJO LAYOFF (40 MW)	-39 (2)								
6- 1-81	LUCERNE VALLEY COMBUSTION TURBINE	120 (12)								
7- 1-81	FUEL CELL 1	26 (13)								
	TOTAL CAPACITY ADDED	587								
	LOADS AND RESOURCES FOR SUMMER 1981		15960		13583	2377	17.5		13280	4.4
	LOADS AND RESOURCES FOR WINTER 1981			15695	11992	3703	30.4			
3- 1-82	LUCERNE VALLEY STEAM TURBINE	130 (12)								
5-15-82	PALO VERDE NUCLEAR 1 (1270/196 MW)	190 (14)								
5-31-82	KAIPAROWITS 1 (775/310 MW)	301 (15)								
6- 1-82	DERATE SAN ONOFRE 1 (210 TO 175)	-35 ()								
6- 1-82	LUCERNE VALLEY STEAM TURBINE	130 (12)								
	TOTAL CAPACITY ADDED	716								
	LOADS AND RESOURCES FOR SUMMER 1982		16676		14137	2539	18.0		13870	4.4
	LOADS AND RESOURCES FOR WINTER 1982			16411	12546	3465	30.8			

FEBRUARY 3, 1976 NUC INITIATIVE CASE 1
 FUTURE GENERATION RESOURCE PROGRAM
 1976-1995

11FEB76DJF

PAGE 4

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN		AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
			SUMMER (MW)	WINTER (MW)		(MW)	(%)			
5- 1-83	FUEL CELLS 2&3	52 (13)								
5-31-83	KAIPAROWITS 2 (775/310 MW)	301 (15)								
6- 1-83	COMBUSTION TURBINE (2 UNITS)	110 ()								
6- 1-83	DERATE SAN ONOFRE 1 (175 TO 140)	-35 ()								
6- 1-83	COMBINED CYCLE (1 UNIT)	234 ()								
6- 1-83	LUCERNE VALLEY STEAM TURBINE	130 (12)								
	TOTAL CAPACITY ADDED	792								
	LOADS AND RESOURCES FOR SUMMER 1983		17468		14837	2631	17.7		14490	4.5
	LOADS AND RESOURCES FOR WINTER 1983			17203	13237	3966	30.0			
1- 1-84	FUEL CELLS 4&5	52 (13)								
3- 1-84	KAIPAROWITS 3 (775/310 MW)	300 (15)								
5-15-84	PALO VERDE NUCLEAR 2 (1270/195 MW)	190 (14)								
6- 1-84	DERATE SAN ONOFRE 1 (140 TO 105)	-35 ()								
6- 1-84	COMBINED CYCLE (1 UNIT)	234 ()								
12- 1-84	KAIPAROWITS 4 (775/310 MW)	301 (15)								
	TOTAL CAPACITY ADDED	1042								
	LOADS AND RESOURCES FOR SUMMER 1984		18209		15510	2699	17.4		15160	4.6
	LOADS AND RESOURCES FOR WINTER 1984			18245	13909	4336	31.2			

FEBRUARY 3, 1976 NUC INITIATIVE CASE 1
 FUTURE GENERATION RESOURCE PROGRAM
 1976-1995

11FEB76DJF

PAGE 5

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
1- 1-85	TERMINATE OROVILLE-THERMALITO (340 MW)	-326 (16)								
1- 1-85	ADJUST DRY-YEAR HYDRO DERATE TO 193MW/225MW TO REMOVE OROVILLE	20/ 39 (16)								
1- 1-85	TERMINATE NAVAJO LAYOFF (265 MW)	-258 (2)								
1- 1-85	FUEL CELLS 6A7	52 (13)								
3- 1-85	FUEL CELLS 8A9	52 (13)								
6- 1-85	DERATE SAN ONOFRE 1 (107 TO 70)	-35 ()								
6- 1-85	COMBINED CYCLE (3 UNITS)	702 ()								
6- 1-85	COMBUSTION TURBINE (6 UNITS)	330 ()								
9- 1-85	KAIPAROWITS PHASE 2 UNIT 5	301 ()								
	TOTAL CAPACITY ADDED	838/ 857								
	LOADS AND RESOURCES FOR SUMMER 1985		19047		16255	2792	17.2		15860	4.6
	LOADS AND RESOURCES FOR WINTER 1985			19102	14655	4447	30.3			
1- 1-86	WIND 1	4 (14)								
3- 1-86	FUEL CELLS 10-15	156 (13)								
3-31-86	TERMINATE EDWARDS AFB EXCHANGE	-18/-15 (8)								
4- 1-86	GEOHEMAL 1&2	100 (18)								
5-15-86	PALO VERDE NUCLEAR 3 (1270/196 MW)	190 (14)								
6- 1-86	DERATE SAN ONOFRE 1 (70 TO 0)	-70 ()								
6- 1-86	KAIPAROWITS PHASE 2 UNIT 6	300 ()								
	TOTAL CAPACITY ADDED	662/ 665								
	LOADS AND RESOURCES FOR SUMMER 1986		20010		17001	3009	17.7		16610	4.7
	LOADS AND RESOURCES FOR WINTER 1986			19767	15346	4421	28.8			

FEBRUARY 3, 1976 NUC INITIATIVE CASE 1
 FUTURE GENERATION RESOURCE PROGRAM
 1976-1995

11FEB76DJF

PAGE 6

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
1- 1-87	WIND 2	6 (18)								
1- 1-87	EAST COAL 1 (1300/520 MW)	504 (23)								
6- 1-87	COMBUSTION TURBINE (1 UNIT)	55 (19)								
6- 1-87	TERMINATE HOOVER	-331 (20)								
6- 1-87	KAIPAROWITS PHASE 2 UNIT 7	300 ()								
6- 1-87	ADJUST DRY-YEAR HYDRO DERATE TO 139MW/171MW TO REMOVE HOOVER	54 (20)								
6- 1-87	COMBINED CYCLE (1 UNIT)	234 (19)								
6- 1-87	HYDRO	140 (21)								
	TOTAL CAPACITY ADDED	962								
	LOADS AND RESOURCES FOR SUMMER 1987		20972		17782	3190	17.9		17390	4.7
	LOADS AND RESOURCES FOR WINTER 1987			20729	16043	4686	29.2			
1- 1-88	WIND 3	10 (18)								
6- 1-88	KAIPAROWITS PHASE 2 UNIT 8	301 ()								
6- 1-88	COMBUSTION TURBINE (3 UNITS)	150 (19)								
6- 1-88	EAST COAL 2 (1300/520 MW)	504 (23)								
	TOTAL CAPACITY ADDED	465								
	LOADS AND RESOURCES FOR SUMMER 1988		21937		18594	3343	18.0		18200	4.7
	LOADS AND RESOURCES FOR WINTER 1988			21694	16734	4960	29.6			
1- 1-89	WIND 4	20 (18)								
6- 1-89	COMBUSTION TURBINE (7 UNITS)	350 ()								
6- 1-89	COMBINED CYCLE (2 UNITS)	468 (19)								
	TOTAL CAPACITY ADDED	838								
	LOADS AND RESOURCES FOR SUMMER 1989		22775		19432	3343	17.2		19050	4.7
	LOADS AND RESOURCES FOR WINTER 1989			22532	17487	5145	28.8			

FEBRUARY 3, 1976 NUC INITIATIVE CASE 1
 FUTURE GENERATION RESOURCE PROGRAM
 1976-1995

11FEB76DJF

PAGE 7

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
1- 1-90	WIND 5	30 (18)								
1- 1-90	FAST COAL 3 (1300/520 MW)	504 (23)								
6- 1-90	GEO THERMAL	100 (18)								
6- 1-90	COMBUSTION TURBINE (7 UNITS)	350 ()								
	TOTAL CAPACITY ADDED	984								
	LOADS AND RESOURCES FOR SUMMER 1990		23759		20242	3467	17.1	.	19900	4.5
	LOADS AND RESOURCES FOR WINTER 1990			23516	18238	5278	28.9	.		
1- 1-91	WIND 6	30 (18)								
1- 1-91	FAST COAL A (1300/520 MW)	504 ()								
6- 1-91	GEO THERMAL	150 (18)								
6- 1-91	FAST COAL 4 (1300/520 MW)	504 (23)								
	TOTAL CAPACITY ADDED	1188								
	LOADS AND RESOURCES FOR SUMMER 1991		24947		21128	3819	18.1	.	20770	4.4
	LOADS AND RESOURCES FOR WINTER 1991			24704	19021	5683	29.9	.		
6- 1-92	COMBUSTION TURBINE (7 UNITS)	350 (19)								
6- 1-92	FAST COAL B (1300/520 MW)	504 ()								
	TOTAL CAPACITY ADDED	854								
	LOADS AND RESOURCES FOR SUMMER 1992		25801		22027	3774	17.1	.	21640	4.2
	LOADS AND RESOURCES FOR WINTER 1992			25558	19823	5735	28.9	.		

FEBRUARY 3, 1976 NUC INITIATIVE CASE 1
 FUTURE GENERATION RESOURCE PROGRAM
 1976-1995

11FEB76DJF

PAGE 8

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN		AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
			SUMMER (MW)	WINTER (MW)		(MW)	(%)			
1- 1-93	EAST COAL 5 (1300/520 MW)	504 ()								
5- 1-93	SOLAR 1	100 (18)								
6- 1-93	COMBUSTION TURBINE (5 UNITS)	250 (19)								
6- 1-93	GEOTHERMAL	150 (18)								
	TOTAL CAPACITY ADDED	1004								
	LOADS AND RESOURCES FOR SUMMER 1993		26805		22904	3901	17.0	.	22520	4.1
	LOADS AND RESOURCES FOR WINTER 1993			26562	20599	5963	28.9			
1- 1-94	EAST COAL C (1300/520 MW)	504 ()								
1- 1-94	RETIPE LONG BEACH 10 & 11	-212 (7)								
6- 1-94	COMBUSTION TURBINE (6 UNITS)	300 (19)								
6- 1-94	EAST COAL 6 (1300/520 MW)	504 ()								
	TOTAL CAPACITY ADDED	1096								
	LOADS AND RESOURCES FOR SUMMER 1994		27901		23843	4058	17.0	.	23430	4.0
	LOADS AND RESOURCES FOR WINTER 1994			27658	21429	6229	29.1			
5- 1-95	SOLAR 2	100 (18)								
6- 1-95	GEOTHERMAL	150 (18)								
6- 1-95	COMBUSTION TURBINE (7 UNITS)	350 (19)								
6- 1-95	EAST COAL D (1300/520 MW)	504 ()								
	TOTAL CAPACITY ADDED	1104								
	LOADS AND RESOURCES FOR SUMMER 1995		29005		24793	4212	17.0	.	24380	4.1
	LOADS AND RESOURCES FOR WINTER 1995			28762	22290	6472	29.0			

FEBRUARY 3, 1976 NUC INITIATIVE CASE 1
FUTURE GENERATION RESOURCE PROGRAM
1976-1995

11FEB76DJF

PAGE 9

DEVELOPMENT OF PERTINENT DATA

- 1) RECONCILIATION OF THE 12-31-75 AGGREGATE RATED CAPACITY WITH THE
JANUARY 1, 1976 REVISION OF THE "GENERATOR RATINGS AND EFFECTIVE
OPERATING CAPACITY OF RESOURCES".

NET MAIN SYSTEM RESOURCES (DECEMBER 31, 1975)	12522
TOTAL FIRM PURCHASES (DECEMBER 31, 1975)	+1092
MWD CAPACITY	+315
WINTER HYDRO DERATE	-264
TOTAL OFF SYSTEM LOSSES	-74
12-31-75 AGGREGATE RATED CAPACITY	<u>13541</u>

FUTURE GENERATION RESOURCE PROGRAM
SEPTEMBER 3, 1975
PRINCIPAL CHANGES FROM THE JULY 2, 1975
FUTURE GENERATION RESOURCE PROGRAM

1. The 1325 MW (24 units) of combustion turbine capacity previously planned for the 1981-1990 period have been reduced to 1302 MW (23 units). The 1981 unit has been increased from 54 to 60 MW.
2. Decrease in layoff power from the Navajo Project has been increased from 56 MW to 65 MW in 1981 to reflect additional capacity withdrawal for the USBR's planned Desalination Project. The 22 MW decrease in layoff shown in 1980 remains unchanged.
3. Fifteen 26 MW fuel cells previously scheduled between 7-1-81 and 4-1-83 have been rescheduled over the period 7-1-81 and 3-1-86.
4. Edison is planning to participate with a 15.4% share (587 MW) in the three unit, 3810 MW Palo Verde Nuclear Project in Arizona. These units are scheduled for operation on 5-15-82, 5-15-84 and 5-15-86.
5. Firm capacity for the San Joaquin Nuclear Project has been delayed from 1985-1988 to the 1987-1991 time frame.
6. The 504 MW of coal capacity previously shown in 1990 has been deleted.

NOTE: This program is based on the 1975-1994 System Forecasts prepared in March 1975.

DJF/sw
9/29/75

SEPTEMBER 3, 1975
 FUTURE GENERATION RESOURCE PROGRAM
 1975-1990.

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	AREA MARGIN (%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
5-31-81	KAIPAROWITS 1 (750/300 MW)	291	(12)							
6- 1-81	DECREASE NAVAJO LAYOFF (65 MW)	-63	(4)							
6- 1-81	COMBUSTION TURBINE (1 UNIT)	60	(13)							
6- 1-81	LUCERNE VALLEY (COMBUSTION TURBINES)	180	(10)							
7- 1-81	FUEL CELL 1	26	(14)							
10- 1-81	PERATE SAN ONOFE 2 (220/176 TO 1100/880 MW)	704	(11)							
	TOTAL CAPACITY ADDED	1198								
	LOADS AND RESOURCES FOR SUMMER 1981		16461		14075	2386	17.0	.99	13780	4.9
	LOADS AND RESOURCES FOR WINTER 1981			17030	12431	4599	37.0			
1- 1-82	SAN ONOFE 3 (220/176 MW)	176	(11)							
5-15-82	PALO VERDE NUCLEAR 1 (1270/196 MW)	190	(15)							
5-31-82	KAIPAROWITS 2 (750/300 MW)	291	(12)							
	TOTAL CAPACITY ADDED	657								
	LOADS AND RESOURCES FOR SUMMER 1982		17822		14751	3071	20.8	.99	14450	4.9
	LOADS AND RESOURCES FOR WINTER 1982			17687	13098	4589	35.0			
1- 1-83	PERATE SAN ONOFE 3 (220/176 TO 1100/880 MW)	704	(11)							
3- 1-83	KAIPAROWITS 3 (750/300 MW)	291	(12)							
5- 1-83	FUEL CELLS 2&3	52	(14)							
12- 1-83	KAIPAROWITS 4 (750/300 MW)	291	(12)							
	TOTAL CAPACITY ADDED	1338								
	LOADS AND RESOURCES FOR SUMMER 1983		18869		15542	3327	21.4	.99	15160	4.9
	LOADS AND RESOURCES FOR WINTER 1983			19025	13899	5126	36.9			

NOTE: MINTINGTON BEACH COMBINED CYCLE IS AN ALTERNATIVE TO CAPACITY SHOWN IN THE 1980-1985 TIME FRAME

- (13) Specific sites for combustion turbines and combined cycle units in the 1981 and 1985-1990 time frame are currently being studied.
- (14) In March 1973, Edison joined a group of investor-owned utilities to fund an electric utility fuel cell program in conjunction with Pratt & Whitney Aircraft. Final commitments to purchase 15 units at 26 MW each (390 MW total capacity) for delivery in 1981-1986 will be made early in 1977. This purchase, however, will be contingent upon a successful validation of a test unit in 1978.
- (15) Edison is planning to participate with a 15.4% share (587 MW) in the three unit, 3810 MW Palo Verde Nuclear Project in Arizona. These units are scheduled for operation on 5-15-82, 5-15-84 and 5-15-86. The project is allocated as follows:

	<u>Participation Percentage</u>
Arizona Public Service Company	28.1
Salt River Project	28.1
El Paso Electric Company	15.8
Southern California Edison Company	15.4
Public Service Company of New Mexico	10.2
Arizona Electric Power Co-OP	<u>2.4</u>
Total	100.0

- (16) On January 1, 1985, the contractual provisions for energy and capacity assigned to Edison from the Oroville-Thermalito facility are terminated. Adjustment for losses reduced Edison's capacity allocation from 332 MW to 319 MW. Consideration of dry year summer/winter hydro conditions further reduced the capacity by 10 MW/29 MW respectively.
- (17) Geothermal generation is presently under research and development. Potential sites presently under investigation include Long Valley and the counties of Mono, Imperial, Inyo and San Bernardino.
- (18) Edison's present 50-year Hoover contract for energy and capacity with the U.S. Department of the Interior expires on June 1, 1987.

September 3, 1975

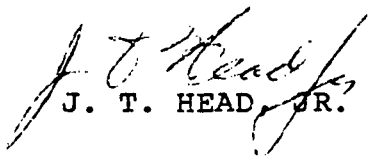
MR. R. N. COE, Chairman
Plant Expenditure Review Committee

Subject: Future Generation Resource
Program 1975-1990

Attached is the schedule of future generation resources covering the years 1975 through 1990, which was approved by PERC on September 3, 1975. Also included is a tabulation of the principal changes from the July 2, 1975, Resource Program.

Edison will be disclosing certain of its generation plans to outside organizations such as the WSCC, the California Power Pool, the California Public Utilities Commission, and various other agencies. In order to preserve uniformity of information releases related to these resources, it is requested that use of the schedule outside the Company be discussed with me before any disclosures are made.

By copy of this letter, the revised generation program is being distributed to the PERC membership and other concerned individuals.


J. T. HEAD, JR.

DJF/sjw
Attachments

FUTURE GENERATION RESOURCE PROGRAM
SEPTEMBER 3, 1975
PRINCIPAL CHANGES FROM THE JULY 2, 1975
FUTURE GENERATION RESOURCE PROGRAM

1. The 1325 MW (24 units) of combustion turbine capacity previously planned for the 1981-1990 period have been reduced to 1302 MW (23 units). The 1981 unit has been increased from 54 to 60 MW.
2. Decrease in layoff power from the Navajo Project has been increased from 56 MW to 65 MW in 1981 to reflect additional capacity withdrawal for the USBR's planned Desalination Project. The 22 MW decrease in layoff shown in 1980 remains unchanged.
3. Fifteen 26 MW fuel cells previously scheduled between 7-1-81 and 4-1-83 have been rescheduled over the period 7-1-81 and 3-1-86.
4. Edison is planning to participate with a 15.4% share (587 MW) in the three unit, 3810 MW Palo Verde Nuclear Project in Arizona. Firm operating dates are scheduled for 5-15-83, 5-15-84 and 5-15-86; non-firm energy may be available as early as 5-15-82.
5. Firm capacity for the San Joaquin Nuclear Project has been delayed from 1985-1988 to the 1987-1991 time frame.
6. The 504 MW of coal capacity previously shown in 1990 has been deleted.

NOTE: This program is based on the 1975-1994 System Forecasts prepared in March 1975.

DJF/sw
8/22/75

SEPTEMBER 3, 1975
FUTURE GENERATION RESOURCE PROGRAM
1975 - 1990

DEFINITION OF COLUMN HEADINGS

Date

Firm operating date of unit or contractual agreement.

Resource

Resource identification. Often includes supplemental information about capacity, particularly when the identification refers to a unit which is undergoing rerate, has associated off-system losses, or is a participation unit.

Net Capacity Added

Effective operating capacity rating of the resource. These have been adjusted for losses incurred outside the Edison main system where applicable.

Total Capacity

Summer total capacity includes resources scheduled as of July 1 of that year, winter includes all capacity added in that year.

Area Peak Demand

Includes Edison net main system peak demand plus firm on-peak sales to other utilities, a constant 295 MW demand for Metropolitan Water District pumping load, and demands for isolated Edison loads commencing when they are expected to be integrated into the main system.

Area Margin

Megawatt margin is the difference between total installed capacity and area peak demand. Percent margin is the megawatt margin divided by area peak demand and multiplied by 100.

Area Reliability Index

The reliability index represents the probability that a particular year's specified resources will be sufficient to serve forecast loads for each hour of the year, allowing for planned generation maintenance and forced outages without requiring delivery of capacity via Edison's interconnections in excess of firm deliveries plus 300 MW from 1975 through 1984, and 600 MW beyond 1984.

Edison Net Peak Demand

Edison net peak demand for 1975-1990 is based on the 1975-1994 System Forecasts prepared in March, 1975 by the System Development Department.

Annual Load Increase

Percent by which Edison net peak demand increases over the previous year net peak demand.

DJF:hdb
8/22/75

SEPTEMBER 3, 1975
 FUTURE GENERATION RESOURCE PROGRAM
 1975-1990

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN		AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
			SUMMER (MW)	WINTER (MW)		(MW)	(%)			
12-31-74	AGGREGATE RATED CAPACITY REDUCED FOR "DRY YEAR HYDRO" CONDITIONS. 110 MW FOR SUMMER AND 148 MW FOR WINTER		13641	13539 (1)						
3-31-75	TERMINATE 159 MW SALE TO PORTLAND GENERAL ELECTRIC	(2)								
4-1-75	TERMINATE PORTLAND GENERAL EXCHANGE (27 MW SCE TO PGE)	(3)								
4-15-75	INCREASE NAVAJO LAYOFF (104 MW)	101 (4)								
5-16-75	REGIN ANNUAL SUMMER PGE EXCHANGE (100 MW PGE TO SCE FROM MAY 16, THRU OCT 15)	94/ 0 (3)								
11-1-75	DERATE FOUR CORNER 4 (800/384 TO 787/378 MW)	-6 (5)								
	TOTAL CAPACITY ADDED	189/ 95								
	LOADS AND RESOURCES FOR SUMMER 1975		13772		10712	3060	28.6		10410	4.1
	LOADS AND RESOURCES FOR WINTER 1975			13634	8972	4662	52.0			

SEPTEMBER 3, 1975
 FUTURE GENERATION RESOURCE PROGRAM
 1975-1990

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
4-15-76	INCREASE NAVAJO LAYOFF (126 MW)	123 (4)								
7- 2-76	LONG BEACH 1 (COMBUSTION TURBINE)	63 (6)								
7-30-76	LONG BEACH 2 (COMBUSTION TURBINE)	63 (6)								
8-27-76	LONG BEACH 3 (COMBUSTION TURBINE)	63 (6)								
9-24-76	LONG BEACH 4 (COMBUSTION TURBINE)	63 (6)								
9-24-76	LONG BEACH 1-4 (STEAM)	82 (6)								
10-22-76	LONG BEACH 5 (COMBUSTION TURBINE)	63 (6)								
11- 1-76	BEGIN ANNUAL WINTER PGE EXCHANGE (106 MW SCF TO PGE FROM NOV 1 THRU MAR 31)	(3)								
11-19-76	LONG BEACH 6 (COMBUSTION TURBINE)	63 (6)								
12-17-76	LONG BEACH 7 (COMBUSTION TURBINE)	63 (6)								
12-17-76	LONG BEACH 5-7 (STEAM)	49 (6)								
	TOTAL CAPACITY ADDED	695								
	LOADS AND RESOURCES FOR SUMMER 1976		13889		11202	2687	24.0	.99	10900	4.7
	LOADS AND RESOURCES FOR WINTER 1976			14329	9608	4721	49.1			
4- 1-77	DERATE FOUR CORNERS 4 (787/378 TO 742/356 MW)	-22 (5)								
6- 1-77	DERATE FOUR CORNERS 5 (800/384 TO 742/356 MW)	-28 (5)								
	TOTAL CAPACITY ADDED	-50								
	LOADS AND RESOURCES FOR SUMMER 1977		14411		11722	2689	22.9	.99	11420	4.8
	LOADS AND RESOURCES FOR WINTER 1977			14279	10108	4171	41.3			

SEPTEMBER 3, 1975
 FUTURE GENERATION RESOURCE PROGRAM
 1975-1990

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
4- 1-78	COOL WATER 3	236								
6- 1-78	COOL WATER 4	236								
	TOTAL CAPACITY ADDED	472								
	LOADS AND RESOURCES FOR SUMMER 1978		14883		12287	2596	21.1	.99	11970	4.8
	LOADS AND RESOURCES FOR WINTER 1978			14751	10663	4088	38.3			
1- 1-79	PERATE LONG BEACH 10 (50 TO 106 MW)	56 (7)								
1- 1-79	PERATE LONG BEACH 11 (50 TO 106 MW)	56 (7)								
4- 1-79	EDWARDS AFB EXCHANGE	18/ 15 (8)								
4- 1-79	INTEGRATE YUMA-AYIS STEAM GENERATION INTO MAIN SYSTEM (75/25 MW)	25 (9)								
4- 1-79	AXIS COMBUSTION TURBINE	25								
	TOTAL CAPACITY ADDED	180/ 177								
	LOADS AND RESOURCES FOR SUMMER 1979		15063		12864	2199	17.1	.99	12540	4.8
	LOADS AND RESOURCES FOR WINTER 1979			14928	11230	3698	32.9			
3- 1-80	HIG CREEK 3 UNIT 5	29								
6- 1-80	LUCERNE VALLEY (COMBUSTION TURBINES)	720 (10)								
6- 1-80	DECREASE NAVAJO LAYOFF (22 MW)	-21 (4)								
10- 1-80	SAN ONOFRE 2 (220/176 MW)	176 (11)								
	TOTAL CAPACITY ADDED	904								
	LOADS AND RESOURCES FOR SUMMER 1980		15791		13471	2320	17.2	.98	13140	4.8
	LOADS AND RESOURCES FOR WINTER 1980			15832	11827	4005	33.9			

SEPTEMBER 3, 1975
 FUTURE GENERATION RESOURCE PROGRAM
 1975-1995

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
5-31-81	KAIPAROWITS 1 (750/300 MW)	291	(12)							
6- 1-81	DECREASE NAVAJO LAYOFF (65 MW)	-63	(4)							
6- 1-81	COMBUSTION TURBINE (1 UNIT)	60	(13)							
6- 1-81	LUCERNE VALLEY (COMBUSTION TURBINES)	180	(10)							
7- 1-81	FUEL CELLS 1	26	(14)							
10- 1-81	PERATE SAN ONOFRE 2 (220/176 TO 1100/880 MW)	704	(11)							
	TOTAL CAPACITY ADDED	1198								
	LOADS AND RESOURCES FOR SUMMER 1981		16461		14075	2386	17.0	.99	13780	4.9
	LOADS AND RESOURCES FOR WINTER 1981			17030	12431	4599	37.0			
1- 1-82	SAN ONOFRE 3 (220/176 MW)	176	(11)							
5-31-82	KAIPAROWITS 2 (750/300 MW)	291	(12)							
	TOTAL CAPACITY ADDED	467								
	LOADS AND RESOURCES FOR SUMMER 1982		17632		14751	2881	19.5	.98	14450	4.9
	LOADS AND RESOURCES FOR WINTER 1982			17497	13098	4399	33.6			
1- 1-83	PERATE SAN ONOFRE 3 (220/176 TO 1100/880 MW)	704	(11)							
3- 1-83	KAIPAROWITS 3 (750/300 MW)	291	(12)							
5- 1-83	FUEL CELLS 2&3	52	(14)							
5-15-83	PAJO VERDE NUCLEAR 1 (1270/196 MW)	190	(15)							
12- 1-83	KAIPAROWITS 4 (750/300 MW)	291	(12)							
	TOTAL CAPACITY ADDED	1528								
	LOADS AND RESOURCES FOR SUMMER 1983		18869		15542	3327	21.4	.99	15160	4.9
	LOADS AND RESOURCES FOR WINTER 1983			19025	13899	5126	36.9			

NOTE: HUNTINGTON BEACH COMBINED CYCLE IS AN ALTERNATIVE
 TO CAPACITY SHOWN IN THE 1980-1985 TIME FRAME

SEPTEMBER 3, 1975
 FUTURE GENERATION RESOURCE PROGRAM
 1975-1990

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
1- 1-84	FUEL CELLS 445	52 (14)								
5-15-84	PALO VERDE NUCLEAR 2 (1270/195 MW)	190 (15)								
	TOTAL CAPACITY ADDED	242								
	LOADS AND RESOURCES FOR SUMMER 1984		19402		16286	3116	19.1	.99	15890	4.8
	LOADS AND RESOURCES FOR WINTER 1984			19267	14643	4624	31.6			
1- 1-85	TERMINATE OROVILLE-THERMALITO (332 MW)	-319 (16)								
1- 1-85	ADJUST DRY-YEAR HYDRO DEBATE TO 100MW/119MW TO REMOVE OROVILLE	10/ 29 (16)								
1- 1-85	TERMINATE NAVAJO LAYOFF (241 MW)	-235 (4)								
1- 1-85	FUEL CELLS 647	52 (14)								
3- 1-85	FUEL CELLS 849	52 (14)								
4- 1-85	GEOTHERMAL 142	100 (17)								
6- 1-85	LUCERNE VALLEY (STEAM TURBINES)	390 (10)								
6- 1-85	COMBUSTION TURBINE (10 UNITS)	570 (13)								
	TOTAL CAPACITY ADDED	620/ 639								
	LOADS AND RESOURCES FOR SUMMER 1985		20022		17081	2941	17.2	.98	16650	4.8
	LOADS AND RESOURCES FOR WINTER 1985			19906	15359	4547	29.6			
3- 1-86	FUEL CELLS 10-15	156 (14)								
3-31-86	TERMINATE EDWARDS AFB EXCHANGE	-18/-15 (8)								
5-15-86	PALO VERDE NUCLEAR 3 (1270/196 MW)	190 (15)								
6- 1-86	COMBINED CYCLE (2 UNITS)	468 (13)								
6- 1-86	COMBUSTION TURBINE (3 UNITS)	159 (13)								
	TOTAL CAPACITY ADDED	955/ 958								
	LOADS AND RESOURCES FOR SUMMER 1986		20977		17880	3097	17.3	.99	17450	4.8
	LOADS AND RESOURCES FOR WINTER 1986			20864	16069	4795	29.8			

SEPTEMBER 3, 1975
 FUTURE GENERATION RESOURCE PROGRAM
 1975-1990

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
6- 1-87	COMBUSTION TURBINE (8 UNITS)	456 (13)								
6- 1-87	TERMINATE HOOVER	-277 (18)								
6- 1-87	COMBINED CYCLE (3 UNITS)	702 (13)								
6- 1-87	SAN JOAQUIN NUC 1 (1270/330 MW)	330 (19)								
8- 1-87	TERMINATE BPA EXCHANGE	-517 (20)								
	TOTAL CAPACITY ADDED	694								
	LOADS AND RESOURCES FOR SUMMER 1987		22188		18694	3494	18.7	.99	18270	4.7
	LOADS AND RESOURCES FOR WINTER 1987			21558	16789	4769	28.4			
6- 1-88	VIDAL HTGR (1540/1386 MW)	1386 (21)								
6- 1-88	COMBUSTION TURBINES (3 UNITS)	171 (13)								
12- 1-88	SAN JOAQUIN NUC 2 (1270/330 MW)	330 (19)								
	TOTAL CAPACITY ADDED	1887								
	LOADS AND RESOURCES FOR SUMMER 1988		23228		19578	3650	18.6	.96	19120	4.7
	LOADS AND RESOURCES FOR WINTER 1988			23445	17585	5860	33.3			
6- 1-89	EASTERN DESERT NUCLEAR (1540/1386 MW)	1386 (21)								
	TOTAL CAPACITY ADDED	1386								
	LOADS AND RESOURCES FOR SUMMER 1989		24944		20456	4488	21.9	.98	20010	4.7
	LOADS AND RESOURCES FOR WINTER 1989			24831	18378	6453	35.1			
3- 1-90	SAN JOAQUIN NUC 3 (1270/330 MW)	330 (19)								
6- 1-90	GEOHEPMAL	100 (17)								
6- 1-90	HYDRO	140 (22)								
	TOTAL CAPACITY ADDED	570								
	LOADS AND RESOURCES FOR SUMMER 1990		25514		21432	4082	19.0	.97	20940	4.6
	LOADS AND RESOURCES FOR WINTER 1990			25401	19235	6166	32.1			

SEPTEMBER 3, 1975
FUTURE GENERATION RESOURCE PROGRAM
1975-1990

DEVELOPMENT OF PERTINENT DATA

- 1) RECONCILIATION OF THE 12-31-74 AGGREGATE RATED CAPACITY WITH THE JANUARY 1, 1975 REVISION OF THE "GENERATOR RATINGS AND EFFECTIVE OPERATING CAPACITY OF RESOURCES".

NET MAIN SYSTEM RESOURCES (DECEMBER 31, 1974)	12468
TOTAL FIRM PURCHASES (DECEMBER 31, 1974)	+980
WIND CAPACITY	+310
WINTER HYDRO DEPRATE	-148
TOTAL OFF SYSTEM LOSSES	-71

12-31-74 AGGREGATE RATED CAPACITY	13539

SEPTEMBER 3, 1975
 FUTURE GENERATION RESOURCE PROGRAM
 1975-1990

2) SUMMARY OF AREA PEAK DEMANDS (1975-1990)

	1975	1976	1977	1978	1979	1980	1981	1982
SUMMER								
EDISON NET PEAK DEMAND ***	10410	10900	11420	11970	12540	13140	13780	14450
MWD LOAD	295	295	295	295	295	295	295	295
STATE WATER PROJECT	7	7	7	22	29	36	-	6
TOTALS	10712	11202	11722	12287	12864	13471	14075	14751
WINTER								
EDISON NET PEAK DEMAND ***	8670	9200	9700	10240	10800	11390	12030	12690
MWD LOAD	295	295	295	295	295	295	295	295
STATE WATER PROJECT	7	7	7	22	29	36	-	7
SALE TO PORTLAND GE	-	106	106	106	106	106	106	106
TOTALS	8972	9508	10108	10663	11230	11827	12431	13098
1983								
SUMMER								
EDISON NET PEAK DEMAND ***	15160	15890	16650	17450	18270	19120	20010	20940
MWD LOAD	295	295	295	295	295	295	295	295
STATE WATER PROJECT	87	101	136	135	129	163	151	197
TOTALS	15542	16286	17081	17880	18694	19578	20456	21432
WINTER								
EDISON NET PEAK DEMAND ***	13410	14140	14820	15530	16260	17020	17180	18640
MWD LOAD	295	295	295	295	295	295	295	295
STATE WATER PROJECT	88	102	138	138	128	164	167	194
SALE TO PORTLAND GE	106	106	106	106	106	106	106	106
TOTALS	13899	14643	15359	16069	16789	17585	18378	19235

*** RLYTHE LOAD IS INCLUDED IN THE EDISON
 NET PEAK DEMAND STARTING IN 1979

SEPTEMBER 3, 1975
FUTURE GENERATION RESOURCE PROGRAM
1975 - 1990

NOTES

- (1) Aggregate rated capacity in accord with the January 1, 1975 revision of "Generator Ratings and Effective Operating Capacity of Resources," adjusted for Edison and Oroville-Thermalito dry year hydro derates and MWD's capacity of 310 MW (260 MW at Hoover, 50 MW at Parker).
- (2) A previously executed service agreement with Portland General Electric providing for the sale of 150 MW of capacity has terminated. Losses increased Edison's obligation to 159 MW.
- (3) An assignment has been negotiated with Pacific Gas & Electric Company and Portland General Electric Company providing for sale and exchange of capacity and energy. The principal effect on Edison's capacity resources is equivalent to a firm capacity purchase in the summer and a firm capacity sale in the winter periods indicated beginning in the winter of 1976. Prior to 1976, special conditions of the agreement prescribe the exchange shown. Exchange amounts are specified at anticipated levels and have been adjusted for Edison's loss obligations.
- (4) A contract has been executed with the U. S. Bureau of Reclamation for layoff of power from the Navajo Project. At such time as USBR needs this power for the Central Arizona Project, USBR has the right to terminate this layoff effective on or after January 1, 1980, upon at least five years advance written notice. Such notice has not been given; however, it is currently anticipated that the layoff will terminate in 1985. Edison has been notified, however, that the layoff will be decreased by 22 MW on June 1, 1980 and 65 MW on June 1, 1981 to provide power for USBR's desalination project.
- (5) To comply with air pollution control standards, installation of additional emission control equipment is required and is expected to result in capacity reductions for Four Corners Units 4 & 5. Edison's share of these reductions amounts to 28 MW for each of the units: 6 MW on November 1, 1975 (for the first scrubber module), plus an additional 22 MW on April 1, 1977, for Unit 4, and 28 MW on June 1, 1977, for Unit 5. For the purpose of planning replacement capacity, the appropriate reductions are shown on the above dates.

- (6) The capacities shown for the Long Beach Combined Cycle Project are for the individual combustion turbines and steam turbines. Total project size is 572 MW.
- (7) Prior to reconditioning in 1979, Long Beach Units 10 & 11 have been derated from 106 to 50 MW each.
- (8) Edwards Air Force Base exchange capacity is available to Edison in the amount of 18.5 MW from March 1 to September 30, and 14.95 MW from October 1 to February 28, annually commencing on April 1, 1976 and terminating on March 31, 1986. However, the capacity is not added to the system until the integration of the Blythe District in 1979.
- (9) Blythe District becomes part of the integrated system in 1979.
- (10) The capacities shown for the Lucerne Valley Combined Cycle Project in 1980-1981 are for 900 MW of combustion turbine capacity. The addition of the 390 MW steam portion in 1985 completes the 1290 MW combined cycle project.
- (11) For planning and reporting purposes, San Onofre Units 2 & 3 are considered a firm capacity resource at 20% of their Full Power rating (1100 MW each) for one year prior to their respective Full Power firm operating dates of 10-1-81 and 1-1-83. Edison's share of Units 2 & 3 is shown as 80% in accordance with agreements with San Diego Gas & Electric Company.
- (12) Edison is participating in the 4-unit, Kaiparowits 3000 MW coal development in Southern Utah. This project capacity has been allocated as follows:

	<u>Percentage</u>
SCE	40.0
APS	18.0
SDG&E	23.4
Uncommitted	<u>18.6</u>
Total	100.0

Capacity available to Edison has been adjusted for losses incurred outside the Edison main system.

- (13) Specific sites for combustion turbines and combined cycle units in the 1981 and 1985-1990 time frame are currently being studied.
- (14) In March 1973, Edison joined a group of investor-owned utilities to fund an electric utility fuel cell program in conjunction with Pratt & Whitney Aircraft. Final commitments to purchase 15 units at 26 MW each (390 MW total capacity) for delivery in 1981-1986 will be made early in 1977. This purchase, however, will be contingent upon a successful validation of a test unit in 1978.
- (15) Edison is planning to participate with a 15.4% share (587 MW) in the three unit, 3810 MW Palo Verde Nuclear Project in Arizona. Firm operating dates are scheduled for 5-15-83, 5-15-84 and 5-15-86; non-firm energy may be available as early as 5-15-82. The project is allocated as follows:

	<u>Participation Percentage</u>
Arizona Public Service Company	28.1
Salt River Project	28.1
El Paso Electric Company	15.8
Southern California Edison Company	15.4
Public Service Company of New Mexico	10.2
Arizona Electric Power Co-OP	<u>2.4</u>
Total	100.0

- (16) On January 1, 1985, the contractual provisions for energy and capacity assigned to Edison from the Oroville-Thermalito facility are terminated. Adjustment for losses reduced Edison's capacity allocation from 332 MW to 319 MW. Consideration of dry year summer/winter hydro conditions further reduced the capacity by 10 MW/29 MW respectively.
- (17) Geothermal generation is presently under research and development. Potential sites presently under investigation include Long Valley and the counties of Mono, Imperial, Inyo and San Bernardino.
- (18) Edison's present 50-year Hoover contract for energy and capacity with the U.S. Department of the Interior expires on June 1, 1987.

- (19) Edison is considering participating in a 4-unit, 5080 MW nuclear development in the San Joaquin Valley. Firm operating dates for this development are based on Edison estimates of nuclear project lead time requirements. Non-firm energy production may commence as early as December 1984. Preliminary project allocation is as follows:

	<u>Participation Percentage</u>
LADWP	35.5
PG&E	23.0
SCE	22.0
Dept. of Water Resources	10.0
City of Anaheim	2.0
City of Glendale	2.0
Northern Calif. Power Agency	2.0
City of Riverside	2.0
City of Pasadena	<u>1.5</u>
Total	100.0

In compliance with the 1972 Settlement Agreement, the Resale Cities' capacity allocation from this Project (Anaheim 2%, Riverside 2%) is included in Edison's Future Generation Resource Planning.

- (20) The contract with the Bonneville Power Administration for 550 MW (517 MW net capacity delivered to SCE) of exchange capacity expires on August 1, 1987.
- (21) Assumed 90 percent allocation to Edison in Vidal HTGR and Eastern Desert Nuclear Project.
- (22) It is planned to increase existing hydro facilities.

DJF/sw
8/22/75

FUTURE GENERATION RESOURCE PROGRAM
JULY 2, 1975
PRINCIPAL CHANGES FROM THE DECEMBER 17, 1974
FUTURE GENERATION RESOURCE PROGRAM

1. To reflect adverse hydro conditions, the Oroville-Thermalito capacity of 319 MW supplied by the California Department of Water Resources to Edison has been reduced to 309 MW and 290 MW for summer and winter respectively.
2. The derate of Four Corners unit 4 previously scheduled for May 1, 1975 has been delayed to November 1, 1975. Edison's share of the derate is estimated to be 6 MW.
3. Integration of the Blythe resources has been rescheduled from 6-1-76 to 4-1-79. Edwards Air Force Base Exchange capacity (18 MW summer, 15 MW winter) from the USBR will be available to Edison from 4-1-76 to 3-31-86. This capacity is included in main system resources in 1979 when integration of the Blythe District takes place.
4. Cool Water combined cycle unit 3 has been delayed from 6-1-77 to 4-1-78.
5. As the result of a moratorium by the Nevada State Legislature on the required installation of pollution control devices on the Mohave units, the previously required capacity reductions on 6-30-77 of 25 MW have not been scheduled until more definite information is available.
6. A 25 MW combustion turbine unit previously planned for 4-1-78 at Yuma Axis Generating Station has been deferred to 4-1-79.
7. Layoff power from the Navajo Project has been decreased 22 MW in 1980 and an additional 56 MW in 1981 to reflect anticipated withdrawal of capacity by USBR for service to a planned desalination project.
8. The Lucerne Valley Combined Cycle Project schedule has been changed from 453 MW in each of 1980, 1984 and 1985 to reflect installation of 720 MW and 180 MW of combustion turbine capacity in 1980 and 1981 respectively and installation of the 390 MW steam portion in 1985. As the major equipment vendor has not been selected, total plant capacity can vary between 1290 and 1430 MW.

9. Initial firm power operation (20% of full firm power rating) of San Onofre units 2 and 3 has been delayed three months to 10-1-80 and 1-1-82 respectively. Full firm power operation of each unit follows one year later. In addition, the full firm power ratings of the units have been reduced from 1140 to 1100 MW each.
10. Fifteen 26 MW fuel cells, previously scheduled between 7-1-80 and 4-1-82, have been delayed by one year.
11. Edison's share of the San Joaquin Nuclear Project has been increased from 20.5% to 22%. In addition, the shares for the cities of Anaheim and Riverside (2% each) have been included in the capacity available to the Edison area.
12. 1649 MW of combined cycle (7 units, excluding Lucerne Valley) and 1881 MW of combustion turbine installations (34 units) previously planned in the 1979-1987 time frame, have been reduced to 1170 MW (5 units) and 1225 MW (22 units) respectively, and are now shown in the 1981-1989 period.
13. The year 1990 was added to the Resource Plan with the following capacity additions:
 - a. 504 MW coal unit (40% assumed SCE participation in a 1300 MW unit)
 - b. 100 MW of geothermal generation
 - c. Development of 140 MW of hydro capacity
 - d. 100 MW of combustion turbine capacity

Note: This program is based on the 1975-1994 system forecasts prepared in March 1975.

DJF/sw
6/23/75

JULY 2, 1975
FUTURE GENERATION RESOURCE PROGRAM
1975 - 1990

DEFINITION OF COLUMN HEADINGS

Date

Firm operating date of unit or contractual agreement.

Resource

Resource identification. Often includes supplemental information about capacity, particularly when the identification refers to a unit which is undergoing rerate, has associated off-system losses, or is a participation unit.

Net Capacity Added

Effective operating capacity rating of the resource. These have been adjusted for losses incurred outside the Edison main system where applicable.

Total Capacity

Summer total capacity includes resources scheduled as of July 1 of that year, winter includes all capacity added in that year.

Area Peak Demand

Includes Edison net main system peak demand plus firm on-peak sales to other utilities, a constant 295 MW demand for Metropolitan Water District pumping load, and demands for isolated Edison loads commencing when they are expected to be integrated into the main system.

Area Margin

Megawatt margin is the difference between total installed capacity and area peak demand. Percent margin is the megawatt margin divided by area peak demand and multiplied by 100.

Area Reliability Index

The reliability index represents the probability that a particular year's specified resources will be sufficient to serve forecast loads for each hour of the year, allowing for planned generation maintenance and forced outages without requiring delivery of capacity via Edison's interconnections in excess of firm deliveries plus 300 MW from 1975 through 1984, and 600 MW beyond 1984.

Edison Net Peak Demand

Edison net peak demand for 1975-1990 is based on the 1975-1994 System Forecasts prepared in March, 1975 by the System Development Department.

Annual Load Increase

Percent by which Edison net peak demand increases over the previous year net peak demand.

DJF:hdb
5/28/75

JULY 2, 1975
 FUTURE GENERATION RESOURCE PROGRAM
 1975-1990

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
12-31-74	AGGREGATE RATED CAPACITY REDUCED FOR "DRY YEAR HYDRO" CONDITIONS. 110 MW FOR SUMMER AND 148 MW FOR WINTER		13641	13539	(1)					
3-31-75	TERMINATE 159 MW SALE TO PORTLAND GENERAL ELECTRIC		(2)							
4-1-75	TERMINATE PORTLAND GENERAL EXCHANGE (27 MW SCE TO PGE)		(3)							
4-15-75	INCREASE NAVAJO LAYOFF (104 MW)	101	(4)							
5-16-75	BEGIN ANNUAL SUMMER PGE EXCHANGE (100 MW PGE TO SCE FROM MAY 16, THRU OCT 15)	94	0	(3)						
11-1-75	DERATE FOUR CORNERS 4 (800/384 TO 787/378 MW)		-6	(5)						
	TOTAL CAPACITY ADDED	1897	95							
	LOADS AND RESOURCES FOR SUMMER 1975		13772		10712	3060	28.6	.99	10410	4.1
	LOADS AND RESOURCES FOR WINTER 1975		13634		8972	4662	52.0			

JULY 2, 1975
 FUTURE GENERATION RESOURCE PROGRAM
 1975-1990

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
4-15-76	INCREASE NAVAJO LAYOFF (126 MW)	123 (4)								
7- 2-76	LONG BEACH 1 (COMBUSTION TURBINE)	63 (6)								
7-30-76	LONG BEACH 2 (COMBUSTION TURBINE)	63 (6)								
8-27-76	LONG BEACH 3 (COMBUSTION TURBINE)	63 (6)								
9-24-76	LONG BEACH 4 (COMBUSTION TURBINE)	63 (6)								
9-24-76	LONG BEACH 1-4 (STEAM)	82 (6)								
10-22-76	LONG BEACH 5 (COMBUSTION TURBINE)	63 (6)								
11- 1-76	BEGIN ANNUAL WINTER PGE EXCHANGE (10% INCREASE TO PGE FROM NOV 1 THRU MAR 31)	(3)								
11-19-76	LONG BEACH 6 (COMBUSTION TURBINE)	63 (6)								
12-17-76	LONG BEACH 7 (COMBUSTION TURBINE)	63 (6)								
12-17-76	LONG BEACH 5-7 (STEAM)	49 (6)								
	TOTAL CAPACITY ADDED	695								
	LOADS AND RESOURCES FOR SUMMER 1976		13889		11202	2687	24.0	.99	10900	4.7
	LOADS AND RESOURCES FOR WINTER 1976			14329	9608	4721	49.1			
4- 1-77	DEBATE FOUR CORNERS 4 (787/378 TO 742/356 MW)	-22 (5)								
6- 1-77	DEBATE FOUR CORNERS 5 (800/384 TO 742/356 MW)	-28 (5)								
	TOTAL CAPACITY ADDED	-50								
	LOADS AND RESOURCES FOR SUMMER 1977		14411		11722	2689	22.9	.99	11420	4.8
	LOADS AND RESOURCES FOR WINTER 1977			14279	10108	4171	41.3			

JULY 2, 1975

FUTURE GENERATION RESOURCE PROGRAM
1975-1990

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
4- 1-78	COOL WATER 3	236								
6- 1-78	COOL WATER 4	236								
	TOTAL CAPACITY ADDED	472								
	LOADS AND RESOURCES FOR SUMMER 1978		14883		12287	2596	21.1	.99	11970	4.8
	LOADS AND RESOURCES FOR WINTER 1978			14751	10663	4088	38.3			
1- 1-79	PERATE LONG BEACH 10 (50 TO 106 MW)	56 (7)								
1- 1-79	PERATE LONG BEACH 11 (50 TO 106 MW)	56 (7)								
4- 1-79	EDWARDS AFB EXCHANGE	18/ 15 (8)								
4- 1-79	INTEGRATE YUMA-AXIS STEAM GENERATION INTO MAIN SYSTEM (75/25 MW)	25 (9)								
4- 1-79	AXIS COMBUSTION TURBINE	25								
	TOTAL CAPACITY ADDED	180/ 177								
	LOADS AND RESOURCES FOR SUMMER 1979		15063		12864	2199	17.1	.99	12540	4.8
	LOADS AND RESOURCES FOR WINTER 1979			14928	11230	3698	32.9			
3- 1-80	RIG CREEK 3 UNIT 5	29 (10)								
6- 1-80	DECREASE NAVAJO LAYOFF (22 MW)	-21 (4)								
(A) 6- 1-80	LUCERNE VALLEY CT	720 (11)								
10- 1-80	SAN ONOFRE 2 (220/176 MW)	176 (12)								
	TOTAL CAPACITY ADDED	904								
	LOADS AND RESOURCES FOR SUMMER 1980		15791		13471	2320	17.2	.98	13140	4.8
	LOADS AND RESOURCES FOR WINTER 1980			15832	11827	4005	33.9			

(A) AN ALTERNATE IS INSTALLATION AT THE HUNTINGTON BEACH SITE

JULY 2, 1975
 FUTURE GENERATION RESOURCE PROGRAM
 1975-1990

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
5-31-81	KAIPAROWITS 1 (750/300 MW)	291 (13)								
6- 1-81	COMBUSTION TURBINE (1 UNIT)	54 (17)								
(A) 6- 1-81	LUCERNE VALLEY CT	180 (11)								
6- 1-81	DECREASE NAVAJO LAYOFF (56 MW)	-55 (4)								
7- 1-81	FUEL CELL 1	26 (14)								
10- 1-81	RERATE SAN ONOFRE 2 (220/176 TO 1100/880 MW)	704 (12)								
10- 1-81	FUEL CELL 2	26 (14)								
12- 1-81	FUEL CELL 3	26 (14)								
	TOTAL CAPACITY ADDED	1252								
	LOADS AND RESOURCES FOR SUMMER 1981		16463		14075	2388	17.0	.98	13780	4.9
	LOADS AND RESOURCES FOR WINTER 1981			17084	12431	4653	37.4			
1- 1-82	SAN ONOFRE 3 (220/176 MW)	176 (12)								
1- 1-82	FUEL CELL 4	26 (14)								
3- 1-82	FUEL CELL 5	26 (14)								
5- 1-82	FUEL CELL 6	26 (14)								
5-31-82	KAIPAROWITS 2 (750/300 MW)	291 (13)								
6- 1-82	FUEL CELL 7	26 (14)								
8- 1-82	FUEL CELLS 8&9	52 (14)								
11- 1-82	FUEL CELLS 10&11	52 (14)								
	TOTAL CAPACITY ADDED	675								
	LOADS AND RESOURCES FOR SUMMER 1982		17790		14751	3039	20.6	.99	14450	4.9
	LOADS AND RESOURCES FOR WINTER 1982			17759	13098	4661	35.6			

(A) AN ALTERNATE IS INSTALLATION AT THE HUNTINGTON BEACH SITE

JULY 2, 1975
 FUTURE GENERATION RESOURCE PROGRAM
 1975-1990

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
1- 1-83	DEGRATE SAN ONOFRF 3 (220/176 TO 1100/880 MW)	704	(12)							
1- 1-83	FUEL CELL 12&13	52	(14)							
3- 1-83	KAIPAROWITS 3 (750/300 MW)	291	(13)							
4- 1-83	FUEL CELLS 14&15	52	(14)							
12- 1-83	KAIPAROWITS 4 (750/300 MW)	291	(13)							
	TOTAL CAPACITY ADDED	1390								
	LOADS AND RESOURCES FOR SUMMER 1983		18993		15542	3451	22.2	.99	15160	4.9
	LOADS AND RESOURCES FOR WINTER 1983			19149	13899	5250	37.8			
1984	NO RESOURCE ADDITIONS									
	LOADS AND RESOURCES FOR SUMMER 1984		19284		16286	2998	18.4	.99	15890	4.8
	LOADS AND RESOURCES FOR WINTER 1984			19149	14643	4506	30.8			
1- 1-85	TERMINATE OROVILLE-THERMALITO (332 MW)	-319	(15)							
1- 1-85	ADJUST DRY-YEAR HYDRO DEGRATE TO 100MW/110MW TO REMOVE OROVILLE	107	29 (15)							
1- 1-85	TERMINATE NAVAJO LAYOFF (250 MW)	-243	(4)							
4- 1-85	GEO THERMAL 1&2	100	(16)							
(A) 6- 1-85	LUCERNE VALLEY STEAM TURBINES	390	(11)							
6- 1-85	COMBUSTION TURBINE (8 UNITS)	456	(17)							
6- 1-85	SAN JOAQUIN NUC 1 (1270/330 MW)	330	(18)							
	TOTAL CAPACITY ADDED	724	743							
	LOADS AND RESOURCES FOR SUMMER 1985		20008		17081	2927	17.1	.98	16650	4.8
	LOADS AND RESOURCES FOR WINTER 1985			19892	15359	4533	29.5			

(A) AN ALTERNATE IS INSTALLATION AT THE HUNTINGTON BEACH SITE

JULY 2, 1975
 FUTURE GENERATION RESOURCE PROGRAM
 1975-1990

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
3-31-86	TERMINATE EDWARDS AFB EXCHANGE	-187-15 (8)								
6- 1-86	COMBINED CYCLE (2 UNITS)	468 (17)								
6- 1-86	COMBUSTION TURBINE (3 UNITS)	159 (17)								
6- 1-86	SAN JOAQUIN NUC 2 (1270/330 MW)	330 (18)								
	TOTAL CAPACITY ADDED	939/ 942								
	LOADS AND RESOURCES FOR SUMMER 1986		20947		17880	3067	17.2	.98	17450	4.8
	LOADS AND RESOURCES FOR WINTER 1986			20834	16069	4765	29.7			
6- 1-87	TERMINATE HOOVER	-277 (19)								
6- 1-87	COMBUSTION TURBINE (8 UNITS)	456 (17)								
6- 1-87	COMBINED CYCLE (3 UNITS)	702 (17)								
6- 1-87	SAN JOAQUIN NUC 3 (1270/330 MW)	330 (18)								
8- 1-87	TERMINATE BPA EXCHANGE	-517 (20)								
	TOTAL CAPACITY ADDED	694								
	LOADS AND RESOURCES FOR SUMMER 1987		22158		18694	3464	18.5	.99	18270	4.7
	LOADS AND RESOURCES FOR WINTER 1987			21528	16789	4739	28.2			
6- 1-88	VIDAL NUCLEAR (1540/1386 MW)	1386 (21)								
6- 1-88	SAN JOAQUIN NUC 4 (1270/330 MW)	330 (18)								
	TOTAL CAPACITY ADDED	1716								
	LOADS AND RESOURCES FOR SUMMER 1988		23357		19578	3779	19.3	.98	19120	4.7
	LOADS AND RESOURCES FOR WINTER 1988			23244	17585	5659	32.2			
6- 1-89	EASTERN DESERT NUCLEAR (1540/1386 MW)	1386 (22)								
6- 1-89	COMBUSTION TURBINES (2 UNITS)	100 (17)								
	TOTAL CAPACITY ADDED	1486								
	LOADS AND RESOURCES FOR SUMMER 1989		24843		20456	4387	21.4	.97	20010	4.7
	LOADS AND RESOURCES FOR WINTER 1989			24730	18378	6352	34.6			

JULY 2, 1975
 FUTURE GENERATION RESOURCE PROGRAM
 1975-1990

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
6- 1-90	EAST COAL 1 (1300/520 MW)	504 (23)								
6- 1-90	GEOTHERMAL	100 (16)								
6- 1-90	COMBUSTION TURBINES (2 UNITS)	100 (17)								
6- 1-90	HYDRO	140 (24)								
	TOTAL CAPACITY ADDED	844								
	LOADS AND RESOURCES FOR SUMMER 1990		25687		21432	4255	19.9	.96	20940	4.6
	LOADS AND RESOURCES FOR WINTER 1990			25574	19235	6339	33.0			

JULY 2, 1975
FUTURE GENERATION RESOURCE PROGRAM
1975-1990

DEVELOPMENT OF PERTINENT DATA

- 1) RECONCILIATION OF THE 12-31-74 AGGREGATE RATED CAPACITY WITH THE
JANUARY 1, 1975 REVISION OF THE "GENERATOR RATINGS AND EFFECTIVE
OPERATING CAPACITY OF RESOURCES".

NET MAIN SYSTEM RESOURCES (DECEMBER 31, 1974)	12468
TOTAL FIRM PURCHASES (DECEMBER 31, 1974)	+980
AND CAPACITY	+310
WINTER HYDRO DEBATE	-148
TOTAL OFE SYSTEM LOSSES	-71

12-31-74 AGGREGATE RATED CAPACITY	13539

JULY 2, 1975
 FUTURE GENERATION RESOURCE PROGRAM
 1975-1990

2) SUMMARY OF AREA PEAK DEMANDS (1975-1990)

	1975	1976	1977	1978	1979	1980	1981	1982
SUMMER								
EDISON NET PEAK DEMAND ***	10410	10900	11420	11970	12540	13140	13780	14450
MWD LOAD	295	295	295	295	295	295	295	295
STATE WATER PROJECT	7	7	7	22	29	36	-	6
TOTALS	10712	11202	11722	12287	12864	13471	14075	14751
WINTER								
EDISON NET PEAK DEMAND ***	8670	9200	9700	10240	10800	11390	12030	12690
MWD LOAD	295	295	295	295	295	295	295	295
STATE WATER PROJECT	7	7	7	22	29	36	-	7
SALE TO PORTLAND GE	-	106	106	106	106	106	106	106
TOTALS	8972	9608	10108	10663	11230	11827	12431	13098
1983								
SUMMER								
EDISON NET PEAK DEMAND ***	15160	15890	16650	17450	18270	19120	20010	20940
MWD LOAD	295	295	295	295	295	295	295	295
STATE WATER PROJECT	87	101	136	135	129	163	151	197
TOTALS	15542	16286	17081	17880	18694	19578	20456	21432
WINTER								
EDISON NET PEAK DEMAND ***	13410	14140	14820	15530	16260	17020	17180	18640
MWD LOAD	295	295	295	295	295	295	295	295
STATE WATER PROJECT	88	102	138	138	128	164	167	194
SALE TO PORTLAND GE	106	106	106	106	106	106	106	106
TOTALS	13899	14643	15359	16069	16789	17585	18378	19235

*** PLYTHE LOAD IS INCLUDED IN THE EDISON NET PEAK DEMAND STARTING IN 1979

JULY 2, 1975
FUTURE GENERATION RESOURCE PROGRAM
1975 - 1990

NOTES

- (1) Aggregate rated capacity in accord with the January 1, 1975 revision of "Generator Ratings and Effective Operating Capacity of Resources," adjusted for Edison and Oroville-Thermalito dry year hydro derates and MWD's capacity of 310 MW (260 MW at Hoover, 50 MW at Parker).
- (2) A previously executed service agreement with Portland General Electric providing for the sale of 150 MW of capacity has terminated. Losses increased Edison's obligation to 159 MW.
- (3) An assignment has been negotiated with Pacific Gas & Electric Company and Portland General Electric Company providing for sale and exchange of capacity and energy. The principal effect on Edison's capacity resources is equivalent to a firm capacity purchase in the summer and a firm capacity sale in the winter periods indicated beginning in the winter of 1976. Prior to 1976, special conditions of the agreement prescribe the exchange shown. Exchange amounts are specified at anticipated levels and have been adjusted for Edison's loss obligations.
- (4) A contract has been executed with the U. S. Bureau of Reclamation for layoff of power from the Navajo Project. At such time as USBR needs this power for the Central Arizona Project, USBR has the right to terminate this layoff effective on or after January 1, 1980, upon at least five years advance written notice. Such notice has not been given; however, it is currently anticipated that the layoff will terminate in 1985. Edison has been notified, however, that the layoff will be decreased by 22 MW on June 1, 1980 and 56 MW on June 1, 1981 to provide power for USBR's desalination project.
- (5) To comply with air pollution control standards, installation of additional emission control equipment is required and is expected to result in capacity reductions for Four Corners Units 4 & 5. Edison's share of these reductions amounts to 28 MW for each of the units: 6 MW on November 1, 1975 (for the first scrubber module), plus an additional 22 MW on April 1, 1977, for Unit 4, and 28 MW on June 1, 1977, for Unit 5. For the purpose of planning replacement capacity, the appropriate reductions are shown on the above dates.

- (6) The capacities shown for the Long Beach Combined Cycle Project are for the individual combustion turbines and steam turbines. Total project size is 572 MW.
- (7) Prior to reconditioning in 1979, Long Beach Units 10 & 11 have been derated from 106 to 50 MW each.
- (8) Edwards Air Force Base exchange capacity is available to Edison in the amount of 18.5 MW from March 1 to September 30, and 14.95 MW from October 1 to February 28, annually commencing on April 1, 1976 and terminating on March 31, 1986. However, the capacity is not added to the system until the integration of the Blythe District in 1979.
- (9) Blythe District becomes part of the integrated system in 1979.
- (10) Big Creek 3 Unit 5 capacity is presently estimated to be 29 MW. Depending upon final evaluation, the size could be as much as 35 MW.
- (11) The capacities shown for the Lucerne Valley Combined Cycle Project are for the combustion turbine and steam portions of the 1290 MW project. As major equipment vendor has not been selected, total plant megawatts can vary between 1290 and 1430 MW.
- (12) For planning and reporting purposes, San Onofre Units 2 & 3 are considered a firm capacity resource at 20% of their Full Power rating (1100 MW each) for one year prior to their respective Full Power firm operating dates of 10-1-81 and 1-1-83. Edison's share of Units 2 & 3 is shown as 80% in accordance with agreements with San Diego Gas & Electric Company.
- (13) Edison is participating in a 4-unit, 3000 MW coal development in Southern Utah. This project capacity has been allocated as follows:

	<u>Percentage</u>
SCE	40.0
APS	18.0
SDG&E	23.4
Uncommitted	<u>18.6</u>
Total	100.0

Capacity available to Edison has been adjusted for losses incurred outside the Edison main system.

- (14) In March 1973, Edison joined a group of investor-owned utilities to fund an electric utility fuel cell program in conjunction with Pratt & Whitney Aircraft. Final commitments to purchase 15 units at 26 MW each (390 MW total capacity) for delivery in 1981-1983 will be made early in 1977. This purchase, however, will be contingent upon a successful validation of a test unit in 1977 or 1978.
- (15) On January 1, 1985, the contractual provisions for energy and capacity assigned to Edison from the Oroville-Thermalito facility are terminated. Adjustment for losses reduced Edison's capacity allocation from 332 MW to 319 MW. Consideration of dry year summer/winter hydro conditions further reduced the capacity by 10 MW/29 MW respectively.
- (16) Geothermal generation is presently under research and development. Potential sites presently under investigation include Long Valley and the counties of Mono, Imperial, Inyo and San Bernardino. Initial operation of the first units could be as early as 1980.
- (17) Specific sites for combustion turbines and combined cycle units in the 1981 and 1985-1990 time frame are currently being studied.
- (18) Edison is considering participating in a 4-unit, 5080 MW nuclear development in the San Joaquin Valley. Firm operating dates for this development are based on Edison estimates of nuclear project lead time requirements. Non-firm energy production may commence as early as November 1983. Preliminary project allocation is as follows:

	<u>Participation Percentage</u>
LADWP	35.5
PG&E	23.0
SCE	22.0
Dept. of Water Resources	10.0
City of Anaheim	2.0
City of Glendale	2.0
Northern Calif. Power Agency	2.0
City of Riverside	2.0
City of Pasadena	<u>1.5</u>
Total	100.0

In compliance with the 1972 Settlement Agreement, the Resale Cities' capacity allocation from this Project

(Anaheim 2%, Riverside 2%) is included in Edison's Future Generation Resource Planning.

- (19) Edison's present 50-year Hoover contract for energy and capacity with the U.S. Department of the Interior expires on June 1, 1987.
- (20) The contract with the Bonneville Power Administration for 550 MW (517 MW net capacity delivered to SCE) of exchange capacity expires on August 1, 1987.
- (21) The Vidal HTGR Nuclear Project is a possible alternative to the combined cycle and combustion turbine units shown in 1986 and 1987.
- (22) Assumed 90 percent allocation to Edison in Eastern Desert Nuclear Project.
- (23) Assumed Edison participation (40%) in an Eastern coal development.
- (24) It is planned to increase existing hydro facilities.

DJF/sw
6/23/75

FUTURE GENERATION RESOURCE PROGRAM
DECEMBER 17, 1974
PRINCIPAL CHANGES FROM THE FEBRUARY 8, 1974
FUTURE GENERATION RESOURCE PROGRAM

1. Until reconditioning can be completed prior to 1979, Long Beach Units 10 & 11 will be derated from 106 to 50 MW each, effective November 1, 1974. Retirement of the units has been deferred beyond 1989.
2. The firm operating dates for each of the Long Beach Combined Cycle Units have been deferred by approximately 4 months, resulting in the first unit being installed by 7-2-76 and the total project being completed by 12-17-76. In addition, the project size has been increased from 563 MW to 572 MW.
3. The Lucerne Valley Combined Cycle Project, previously shown as an alternative to the Huntington Beach Combined Cycle Project (6-236 MW), has been substituted for planning and budgeting purposes. The 1416 MW Huntington Beach Combined Cycle Project remains as the preferred site. The new project size of Lucerne Valley Combined Cycle Project (6-226 MW) is shown with the initial two units starting in 1980 and the remaining units in the 1984-1985 time frame.
4. Fifteen 26 MW fuel cell units, previously shown during the 1979-1981 time frame, have been delayed by one year to 1980-1982.
5. Initial Full Power Operation (20% Full Power rating) of San Onofre Units 2 & 3, formerly scheduled for 9-1-79 and 12-1-80, has been delayed by 10 months to 7-1-80 and 10-1-81 respectively. Dates of Firm Operation (100% Full Power rating) of units 2 & 3 follow one year later on 7-1-81 and 10-1-82 respectively.
6. The Kaiparowits Project previously shown beginning 6-1-80 has been rescheduled one year later to 5-31-81 with project completion on 12-1-83. Timely regulatory approval and/or favorable construction progress may allow advancement of the firm operating dates by as much as one year.
7. The Big Creek Area Development Phases I (A&B), II and III, which had been planned for 1981-82, 1985 and 1987 respectively, have been deleted. However, Big Creek 3

Unit 5, which was scheduled for 1981 as part of Phase I has been retained and rescheduled for 3-1-80 firm operation.

8. The Navajo layoff (318 MW) originally terminated on 1-1-81 has been extended to 1-1-85.
9. The two 760 MW Vidal Nuclear units, previously scheduled for 1984-1985 firm operation, have been cancelled and have been replaced with one 1540 MW Nuclear unit in 1988.
10. The 6-760 MW Nuclear units previously shown in the 1986-1992 time frame and three 1140 MW Nuclear units, previously shown for 1988 through 1993, have been delayed beyond 1989.
11. A 1540 MW Nuclear unit (Edison share assumed 1386 MW) is included at an undetermined Eastern Desert site for 1989 firm operation.
12. Four 750 MW East Coal units (SCE share 300 MW each), previously shown for 1984-1987 and four 1100 MW East Coal units (SCE share 440 MW each), previously shown for the 1987-1991 time period, have been removed.
13. A 25 MW combustion turbine is planned for firm operation in 1978 at the Yuma Axis Generating Station in Yuma, Arizona.
14. 1881 MW (34 units) of combustion turbine capacity and 1649 MW (7 units) of combined cycle capacity have been added in the 1979-1987 time frame.
15. The derating of Mohave Units 1 & 2 has been delayed 6 months to 6-30-77 due to delays in implementation schedules.

CAS/bm

DECEMBER 17, 1974
 FUTURE GENERATION RESOURCE PROGRAM
 1974-1989

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PFAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
12-31-73	AGGREGATE RATED CAPACITY REDUCED FOR "DRY YEAR HYDRO" CONDITIONS, 100 MW FOR SUMMER AND 119 MW FOR WINTER		13401	13523	(1)					
1- 1-74	PERATE MOHAVE 1 (760/425 TO 790/442 MW)	17 (2)								
1- 1-74	PERATE MOHAVE 2 (760/426 TO 790/443 MW)	17 (2)								
3- 6-74	TERMINATE VERNON	-20 (3)								
3-31-74	TERMINATE 159 MW SALE TO PORTLAND GENERAL ELECTRIC	(4)								
4- 1-74	TERMINATE PORTLAND GENERAL EXCHANGE (53 MW SCE TO PG&E)	(5)								
5-31-74	TERMINATE 400 MW SALE TO NORTHWEST	(6)								
5-31-74	NAVAJO 1 LAYOFF (98 MW)	95 (7)								
8- 1-74	ELLWOOD ENERGY SUPPORT FACILITY	54								
10-18-74	TERMINATE GABBS	-6 (8)								
11- 1-74	BEGIN 159 MW SALE TO PORTLAND GENERAL ELECTRIC	(4)								
11- 1-74	BEGIN PORTLAND GENERAL EXCHANGE (27 MW SCE TO PGE)	(5)								
11- 1-74	DERATE LONG BEACH 10 (106 TO 50 MW)	-56 (9)								
11- 1-74	DERATE LONG BEACH 11 (106 TO 50 MW)	-56 (9)								
	TOTAL CAPACITY ADDED	45								
	LOADS AND RESOURCES FOR SUMMER 1974		13651		10279	3372	32.8	.99	9997	-2.5
	LOADS AND RESOURCES FOR WINTER 1974			13568	9181	4387	47.8			

DATE -----	RESOURCE -----	TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN		AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)	
		NET CAPACITY ADDED (MW)	SUMMER (MW)		WINTER (MW)	(MW)				(%)
3-31-75	TERMINATE 159 MW SALE TO PORTLAND GENERAL ELECTRIC									
		(4)								
4- 1-75	TERMINATE PORTLAND GENERAL EXCHANGE (27 MW SCE TO PGE)									
		(5)								
4-15-75	RERATE NAVAJO 1 LAYOFF (98 TO 101 MW)	3								
		(7)								
4-15-75	NAVAJO 2 LAYOFF (101 MW)	98								
		(7)								
5- 1-75	DERATE FOUR CORNERS 4 (800/384 TO 787/378 MW)	-6								
		(10)								
5-16-75	BEGIN ANNUAL SUMMER PGE EXCHANGE (100 MW PGE TO SCE FROM MAY 16, THRU OCT 15)	94/ 0								
		(5)								
	TOTAL CAPACITY ADDED	189/ 95								
	LOADS AND RESOURCES FOR SUMMER 1975		13776		10842	2934	27.1	.99	10540	5.4
	LOADS AND RESOURCES FOR WINTER 1975			13663	9682	3981	41.1			

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)		
4-15-76	RERATE NAVAJO 1 LAYOFF (101 TO 109 MW)	8 (7)								
4-15-76	RERATE NAVAJO 2 LAYOFF (101 TO 109 MW)	8 (7)								
4-15-76	NAVAJO 3 LAYOFF (109 MW)	106 (7)								
6- 1-76	INTFGPATE YUMA-AXIS STEAM GENERATION INTO MAIN SYSTEM (75/25 MW)	25 (11)								
7- 2-76	LONG BEACH 1 (COMBUSTION TURBINE)	63 (12)								
7-30-76	LONG BFACH 2 (COMBUSTION TURBINE)	63 (12)								
8-27-76	LONG BFACH 3 (COMBUSTION TURBINE)	63 (12)								
9-24-76	LONG BFACH 4 (COMBUSTION TURBINE)	63 (12)								
9-24-76	LONG BEACH 1-4 (STEAM)	82 (12)								
10-22-76	LONG BEACH 5 (COMBUSTION TURBINE)	63 (12)								
11- 1-76	BEGIN ANNUAL WINTER PGE EXCHANGE (106 MW SCE TO PGE FROM NOV 1 THRU MAR 31)	(5)								
11-19-76	LONG BEACH 6 (COMBUSTION TURBINE)	63 (12)								
12-17-76	LONG BEACH 7 (COMBUSTION TURBINE)	63 (12)								
12-17-76	LONG BEACH 5-7 (STEAM)	49 (12)								
	TOTAL CAPACITY ADDED	719								
	LOADS AND RESOURCES FOR SUMMER 1976		14049		11352	2697	23.8	.99	11050	4.8
	LOADS AND RESOURCES FOR WINTER 1976			14382	10348	4034	39.0			

DECEMBER 17, 1974
 FUTURE GENERATION RESOURCE PROGRAM
 1974-1989

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
4- 1-77	DERATE FOUR CORNERS 4 (787/378 TO 742/356 MW)	-22 (10)								
6- 1-77	COOLWATER 3	236								
6- 1-77	DERATE FOUR CORNERS 5 (800/384 TO 742/356 MW)	-28 (10)								
6-30-77	DERATE MOHAVE 1 (790/442 TO 746/417 MW)	-25 (10)								
6-30-77	DERATE MOHAVE 2 (790/443 TO 746/418 MW)	-25 (10)								
	TOTAL CAPACITY ADDED	136								
	LOADS AND RESOURCES FOR SUMMER 1977		14631		11879	2752	23.2	.99	11580	4.8
	LOADS AND RESOURCES FOR WINTER 1977			14518	10945	3573	32.6			
4- 1-78	AXIS COMBUSTION TURBINE	25								
6- 1-78	COOLWATER 4	236								
	TOTAL CAPACITY ADDED	261								
	LOADS AND RESOURCES FOR SUMMER 1978		14892		12467	2425	19.5	.99	12150	4.9
	LOADS AND RESOURCES FOR WINTER 1978			14779	11603	3176	27.4			
1- 1-79	DERATE LONG BEACH 10 (50 TO 106 MW)	56 (9)								
1- 1-79	DERATE LONG BEACH 11 (50 TO 106 MW)	56 (9)								
6- 1-79	COMBUSTION TURBINES (5 UNITS)	270 (13)								
	TOTAL CAPACITY ADDED	382								
	LOADS AND RESOURCES FOR SUMMER 1979		15274		13084	2190	16.7	.99	12760	5.0
	LOADS AND RESOURCES FOR WINTER 1979			15161	12170	2991	24.6			

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
3- 1-80	RIG CREEK 3 UNIT 5 (A)	29	(14)							
5-31-80	KAIPAROWITS 1 (B)		(15)							
6- 1-80	LUCERNE VALLEY 1&2	452	(16)							
7- 1-80	SAN ONOFRE 2 (228/182 MW)	182	(17)							
7- 1-80	FUEL CELL 1	26	(18)							
10- 1-80	FUEL CELL 2	26	(18)							
12- 1-80	FUEL CELL 3	26	(18)							
	TOTAL CAPACITY ADDED	741								
	LOADS AND RESOURCES FOR SUMMER 1980		15963		13705	2258	16.5	.98	13410	5.1
	LOADS AND RESOURCES FOR WINTER 1980			15902	12741	3161	24.8			
1- 1-81	FUEL CELL 4	26	(18)							
3- 1-81	FUEL CELL 5	26	(18)							
5- 1-81	FUEL CELL 6	26	(18)							
5-31-81	KAIPAROWITS 1 (750/300 MW)	291	(15)							
6- 1-81	COMBUSTION TURBINE (1 UNIT)	54	(13)							
6- 1-81	FUEL CELL 7	26	(18)							
7- 1-81	RERATE SAN ONOFRE 2 (228/182 TO 1140/912 MW)	730	(17)							
8- 1-81	FUEL CELLS 8&9	52	(18)							
10- 1-81	SAN ONOFRE 3 (228/182 MW)	182	(17)							
11- 1-81	FUEL CELLS 10&11	52	(18)							
	TOTAL CAPACITY ADDED	1465								
	LOADS AND RESOURCES FOR SUMMER 1981		17246		14395	2851	19.8	.96	14100	5.1
	LOADS AND RESOURCES FOR WINTER 1981			17367	13371	3996	29.9			

(A)

NON-FIRM ENERGY PRODUCTION ONLY. TIMELY REGULATORY APPROVAL AND/OR FAVORABLE CONSTRUCTION PROGRESS MAY ALLOW ADVANCEMENT OF THE FIRM OPERATING DATES OF THE KAIPAROWITS PROJECT BY AS MUCH AS ONE YEAR ALLOWING FIRM COMMERCIAL OPERATION OF UNIT 1 ON 5-31-80.

(B)

ALTHOUGH HUNTINGTON BEACH IS THE PREFERRED SITE, LUCERNE VALLEY REPRESENTS THE GREATER COST EXPOSURE AND THUS IS BEING USED FOR PLANNING AND BUDGETING PURPOSES.

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
1- 1-82	FUEL CELLS 12&13	52 (18)								
4- 1-82	FUEL CELLS 14&15	52 (18)								
5-31-82	KAIPAROWITS 2 (750/300 MW)	291 (15)								
10- 1-82	PERATE SAN ONOFRE 3 (228/182 TO 1140/912 MW)	730 (17)								
	TOTAL CAPACITY ADDED	1125								
	LOADS AND RESOURCES FOR SUMMER 1982		17875		15131	2744	18.1	.96	14830	5.2
	LOADS AND RESOURCES FOR WINTER 1982			18492	14048	4444	31.6			
3- 1-83	KAIPAROWITS 3 (750/300 MW)	291 (15)								
12- 1-83	KAIPAROWITS 4 (750/300 MW)	291 (15)								
	TOTAL CAPACITY ADDED	582								
	LOADS AND RESOURCES FOR SUMMER 1983		18896		15982	2914	18.2	.98	15600	5.2
	LOADS AND RESOURCES FOR WINTER 1983			19074	14839	4235	28.5			
	(B)									
6- 1-84	LUCERNE VALLEY 3&4	453 (16)								
6- 1-84	COMBUSTION TURBINE (1 UNIT)	53 (13)								
	TOTAL CAPACITY ADDED	506								
	LOADS AND RESOURCES FOR SUMMER 1984		19693		16826	2867	17.0	.97	16430	5.3
	LOADS AND RESOURCES FOR WINTER 1984			19580	15623	3957	25.3			

(B).

ALTHOUGH HUNTINGTON BEACH IS THE PREFERRED SITE, LUCERNE VALLEY REPRESENTS THE GREATER COST EXPOSURE AND THUS IS BEING USED FOR PLANNING AND BUDGETING PURPOSES.

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
1- 1-85	TERMINATE OROVILLF-THERMALITO	-318	(19)							
1- 1-85	TERMINATE NAVAJO LAYOFF (327 MW)	-318	(7)							
4- 1-85	GEO THERMAL 1&2	100	(20)							
6- 1-85	COMBINED CYCLE (1 UNIT)	245	(13)							
6- 1-85	LUCERNE VALLEY 5&6 (8)	453	(16)							
6- 1-85	COMBUSTION TURBINE (9 UNITS)	502	(13)							
6- 1-85	SAN JOAQUIN NUC 1 (1270/260 MW)	260	(21)							
	TOTAL CAPACITY ADDED	924								
	LOADS AND RESOURCES FOR SUMMER 1985		20617		17741	2876	16.2	.97	17310	5.4
	LOADS AND RESOURCES FOR WINTER 1985			20504	16469	4035	24.5			
6- 1-86	COMBINED CYCLE (2 UNITS)	468	(13)							
6- 1-86	COMBUSTION TURBINE (6 UNITS)	342	(13)							
6- 1-86	SAN JOAQUIN NUC 2 (1270/260 MW)	260	(21)							
	TOTAL CAPACITY ADDED	1070								
	LOADS AND RESOURCES FOR SUMMER 1986		21687		18640	3047	16.3	.99	18210	5.2
	LOADS AND RESOURCES FOR WINTER 1986			21574	17289	4285	24.8			
6- 1-87	TERMINATE HOOVER	-277	(22)							
6- 1-87	COMBUSTION TURBINE (12 UNITS)	660	(13)							
6- 1-87	COMBINED CYCLE (4 UNITS)	936	(13)							
6- 1-87	SAN JOAQUIN NUC 3 (1270/260 MW)	260	(21)							
8- 1-87	TERMINATE BPA EXCHANGE	-517	(23)							
	TOTAL CAPACITY ADDED	1062								
	LOADS AND RESOURCES FOR SUMMER 1987		22749		19574	3175	16.2	.99	19150	5.2
	LOADS AND RESOURCES FOR WINTER 1987			22636	18149	4487	24.7			

(8)

ALTHOUGH HUNTINGTON BEACH IS THE PREFERRED SITE, LUCERNE VALLEY REPRESENTS THE GREATER COST EXPOSURE AND THUS IS BEING USED FOR PLANNING AND BUDGETING PURPOSES.

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
	(C)									
6- 1-88	VIDAL NUCLEAR (1540/1386 MW)	1386	(24)							
6- 1-88	SAN JOAQUIN NUC 4 (1270/260 MW)	260	(21)							
	TOTAL CAPACITY ADDED	1646								
	LOADS AND RESOURCES FOR SUMMER 1988		24395		20568	3827	18.6	.99	20110	5.0
	LOADS AND RESOURCES FOR WINTER 1988			24282	19065	5217	27.4			
6- 1-89	EASTERN DESERT NUCLEAR (1540/1386 MW)	1386	(25)							
	TOTAL CAPACITY ADDED	1386								
	LOADS AND RESOURCES FOR SUMMER 1989		25781		21546	4235	19.7	.98	21100	4.9
	LOADS AND RESOURCES FOR WINTER 1989			25668	19978	5690	28.5			

(C)

THE VIDAL NUCLEAR PROJECT SHOWN IN 1988 IS A POSSIBLE ALTERNATIVE TO THE COMBINED CYCLE AND COMBUSTION TURBINE UNITS SHOWN IN 1985 AND 1986.

DEVELOPMENT OF PERTINENT DATA

- 1) RECONCILIATION OF THE 12-31-73 AGGREGATE RATED CAPACITY WITH THE DECEMBER 31, 1973 REVISION OF THE "GENERATOR RATINGS AND EFFECTIVE OPERATING CAPACITY OF RESOURCES".

NET MAIN FOISON OWNED SYSTEM RESOURCES (DECEMBER 31, 1973)	12215
TOTAL FIRM PURCHASES (DECEMBER 31, 1973)	+1185
MWD CAPACITY	+310
WINTER HYDRO DERATE	-119
TOTAL OFF SYSTEM LOSSES	-68

12-31-73 AGGREGATE RATED CAPACITY	13523

2) SUMMARY OF APEA PEAK DEMANDS (1974-1989)

	1974	1975	1976	1977	1978	1979	1980	1981
SUMMER								
EDISON NET PEAK DEMAND ***	9997	10540	11050	11580	12150	12760	13410	14100
MWD LOAD	292	295	295	295	295	295	295	295
STATE WATER PROJECT	-	7	7	4	22	29	-	-
TOTALS	10279	10842	11352	11879	12467	13084	13705	14395
WINTER								
EDISON NET PEAK DEMAND ***	8700	9380	9940	10540	11180	11740	12340	12970
MWD LOAD	295	295	295	295	295	295	295	295
STATE WATER PROJECT	-	7	7	4	22	29	-	-
SALE TO PORTLAND GE	27	-	106	106	106	106	106	106
SALE TO PORTLAND GE	159	-	-	-	-	-	-	-
TOTALS	9181	9682	10348	10945	11603	12170	12741	13371
1982								
SUMMER								
EDISON NET PEAK DEMAND ***	14830	15600	16430	17310	18210	19150	20110	21100
MWD LOAD	295	295	295	295	295	295	295	295
STATE WATER PROJECT	6	87	101	136	135	129	163	151
TOTALS	15131	15982	16826	17741	18640	19574	20568	21546
WINTER								
EDISON NET PEAK DEMAND ***	13640	14350	15120	15930	16750	17620	18500	19410
MWD LOAD	295	295	295	295	295	295	295	295
STATE WATER PROJECT	7	88	102	138	138	128	164	167
SALE TO PORTLAND GE	106	106	106	106	106	106	106	106
TOTALS	14048	14839	15623	16469	17289	18149	19065	19978

*** BLYTHE LOAD IS INCLUDED IN THE EDISON
 NET PEAK DEMAND STARTING IN 1976

DECEMBER 17, 1974
FUTURE GENERATION RESOURCE PROGRAM
1974 - 1989

DEFINITION OF COLUMN HEADINGS

Date

Firm operating date of unit or contractual agreement.

Resource

Resource identification. Often includes supplemental information about capacity particularly when the identification refers to a unit which is undergoing rerate, has associated off-system losses, or is a participation unit.

Net Capacity Added

Effective operating capacity rating of the resource. These have been adjusted for losses incurred outside the Edison main system where applicable.

Total Capacity

Summer total capacity includes resources scheduled as of August 1 of that year, or at time of recorded peak demand. Winter total capacity includes all capacity added in that year.

Area Peak Demand

Includes Edison net main system peak demand plus firm on-peak sales to other utilities, a constant 295 MW demand for Metropolitan Water District pumping load, and demands for presently isolated Edison loads commencing when they are expected to be integrated into the main system.

Area Margin

Megawatt margin is the difference between total capacity and area peak demand. Percent margin is the megawatt margin divided by area peak demand and multiplied by 100.

DEFINITION OF COLUMN HEADINGS

Area Reliability Index

The reliability index represents the probability that a particular year's specified resources will be sufficient to serve forecast loads for every hour of the year, allowing for planned generation maintenance and forced outages without requiring delivery of capacity via Edison's interconnections in excess of firm deliveries plus 300 MW from 1974 through 1984, 500 MW from 1985 through 1988, and 600 MW beyond 1988.

Edison Net Peak Demand

Edison net peak demand for 1974-1989 is based on the "System Forecast 1974-2000", prepared in October, 1974 by the System Development Department.

Annual Load Increase

Percent by which Edison net peak demand increases over the previous year net peak demand.

12/4/74
CAS/bm

DECEMBER 17, 1974
FUTURE GENERATION RESOURCE PROGRAM
1974 - 1990

NOTES

- (1) Aggregate rated capacity in accord with the December 31, 1973 revision of "Generator Ratings and Effective Operating Capacity of Resources," which includes total generation capacities of SCE and MWD. MWD capacity is rated at 310 MW (260 MW at Hoover, 1,213 foot surface elevation and 50 MW at Parker).
- (2) Mohave Units 1 and 2 were each rerated from 760 MW to 790 MW on January 1, 1974. Edison's 56% share of the rerate is 16.8 MW for each unit; following these rerates, Edison's share of the capacity is 442.4 MW for each unit.
- (3) The existing operating agreement between Edison and the City of Vernon, which makes 20 MW of diesel capacity available, was terminated on March 6, 1974 due to sale of these units by the City of Vernon.
- (4) A service agreement has been executed with Portland General Electric providing for a sale of 150 MW of capacity and limited energy for the winters of 1973-74 and 1974-75. Contract losses to the point of delivery increase Edison's obligation by an additional 9 MW.
- (5) An assignment has been negotiated with Pacific Gas & Electric Company and Portland General Electric Company providing for sale and exchange of capacity and energy. The principal effect on Edison's capacity resources is equivalent to a firm capacity purchase in the summer and a firm capacity sale in the winter periods indicated beginning in the winter of 1976. In the three years prior to 1976, special conditions of the agreement prescribe the exchanges shown. Exchange amounts are specified at anticipated levels and have been adjusted for Edison's loss obligations.
- (6) A contract has been executed with the Bonneville Power Administration, Pacific Power & Light, and the Portland General Electric Company for the sale of 400 MW of capacity and associated energy from December 1, 1973 to May 31, 1974.
- (7) A contract has been executed with the U. S. Bureau of

NOTES:

Reclamation for layoff of power from the Navajo Project. At such time as USBR needs this power for the Central Arizona Project, USBR has the right to terminate this layoff effective on or after January 1, 1980, upon at least five years advance written notice. Such notice has not been given; however, it is currently anticipated the layoff will terminate in 1985.

- (8) Sale of Edison's former Tonopah District facilities to the Sierra Pacific Power Company was concluded September 30, 1969. Until such time as Sierra provided power to the former Tonopah District from its main system, which was to be accomplished within five years of the date of sale, Edison sold power to Sierra and had exclusive use of the Gabbs generation. Service from Sierra began October 18, 1974; therefore, the Nevada resources (Gabbs) and load (including Mineral County) were removed from the Edison system.
- (9) Until reconditioning can be completed prior to 1979, Long Beach Units 10 & 11 will be derated from 106 to 50 MW each, effective November 1, 1974.
- (10) To comply with air pollution control standards, installation of additional emission control equipment is required and is expected to result in capacity reductions for Four Corners Units 4 & 5 and Mohave Units 1 & 2. Edison's share of these reductions amounts to 28 MW for each of the Four Corners units - 6 MW on May 1, 1975 (for the first scrubber module) plus an additional 22 MW on April 1, 1977 for Unit 4, and 28 MW on June 1, 1977 for Unit 5. Similarly, on June 30, 1977, Edison's share of each Mohave unit will be reduced by 25 MW. For the purpose of planning replacement capacity, the appropriate reductions are shown on the above dates.
- (11) Blythe District becomes part of integrated system in 1976; therefore, Yuma Axis resources and Blythe demand are added to the system.
- (12) The capacities shown for the Long Beach Combined Cycle Project are for the individual combustion turbines and steam turbines. Total project size is 572 MW.
- (13) Specific sites for combustion turbines and combined cycle units in the 1979-1987 time frame are currently being studied.
- (14) The project size of Big Creek 3 Unit 5 is presently

NOTES:

estimated to be 29 MW. Depending upon final evaluation, the size could be as much as 35 MW.

- (15) Edison is participating in a 4-unit, 3000 MW coal development in Southern Utah. This project capacity has been allocated as follows:

	<u>Participation Percentage</u>
SCE	40.0
APS	18.0
SDG&E	23.4
SRP	10.0
UNCOMMITTED	<u>8.6</u>
Total	100.0

Timely regulatory approval and/or favorable construction progress may allow advancement of the firm operating date by as much as one year. Capacity available to Edison has been adjusted for losses incurred outside the Edison main system.

- (16) Although Huntington Beach is the preferred site, Lucerne Valley represents the greater cost exposure and thus is being used for planning and budgeting purposes. The total Lucerne Valley Project capacity delivered to the main system is 1358 MW.
- (17) For planning and reporting purposes San Onofre Units 2 & 3 are considered a firm capacity resource at 20% of their Full Power rating (1140 MW each) for one year prior to their respective Full Power firm operating dates of 7-1-81 and 10-1-82. Edison's share of Units 2 & 3 is shown as 80% in accordance with agreements with San Diego Gas & Electric Company.
- (18) In March 1973, Edison joined a group of investor-owned utilities to fund an electric utility fuel cell program in conjunction with Pratt & Whitney Aircraft. Final commitments to purchase 15 units at 26 MW each (390 MW total capacity) for delivery in 1979-1981 will be made late in 1976. This purchase, however, will be contingent upon a successful validation of a test unit in 1977 or 1978.
- (19) On November 1, 1984, the contractual provisions for energy and capacity from the Oroville Thermalito facility

NOTES:

with the State of California, Southern California Edison Company and San Diego Gas & Electric Company are terminated. Other contractual agreements require Pacific Gas & Electric Company to provide equivalent energy and capacity to Southern California Edison Company and San Diego Gas & Electric Company until January 1, 1985.

- (20) Geothermal generation is presently under research and development. Potential sites presently under investigation include Long Valley and the counties of Mono, Imperial, Inyo, and San Bernardino. Initial operation of the first units could be as early as 1980.
- (21) Edison is considering participating in a 4-unit, 5080 MW nuclear development in the San Joaquin Valley. Firm operating dates for this development are based on Edison estimates of nuclear project lead time requirements. Non-firm energy production may commence as early as August 1983. Preliminary project allocation is as follows:

	<u>Participation Percentage</u>
LADWP	38.5
PG&E	21.5
SCE	20.5
SDG&E	3.0
State	10.0
Others	<u>6.5</u>
Total	100.0

- (22) Edison's present 50-year Hoover contract for energy and capacity with the U.S. Department of the Interior expires on June 1, 1987.
- (23) The contract with the Bonneville Power Authority for 550 MW (517 MW net capacity delivered to SCE) of exchange capacity expires on August 1, 1987.
- (24) The Vidal HTGR Nuclear Project is a possible alternative to the combined cycle and combustion turbine units shown in 1985 and 1986.
- (25) Assumed 90 percent allocation to Edison in Eastern Desert Nuclear Project.

DECEMBER 17, 1974 FGRP (1974-1989) + 5 YEAR EXTENSION FOR PLANNING ONLY
 FUTURE GENERATION RESOURCE PROGRAM
 1974-1994

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN	AREA	EDISON NET	ANNUAL	
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
12-31-73	AGGREGATE RATED CAPACITY REDUCED FOR "DRY YEAR HYDRO" CONDITIONS. 100 MW FOR SUMMER AND 119 MW FOR WINTER		13401	13523 (1)						
1- 1-74	DERATE MOHAVE 1 (760/425 TO 790/442 MW)	17 (2)								
1- 1-74	DERATE MOHAVE 2 (760/426 TO 790/443 MW)	17 (2)								
3- 6-74	TERMINATE VERNON	-20 (3)								
3-31-74	TERMINATE 159 MW SALE TO PORTLAND GENERAL ELECTRIC	(4)								
4- 1-74	TERMINATE PORTLAND GENERAL EXCHANGE (53 MW SCE TO PGE)	(5)								
5-31-74	TERMINATE 400 MW SALE TO NORTHWEST	(6)								
5-31-74	NAVAJO 1 LAYOFF (98 MW)	95 (7)								
8- 1-74	ELLWOOD ENERGY SUPPORT FACILITY	54								
10-18-74	TERMINATE GABBS	-6 (8)								
11- 1-74	REGIN 159 MW SALE TO PORTLAND GENERAL ELECTRIC	(4)								
11- 1-74	REGIN PORTLAND GENERAL EXCHANGE (27 MW SCE TO PGE)	(5)								
11- 1-74	DERATE LONG BEACH 10 (106 TO 50 MW)	-56 (9)								
11- 1-74	DERATE LONG BEACH 11 (106 TO 50 MW)	-56 (9)								
	TOTAL CAPACITY ADDED	45								
	LOADS AND RESOURCES FOR SUMMER 1974		13705		10279	3426	33.3	.99	9997	-2.5
	LOADS AND RESOURCES FOR WINTER 1974			13568	9181	4387	47.8			

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN	AREA	EDISON NET	ANNUAL	
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
3-31-75	TERMINATE 159 MW SALE TO PORTLAND GENERAL ELECTRIC	(4)								
4- 1-75	TERMINATE PORTLAND GENERAL EXCHANGE (27 MW SCE TO PGE)	(5)								
4-15-75	REFRATE NAVAJO 1 LAYOFF (98 TO 101 MW)	3 (7)								
4-15-75	NAVAJO 2 LAYOFF (101 MW)	98 (7)								
5- 1-75	DEPRATE FOUR CORNERS 4 (800/384 TO 787/378 MW)	-6 (10)								
5-16-75	BEGIN ANNUAL SUMMER PGE EXCHANGE (100 MW PGE TO SCE FROM MAY 16, THRU OCT 15)	94/ 0 (5)								
	TOTAL CAPACITY ADDED	189/ 95								
	LOADS AND RESOURCES FOR SUMMER 1975		13776		10842	2934	27.1	.99	10540	5.4
	LOADS AND RESOURCES FOR WINTER 1975			13663	9682	3981	41.1			

DATE	RESOURCE	TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN		AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
		NET CAPACITY ADDED (MW)	SUMMER (MW)		WINTER (MW)	(MW)			
4-15-76	PERATE NAVAJO 1 LAYOFF (101 TO 109 MW)	8							
4-15-76	PERATE NAVAJO 2 LAYOFF (101 TO 109 MW)	8							
4-15-76	NAVAJO 3 LAYOFF (109 MW)	106							
6- 1-76	INTEGRATE YUMA-AXIS STEAM GENERATION INTO MAIN SYSTEM (75/25 MW)	25							
7- 2-76	LONG BEACH 1 (COMBUSTION TURBINE)	63							
7-30-76	LONG BEACH 2 (COMBUSTION TURBINE)	63							
8-27-76	LONG BEACH 3 (COMBUSTION TURBINE)	63							
9-24-76	LONG BEACH 4 (COMBUSTION TURBINE)	63							
9-24-76	LONG BEACH 1-4 (STEAM)	82							
10-22-76	LONG BEACH 5 (COMBUSTION TURBINE)	63							
11- 1-76	BEGIN ANNUAL WINTER PGE EXCHANGE (106 MW SCE TO PGE FROM NOV 1 THRU MAR 31)								
11-19-76	LONG BEACH 6 (COMBUSTION TURBINE)	63							
12-17-76	LONG BEACH 7 (COMBUSTION TURBINE)	63							
12-17-76	LONG BEACH 5-7 (STEAM)	49							
	TOTAL CAPACITY ADDED	719							
	LOADS AND RESOURCES FOR SUMMER 1976		14049	11352	2697	23.8	.99	11050	4.8
	LOADS AND RESOURCES FOR WINTER 1976			14382	10348	39.0			

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
4- 1-77	DERATE FOUR CORNERS 4 (787/378 TO 742/356 MW)	-22 (10)								
6- 1-77	COOL WATER 3	236								
6- 1-77	DERATE FOUR CORNERS 5 (800/384 TO 742/356 MW)	-28 (10)								
6-30-77	DERATE MOHAVE 1 (790/442 TO 746/417 MW)	-25 (10)								
6-30-77	DERATE MOHAVE 2 (790/443 TO 746/418 MW)	-25 (10)								
	TOTAL CAPACITY ADDED	136								
	LOADS AND RESOURCES FOR SUMMER 1977		14631		11879	2752	23.2	.99	11580	4.8
	LOADS AND RESOURCES FOR WINTER 1977			14518	10945	3573	32.6			
4- 1-78	AXIS COMBUSTION TURBINE	25								
6- 1-78	COOL WATER 4	236								
	TOTAL CAPACITY ADDED	261								
	LOADS AND RESOURCES FOR SUMMER 1978		14892		12467	2425	19.5	.99	12150	4.9
	LOADS AND RESOURCES FOR WINTER 1978			14779	11603	3176	27.4			
1- 1-79	DERATE LONG BEACH 10 (50 TO 106 MW)	56 (9)								
1- 1-79	DERATE LONG BEACH 11 (50 TO 106 MW)	56 (9)								
6- 1-79	COMBUSTION TURBINES (5 UNITS)	270 (13)								
	TOTAL CAPACITY ADDED	382								
	LOADS AND RESOURCES FOR SUMMER 1979		15274		13084	2190	16.7	.99	12760	5.0
	LOADS AND RESOURCES FOR WINTER 1979			15161	12170	2991	24.6			

DATE	RESOURCE	NET CAPACITY ADDED (MW)		TOTAL CAPACITY (MW)		AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	AREA MARGIN (%)	APEA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
		SUMMER	WINTER	SUMMER	WINTER						
3- 1-80	BIG CREEK 3 UNIT 5			29	(14)						
5-31-80	KAIPAROWITS 1				(15)						
6- 1-80	LUCERNE VALLEY 1&2			452	(16)						
7- 1-80	SAN ONOFRE 2 (228/182 MW)			182	(17)						
7- 1-80	FUEL CELL 1			26	(18)						
10- 1-80	FUEL CELL 2			26	(18)						
12- 1-80	FUEL CELL 3			26	(18)						
	TOTAL CAPACITY ADDED			741							
	LOADS AND RESOURCES FOR SUMMER 1980			15963		13705	2258	16.5	.98	13410	5.1
	LOADS AND RESOURCES FOR WINTER 1980				15902	12741	3161	24.8			
1- 1-81	FUEL CELL 4			26	(18)						
3- 1-81	FUEL CELL 5			26	(18)						
5- 1-81	FUEL CELL 6			26	(18)						
5-31-81	KAIPAROWITS 1 (750/300 MW)			291	(15)						
6- 1-81	COMBUSTION TURBINE (1 UNIT)			54	(13)						
6- 1-81	FUEL CELL 7			26	(18)						
7- 1-81	REPEAT SAN ONOFRE 2 (228/182 TO 1140/912 MW)			730	(17)						
8- 1-81	FUEL CELLS 8&9			52	(18)						
10- 1-81	SAN ONOFRE 3 (228/182 MW)			182	(17)						
11- 1-81	FUEL CELLS 10&11			52	(18)						
	TOTAL CAPACITY ADDED			1465							
	LOADS AND RESOURCES FOR SUMMER 1981			17246		14395	2851	19.8	.96	14100	5.1
	LOADS AND RESOURCES FOR WINTER 1981				17367	13371	3996	29.9			

DATE	RESOURCE	NET TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN		AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
		ADDED (MW)	SUMMER (MW)		WINTER (MW)	(MW)			
1- 1-82	FUEL CELLS 12&13	52	(18)						
4- 1-82	FUEL CELLS 14&15	52	(18)						
5-31-82	KAIPAROWITS 2 (750/300 MW)	291	(15)						
10- 1-82	PERATE SAN ONOFRE 3 (228/182 TO 1140/912 MW)	730	(17)						
TOTAL CAPACITY ADDED		1125							
LOADS AND RESOURCES FOR SUMMER 1982			17875	15131	2744	18.1	.96	14830	5.2
LOADS AND RESOURCES FOR WINTER 1982				18492	14048	4444	31.6		
3- 1-83	KAIPAROWITS 3 (750/300 MW)	291	(15)						
12- 1-83	KAIPAROWITS 4 (750/300 MW)	291	(15)						
TOTAL CAPACITY ADDED		582							
LOADS AND RESOURCES FOR SUMMER 1983			18896	15982	2914	18.2	.98	15600	5.2
LOADS AND RESOURCES FOR WINTER 1983				19074	14839	4235	28.5		
6- 1-84	LUCERNE VALLEY 3&4	453	(16)						
6- 1-84	COMBUSTION TURBINE (1 UNIT)	53	(13)						
TOTAL CAPACITY ADDED		506							
LOADS AND RESOURCES FOR SUMMER 1984			19693	16826	2867	17.0	.97	16430	5.3
LOADS AND RESOURCES FOR WINTER 1984				19580	15623	3957	25.3		

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
1- 1-85	TERMINATE OROVILLE-THERMALITO	-318 (19)								
1- 1-85	TERMINATE NAVAJO LAYOFF (327 MW)	-318 (7)								
4- 1-85	GEOHERMAL 1&2	100 (20)								
6- 1-85	COMBINED CYCLE (1 UNIT)	245 (13)								
6- 1-85	COMBUSTION TURBINE (9 UNITS)	502 (13)								
6- 1-85	LUCERNE VALLEY 5&6	453 (16)								
6- 1-85	SAN JOAQUIN NUC 1 (1270/260 MW)	260 (21)								
	TOTAL CAPACITY ADDED	924								
	LOADS AND RESOURCES FOR SUMMER 1985		20617		17741	2876	16.2	.97	17310	5.4
	LOADS AND RESOURCES FOR WINTER 1985			20504	16469	4035	24.5			
6- 1-86	COMBINED CYCLE (2 UNITS)	468 (13)								
6- 1-86	COMBUSTION TURBINE (6 UNITS)	342 (13)								
6- 1-86	SAN JOAQUIN NUC 2 (1270/260 MW)	260 (21)								
	TOTAL CAPACITY ADDED	1070								
	LOADS AND RESOURCES FOR SUMMER 1986		21687		18640	3047	16.3	.99	18210	5.2
	LOADS AND RESOURCES FOR WINTER 1986			21574	17289	4285	24.8			
6- 1-87	COMBUSTION TURBINE (12 UNITS)	660 (13)								
6- 1-87	TERMINATE HOOVER	-277 (22)								
6- 1-87	COMBINED CYCLE (4 UNITS)	936 (13)								
6- 1-87	SAN JOAQUIN NUC 3 (1270/260 MW)	260 (21)								
8- 1-87	TERMINATE BPA EXCHANGE	-517 (23)								
	TOTAL CAPACITY ADDED	1062								
	LOADS AND RESOURCES FOR SUMMER 1987		22749		19574	3175	16.2	.99	19150	5.2
	LOADS AND RESOURCES FOR WINTER 1987			22636	18149	4487	24.7			

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NPT PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
6- 1-88	VIDAL NUCLEAR (1540/1386 MW)	1386	(24)							
6- 1-88	SAN JOAQUIN NUC 4 (1270/260 MW)	260	(21)							
	TOTAL CAPACITY ADDED	1646								
	LOADS AND RESOURCES FOR SUMMER 1988		24395		20568	3827	18.6	.99	20110	5.0
	LOADS AND RESOURCES FOR WINTER 1988			24282	19065	5217	27.4			
6- 1-89	EASTERN DESERT NUCLEAR (1540/1386 MW)	1386	(25)							
	TOTAL CAPACITY ADDED	1386								
	LOADS AND RESOURCES FOR SUMMER 1989		25781		21546	4235	19.7	.98	21100	4.9
	LOADS AND RESOURCES FOR WINTER 1989			25668	19978	5690	28.5			
6- 1-90	EAST COAL 1 (1300/520 MW)	504								
6- 1-90	GEO THERMAL	100								
6- 1-90	COMBUSTION TURBINES (4 UNITS)	200								
6- 1-90	BALSAM FLOW-THRU	140								
	TOTAL CAPACITY ADDED	944								
	LOADS AND RESOURCES FOR SUMMER 1990		26725		22612	4113	18.2		22120	4.8
	LOADS AND RESOURCES FOR WINTER 1990			26612	20945	5667	27.1			
6- 1-91	NUCLEAR LWR 1 (1140/912 MW)	912								
6- 1-91	EAST COAL 2 (1300/520 MW)	504								
	TOTAL CAPACITY ADDED	1416								
	LOADS AND RESOURCES FOR SUMMER 1991		28141		23684	4457	18.8		23190	4.8
	LOADS AND RESOURCES FOR WINTER 1991			28028	21908	6120	27.9			

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PEP UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
6- 1-92	NUCLEAR LWR 2 (1140/912 MW)	912								
6- 1-92	EAST COAL 3 (1300/520 MW)	504								
	TOTAL CAPACITY ADDED	1416								
	LOADS AND RESOURCES FOR SUMMER 1992		29557		24743	4814	19.5		24220	4.4
	LOADS AND RESOURCES FOR WINTER 1992			29444	22910	6534	28.5			
6- 1-93	COMBUSTION TURBINES (2 UNITS)	100								
6- 1-93	EAST COAL 4 (1300/520 MW)	504								
6- 1-93	GEOTHERMAL	100								
	TOTAL CAPACITY ADDED	704								
	LOADS AND RESOURCES FOR SUMMER 1993		30261		25840	4421	17.1		25320	4.5
	LOADS AND RESOURCES FOR WINTER 1993			30148	23916	6232	26.1			
6- 1-94	NUCLEAR LWR A (1500/1200 MW)	1200								
6- 1-94	BLACKSTAR 1	275								
	TOTAL CAPACITY ADDED	1475								
	LOADS AND RESOURCES FOR SUMMER 1994		31736		27009	4727	17.5		26460	4.5
	LOADS AND RESOURCES FOR WINTER 1994			31623	24986	6637	26.6			

FUTURE GENERATION RESOURCE PROGRAM
FEBRUARY 8, 1974
PRINCIPAL CHANGES FROM THE RESOURCE
PROGRAM OF JUNE 5, 1973

1. The firm operating dates for each of the Long Beach Combined Cycle Units have been deferred by nine months. This results in the first unit being installed by 3-1-1976, and the total project being completed by 9-1-76.
2. The Coolwater Combined Cycle Units 3&4 previously scheduled for 6-1-75, have been deferred to 6-1-77 and 6-1-78, respectively.
3. The firm operating dates for the combustion turbine portions of the Huntington Beach Combined Cycle Project have been deferred two years, eight months for the first three units and three years for the remaining three units; the steam portion has been deferred one year. This results in simultaneous firm operation of both the combustion turbine and steam portions in 1978 and 1979.
4. The Lucerne Valley Combined Cycle Project previously shown for 1977 and 1978 has been delayed, however, the project remains an alternative to the Huntington Beach Combined Cycle Project.
5. Fifteen 26 MW Fuel Cells are shown during the 1979-1981 time frame.
6. Through improvements and additions, the capacity of hydro facilities in the Big Creek area will be increased by 344 MW during 1981 and 1982.
7. The 1765 MW of unnamed combined cycle projects previously scheduled in 1979-1981 have been deleted.
8. Long Beach Units 10 & 11 are shown retired in place in 1982 one year, nine months earlier than previously shown.
9. The Vidal Nuclear Units 1 and 2, formerly called HTGR 1 & 2, have each been deferred two years to 6-1-84 and 6-1-85, respectively; however, non-firm energy production may be available as early as 6-1-82 for Unit 1 and 6-1-83 for Unit 2.
10. Edwards Air Force Base Exchange capacity from the USBR previously shown as integrated into the main system in 1975 and terminated in 1976, has been deleted.

11. The integration into the main system of the Yuma-Axis generation previously shown on 6-1-1975, has been deferred by one year.
12. Four Corners Units 4 & 5 are shown derated by an additional 7 MW to 28 MW each. Also, the effective date of derate has been deferred from 1-1-76 to 4-1-77 and 6-1-77 for Units 4 & 5, respectively. In addition, the derate for Unit 4 is shown in two parts, 6 MW when the first scrubber module goes into operation on 5-1-75, and the remaining 22 MW on 4-1-77.
13. The existing operating agreement with the City of Vernon, which makes 20 MW of diesel capacity available, is being terminated on March 4, 1974 due to the sale of these units by the City of Vernon.
14. Edison is participating (planned 23 percent share) in a four unit, 4000 MW nuclear development in the San Joaquin Valley. Operating dates based on Edison estimates of nuclear lead time requirements indicate that firm power will be available by 6-1-1985 from the first unit, with firm power from the remaining three units following on one-year intervals. Non-firm energy production may commence as early as 12-1/81.

Note: This schedule is based on a 4-1/2% average annual compound growth rate for the total system through 1983. ✓

DJF:1m
February 8, 1974

FEBRUARY 8, 1974
 FUTURE GENERATION RESOURCE PROGRAM
 1974-1983

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
12-31-73	AGGREGATE RATED CAPACITY REDUCED FOR "DRY YEAR HYDRO" CONDITIONS, 100 MW FOR SUMMER AND 119 MW FOR WINTER		13401	13523	(1)					
1- 1-74	RERATE MOHAVE 1 (760/425 TO 790/442 MW)	17			(2)					
1- 1-74	RERATE MOHAVE 2 (760/426 TO 790/443 MW)	17			(2)					
3- 4-74	TERMINATE VERNON	-20			(3)					
3-31-74	TERMINATE 159 MW SALE TO PORTLAND GENERAL ELECTRIC	(4)								
4- 1-74	TERMINATE PORTLAND GENERAL EXCHANGE (53 MW SCE TO PGE)	(5)								
5-31-74	TERMINATE 400 MW SALE TO NORTHWEST	(6)								
6- 1-74	NAVAJO 1 LAYOFF (97 MW)	94			(7)					
6- 1-74	ELLWOOD ENERGY SUPPORT FACILITY	54								
9-30-74	TERMINATE GABBS	-6			(8)					
11- 1-74	BEGIN 159 MW SALE TO PORTLAND GENERAL ELECTRIC	(4)								
11- 1-74	BEGIN PORTLAND GENERAL EXCHANGE (27 MW SCE TO PGE)	(5)								
	TOTAL CAPACITY ADDED	156								
	LOADS AND RESOURCES FOR SUMMER 1974		13704		11005	2699	24.5 /	.99	10710	4.5
	LOADS AND RESOURCES FOR WINTER 1974			13679	10441	3238	31.0			

FEBRUARY 8, 1974
 FUTURE GENERATION RESOURCE PROGRAM
 1974-1983

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	AREA MARGIN (%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
3-31-75	TERMINATE 159 MW SALE TO PORTLAND GENERAL ELECTRIC	(4)								
4-1-75	TERMINATE PORTLAND GENERAL EXCHANGE (27 MW SCE TO PGE)	(5)								
5-1-75	DERATE FOUR CORNERS 4... (800/384 TO 787/378 MW)	(9)								
5-16-75	BEGIN ANNUAL SUMMER PGE EXCHANGE (100 MW PGE TO SCE FROM MAY 16, THRU OCT 15)	94								
6-1-75	NAVAJO 2 LAYOFF (104 MW)	(104)								
TOTAL CAPACITY ADDED		189	95							
LOADS AND RESOURCES FOR SUMMER 1975			13887		11485	2402	20.9	.99	11190	4.5
LOADS AND RESOURCES FOR WINTER 1975				13774	10311	2963	27.4			

FEBRUARY 8, 1974
 FUTURE GENERATION RESOURCE PROGRAM
 1974-1983

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)	
3- 1-76	LONG BEACH 1 (COMBUSTION TURBINE)	60	(10)							
4- 1-76	LONG BEACH 2 (COMBUSTION TURBINE)	60	(10)							
5- 1-76	LONG BEACH 3 (COMBUSTION TURBINE)	60	(10)							
6- 1-76	LONG BEACH 4 (COMBUSTION TURBINE)	60	(10)							
6- 1-76	LONG BEACH 1-4 (STEAM TURBINE)	78	(10)							
6- 1-76	NAVAJO 3 LAYOFF (126 MW)	122	(7)							
6- 1-76	YUMA AXIS	25	(11)							
7- 1-76	LONG BEACH 5 (COMBUSTION TURBINE)	60	(10)							
8- 1-76	LONG BEACH 6 (COMBUSTION TURBINE)	60	(10)							
9- 1-76	LONG BEACH 7 (COMBUSTION TURBINE)	60	(10)							
9- 1-76	LONG BEACH 5-7 (STEAM TURBINE)	65	(10)							
11- 1-76	BEGIN ANNUAL WINTER PGE EXCHANGE (106 MW SCE TO PGE FROM NOV 1 THRU MAR 31)		(5)							
TOTAL CAPACITY ADDED		710								
LOADS AND RESOURCES FOR SUMMER 1976			14472		11995	2477	20.7	.99	11700	4.6
LOADS AND RESOURCES FOR WINTER 1976				14484	11271	3213	28.5			
1- 1-77	DERATE MOHAVE 1 (790/442 TO 746/417 MW)	-25	(9)							
1- 1-77	DERATE MOHAVE 2 (790/443 TO 746/418 MW)	-25	(9)							
4- 1-77	DERATE FOUR CORNERS 4 (787/378 TO 742/356 MW)	-22	(9)							
6- 1-77	COOLWATER 3	236								
6- 1-77	DERATE FOUR CORNERS 5 (800/384 TO 742/356 MW)	-28	(9)							
TOTAL CAPACITY ADDED		136								
LOADS AND RESOURCES FOR SUMMER 1977			14733		12595	2138	17.0	.96	12300	5.1
LOADS AND RESOURCES FOR WINTER 1977				14620	11821	2799	23.7			

FEBRUARY 8, 1974
 FUTURE GENERATION RESOURCE PROGRAM
 1974-1983

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	TOTAL CAPACITY WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	AREA MARGIN (%)	AREA RELIABILITY INDEX (PER. UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
	PORTINGTON BEACH 3	236								
	PORTINGTON BEACH 4	236								
	PORTINGTON BEACH 5	236								
6- 1-78	COOLWATER 4	236								
	TOTAL CAPACITY ADDED	944								
	LOADS AND RESOURCES FOR SUMMER 1978		15677		13265	2412	18.2	.98	12970	5.4
	LOADS AND RESOURCES FOR WINTER 1978			15564	12451	3113	25.0			
	PORTINGTON BEACH 6	236								
	PORTINGTON BEACH 7	236								
	PORTINGTON BEACH 8	236								
7- 1-79	FUEL CELL 1	26 (12)								
9- 1-79	SAN ONOFRE 2 (228/182 MW)	182 (13)								
10- 1-79	FUEL CELL 2	26 (12)								
12- 1-79	FUEL CELL 3	26 (12)								
	TOTAL CAPACITY ADDED	968								
	LOADS AND RESOURCES FOR SUMMER 1979		16411		13812	2599	18.8	.99	13510	4.2
	LOADS AND RESOURCES FOR WINTER 1979			16532	12958	3574	27.6			
	PORTINGTON BEACH 9	236								
	PORTINGTON BEACH 10	236								
	PORTINGTON BEACH 11	236								
	PORTINGTON BEACH 12	236								
	PORTINGTON BEACH 13	236								
	PORTINGTON BEACH 14	236								
	PORTINGTON BEACH 15	236								
	PORTINGTON BEACH 16	236								
	PORTINGTON BEACH 17	236								
	PORTINGTON BEACH 18	236								
	PORTINGTON BEACH 19	236								
	PORTINGTON BEACH 20	236								
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	PORTINGTON BEACH 54	236								
	PORTINGTON BEACH 55	236								
	PORTINGTON BEACH 56	236								
	PORTINGTON BEACH 57	236								
	PORTINGTON BEACH 58	236								
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	PORTINGTON BEACH 89	236								
	PORTINGTON BEACH 90	236								
	PORTINGTON BEACH 91	236								
	PORTINGTON BEACH 92	236								
	PORTINGTON BEACH 93	236								
	PORTINGTON BEACH 94	236								
	PORTINGTON BEACH 95	236								
	PORTINGTON BEACH 96	236								
	PORTINGTON BEACH 97	236								
	PORTINGTON BEACH 98	236								
	PORTINGTON BEACH 99	236								
	PORTINGTON BEACH 100	236								

FEBRUARY 8, 1974
 FUTURE GENERATION RESOURCE PROGRAM
 1974-1983.

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PFAK DEMAND (MW)	AREA MARGIN (MW)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
1- 1-80	FUEL CELL 4	26	(12)						
3- 1-80	FUEL CELL 5	26	(12)						
5- 1-80	FUEL CELL 6	26	(12)						
6- 1-80	KAIPARJWITS 1 (750/300 MW)	291	(14)						
6- 1-80	FUEL CELL 7	26	(12)						
8- 1-80	FUEL CELL 8	26	(12)						
8- 1-80	FUEL CELL 9	26	(12)						
9- 1-80	RERATE SAN ONOFRE 2 (223/182 TO 1140/912 MW)	730	(13)						
11- 1-80	FUEL CELL 10	26	(12)						
11- 1-80	FUEL CELL 11	26	(12)						
12- 1-80	SAN ONOFRE 3 (223/182 MW)	182	(13)						
	TOTAL CAPACITY ADDED	1411							
	LOADS AND RESOURCES FOR SUMMER 1980		17092		14381	2711	18.9	14080	4.2
	LOADS AND RESOURCES FOR WINTER 1980			17943	13487	4456	33.0		

FEBRUARY 8, 1974
 FUTURE GENERATION RESOURCE PROGRAM
 1974-1983

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)	
1- 1-81	TERMINATE NAVAJO LAYOFF (127 MW)	-317	(17)							
1- 1-81	FUEL CELL 12	26	(12)							
1- 1-81	FUEL CELL 13	26	(12)							
4- 1-81	FUEL CELL 14	26	(12)							
4- 1-81	FUEL CELL 15	26	(12)							
6- 1-81	KAIPAROWITS 2 (750/300 MW)	291	(14)							
6- 1-81	BIG CREEK AREA DEVELOPMENT PHASE I-A	180	(15)							
12- 1-81	REDATE SAN ONOFRE 3 (228/182 TO 1140/912 MW)	730	(13)							
TOTAL CAPACITY ADDED (A)		988								
LOADS AND RESOURCES FOR SUMMER 1981			18314		14961	3353	22.4	.97	14660	4.1
LOADS AND RESOURCES FOR WINTER 1981				18931	14027	4904	35.0			
1- 1-82	RETIRE LONG BEACH 10	-106								
1- 1-82	RETIRE LONG BEACH 11	-106								
3- 1-82	KAIPAROWITS 3 (750/300 MW)	291	(14)							
6- 1-82	BIG CREEK AREA DEVELOPMENT PHASE I-B	164	(15)							
12- 1-82	KAIPAROWITS 4 (750/300 MW)	291	(14)							
TOTAL CAPACITY ADDED (B)		534								
LOADS AND RESOURCES FOR SUMMER 1982			19287		15574	3713	23.8	.99	15260	4.1
LOADS AND RESOURCES FOR WINTER 1982				19465	14590	4875	33.4			

(A) GENERATION FROM THE SAN JOAQUIN NUCLEAR PROJECT MAY BE AVAILABLE AS EARLY AS 12-1-81 ON A NON-FIRM BASIS

(B) NON FIRM GENERATION FROM VIDAL NUCLEAR UNITS 1&2 MAY COMMENCE AS EARLY AS 4-1-82 AND 6-1-82 RESPECTIVELY

FEBRUARY 8, 1974
 FUTURE GENERATION RESOURCE PROGRAM
 1974-1983

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	AREA MARGIN (%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
1983	NEW RESOURCE ADDITIONS									
	LOADS AND RESOURCES FOR SUMMER 1983		19578		16278	3300	20.3	.99	15900	4.2
	LOADS AND RESOURCES FOR WINTER 1983			19465	15254	4211	27.6			

FEBRUARY 8, 1974
 FUTURE GENERATION RESOURCE PROGRAM
 1974-1983

DEVELOPMENT OF PERTINENT DATA

1) RECONCILIATION OF THE 12-31-73 AGGREGATE RATED CAPACITY WITH THE
 DECEMBER 31, 1973 REVISION OF THE "GENERATOR RATINGS AND EFFECTIVE
 OPERATING CAPACITY OF RESOURCES".

NET MAIN EDISON OWNED SYSTEM RESOURCES (DECEMBER 31, 1973)	12215
TOTAL FIRM PURCHASES (DECEMBER 31, 1973)	+1185
MWD CAPACITY	+310
WINTER HYDRO DERATE	-119
TOTAL OFF SYSTEM LOSSES	-68
12-31-73 AGGREGATE RATED CAPACITY	13523

2) SUMMARY OF AREA PEAK DEMANDS (1974-1983)

	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
SUMMER										
EDISON NET PEAK DEMAND	10710	11190	11659	12257	12926	13464	14032	14611	15209	15846
BLYTHE	-	-	41	43	44	46	48	49	51	54
MWD LOAD	295	295	295	295	295	295	295	295	295	295
STATE WATER PROJECT	-	-	-	-	-	7	6	6	19	83
TOTALS	11005	11485	11995	12595	13265	13812	14381	14961	15574	16278
WINTER										
EDISON NET PEAK DEMAND	9960	10410	10847	11396	12025	12524	13053	13592	14141	14740
BLYTHE	-	-	23	24	25	26	27	28	29	30
MWD LOAD	295	295	295	295	295	295	295	295	295	295
STATE WATER PROJECT	-	-	-	-	-	7	6	6	19	83
SALE TO PORTLAND GE	27	106	106	106	106	106	106	106	106	106
SALE TO PORTLAND GE	159	-	-	-	-	-	-	-	-	-
TOTALS	10441	10811	11271	11821	12451	12958	13487	14027	14590	15254

FEBRUARY 8, 1974
FUTURE GENERATION RESOURCE PROGRAM
1974 - 1983

DEFINITION OF COLUMN HEADINGS

Date

Firm operating date of unit or contractual agreement.

Resource

Resource identification. Often includes supplemental information about capacity particularly when the identification refers to a unit which is undergoing rerate, has associated off system losses, or is a participation unit.

Net Capacity Added

Effective operating capacity rating of the resource. These have been adjusted for losses incurred outside the Edison control area where applicable.

Total Capacity

Summer total capacity includes resources scheduled as of August 1 of that year, winter includes all capacity added in that year.

Area Peak Demand

Includes Edison net main system peak demand plus firm on-peak sales to other utilities, a constant 295 MW demand for Metropolitan Water District pumping load, and demands for isolated Edison loads commencing when they are expected to be integrated into the main system.

Area Margin

Megawatt margin is the difference between total installed capacity and area peak demand. Percent margin is the megawatt margin divided by area peak demand and multiplied by 100.

DEFINITION OF COLUMN HEADINGS

Area Reliability Index

The reliability index represents the probability that a particular year's specified resources will be sufficient to serve forecast loads for each hour of the year, allowing for planned generation maintenance and forced outages without requiring delivery of capacity via Edison's interconnections in excess of firm deliveries through 1973 or in excess of firm deliveries plus 300 MW from 1974 through 1983.

Edison Net Peak Demand

Edison net peak demand for 1974-1983 is based on a 4-1/2% average annual compound growth rate for the total system through 1983.

Annual Load Increase

Percent that Edison net peak demand increases over the previous year.

FEBRUARY 8, 1974
FUTURE GENERATION RESOURCE PROGRAM
1974-1983

NOTES

- (1) Aggregate rated capacity in accord with the December 31, 1973 revision of "Generator Ratings and Effective Operating Capacity of Resources," which includes total generation capacities of SCE and MWD. MWD capacity is rated at 310 MW (260 MW at Hoover, 1,213 foot surface elevation and 50 MW at Parker).
- (2) Mohave Units 1 and 2 were each rerated from 760 MW to 790 MW on January 1, 1974. Edison's 56% share of the rerate is 16.8 MW for each unit; following these rerates, Edison's share of the capacity is 442.4 MW for each unit.
- (3) The existing operating agreement between Edison and the City of Vernon, which makes 20 MW of diesel capacity available, is being terminated on March 4, 1974 due to sale of these units by the City of Vernon.
- (4) A service agreement has been executed with Portland General Electric providing for a sale of 150 MW of capacity and limited energy for the winters of 1973-74 and 1974-75. Contract losses to the point of delivery increase Edison's obligation by an additional 9 MW.
- (5) An assignment has been negotiated with Pacific Gas & Electric Company and Portland General Electric Company providing for sale and exchange of capacity and energy. The principal effect on Edison's capacity resources is equivalent to a firm capacity purchase in the summer and a firm capacity sale in the winter periods indicated beginning in the winter of 1976. In the three years prior to 1976, special conditions of the agreement prescribe the exchanges shown in those years. Exchange amounts are specified at anticipated levels and have been adjusted for Edison's loss obligations.
- (6) A contract has been executed with the Bonneville Power Administration, Pacific Power & Light, and the Portland General Electric Company for the sale of 400 MW of capacity and associated energy from December 1, 1973 to May 31, 1974. This contract provides that scheduled energy deliveries may be curtailed in the event that such schedules would result in curtailment of service to Edison's firm customers. The winter area peak demand for 1973 includes this sale.

- (7) A contract has been executed with the U. S. Bureau of Reclamation for layoff of power from the Navajo Project. At such time as USBR needs this power for the Central Arizona Project, USBR has the right to terminate this layoff effective on or after January 1, 1980, upon at least five years advance written notice. Such notice has not been given; however, it is currently anticipated the layoff will terminate in 1981.
- (8) Sale of Edison's former Tonopah District facilities to the Sierra Pacific Power Company was concluded September 30, 1969. Until such time as Sierra provides power to the former Tonopah District from its main system, which is to be accomplished within five years of the date of sale, Edison will sell power to Sierra and has exclusive use of the Gabbs generation. It has been assumed service from Sierra will begin September 30, 1974; therefore, the Nevada resources (Gabbs) and load (including Mineral County) were removed from the Edison system.
- (9) To comply with air pollution control standards, installation of additional emission control equipment is required and is expected to result in capacity reductions for Four Corners Units 4 & 5 and Mohave Units 1 & 2. Edison's share of these reductions amounts to 28 MW for each of the Four Corners units - 6 MW on May 1, 1975 (for the first scrubber module) plus an additional 22 MW on April 1, 1977 for Unit 4, and 28 MW on June 1, 1977 for Unit 5. Similarly, on January 1, 1977, Edison's share of each Mohave unit will be reduced by 25 MW. For the purpose of planning replacement capacity, the appropriate reductions are shown on the above dates.
- (10) The capacities shown for the Long Beach Combined Cycle Project are for the individual combustion turbines and steam turbines.
- (11) Blythe District becomes part of integrated system; therefore, Yuma Axis resources and Blythe demand are added to the system.
- (12) In March 1973, Edison joined a group of investor-owned utilities to fund an electric utility fuel cell program in conjunction with Pratt & Whitney Aircraft. Final commitments to purchase 15 units at 26 MW each for delivery in 1978-1980 will be made late in 1975. This purchase, however, will be contingent upon a successful validation of a test unit in 1976 or 1977.
- (13) Edison's share of San Onofre Units 2 and 3 is shown as 80% in accordance with agreements with San Diego Gas & Electric Company.

- (14) Edison is participating in a 3000 MW coal development in Southern Utah. The project capacity has been allocated as follows:

	<u>Participation Percentage</u>
SCE	40.0
APS	18.0
SDG&E	23.4
SRP	10.0
UNCOMMITTED	<u>8.6</u>
Total	100.0

- (15) It is planned to increase the existing 690 MW Big Creek facility by 344 MW through expansion of some present plants, tunnel modifications, and additional powerhouses and tunnels.

DJF:lm
February 8, 1974

27.3.7


February 8, 1974

MESSRS: W. R. GOULD W. H. SEAMAN
 H. P. ALLEN A. ARENAL
 R. N. COE P. B. PEECOOK
 E. A. MYERS J. T. HEAD
 G. E. WILCOX A. L. MAXWELL

Subject: Future Generation Resources from 1984 to 1993

A ten year extension to the 1974-1983 Future Generation Resource Program, dated February 8, 1974, is attached for your information. This extension, covering the years 1984 through 1993, will be used for conceptual planning purposes including developing estimates of long term fuel requirements, air emissions and capital expenditures. The information will also form the basis for the 1974 California Public Utilities Commissions G.O. 131 Twenty-Year Resource Plan submittal which will be transmitted to the CPUC in March.

This schedule is released for in-house use only. Please contact me regarding any contemplated use of this information outside of Edison.


D. J. FOGARTY

DJF/sm
Attachment

cc: W. M. Marriott
 G. A. Davis
 O. J. Ortega
 P. J. West
 R. H. Bridenbecker

SECOND TEN YEARS OF THE FEBRUARY 8, 1974
 FUTURE GENERATION RESOURCE PROGRAM
 1984-1993

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
12-31-83	AGGREGATE RATED CAPACITY REDUCED FOR "DRY YEAR HYDRO" CONDITIONS, 100 MW FOR SUMMER AND 119 MW FOR WINTER		19578	19465 (1)					
5-16-84	ANNUAL SUMMER PGE EXCHANGE (100 MW PGE TO SCE FROM MAY 16 THRU OCT. 15)	94/ 0 (2)							
6- 1-84	VIDAL NUCLEAR 1 (A)	760 (3)							
6- 1-84	EAST COAL 1 (750/300 MW)	291 (4)							
11- 1-84	ANNUAL WINTER PGE EXCHANGE (106 MW SCE TO PGE FROM NOV. 1 THRU MAR. 31)								
	TOTAL CAPACITY ADDED	1145/1051							
	LOADS AND RESOURCES FOR SUMMER 1984		20629		17105	3524	20.6	.96	16710
	LOADS AND RESOURCES FOR WINTER 1984			20516	16041	4475	27.9		
1- 1-85	TERMINATE OROVILLE-THERMALITO	-318 (5)							
1- 1-85	GEO THERMAL 1	50 (4)							
4- 1-85	GEO THERMAL 2	50 (4)							
6- 1-85	VIDAL NUCLEAR 2	760 (3)							
6- 1-85	EAST COAL 2 (750/300 MW)	291 (4)							
6- 1-85	BIG CREEK AREA DEVELOPMENT PHASE II	324 (6)							
6- 1-85	SAN JOAQUIN NUC 1 (1100/253MW) (B)	253 (7)							
	TOTAL CAPACITY ADDED	1410							
	LOADS AND RESOURCES FOR SUMMER 1985		22039		18123	3916	21.6	.96	17730
	LOADS AND RESOURCES FOR WINTER 1985			21926	16989	4937	29.1		

(A) NON-FIRM ENERGY PRODUCTION COULD BE AVAILABLE AS EARLY AS 6-1-82
 FOR UNIT 1 AND 6-1-83 FOR UNIT 2

(B) NON-FIRM ENERGY PRODUCTION COULD BE AVAILABLE BY 12-1-81

SECOND TEN YEARS OF THE FEBRUARY 1974
 FUTURE GENERATION RESOURCE PROGRAM
 1984-1993

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)	
6- 1-86	NUCLEAR 1	760 (4)								
6- 1-86	EAST COAL 3 (750/300 MW)	291 (4)								
6- 1-86	SAN JOAQUIN NUC 2 (1100/253MW)	253 (7)								
	TOTAL CAPACITY ADDED	1304								
	LOADS AND RESOURCES FOR SUMMER 1986		23343		19362	3981	20.6	.99	18960	6.9
	LOADS AND RESOURCES FOR WINTER 1986			23230	18138	5092	28.1			
6- 1-87	TERMINATE HOOVER	-277 (8)								
6- 1-87	EAST COAL A (1100/440)	414 (4)								
6- 1-87	NUCLEAR 2	760 (4)								
6- 1-87	EAST COAL 4 (750/300 MW)	291 (4)								
6- 1-87	BIG CREEK AREA DEVELOPMENT PHASE III	280 (9)								
6- 1-87	SAN JOAQUIN NUC 3 (1100/253MW)	253 (7)								
8- 1-87	TERMINATE BPA EXCHANGE	-517 (10)								
	TOTAL CAPACITY ADDED	1204								
	LOADS AND RESOURCES FOR SUMMER 1987		24547		20685	3862	18.7	.99	20280	7.0
	LOADS AND RESOURCES FOR WINTER 1987			24434	19371	5063	26.1			
6- 1-88	EAST COAL B (1100/440)	414 (4)								
6- 1-88	NUCLEAR 3	1140 (4)								
6- 1-88	SAN JOAQUIN NUC 4 (1100/253MW)	253 (7)								
	TOTAL CAPACITY ADDED	1807								
	LOADS AND RESOURCES FOR SUMMER 1988		26354		22159	4195	18.9	.96	21730	7.1
	LOADS AND RESOURCES FOR WINTER 1988			26241	20745	5496	26.5			

RECORD IN YEARS OF THE FEBRUARY 9, 1974
 FUTURE GENERATION RESOURCE PROGRAM
 1984-1

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
6- 1-89	EAST COAL C (1100/440)	414 (4)								
6- 1-89	NUCLEAR 4	1140 (4)								
6- 1-89	NUCLEAR 5	760 (4)								
	TOTAL CAPACITY ADDED	2314								
	LOADS AND RESOURCES FOR SUMMER 1989		28668		23733	4935	20.8	.97	23270	7.1
	LOADS AND RESOURCES FOR WINTER 1989			28555	22209	6346	28.6			
1- 1-90	BLACK STAR 1	275 (11)								
4- 1-90	BLACK STAR 2	275 (11)								
6- 1-90	NUCLEAR 6	760 (4)								
7- 1-90	BLACK STAR 3	275 (11)								
10- 1-90	BLACK STAR 4	275 (11)								
	TOTAL CAPACITY ADDED	1860								
	LOADS AND RESOURCES FOR SUMMER 1990		30253		25429	4824	19.0	.98	24930	7.1
	LOADS AND RESOURCES FOR WINTER 1990			30415	23785	6630	27.9			
1- 1-91	GEOTHERMAL 3	50 (4)								
6- 1-91	EAST COAL D (1100/440)	414 (4)								
6- 1-91	NUCLEAR 7	760 (4)								
6- 1-91	PUMPED STORAGE A	250 (4)								
10- 1-91	PUMPED STORAGE B	250 (4)								
	TOTAL CAPACITY ADDED	1724								
	LOADS AND RESOURCES FOR SUMMER 1991		32002		27183	4819	17.7	.99	26670	7.0
	LOADS AND RESOURCES FOR WINTER 1991			32139	25419	6720	26.4			

SECOND TEN YEARS OF THE FEBRUARY 8, 1974
 FUTURE GENERATION RESOURCE PROGRAM
 1984-1-13

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN		AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
			SUMMER (MW)	WINTER (MW)		(MW)	(%)			
1- 1-92	GEO THERMAL 4	50 (4)								
1- 1-92	PUMPED STORAGE C	250 (4)								
5- 1-92	PUMPED STORAGE D	250 (4)								
6- 1-92	EAST COAL E (1100/440)	414 (4)								
6- 1-92	EAST COAL F (1100/440)	414 (4)								
6- 1-92	NUCLEAR 8	760 (4)								
	TOTAL CAPACITY ADDED	2138								
	LOADS AND RESOURCES FOR SUMMER 1992		34390		29035	5355	18.4	.99	28510	6.9
	LOADS AND RESOURCES FOR WINTER 1992			34277	27141	7136	26.3			
6- 1-93	EAST COAL H (1100/440)	414 (4)								
6- 1-93	EAST COAL G (1100/440)	414 (4)								
6- 1-93	NUCLEAR 9	1140 (4)								
	TOTAL CAPACITY ADDED	1968								
	LOADS AND RESOURCES FOR SUMMER 1993		36358		30846	5512	17.9	.99	30330	6.4
	LOADS AND RESOURCES FOR WINTER 1993			36245	28832	7413	25.7			

SECOND TEN YEARS OF THE FEBRUARY 8, 1974
 FUTURE GENERATION RESOURCE PROGRAM
 1984-1993

SUMMARY OF AREA PEAK DEMANDS (1984-1993)

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
SUMMER										
EDISON NET PEAK DEMAND	16710	17730	18960	20280	21730	23270	24930	26670	28510	30330
MWD LOAD	295	295	295	295	295	295	295	295	295	295
STATE WATER PROJECT	100	98	107	110	134	168	204	218	230	221
TOTALS	17105	18123	19362	20685	22159	23733	25429	27183	29035	30846
WINTER										
EDISON NET PEAK DEMAND	15540	16490	17630	18860	20210	21640	23180	24800	26510	28210
MWD LOAD	295	295	295	295	295	295	295	295	295	295
STATE WATER PROJECT	100	98	107	110	134	168	204	218	230	221
SALE TO PORTLAND GE	106	106	106	106	106	106	106	106	106	106
TOTALS	16041	16989	18138	19371	20745	22209	23785	25419	27141	28832

SECOND TEN YEARS (1984-1993) OF THE
FEBRUARY 8, 1974 FUTURE
GENERATION RESOURCE PROGRAM

DEFINITION OF COLUMN HEADINGS

Date

Firm operating date of unit or contractual agreement.

Resource

Resource identification. Often includes supplemental information about capacity, particularly when the identification refers to a unit which is undergoing rerate, has associated off system losses, or is a participation unit.

Net Capacity Added

Effective operating capacity rating of the resource. These have been adjusted for losses incurred outside the Edison control area where applicable.

Total Capacity

Summer total capacity includes resources scheduled as of August 1 of that year, winter includes all capacity added in that year.

Area Peak Demand

Includes Edison net main system peak demand plus firm on-peak sales to other utilities, a constant 295 MW demand for Metropolitan Water District pumping load, and demands for isolated Edison loads commencing when they are expected to be integrated into the main system.

Area Margin

Megawatt margin is the difference between total installed capacity and area peak demand. Percent margin is the megawatt margin divided by area peak demand and multiplied by 100.

DEFINITION OF COLUMN HEADINGS

Area Reliability Index

The reliability index represents the probability that a particular year's specified resources will be sufficient to serve forecast loads for each hour of the year, allowing for planned generation maintenance and forced outages without requiring delivery of capacity via Edison's interconnections in excess of firm deliveries through 1973 or in excess of firm deliveries plus 300 MW from 1974-1984, 500 MW from 1985-1988 and 600 MW from 1989-1993.

Edison Net Peak Demand

Edison net peak demand for 1984-1993 is based on the forecast prepared in December 1973 by the System Development Department.

Annual Load Increase

Percent that Edison net peak demand increases over the previous year.

DJF/sm
February 6, 1974

SECOND TEN YEARS (1984-1993) OF THE
FEBRUARY 8, 1974 FUTURE
GENERATION RESOURCE PROGRAM

NOTES

- (1) Aggregate rated capacity in accord with the December 31, 1973 revision of "Generation Ratings and Effective Operating Capacity of Resources," which includes MWD and total generation of SCE to the year 1983 from the February 8, 1974 "Future Generation Resource Program, 1974-1983." MWD capacity is rated at 310 MW (260 at Hoover, 1213 foot surface elevation and 50 MW at Parker).
- (2) An assignment has been negotiated with Pacific Gas & Electric Company and Portland General Electric Company, providing for sale and exchange of capacity and energy. The principal effect on Edison's capacity resources is equivalent to a firm capacity sale in the winter periods indicated. Exchange amounts are specified at anticipated levels and have been adjusted for Edison's loss obligations.
- (3) Vidal Nuclear Units 1 & 2 were formerly named HTGR 1 & 2; non-firm energy production could be available as early as 6-1-82 for Unit 1 and 6-1-83 for Unit 2.
- (4) Specific sites for these units have not been determined. Some potential sites currently under investigation include:

Coal Sites

Emery
Cedar City
Alton

Nuclear Sites

Rice
Kings County
Pt. Conception
Chemehuevi

Geothermal

Mono County
Long Valley
Imperial County
Inyo County
San Bernardino County

Pumped Storage Hydro

Madera County
Fresno County
San Diego County

Assumed Edison participation (40%) in Eastern Coal Development. Geothermal generation is presently under research and development. Initial operation of the first unit could be as early as 1980.

(5) On November 1, 1984, the contractual provisions for energy and capacity, from the Oroville Thermalito facility with the State of California, Southern California Edison Company and San Diego Gas & Electric Company are terminated. Other contractual agreements require Pacific Gas & Electric Company to provide equivalent energy and capacity to Southern California Edison Company and San Diego Gas & Electric Company until January 1, 1985.

(6) Additional 324 MW expansion in the Big Creek area.

(7) Edison is participating in a 4-unit, 4400 MW nuclear development in the San Joaquin Valley. Firm operating dates for this development are based on Edison estimates of nuclear project lead time requirements. Non-firm energy production may commence as early as 12-1-81. Preliminary project allocation is as follows:

	<u>Participation Percentage</u>
LADWP	50
PG&E	24
SCE	23
SDG&E	<u>3</u>
Total	100

(8) Edison's present 50-year Hoover contract for energy and capacity with the U. S. Department of the Interior expires on June 1, 1987.

(9) Additional 280 MW expansion in the Big Creek area.

(10) The contract with the Bonneville Power Authority for 550 MW of exchange capacity expires on August 1, 1987.

(11) Assumed 1100 MW pumped storage development.

DJF/sm
February 6, 1974

FUTURE GENERATION RESOURCE SCHEDULE - JUNE 5, 1973
PRINCIPAL CHANGES FROM THE RESOURCE
SCHEDULE OF DECEMBER 6, 1972

1. The effective operating capacity of the Ellwood energy support facility has been increased by 4 MW.
2. Initial dates for Long Beach Combined Cycle generation have been modified in 1975 with the total project being completed by 12-1-75. In addition, the project size has been reduced from 582 MW to 563 MW.
3. The total capacity of the Huntington Beach Combined Cycle Project remained unchanged; however, the combustion turbine portion was increased from 124 MW to 141 MW.
4. The Piru Creek pumped hydro project scheduled for 1981-82 has been deleted.
5. The Kaiparowits Project firm operating dates have been rescheduled within the 1980-82 time frame to allow for spacing of four 750 MW units which are replacing the previously planned three 1000 MW size units.
6. The size of the HTGR nuclear Unit 1 in 1982 has been reduced in size from 770 MW to 760 MW. The companion HTGR nuclear Unit 2 is shown in 1983.
7. The San Onofre Units 2 & 3 Project formerly scheduled for 1978 and 1979 has been deferred by 11 and 14 months respectively to 9-1-79 and 12-1-80.
8. Long Beach Units 10 & 11 are shown retired in place in 1983.
9. A Edison-Portland Service Agreement for 150 MW in 1973-1975 has been executed.
10. The total combined cycle capacity in the 1979 to 1981 time frame has been increased from 1350 MW to 1765 MW.
11. The 20 MW of diesel capacity from Vernon is shown terminated on 4-2-1977.

Note: This schedule is based on the February 1973-1995 System Forecasts.

DJF/yg
May 30, 1973

PERC APPROVED JUNE 5, 1973
 FUTURE GENERATION RESOURCE PROGRAM
 1973-1983

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN		AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
			SUMMER (MW)	WINTER (MW)		(MW)	(%)			
12-31-72	AGGREGATE RATED CAPACITY REDUCED FOR "DRY YEAR HYDRO" CONDITIONS, 100 MW FOR SUMMER AND 119 MW FOR WINTER		12717	12698	(1)					
1- 1-73	RERATE MOHAVE 2 (700/392 TO 760/426 MW)	34			(2)					
1- 1-73	INCREASE NEVADA LAYOFF (102 TO 106 MW)	4			(2)					
2- 1-73	NORTHWEST POWER DECREASED TRANSMISSION LOSSES	2			(3)					
4- 1-73	SALE TO NEVADA POWER (35 MW)				(4)					
5-31-73	TERMINATE NEVADA POWER LAYOFF (106 MW)	-106			(2)					
6- 1-73	ORMOND BEACH 2	750								
7- 1-73	NORTHWEST POWER (150 MW)	141			(5)					
9-30-73	TERMINATE SALE TO NEVADA POWER (35 MW)				(4)					
11- 1-73	PORTLAND GENERAL EXCHANGE (-53 MW)				(6)					
11- 1-73	SALE TO PORTLAND GENERAL (159 MW)				(7)					
12- 1-73	SALE TO NORTHWEST (400 MW)				(8)					
	TOTAL CAPACITY ADDED	825								
	LOADS AND RESOURCES FOR SUMMER 1973		13542		10620	2922	27.5		10290	4.8
	LOADS AND RESOURCES FOR WINTER 1973			13523	10557	2966	28.1			

PERC APPROVED JUNE 5, 1973
 FUTURE GENERATION RESOURCE PROGRAM
 1973-1983

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN		AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
			SUMMER (MW)	WINTER (MW)		(MW)	(%)			
1- 1-74	RERATE MOHAVE 1 (760/425 TO 790/442 MW)	17 (2)								
1- 1-74	RERATE MOHAVE 2 (760/426 TO 790/443 MW)	17 (2)								
3-31-74	TERMINATE SALE TO PORTLAND GENERAL (159 MW)	(7)								
4- 1-74	TERMINATE PORTLAND GENERAL EXCHANGE (-53 MW)	(6)								
5-31-74	TERMINATE SALE TO NORTHWEST (400 MW)	(8)								
6- 1-74	NAVAJU 1 LAYOFF (97 MW)	94 (9)								
6- 1-74	ELLWOOD ENERGY SUPPORT FACILITY	54								
9-30-74	TERMINATE GABBS	-6 (10)								
11- 1-74	PORTLAND GENERAL EXCHANGE (-27 MW)	(6)								
11- 1-74	SALE TO PORTLAND GENERAL (159 MW)	(7)								
	TOTAL CAPACITY ADDED	176								
	LOADS AND RESOURCES FOR SUMMER 1974		13724		11365	2359	20.8	.987	11070	7.6
	LOADS AND RESOURCES FOR WINTER 1974			13699	10801	2898	26.8			

PERC APPROVED JUNE 5, 1973
 FUTURE GENERATION RESOURCE PROGRAM
 1973-1983

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
3-31-75	TERMINATE SALE TO PORTLAND GENERAL (159 MW)				(7)					
4- 1-75	TERMINATE PORTLAND GENERAL EXCHANGE (-27 MW)				(6)					
5-16-75	ANNUAL SUMMER PORTLAND GENERAL EXCHANGE (FROM MAY 16 THRU OCT. 15) 100 MW	94/ 0	(6)							
6- 1-75	NAVAJO 2 LAYOFF (104 MW)	101			(9)					
6- 1-75	EDWARDS AFB EXCHANGE (SUMMER/WINTER)	177/ 13			(11)					
6- 1-75	YUMA AXIS	25			(11)					
6- 1-75	LONG BEACH 1 (COMBUSTION TURBINE)	60			(12)					
6- 1-75	COOLWATER 3	236								
6- 1-75	COOLWATER 4	236								
7- 1-75	LONG BEACH 2 (COMBUSTION TURBINE)	60			(12)					
8- 1-75	WASHINGTON BEACH 6 (TWO 70.5 MW COMBUSTION TURBINES)	141								
8- 1-75	LONG BEACH 3 (COMBUSTION TURBINE)	60			(12)					
8- 1-75	WASHINGTON BEACH 7 (TWO 70.5 MW COMBUSTION TURBINES)	141								
9- 1-75	LONG BEACH 4 (COMBUSTION TURBINE)	60			(12)					
9- 1-75	LONG BEACH 1-4 (STEAM TURBINE)	78			(12)					
10- 1-75	WASHINGTON BEACH 8 (TWO 70.5 MW COMBUSTION TURBINES)	141								
10- 1-75	LONG BEACH 5 (COMBUSTION TURBINE)	60			(12)					
11- 1-75	LONG BEACH 6 (COMBUSTION TURBINE)	60			(12)					
12- 1-75	LONG BEACH 7 (COMBUSTION TURBINE)	60			(12)					
12- 1-75	LONG BEACH 5-7 (STEAM TURBINE)	65			(12)					
	TOTAL CAPACITY ADDED	1695/1597								
	LOADS AND RESOURCES FOR SUMMER 1975		14748		12217	2531	20.7	.999	11922	7.7
	LOADS AND RESOURCES FOR WINTER 1975			15296	11399	3897	34.2			

PERC APPROVED JUNE 5, 1973
 FUTURE GENERATION RESOURCE PROGRAM
 1973-1983

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
1- 1-76	DERATE FOUR CORNERS 4 (800/384 TO 755/362 MW)	-21			(13)					
1- 1-76	DERATE FOUR CORNERS 5 (800/384 TO 755/362 MW)	-21			(13)					
4- 1-76	TERMINATE EDWARDS AFB EXCHANGE	-177			-13					
4- 1-77	HUNTINGTON BEACH 1 (TWO 70.5 MW COMBUSTION TURBINES)				141					
5- 1-77	HUNTINGTON BEACH 2 (TWO 70.5 MW COMBUSTION TURBINES)				141					
6- 1-76	NAVAJO 3 LAYOFF (126 MW)				122		(9)			
4- 1-77	HUNTINGTON BEACH 3 (TWO 70.5 MW COMBUSTION TURBINES)				141					
11- 1-76	ANNUAL WINTER PORTLAND GENERAL EXCHANGE (FROM NOV. 1 THRU MAR. 31) -106 MW				(6)					
	TOTAL CAPACITY ADDED	486	490							
	LOADS AND RESOURCES FOR SUMMER 1976		15899		13050	2849	21.8	.999	12755	7.0
	LOADS AND RESOURCES FOR WINTER 1976			15786	12246	3540	28.9			
1- 1-77	DERATE MOHAVE 1 (790/442 TO 746/417 MW)	-25			(13)					
1- 1-77	DERATE MOHAVE 2 (790/443 TO 746/418 MW)	-25			(13)					
4- 2-77	TERMINATE VERNON	-20			(14)					
4- 1-77	LUCERNE VALLEY 1				414					
4- 1-77	HUNTINGTON BEACH 6 (STEAM)				95					
5- 1-77	HUNTINGTON BEACH 7 (STEAM)				95					
6- 1-77	HUNTINGTON BEACH 8 (STEAM)				95					
6- 1-77	LUCERNE VALLEY 2				414					
	TOTAL CAPACITY ADDED		1043							
	LOADS AND RESOURCES FOR SUMMER 1977		16942		13903	3039	21.9	.999	13608	6.7
	LOADS AND RESOURCES FOR WINTER 1977			16829	13068	3761	28.8			

PERC APPROVED JUNE 5, 1973
 FUTURE GENERATION RESOURCE PROGRAM
 1973-1983

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
4-1-78	HUNTINGTON BEACH 9 (STEAM)	95								
5-1-78	HUNTINGTON BEACH 10 (STEAM)	95								
6-1-78	HUNTINGTON BEACH 11 (STEAM)	95								
6-1-78	LUCERNE VALLEY 3	414								
	TOTAL CAPACITY ADDED	699								
	LOADS AND RESOURCES FOR SUMMER 1978		17641		14766	2875	19.5	.996	14471	6.3
	LOADS AND RESOURCES FOR WINTER 1978			17528	13940	3588	25.7			
6- 1-79	COMBINED CYCLE A	225								
6- 1-79	COMBINED CYCLE B	225								
9- 1-79	SAN UNDFRE 2 (228/182 MW)	182 (15)								
	TOTAL CAPACITY ADDED	632								
	LOADS AND RESOURCES FOR SUMMER 1979		18091		15689	2402	15.3	.994	15394	6.4
	LOADS AND RESOURCES FOR WINTER 1979			18160	14821	3339	22.5			
6- 1-80	KAIPAROWITS 1 (750/300 MW)	291 (16)								
6- 1-80	COMBINED CYCLE C	225								
6- 1-80	COMBINED CYCLE D	225								
6- 1-80	COMBINED CYCLE D	225								
6- 1-80	COMBINED CYCLE E	225								
9- 1-80	RERATE SAN UNDFRE 2 (228/182 TO 1140/912 MW)	730 (15)								
12- 1-80	SAN UNDFRE 3 (228/182 MW)	182 (15)								
	TOTAL CAPACITY ADDED	2103								
	LOADS AND RESOURCES FOR SUMMER 1980		19464		16683	2781	16.7	.992	16388	6.5
	LOADS AND RESOURCES FOR WINTER 1980			20263	15674	4589	29.3			

PERC APPROVED JUNE 5, 1973
 FUTURE GENERATION RESOURCE PROGRAM
 1973-1983

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
1- 1-81	TERMINATE NAVAJO LAYOFF (327 MW)	-317 (9)								
6- 1-81	KAIPAROWITS 2 (750/300 MW)	291 (16)								
6- 1-81	COMBINED CYCLE F	225								
6- 1-81	COMBINED CYCLE G	415								
12- 1-81	RERATE SAN ONOFRE 3 (228/182 TO 1140/912 MW)	730 (15)								
	TOTAL CAPACITY ADDED	1344								
	LOADS AND RESOURCES FOR SUMMER 1981		20990		17686	3304	18.7	.976	17391	6.1
	LOADS AND RESOURCES FOR WINTER 1981			21607	16695	4912	29.4			
3- 1-82	KAIPAROWITS 3 (750/300 MW)	291 (16)								
6- 1-82	HTGR 1	760								
12- 1-82	KAIPAROWITS 4 (750/300 MW)	291 (16)								
	TOTAL CAPACITY ADDED	1342								
	LOADS AND RESOURCES FOR SUMMER 1982		22771		18718	4053	21.7	.995	18405	5.8
	LOADS AND RESOURCES FOR WINTER 1982			22949	17765	5184	29.2			
6- 1-83	HTGR 2	760								
10- 1-83	RETIRE LONG BEACH 10	-106								
10- 1-83	RETIRE LONG BEACH 11	-106								
	TOTAL CAPACITY ADDED	548								
	LOADS AND RESOURCES FOR SUMMER 1983		23822		19832	3990	20.1	.997	19459	5.7
	LOADS AND RESOURCES FOR WINTER 1983			23497	18878	4619	24.5			

JUNE 5, 1973
FUTURE GENERATION RESOURCE SCHEDULE
1973 - 1983

DEFINITION OF COLUMN HEADINGS

Date

Firm operating date of unit or contractual agreement.

Resource

Resource identification. Often includes supplemental information about capacity particularly when the identification refers to a unit which is undergoing rerate, has associated off system losses, or is a participation unit.

Net Capacity Added

Effective operating capacity rating of the resource. These have been adjusted for losses incurred outside the Edison control area where applicable.

Total Capacity

Summer total capacity includes resources scheduled as of August 1 of that year; winter includes all capacity added in that year.

Area Peak Demand

Includes forecast annual peak demands of SCE and MWD. Demand forecast includes sales to other utilities and a constant 295 MW demand for MWD.

Area Margin

Megawatt margin is the difference between total installed capacity and area peak demand. Percent margin is the megawatt margin divided by area peak demand multiplied by 100.

Area Reliability Index

The reliability index represents the probability that a particular year's specified resources will be sufficient to serve forecast loads for each hour of the year, allowing for planned generation maintenance and forced outages without requiring delivery of capacity via Edison's interconnections in excess of firm deliveries through 1973 or in excess of firm deliveries plus 300 MW from 1974 through 1983.

Edison Net Peak Demand

Edison net peak demand for 1973-1983 is based on the February 1973, forecast prepared by the System Development Department.

Annual Load Increase

Percent Edison net peak demand increased over previous year.

JUNE 5, 1973
 FUTURE GENERATION RESOURCE SCHEDULE
 1973 - 1983

NOTES

- (1) Aggregate rated capacity in accord with the December 31, 1972, revision of "Generator Ratings and Effective Operating Capacity of Resources," which includes total generation capacities of SCE and MWD. MWD capacity is rated at 310 MW (260 MW at Hoover, 1,213 surface elevation and 50 MW at Parker).
- (2) Unit No. 1 at Mohave is currently rated at an effective capacity of 760 MW. When Unit No. 2 at Mohave went into service on October 1, 1971, it was rated at 450 MW. On March 24, 1972, Mohave No. 2 was rerated to 600 MW, and on June 6, 1972, it was rerated to 700 MW. This rating was increased to 760 MW on January 1, 1973. Finally, both Units 1 and 2 at Mohave will be rerated to 755 MW nameplate each and 790 MW effective each on January 1, 1974 and allocated as follows:

	<u>Unit No. 1 Only</u>	<u>Unit Nos. 1 & 2</u>	<u>Participation Percentage</u>
DW&P	158.0 MW	316.0 MW	20
Nevada	110.6	221.2	14
SRPD	79.0	158.0	10
SCE	<u>442.4</u>	<u>884.8</u>	<u>56</u>
TOTAL	790.0 MW	1,580.0 MW	100

The Nevada Power Company laid off to Edison 50% (85 MW) of its total Mohave entitlement when Mohave No. 2 went into operation. When Mohave No. 2 was rerated to 600 MW on March 24, 1972, the Nevada layoff to Edison was increased to a total of 95 MW. On June 6, 1972, Mohave No. 2 was once again rerated, this time to 700 MW and the Nevada layoff was increased to a total of 102 MW. This layoff was increased to a total of 106 MW when Mohave No. 2 was rerated to 760 MW on January 1, 1973. The Nevada layoff was terminated on May 31, 1973 at 106 MW prior to the final rerating of both Units 1 and 2 at Mohave on January 1, 1974.

- (3) On February 1, 1973, capacity losses for Northwest Power allotments were decreased from 6.5% to 6.0%. This results in 2 MW of additional capacity to Edison.
- (4) A contract has been executed with the Nevada Power Company for the sale of capacity and associated energy on the dates and for the amounts shown. This contract provides that scheduled energy deliveries may be curtailed in the event that such schedules would result in curtailment of service to Edison's firm customers. The summer area peak demand for 1973 includes this sale.
- (5) Northwest Power is a combination of both Canadian Entitlement and BPA Exchange Power. The amounts of Canadian Entitlement Power shown below are the amounts available to Edison at the California-Oregon or Nevada-Oregon border. Such amounts are firm through 1976 and are estimated beyond that time. Such amounts include Edison's basic entitlement of Canadian Entitlement Power plus or minus the amounts of such power purchased from or sold to PG&E, SMUD, or the State of California pursuant to Pacific Intertie EHV contracts. The remainder of the total Northwest Power up to 400 MW through June 30, 1973, and 550 MW thereafter, will be made up with BPA Exchange capacity in the amounts shown.

Month and Year	Canadian Entitlement Power (MW)	BPA Exchange (MW)	Total Northwest Power (MW)	Capacity Delivered To Edison Control Area (MW)
4-1-68	69	-	69	67
4-1-69	273	-	273	261
4-1-70	285	-	285	273
7-1-70	285	115	400	378
1-1-71	281	119	400	378
2-1-71	242	158	400	378
4-1-71	243	157	400	376
1-1-72	248	152	400	376
2-1-72	223	177	400	376
4-1-72	225	175	400	376
1-1-73	223	177	400	376
4-1-73	298	102	400	376
6-1-73	369	31	400	376
7-1-73	369	181	550	517
1-1-74	375	175	550	517
4-1-74	377	173	550	517
1-1-75	383	167	550	517
4-1-75	129	421	550	517
1-1-76	123	427	550	517
1-1-77	86	464	550	517
1-1-78	-	550	550	517
4-1-78	-	550	550	517
1-1-79	-	550	550	517
1-1-80	-	550	550	517
1-1-81	-	550	550	517
(Thru 1982)				

(6) An assignment has been negotiated with Pacific Gas & Electric Company and Portland General Electric Company providing for sale and exchange of capacity and energy. The principal effect on Edison's capacity resources is equivalent to a firm capacity purchase in the summer and a firm capacity sale in the winter periods indicated beginning in the winter of 1976. In the three years prior to 1976, special conditions of the agreement prescribe the exchanges shown in those years. Exchange amounts are specified at anticipated levels and have been adjusted for Edison's loss obligations.

- (7) A service agreement has been executed with Portland General Electric providing for a sale of 150 MW of capacity and limited energy for the winters of 1973-74 and 1974-75. Contract losses to the point of delivery increase Edison's obligation by an additional 9 MW.
- (8) A contract has been executed with the Bonneville Power Administration, Pacific Power & Light, and the Portland General Electric Company for the sale of 400 MW of capacity and associated energy from December 1, 1973 to May 31, 1974. This contract provides that scheduled energy deliveries may be curtailed in the event that such schedules would result in curtailment of service to Edison's firm customers. The winter area peak demand for 1973 includes this sale.
- (9) A contract has been executed with the U. S. Bureau of Reclamation for layoff of power from the Navajo Project. At such time as USBR needs this power for the Central Arizona Project, USBR has the right to terminate this layoff effective on or after January 1, 1980, upon at least five years advance written notice. Such notice has not been given; however, it is currently anticipated the layoff will terminate in 1981.
- (10) Sale of Edison's former Tonopah District facilities to the Sierra Pacific Power Company was concluded September 30, 1969. Until such time as Sierra provides power to the former Tonopah District from its main system, which is to be accomplished within five years of the date of sale, Edison will sell power to Sierra and has exclusive use of the Gabbs generation. It has been assumed service from Sierra will begin September 30, 1974; therefore, the Nevada resources (Gabbs) and load (including Mineral County) were removed from the Edison system.
- (11) Blythe District becomes part of integrated system; therefore, resources and demand are added to the system. Edwards Air Force Base exchange capacity is available to Edison in the amount of 17.0 MW from March 1 to September 30, and 12.75 MW from October 1 to February 28. Both values are shown in the table and are included in the annual summer and winter total capacities. Edison has been notified by USBR of their intent to terminate this agreement on April 1, 1976, which is reflected in the table.
- (12) The capacities shown for the Long Beach Combined Cycle Project are for the individual combustion turbines and steam turbines.

- (13) To comply with air pollution control standards, additional emission control equipment is estimated to result in capacity reductions for Four Corners Units 4 & 5 and Mohave Units 1 & 2. Edison's share of these reductions amounts to 21 MW for each of the Four Corners Units on January 1, 1976 and 25 MW for each of the Mohave Units on January 1, 1977. For the purpose of planning replacement capacity, the appropriate reductions are shown on the above dates.
- (14) The existing operating agreement between Edison and the City of Vernon, which makes 20 MW of diesel capacity available, will be terminated on April 2, 1973.
- (15) Edison's share of San Onofre Units Nos. 2 and 3 is shown as 80% in accordance with agreements with San Diego Gas & Electric Company.
- (16) Assumed Edison participation (40%) in eastern coal development.

DJF/yg

SECOND TEN YEARS OF JUNE 5, 1973 RESOURCE PROGRAM (22 JUNE 1973)
 FUTURE GENERATION RESOURCE SCHEDULE
 1984-1993

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
12-31-83	AGGREGATE RATED CAPACITY REDUCED FOR "DRY YEAR HYDRO" CONDITIONS, 100 MW FOR SUMMER AND 119 MW FOR WINTER		23597	23272						
6- 1-84	EAST COAL 1 (750/300 MW)	291								
6- 1-84	NUCLEAR LWR 1	1140								
11- 1-84	TERMINATE GROVILLE-THERMALITO	-313								
	TOTAL CAPACITY ADDED	1118								
	LOADS AND RESOURCES FOR SUMMER 1984		24816		20956	3860	18.4		20553	5.6
	LOADS AND RESOURCES FOR WINTER 1984			24385	19940	4445	22.3			
6- 1-85	GRANITE CREEK	240								
6- 1-85	FORKS	90								
6- 1-85	EAST COAL 2 (750/300 MW)	291								
6- 1-85	NUCLEAR LWR 2	1140								
	TOTAL CAPACITY ADDED	1761								
	LOADS AND RESOURCES FOR SUMMER 1985		26259		22123	4136	18.7		21715	5.7
	LOADS AND RESOURCES FOR WINTER 1985			26146	21045	5101	24.2			
4- 1-86	BIG CREEK 1-A	100								
6- 1-86	EAST COAL 3 (750/300 MW)	291								
6- 1-86	NUCLEAR HTGR 3	1100								
9- 1-86	BLACK STAR 1	275								
12- 1-86	BLACK STAR 2	275								
	TOTAL CAPACITY ADDED	2101								
	LOADS AND RESOURCES FOR SUMMER 1986		27810		23301	4509	19.4		22883	5.4
	LOADS AND RESOURCES FOR WINTER 1986			28247	22161	6086	27.5			

SECOND TEN YEARS OF JUNE 5, 1973 RESOURCE PROGRAM (22 JUNE 1973)
 FUTURE GENERATION RESOURCE SCHEDULE
 1984-1993

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN		AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
			SUMMER (MW)	WINTER (MW)		(MW)	(%)			
3- 1-87	BLACK STAR 3	275								
6- 1-87	TERMINATE HOOVER	-277								
6- 1-87	BLACK STAR 4	275								
6- 1-87	EAST COAL 4 (750/300 MW)	291								
6- 1-87	NUCLEAR HTGR 4	1160								
8- 1-87	TERMINATE BPA EXCHANGE	-517								
	TOTAL CAPACITY ADDED	1207								
	LOADS AND RESOURCES FOR SUMMER 1987		29567		24573	4994	20.3		24108	5.4
	LOADS AND RESOURCES FOR WINTER 1987			29454	23371	6083	26.0			
6- 1-88	EMERY COAL 1	1100								
6- 1-88	GEO THERMAL 162	110								
	TOTAL CAPACITY ADDED	1210								
	LOADS AND RESOURCES FOR SUMMER 1988		30777		25883	4894	18.9		25404	5.4
	LOADS AND RESOURCES FOR WINTER 1988			30664	24608	6056	24.6			
3- 1-89	PUMPED STORAGE A	250								
6- 1-89	PUMPED STORAGE B	250								
6- 1-89	EMERY COAL 2	1100								
6- 1-89	GEO THERMAL 364	110								
9- 1-89	PUMPED STORAGE C	250								
12- 1-89	PUMPED STORAGE D	250								
	TOTAL CAPACITY ADDED	2210								
	LOADS AND RESOURCES FOR SUMMER 1989		32487		27270	5217	19.1		26780	5.4
	LOADS AND RESOURCES FOR WINTER 1989			32874	25912	6962	26.9			

SECOND TEN YEARS OF JUNE 5, 1973 RESOURCE PROGRAM (22 JUNE 1973)
 FUTURE GENERATION RESOURCE SCHEDULE
 1984-1993

PAGE 3

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN		AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
			SUMMER (MW)	WINTER (MW)		(MW)	(%)			
6- 1-90	NUCLEAR HTGR 5	1160								
	TOTAL CAPACITY ADDED	1160								
	LOADS AND RESOURCES FOR SUMMER 1990		34147		28687	5460	19.0			
	LOADS AND RESOURCES FOR WINTER 1990			34034	27257	6777	24.9	28176	5.2	
3- 1-91	PUMPED STORAGE E	275								
6- 1-91	PUMPED STORAGE F	275								
6- 1-91	NUCLEAR HTGR 6	1160								
9- 1-91	PUMPED STORAGE G	275								
12- 1-91	PUMPED STORAGE H	275								
	TOTAL CAPACITY ADDED	2260								
	LOADS AND RESOURCES FOR SUMMER 1991		35857		30064	5793	19.3			
	LOADS AND RESOURCES FOR WINTER 1991			36294	28587	7707	27.0	29533	4.8	
6- 1-92	NUCLEAR LWR 3	1140								
	TOTAL CAPACITY ADDED	1140								
	LOADS AND RESOURCES FOR SUMMER 1992		37547		31469	6078	19.3			
	LOADS AND RESOURCES FOR WINTER 1992			37434	29882	7552	25.3	30930	4.7	
6- 1-93	NUCLEAR LWR 4	1140								
6- 1-93	COMBINED CYCLE	415								
	TOTAL CAPACITY ADDED	1555								
	LOADS AND RESOURCES FOR SUMMER 1993		39102		32918	6184	18.8			
	LOADS AND RESOURCES FOR WINTER 1993			38989	31259	7730	24.7	32377	4.7	

December 6, 1972

MR. R. N. COE, Chairman
Plant Expenditure Review Committee

Subject: Future Generation Resource Schedule

Attached is a revised schedule of Future Generation Resources covering the years 1972 through 1982, which was approved by PERC at the December 6, 1972 meeting. A list of the principal changes reflected in this version compared with the September 6, 1972 issue is also attached.

Some of the resources shown in the schedule are in various stages of regulatory review, others are not presently committed, and alternatives are under continual evaluation as new information regarding sites, contractual agreements, costs, load estimates and related factors are updated.

Edison will be disclosing certain of its generation plans to outside organizations, such as the WSCC, the California Power Pool, the California Public Utilities Commission, and various other agencies. In order to preserve uniformity of information releases related to these resources, it is requested that use of the schedule outside the Company be discussed with me before any disclosures are made.


D. J. FOGARTY

MHK/pdd
Attachment

PRINCIPAL CHANGES FROM RESOURCE SCHEDULE OF 9-6-72

1. An annual seasonal capacity exchange currently being negotiated with Portland General Electric has been added.
2. The Huntington Beach Combined Cycle Project has been added in the 1975-78 period.
3. The firm operating date for Cool Water 4 has been advanced from 1977 to 6-1-75, coincident with the date for Unit 3.
4. Initial dates for Long Beach Combined Cycle generation have been modified from 1974 to 1975, with no change in the total project completion date of 8-1-75.
5. The Lucerne Valley Combined Cycle Project dates have been deferred by one year from 1976-77 to 1977-78, and the total project size has been reduced from 1,416 MW in six units to 1,250 MW in three units.
6. Piru Creek Pumped Hydro Project operating dates have been deferred from 1978-79 to 1981-82.
7. The Kaiparowits Project has been deferred one year resulting in firm operating dates for the first three units in 1980-81-82. Also, the assumed SCE participation in the project has been changed from 44% to 40%.
8. The PWR nuclear unit formerly scheduled for 1981 has been rescheduled to 1983.
9. The size of the HTGR nuclear unit in 1982 has been reduced from 1,160 MW to 770 MW.
10. The need for combined cycle units at unidentified locations has changed from 1,125 MW in the 1978-80 period to 1,350 MW in the 1979-81 period.

NOTE: This Schedule is based on the February, 1972
System Forecast--the same as the 9-6-72 Schedule.

12/6/72

PERC APPROVED DECEMBER 6, 1972
 FUTURE GENERATION RESOURCE SCHEDULE
 1972-1982

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
12-31-71	AGGREGATE RATED CAPACITY REDUCED FOR "DRY YEAR HYDRO" CONDITIONS, 100 MW FOR SUMMER AND 119 MW FOR WINTER									12543 (1)
3-24-72	RERATE MOHAVE 2 (450/252 TO 600/336 MW)	84 (2)								
3-24-72	INCREASE NEVADA LAYOFF (85 TO 95 MW)	10 (2)								
4- 1-72	SALE TO NEVADA POWER (35 MW)	(3)								
6- 6-72	RERATE MOHAVE 2 (600/336 TO 700/392 MW)	56 (2)								
6- 6-72	INCREASE NEVADA LAYOFF (95 TO 102 MW)	7 (2)								
7- 1-72	NORTHWEST POWER INCREASED TRANSMISSION LOSSES	-2 (4)								
9-30-72	TERMINATE SALE TO DWP (150 MW)	(5)								
9-30-72	TERMINATE SALE TO NEVADA POWER (35 MW)	(3)								
	TOTAL CAPACITY ADDED	155								
	LOADS AND RESOURCES FOR SUMMER 1972		12717		10317*	2400	23.3		9815	5.0
	LOADS AND RESOURCES FOR WINTER 1972			12698	9395	3303	35.2			

* INCLUDES A RECORDED MAIN SYSTEM NET PEAK DEMAND ON JULY 31, 1972 OF 9815 MW AND 317 MW MWD DEMAND PLUS SALES OF 35 MW AND 150 MW TO NEVADA POWER AND L.A. DW&P RESPECTIVELY.

PERC APPROVED DECEMBER 6, 1972
 FUTURE GENERATION RESOURCE SCHEDULE
 1972-1982

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
1- 1-73	RERATE ORMOND BEACH 1 (750 TO 800 MW)	50								
1- 1-73	RERATE MUHAVE 2 (700/392 TO 760/426 MW)	34 (2)								
1- 1-73	INCREASE NEVADA LAYOFF (102 TO 106 MW)	4 (2)								
4- 1-73	SALE TO NEVADA POWER (35 MW)	(3)								
5-31-73	TERMINATE NEVADA POWER LAYOFF (106 MW)	-106 (2)								
6- 1-73	ORMOND BEACH 2	800								
7- 1-73	NORTHWEST POWER (150 MW)	140 (6)								
9-30-73	TERMINATE SALE TO NEVADA POWER (35 MW)	(3)								
11- 1-73	PORTLAND GENERAL EXCHANGE (-53 MW)	(14)								
12- 1-73	SALE TO NORTHWEST (400 MW)	(7)								
	TOTAL CAPACITY ADDED	922								
	LOADS AND RESOURCES FOR SUMMER 1973		13639		10720	2919	27.2	.951	10390	5.9
	LOADS AND RESOURCES FOR WINTER 1973			13620	10398	3222	31.0			
1- 1-74	RERATE MUHAVE 1 (760/425 TO 790/442 MW)	17 (2)								
1- 1-74	RERATE MUHAVE 2 (760/426 TO 790/443 MW)	17 (2)								
4- 1-74	TERMINATE PORTLAND GENERAL EXCHANGE (-53 MW)	(14)								
5-31-74	TERMINATE SALE TO NORTHWEST (400 MW)	(7)								
6- 1-74	NAVAJO 1 LAYOFF (97 MW)	94 (8)								
6- 1-74	ELLWOOD ENERGY SUPPORT FACILITY	50								
9-30-74	TERMINATE GABBS	-6 (10)								
11- 1-74	PORTLAND GENERAL EXCHANGE (-27 MW)	(14)								
	TOTAL CAPACITY ADDED	172								
	LOADS AND RESOURCES FOR SUMMER 1974		13817		11445	2372	20.7	.964	11150	7.3
	LOADS AND RESOURCES FOR WINTER 1974			13792	11192	2600	23.2			

PERC APPROVED DECEMBER 6, 1972
 FUTURE GENERATION RESOURCE SCHEDULE
 1972-1982

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
4- 1-75	TERMINATE PORTLAND GENERAL EXCHANGE (-27 MW)									
5- 1-75	LUNG BEACH COMBINED CYCLE 1	83								
5-16-75	ANNUAL SUMMER PORTLAND GENERAL EXCHANGE (FROM MAY 16 THRU OCT. 15) 100 MW	94/ 0								
6- 1-75	LUNG BEACH COMBINED CYCLE 2	86								
6- 1-75	LUNG BEACH COMBINED CYCLE 3	84								
6- 1-75	COOL WATER 3	236								
6- 1-75	COOL WATER 4	236								
6- 1-75	NAVAJO 2 LAYOFF (104 MW)	101								
6- 1-75	EDWARDS AFB EXCHANGE (SUMMER/WINTER)	17/ 13								
6- 1-75	YUMA AXIS	25								
7- 1-75	LUNG BEACH COMBINED CYCLE 4	83								
7- 1-75	LUNG BEACH COMBINED CYCLE 5	84								
8- 1-75	LUNG BEACH COMBINED CYCLE 6	80								
8- 1-75	LUNG BEACH COMBINED CYCLE 7	82								
8- 1-75	HUNTINGTON BEACH 6 (TWO 62 MW COMBUSTION TURBINES)	124								
8- 1-75	HUNTINGTON BEACH 7 (TWO 62 MW COMBUSTION TURBINES)	124								
8- 1-75	HUNTINGTON BEACH 8 (TWO 62 MW COMBUSTION TURBINES)	124								
	TOTAL CAPACITY ADDED	1663/1565								
	LOADS AND RESOURCES FOR SUMMER 1975		15226		12309	2917	23.7	.998	12014	7.7
	LOADS AND RESOURCES FOR WINTER 1975			15357	11971	3386	28.3			

PERC APPROVED DECEMBER 6, 1972
 FUTURE GENERATION RESOURCE SCHEDULE
 1972-1982

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY SUMMER (MW)	WINTER (MW)	AREA PEAK DEMAND (MW)	AREA MARGIN (MW)	(%)	AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
5-1-76	HUNTINGTON BEACH 9 (TWO 62 MW COMBUSTION TURBINES)	124								
9-1-76	HUNTINGTON BEACH 10 (TWO 62MW COMBUSTION TURBINES)	124								
6-1-76	HUNTINGTON BEACH 11 (TWO 62MW COMBUSTION TURBINES)	124								
6- 1-76	NAVAJO 3 LAYOFF (126 MW)	122								
11- 1-76	ANNUAL WINTER PORTLAND GENERAL EXCHANGE (FROM NOV. 1 THRU MAR. 31) -106 MW									
	TOTAL CAPACITY ADDED	494								
	LOADS AND RESOURCES FOR SUMMER 1976		15968		13171	2797	21.2	.997	12876	7.2
	LOADS AND RESOURCES FOR WINTER 1976			15851	12899	2952	22.9			
4-1-77	LUCERNE VALLEY 1	416								
4-1-77	HUNTINGTON BEACH 6 (STEAM)	112								
5-1-77	HUNTINGTON BEACH 7 (STEAM)	112								
6-1-77	HUNTINGTON BEACH 8 (STEAM)	112								
6-1-77	LUCERNE VALLEY 2	416								
	TOTAL CAPACITY ADDED	1168								
	LOADS AND RESOURCES FOR SUMMER 1977		17136		14084	3052	21.7	.998	13789	7.1
	LOADS AND RESOURCES FOR WINTER 1977			17019	13770	3249	23.6			

PERC APPROVED DECEMBER 6, 1972
 FUTURE GENERATION RESOURCE SCHEDULE
 1972-1982

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
1-78	MONTELEONE BEACH 9 (STEAM)	112								
5-1-78	MONTELEONE BEACH 10 (STEAM)	112								
1-78	MONTELEONE BEACH 11 (STEAM)	112								
6-1-78	LUCERNE VALLEY 3	416								
10- 1-78	SAN ONOFRE 2 (228/182 MW)	182 (12)								
	TOTAL CAPACITY ADDED	934								
	LOADS AND RESOURCES FOR SUMMER 1978		17888		15057	2831	18.8	.998	14762	7.1
	LOADS AND RESOURCES FOR WINTER 1978			17953	14702	3251	22.1			
6- 1-79	COMBINED CYCLE UNITS	900								
10- 1-79	SAN ONOFRE 3 (228/182 MW)	182 (12)								
10- 1-79	RERATE SAN ONOFRE 2 (228/182 TO 1140/912 MW)	730 (12)								
	TOTAL CAPACITY ADDED	1812								
	LOADS AND RESOURCES FOR SUMMER 1979		18970		16091	2879	17.9	.996	15796	7.0
	LOADS AND RESOURCES FOR WINTER 1979			19765	15685	4080	26.0			
6- 1-80	KAIPAROWITS 1 (1000/400 MW)	388 (13)								
10- 1-80	RERATE SAN ONOFRE 3 (228/182 TO 1140/912 MW)	730 (12)								
	TOTAL CAPACITY ADDED	1118								
	LOADS AND RESOURCES FOR SUMMER 1980		20270		17184	3086	18.0	.953	16889	6.9
	LOADS AND RESOURCES FOR WINTER 1980			20883	16727	4153	24.8			

PERC APPROVED DECEMBER 6, 1972
 FUTURE GENERATION RESOURCE SCHEDULE
 1972-1982

DATE	RESOURCE	NET	TOTAL CAPACITY		AREA	AREA MARGIN		AREA	EDISON NET	ANNUAL
		CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	(MW)	(%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
6- 1-81	COMBINED CYCLE UNITS	450								
6- 1-81	KATPAKOWITS 2 (1000/400 MW)	388 (13)								
6- 1-81	TERMINATE NAVAJO LAYOFF (327 MW)	-317 (8)								
7- 1-81	PIRU CREEK 1 (PUMPED HYDRO)	200								
	TOTAL CAPACITY ADDED	721								
	LOADS AND RESOURCES FOR SUMMER 1981		21721		13348	3373	18.4	.988	18053	6.9
	LOADS AND RESOURCES FOR WINTER 1981			21604	17839	3765	21.1			
1- 1-82	PIRU CREEK 3 (PUMPED HYDRO)	200								
6- 1-82	KATPAKOWITS 3 (1000/400 MW)	388 (13)								
6- 1-82	NUCLEAR-HTGR 1	770								
7- 1-82	PIRU CREEK 5 (PUMPED HYDRO)	200								
	TOTAL CAPACITY ADDED	1558								
	LOADS AND RESOURCES FOR SUMMER 1982		23279		19582	3697	18.9	.985	19287	6.8
	LOADS AND RESOURCES FOR WINTER 1982			23162	19011	4151	21.8			

DEVELOPMENT OF PERTINENT DATA

1) RECONCILIATION OF 12-31-71 AGGREGATE RATED CAPACITY WITH JUNE 30, 1972, REVISION OF "GENERATOR RATINGS AND EFFECTIVE OPERATING CAPACITY OF RESOURCES".

NET MAIN SYSTEM RESOURCES (JUNE 30, 1972)	12509
MWD CAPACITY	+310
3-24-72 AND 6-6-72 RERATES OF MOHAVE 2	-140
3-24-72 AND 6-6-72 INCREASES IN NEVADA LAYOFF	-17
WINTER HYDRO DERATES	-119

	12543

2) SUMMARY OF AREA PEAK DEMANDS (1972-1982)

	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982
SUMMER											
EDISON NET PEAK DEMAND	9815	10390	11150	11970	12830	13740	14710	15740	16830	17990	19220
BLYTHE	-	-	-	44	46	49	52	56	59	63	67
SALE TO NEVADA POWER	35	35	-	-	-	-	-	-	-	-	-
SALE TO DWP	150	-	-	-	-	-	-	-	-	-	-
MWD LOAD	317	295	295	295	295	295	295	295	295	295	295
	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
TOTALS	10317	10720	11445	12309	13171	14084	15057	16091	17184	18348	19582
WINTER											
EDISON NET PEAK DEMAND	9100	9650	10870	11650	12470	13340	14270	15250	16290	17400	18570
BLYTHE	-	-	-	26	28	29	31	34	36	38	40
SALE TO NORTHWEST	-	400	-	-	-	-	-	-	-	-	-
SALE TO PORTLAND GENERAL	-	53	27	-	106	106	106	106	106	106	106
MWD LOAD	295	295	295	295	295	295	295	295	295	295	295
	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
TOTALS	9395	10398	11192	11971	12899	13770	14702	15685	16727	17839	19011

* RECORDED

DECEMBER 6, 1972
FUTURE GENERATION RESOURCE SCHEDULE
1972 - 1982

DEFINITION OF COLUMN HEADINGS

Date

Firm operating date of unit or contractual agreement.

Resource

Resource identification. Often includes supplemental information about capacity particularly when the identification refers to a unit which is undergoing rerate, has associated off system losses, or is a participation unit.

Net Capacity Added

Effective operating capacity rating of the resource. These have been adjusted for losses incurred outside the Edison control area where applicable.

Total Capacity

Summer total capacity includes resources scheduled as of August 1 of that year; winter includes all capacity added in that year.

Area Peak Demand

Includes forecasted annual peak demands of SCE and MWD. Demand forecast includes sales to other utilities and a constant 295 MW demand for MWD.

Area Margin

Megawatt margin is the difference between total installed capacity and area peak demand. Percent margin is the megawatt margin divided by area peak demand multiplied by 100.

Area Reliability Index

The reliability index represents the probability that a particular year's specified resources will be sufficient to serve forecast loads for each hour of the year, allowing for planned generation maintenance and forced outages without requiring delivery of capacity via Edison's interconnections in excess of firm deliveries from 1972 through 1973 or in excess of firm deliveries plus 300 MW from 1974 through 1982.

Edison Net Peak Demand

Edison net peak demand for 1972-1982 is based on the February 1972, forecast prepared by the System Development Department.

Annual Load Increase

Percent Edison net peak demand increased over previous year.

DECEMBER 6, 1972
 FUTURE GENERATION RESOURCE SCHEDULE
1972 - 1982

NOTES

- (1) Aggregate rated capacity in accord with the June 30, 1972, revision of "Generator Ratings and Effective Operating Capacity of Resources", which includes total generation capacities of SCE and MWD. MWD capacity is rated at 310 MW (260 MW at Hoover, 1,123 surface elevation and 50 MW at Parker).
- (2) Unit No. 1 at Mohave is currently rated at an effective capacity of 760 MW. When Unit No. 2 at Mohave went into service on October 1, 1971, it was rated at 450 MW. On March 24, 1972, Mohave No. 2 was rerated to 600 MW, and on June 6, 1972, it was rerated to 700 MW. It is estimated that this rating will be increased to 760 MW on January 1, 1973. Finally, both Units 1 and 2 at Mohave will be rerated to 755 MW nameplate each and 790 MW effective each on July 1, 1973, and allocated as follows:

	<u>Unit No. 1 Only</u>	<u>Unit Nos. 1 & 2</u>	<u>Participation Percentage</u>
DW&P	158.0 MW	316.0 MW	20
Nevada	110.6	221.2	14
SRPD	79.0	158.0	10
SCE	<u>442.4</u>	<u>884.8</u>	<u>56</u>
TOTAL	790.0 MW	1,580.0 MW	100

The Nevada Power Company laid off to Edison 50% (85 MW) of its total Mohave entitlement when Mohave No. 2 went into operation. When Mohave No. 2 was rerated to 600 MW on March 24, 1972, the Nevada layoff to Edison was increased to a total of 95 MW. On June 6, 1972, Mohave No. 2 was once again rerated, this time to 700 MW and the Nevada layoff was increased to a total of 102 MW. This layoff will increase to a total of 106 MW when Mohave No. 2 is rerated to 760 MW on January 1, 1973. The Nevada layoff will terminate on May 31, 1973 at 106 MW prior to the final rerating of both Units 1 and 2 at Mohave on July 1, 1973.

- (3) A contract has been executed with the Nevada Power Company for the sale of capacity and associated energy on the dates and for the amounts shown. This contract provides that scheduled energy deliveries may be curtailed in the event that such schedules would result in curtailment of service to Edison's firm customers. The summer area peak demands for 1972 and 1973 include this sale.
- (4) On July 1, 1972, capacity losses for Northwest Power allotments were increased from 6.0% to 6.5%. This results in 2 MW of additional losses to Edison.
- (5) A contract has been executed with the Department of Water and Power for the sale of capacity and energy. This summer area peak demand for 1972 includes 150 MW for this sale.
- (6) Northwest Power is a combination of both Canadian Entitlement and BPA Exchange Power. The amounts of Canadian Entitlement Power shown below are the amounts available to Edison at the California-Oregon or Nevada-Oregon border. Such amounts are firm through 1976 and are estimated beyond that time. Such amounts include Edison's basic entitlement of Canadian Entitlement Power plus or minus the amounts of such power purchased from or sold to PG&E, SMUD, or the State of California pursuant to Pacific Intertie EHV contracts. The remainder of the total Northwest Power up to 400 MW through June 30, 1973, and 550 MW thereafter, will be made up with BPA Exchange capacity in the amounts shown.

Month And Year	Canadian Entitlement Power (MW)	BPA Exchange (MW)	Total Northwest Power (MW)	Capacity Delivered To Edison Control Area (MW)
4-1-68	69	-	69	67
4-1-69	273	-	273	261
4-1-70	285	-	285	273
7-1-70	285	115	400	378
1-1-71	281	119	400	378
2-1-71	242	158	400	378
4-1-71	243	157	400	376
1-1-72	248	152	400	376
2-1-72	223	177	400	376
4-1-72	225	175	400	376
1-1-73	223	177	400	374
4-1-73	298	102	400	374
6-1-73	369	31	400	374
7-1-73	369	181	550	514
1-1-74	347	203	550	514
4-1-74	349	201	550	514
1-1-75	383	167	550	514
4-1-75	129	421	550	514
1-1-76	123	427	550	514
1-1-77	86	464	550	514
1-1-78	120	430	550	514
4-1-78	56	494	550	514
1-1-79	19	531	550	514
1-1-80	9	541	550	514
1-1-81	2	548	550	514
(Thru 1982)				

- (7) A contract has been executed with the Bonneville Power Administration, Pacific Power & Light, and the Portland General Electric Company for the sale of 400 MW of capacity and associated energy from December 1, 1973 to May 31, 1974. This contract provides that scheduled energy deliveries may be curtailed in the event that such schedules would result in curtailment of service to Edison's firm customers. The winter area peak demand for 1973 includes this sale.

- (8) A contract has been executed with the U.S. Bureau of Reclamation for layoff of power from the Navajo Project. At such time as USBR needs this power for the Central Arizona Project, USBR has the right to terminate this layoff effective on or after January 1, 1980, upon at least five years advance written notice. Such notice has not been given, however, it is currently anticipated the layoff will terminate in 1981.
- (9) The capacity shown for each Long Beach Combined Cycle unit includes the capacity of one combustion turbine and a portion of the steam turbine capacity.
- (10) Sale of Edison's former Tonopah District facilities to the Sierra Pacific Power Company was concluded September 30, 1969. Until such time as Sierra provides power to the former Tonopah District from its main system, which is to be accomplished within five years of the date of sale, Edison will sell power to Sierra and has exclusive use of the Gabbs generation. It has been assumed service from Sierra will begin September 30, 1974; therefore, the Nevada resources (Gabbs) and load (including Mineral County) were removed from the Edison system.
- (11) Blythe District becomes part of integrated system; therefore, resources and demand are added to the system. Edwards Air Force Base exchange capacity is available to Edison in the amount of 17.0 MW from March 1 to September 30, and 12.75 MW from October 1 to February 28, annually. Both values are shown in the table and are included in the annual summer and winter total capacities.
- (12) Edison's share of San Onofre Unit Nos. 2 and 3 is shown as 80% in accordance with agreements with San Diego Gas & Electric Company.
- (13) Assumed Edison participation in further eastern coal development.
- (14) An assignment agreement is being negotiated with Pacific Gas & Electric Company and Portland General Electric Company providing for sale and exchange of capacity and energy. The principle effect on Edison's capacity resources is equivalent to a firm capacity purchase in the summer and a firm capacity sale in the winter periods indicated beginning in the winter of 1976. In the three years prior to 1976, special conditions of the agreement prescribe the exchanges shown in those years. Exchange amounts are specified at anticipated levels and have been adjusted for Edison's loss obligations.

PRELIMINARY SECOND TEN YEARS DECEMBER 6, 1972
 FUTURE GENERATION RESOURCE SCHEDULE
 1983-1992

RESOURCE	NET	TOTAL CAPACITY		AREA	AREA	AREA	EDISON NET	ANNUAL	
	CAPACITY ADDED (MW)	SUMMER (MW)	WINTER (MW)	PEAK DEMAND (MW)	MARGIN (MW)	MARGIN (%)	RELIABILITY INDEX (PER UNIT)	PEAK DEMAND (MW)	LOAD INCREASE (%)
REGATE RATED CAPACITY REDUCED FOR YEAR HYDRO" CONDITIONS, 100 MW SUMMER AND 119 MW FOR WINTER		23279	23162						
PAROWITS 4 (1000/400 MW)	388								
PAR-PWR 1	1140								
LONG BEACH 10	-106								
LONG BEACH 11	-106								
CAPACITY ADDED	1316								
AND RESOURCES FOR SUMMER 1983		24807		20950	3857	18.4	.985	20581	6.7
AND RESOURCES FOR WINTER 1983			24478	20338	4140	20.4			
BLACK STAR 1 (PUMPED HYDRO)	275								
BLACK STAR 2 (PUMPED HYDRO)	275								
PAROWITS 5 (1000/400 MW)	388								
BLACK STAR 3 (PUMPED HYDRO)	275								
CLEAR-HTGR 2	770								
BLACK STAR 4 (PUMPED HYDRO)	275								
TERMINATE DROVILLE-THERMALITO	-318								
TOTAL CAPACITY ADDED	1940								
AND RESOURCES FOR SUMMER 1984		26578		22317	4261	19.1	.989	21915	6.5
AND RESOURCES FOR WINTER 1984			26418	21653	4765	22.0			

PRELIMINARY SECOND TEN YEARS DECEMBER 6, 1972
 FUTURE GENERATION RESOURCE SCHEDULE
 1983-1992

DATE	RESOURCE	NET. CAPACITY ADDED (MW)	TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN		AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
			SUMMER (MW)	WINTER (MW)		(MW)	(%)			
6- 1-85	KAIPARDWITS 6 (1000/400 MW)	388								
6- 1-85	NUCLEAR-PWR 2	1140								
6- 1-85	EMERY COAL 1	1000								
	TOTAL CAPACITY ADDED	2528								
	LOADS AND RESOURCES FOR SUMMER 1985		29063		23711	5352	22.6	.996	23300	6.3
	LOADS AND RESOURCES FOR WINTER 1985			28946	22995	5951	25.9			
6- 1-86	NUCLEAR A	1160								
6- 1-86	BIG CREEK 1A	100								
	TOTAL CAPACITY ADDED	1260								
	LOADS AND RESOURCES FOR SUMMER 1986		30323		25226	5097	20.2	.996	24775	6.3
	LOADS AND RESOURCES FOR WINTER 1986			30206	24458	5748	23.5			
6- 1-87	EMERY COAL 2	1000								
6- 1-87	BIG CREEK 3	300								
6- 1-87	GEOTHERMAL A	110								
6- 1-87	COMBINED CYCLE UNITS	450								
6- 1-87	TERMINATE HOOVER	-277								
6- 1-87	PUMPED STORAGE A	500								
8- 1-87	TERMINATE BPA EXCHANGE	-517								
10- 1-87	RETIRE HIGHGROVE 1-4	-154								
	TOTAL CAPACITY ADDED	1412								
	LOADS AND RESOURCES FOR SUMMER 1987		31889		26781	5108	19.1	.994	26290	6.1
	LOADS AND RESOURCES FOR WINTER 1987			31618	25961	5657	21.8			

PRELIMINARY SECOND TEN YEARS DECEMBER 6, 1972
 FUTURE GENERATION RESOURCE SCHEDULE
 1983-1992

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN		AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
			SUMMER (MW)	WINTER (MW)		(MW)	(%)			
6- 1-88	NUCLEAR B	1160								
6- 1-88	GRANITE CREEK	240								
6- 1-88	PUMPED STORAGE B	500								
6- 1-88	GEOTHERMAL B	110								
10- 1-88	RETIRE REDONDO 1&2	-148								
	TOTAL CAPACITY ADDED	1862								
	LOADS AND RESOURCES FOR SUMMER 1988		33745		28406	5339	18.8	.979	27886	6.1
	LOADS AND RESOURCES FOR WINTER 1988			33480	27534	5946	21.6			
6- 1-89	NUCLEAR C	1500								
6- 1-89	PUMPED STORAGE C	500								
6- 1-89	COMBINED CYCLE	225								
10- 1-89	RETIRE REDONDO 3&4	-144								
	TOTAL CAPACITY ADDED	2081								
	LOADS AND RESOURCES FOR SUMMER 1989		35822		30097	5725	19.0	.956	29562	6.0
	LOADS AND RESOURCES FOR WINTER 1989			35561	29162	6399	21.9			
6- 1-90	NUCLEAR D	1500								
6- 1-90	COMBINED CYCLE	225								
6- 1-90	PUMPED STORAGE D	500								
10- 1-90	RETIRE ETIWANDA 1&2	-264								
	TOTAL CAPACITY ADDED	1961								
	LOADS AND RESOURCES FOR SUMMER 1990		37903		31833	6070	19.1	.962	31268	5.8
	LOADS AND RESOURCES FOR WINTER 1990			37522	30836	6686	21.7			

PRELIMINARY SECOND TEN YEARS DECEMBER 6, 1972
 FUTURE GENERATION RESOURCE SCHEDULE
 1983-1992

DATE	RESOURCE	NET CAPACITY ADDED (MW)	TOTAL CAPACITY		AREA PEAK DEMAND (MW)	AREA MARGIN		AREA RELIABILITY INDEX (PER UNIT)	EDISON NET PEAK DEMAND (MW)	ANNUAL LOAD INCREASE (%)
			SUMMER (MW)	WINTER (MW)		(MW)	(%)			
6- 1-91	COMBINED CYCLE UNITS	450								
6- 1-91	NUCLEAR E	1500								
10- 1-91	RETIRE REDONDO 5	-175								
	TOTAL CAPACITY ADDED	1775								
	LOADS AND RESOURCES FOR SUMMER 1991		39589		33370	6219	18.6	.968	33075	5.8
	LOADS AND RESOURCES FOR WINTER 1991			39297	32310	6987	21.6			
6- 1-92	NUCLEAR F	1500								
6- 1-92	COMBINED CYCLE UNITS	900								
10- 1-92	RETIRE EL SEGUNDO 1	-175								
10- 1-92	RETIRE REDONDO 6	-175								
	TOTAL CAPACITY ADDED	2050								
	LOADS AND RESOURCES FOR SUMMER 1992		41814		35277	6537	18.5	.964	34982	5.8
	LOADS AND RESOURCES FOR WINTER 1992			41347	34154	7193	21.1			

PRELIMINARY SECOND TEN YEARS DECEMBER 6, 1972
 FUTURE GENERATION RESOURCE SCHEDULE
 1983-1992

DEVELOPMENT OF PERTINENT DATA

1) 12-31-82 AGGREGATE RATED CAPACITY IN ACCORD WITH DECEMBER 6, 1972
 FUTURE GENERATION RESOURCE SCHEDULE.

2) SUMMARY OF AREA PEAK DEMANDS (1983-1992)

	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
SUMMER										
EDISON NET PEAK DEMAND	20510	21840	23220	24690	26200	27790	29460	31160	32960	34860
BLYTHE	71	75	80	85	90	96	102	108	115	122
SWP LOAD	74	107	116	156	196	225	240	270	-	-
MWD LOAD	295	295	295	295	295	295	295	295	295	295
TOTALS	20950	22317	23711	25226	26781	28406	30097	31833	33370	35277
WINTER										
EDISON NET PEAK DEMAND	19820	21100	22430	23850	25310	26850	28460	30100	31840	33680
BLYTHE	43	45	48	51	54	58	61	65	69	73
PG LOAD	106	106	106	106	106	106	106	106	106	106
SWP LOAD	74	107	116	156	196	225	240	270	-	-
MWD LOAD	295	295	295	295	295	295	295	295	295	295
TOTALS	20338	21653	22995	24458	25961	27534	29162	30836	32310	34154

AGREEMENT

THIS AGREEMENT, made and entered into this second day of February, 1973, by and between the ANZA ELECTRIC COOPERATIVE, INC., ("Anza"), and SOUTHERN CALIFORNIA EDISON COMPANY, a corporation ("Edison"),

W I T N E S S E T H:

WHEREAS Anza and Edison are parties to a Service Agreement ("Agreement"), and

WHEREAS Edison has settled, subject to certain approvals by the Federal Power Commission, with the United States Navy at Hawthorne, Nevada ("Navy"), rate issues between them involved in Federal Power Commission Docket No. E-7618, by making certain adjustments in the rates under which service is rendered to Navy, and

WHEREAS Anza desires to similarly participate in such rate adjustments.

NOW, THEREFORE, in consideration of the mutual promises contained herein, and subject to such approvals, Anza and Edison agree as follows:

1. Promptly upon the execution of this Agreement, Edison will tender for filing with the Federal Power Commission, a modification of rate Schedule R-1 applicable to Anza, in the form attached hereto as Exhibit 1, which will be effective as of November 14, 1971, and Anza will withdraw all objections

to the approval of the Settlement Agreement entered into between Edison and the Cities of Anaheim, Riverside and Banning, California and filed with the Commission on August 17, 1972, in Docket No. E-7618.

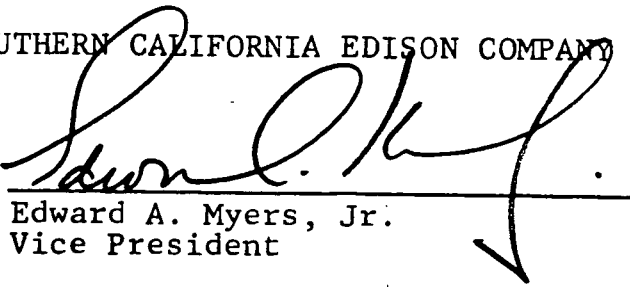
2. The signatories hereto represent that they have been appropriately authorized to enter into this Agreement on behalf of the party for whom they sign.

Executed this second day of February, 1973.

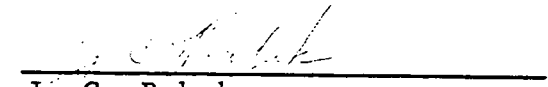
SOUTHERN CALIFORNIA EDISON COMPANY

(Seal)

By


Edward A. Myers, Jr.
Vice President


ATTEST:


J. C. Bobek
Assistant Secretary

ANZA ELECTRIC COOPERATIVE, INC.

(Seal)

By


President

ATTEST:


General Manager

Schedule R-1
RESALE SERVICE

APPLICABILITY

Applicable to electric energy for resale delivered to Anza Electric Cooperative, Inc., at Anza Electric Cooperative Substation near Mountain Center, California, at a nominal voltage of 33,000 volts.

RATES

	<u>Per Meter</u> <u>Per Month</u>
Demand Charge:	
First 500 kw or less of billing demand.....	\$550.00
Next 1,500 kw of billing demand, per kw.....	0.95
Next 8,000 kw of billing demand, per kw.....	0.75
Next 40,000 kw of billing demand, per kw.....	0.65
All excess kw of billing demand, per kw.....	0.55
Energy Charge (to be added to Demand Charge):	
First 150 kwhr per kw of billing demand:	
First 30,000 kwhr, per kwhr.....	1.85¢
Balance of kwhr, per kwhr.....	1.18¢
Next 150 kwhr per kw of billing demand, per kwhr.....	0.81¢
All excess kwhr, per kwhr.....	0.63¢

Minimum Charge:

The monthly minimum charge shall be the monthly Demand Charge.

SPECIAL CONDITIONS

1. **Voltage:** Service will be supplied at one standard voltage.
2. **Billing Demand:** The billing demand shall be the kilowatts of maximum demand but not less than 50% of the highest maximum demand established in the preceding 11 months, however, in no case shall the billing demand be less than 500 kw. Billing demand shall be determined to the nearest kw.
3. **Maximum Demand:** The maximum demand in any month shall be the measured maximum average kilowatt input, indicated or recorded by instruments to be supplied by the utility, during any 30-minute metered interval in the month.
4. **Voltage Discount:** The charges before power factor adjustment will be reduced by 3% for service delivered and metered at voltages of from 2 kv to 10 kv; by 4% for service delivered and metered at voltages of from 11 kv to 50 kv; and by 5% for service delivered and metered at voltages over 50 kv; except that when only one transformation from a transmission voltage level is involved, a customer normally entitled to a 3% discount will be entitled to a 4% discount.
5. **Power Factor Adjustment:** The charges will be adjusted each month for the power factor as follows:
 The charges will be decreased by 20 cents per kilowatt of measured maximum demand and will be increased by 20 cents per kilovar of reactive demand. However, in no case shall the kilovars used for the adjustment be less than one-fifth the number of kilowatts.
 The kilovars of reactive demand shall be calculated by multiplying the kilowatts of measured maximum demand by the ratio of the kilovar-hours to the kilowatt-hours. Demands in kilowatts and kilovars shall be determined to the nearest unit. A ratchet device will be installed on the kilovar-hour meter to prevent its reverse operation on leading power factors.
6. **Adjustment for Off-Peak Demand:** Upon application by the customer, any kilowatts of maximum demand in excess of the on-peak demand will not be considered in establishing the billing demand for computing the energy charge, but will be considered in establishing the billing demand for computing the demand charge, by adding one-half of the amount that the maximum demand exceeds the on-peak demand, to the on-peak demand. The on-peak demand will be the maximum demand occurring between the hours of 6:30 a.m. and 10:30 p.m., Pacific Standard Time, of any day except Sundays and the following holidays: New Years, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas.

THIS SCHEDULE IS ALSO SUBJECT TO THE RULES FOLLOWING.

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SETTLEMENT AGREEMENT

BETWEEN

SOUTHERN CALIFORNIA EDISON COMPANY

AND

ANZA ELECTRIC COOPERATIVE, INC.

6/8/78

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SETTLEMENT AGREEMENT

TABLE OF CONTENTS

<u>SECTION</u>		<u>PAGE</u>
1	PARTIES	1
2	EFFECTIVE DATE	1
3	RECITALS	1
4	AGREEMENT	2
5	SERVICES	2
6	DISPOSITION OF PENDING PROCEEDINGS	5
7	RELEASE	5
8	GENERAL CONDITIONS	6

SETTLEMENT AGREEMENT

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3 1. PARTIES: The Parties to this Agreement are SOUTHERN
4 CALIFORNIA EDISON COMPANY ("Edison"), a California
5 corporation, and ANZA ELECTRIC COOPERATIVE, INC.,
6 ("Anza"), a California corporation, individually
7 "Party", collectively "Parties".

8 2. EFFECTIVE DATE: This Agreement shall be effective on
9 the date it is executed by both Parties.

10 3. RECITALS: This Agreement is made with reference to the
11 following facts, among others:

12 3.1 Both Edison and Anza are parties to Federal
13 Energy Regulatory Commission ("FERC") Docket Nos.
14 E-7777 (Phase II) and E-7796.

15 3.2 Edison wishes to dispose of Anza's claims of
16 anti-competitive conduct by Edison made in FERC Docket
17 Nos. E-7777 (Phase II) and E-7796.

18 3.3 Edison and Anza wish to settle as between
19 them issues involved in said FERC Docket Nos. E-7777
20 (Phase II) and E-7796.

21 3.4 Pursuant to a Settlement Agreement dated
22 August 4, 1972, Edison has entered into Integrated
23 Operations Agreements with the cities of Anaheim and
24 Riverside, California, copies of which have been fur-
25 nished to Anza.

26 3.5 Anza wishes to have available to it from

1 Edison certain services which may facilitate its use
2 of power and energy obtained from sources other than
3 Edison.

4 3.6 Anza desires to enter into an agreement with
5 Edison similar to the Integrated Operations Agreements
6 between Edison and the cities of Anaheim and Riverside.

7 4. AGREEMENT: The Parties, with the express understanding
8 that each condition of this Agreement is in considera-
9 tion and support of every other condition, agree as
10 follows:

11 5. SERVICES:

12 5.1 Anza may seek to acquire capacity and energy
13 resources from sources other than Edison in order to
14 serve all or part of Anza's system load requirements,
15 which otherwise would be served by Edison. Subject to
16 Section 5.1.7, Edison agrees, in such event, to make
17 available certain services to Anza to enable Anza to
18 utilize such alternate resources. Unless otherwise
19 agreed, Edison will make available such services under
20 rates, charges, terms and conditions which are
21 appropriate for the particular characteristics of
22 Anza's system and which are not inconsistent with
23 those pursuant to which such services are made available
24 to the cities of Anaheim and Riverside in their
25 respective Integrated Operations Agreements. Such
26 services which the Parties will negotiate in good faith

1 to incorporate into an integrated operations agreement,
2 appropriate for the particular characteristics of Anza's
3 system, will include, but not necessarily be limited to,
4 the following:

5 5.1.1 Integration of Anza's capacity and
6 energy resources with those of Edison to enable compre-
7 hensive planning and operation of all of such resources
8 by Edison to meet the combined system loads of Edison
9 and Anza.

10 5.1.2 Firm transmission service for Anza's
11 integrated resources from a point of interconnection or
12 point of attachment with Edison-owned transmission
13 facilities to the Anza point of delivery.

14 5.1.3 Scheduling and dispatching of Anza's
15 integrated resources.

16 5.1.4 Replacement capacity and energy to
17 provide service when Anza's integrated resources are
18 not available or dispatched by Edison.

19 5.1.5 Billing credits for Anza's integrated
20 resources with provision for transmission losses and
21 contribution to reserves.

22 5.1.6 Partial requirements service to pro-
23 vide service for Anza's system load in excess of that
24 supplied by Anza's integrated resources.

25 5.1.7 The above enumeration of services to
26 be made available to Anza is set forth merely as a

1 general list of services and is not to be interpreted
2 in such a manner as to in any way broaden, increase, or
3 narrow the scope of Edison's obligation to provide
4 services to Anza in accordance with Edison's present
5 obligations to provide such services to the cities of
6 Anaheim and Riverside pursuant to their respective
7 Integrated Operations Agreements.

8 5.2 The Parties agree that they will promptly
9 move to negotiate an integrated operations agreement
10 appropriate for the particular characteristics of
11 Anza's system which will provide for the services
12 referred to in Section 5.1. If the Parties are unable
13 to agree upon the terms of an integrated operations
14 agreement, Edison, upon request of Anza or upon its own
15 initiative, shall tender for filing with the FERC, or
16 its successor, its proposed agreement containing the
17 rate provisions, charges, terms and conditions for such
18 services, and Anza may oppose or seek modification
19 thereof.

20 5.3 Edison shall enter into agreements with Anza
21 to provide Anza with interruptible transmission service
22 on terms and conditions not inconsistent with those
23 separate agreements under which such service is made
24 available to the cities of Anaheim and Riverside. As
25 used herein, the term "interruptible transmission
26 service" means transmission service, the availability

1 of which at any particular time is determined in the
2 sole discretion of Edison and which is interruptible
3 by Edison at any time and for any reason upon notice
4 given by Edison's dispatcher.

5 5.4 If it is determined, by settlement or by
6 final decision no longer subject to judicial review in
7 FERC Docket Nos. E-7777 (Phase II) and E-7796, that
8 Edison is to provide or make available additional
9 services to the remaining intervening parties in such
10 FERC Dockets, Edison shall provide or make such services
11 available to Anza, modified as necessary to be
12 appropriate for a system with the characteristics of
13 Anza; provided, however, that if a decision is not
14 stayed and is effective as to the remaining intervening
15 parties, pending such judicial review, then such
16 decision shall be similarly effective as to Anza,
17 pending such judicial review.

18 6. DISPOSITION OF PENDING PROCEEDINGS: Anza shall withdraw
19 with prejudice its intervention in FERC Docket Nos.
20 E-7777 (Phase II) and E-7796.

21 7. RELEASE: Anza hereby releases Edison, its directors,
22 officers, employees, agents and attorneys from any and
23 all claims, demands, liabilities, damages and costs in
24 connection with Edison's negotiations for, participation
25 in, or the operation of the California Power Pool and
26 the Seven Party Agreement for the Sale and Purchase of

1 Electric Energy, or either of them, of whatever nature,
2 anticipated or unanticipated, known or unknown, arising
3 out of, or by virtue of, any conduct of Edison, past or
4 present, which conduct might constitute an alleged
5 breach of any contractual relationship or an alleged
6 violation of the laws or regulations of the United
7 States government, or any agency thereof, or the laws
8 or regulations of the State of California, or any
9 political subdivision or any agency of the State of
10 California or of the several states. With respect to
11 Edison's negotiations for, participation in, or the
12 operation of the California Power Pool and the Seven
13 Party Agreement for the Sale and Purchase of Electric
14 Energy, or either of them, Anza expressly waives the
15 provisions of Section 1542 of the Civil Code of
16 California, which reads as follows:

17 "1542 Certain claims not affected by general
18 release. A general release does not
19 extend to claims which the creditor
20 does not know or suspect to exist in
21 his favor at the time of executing the
release, which if known by him must
have materially affected his settle-
ment with the debtor."

22 8. GENERAL CONDITIONS:

23 8.1 The making of this Agreement or the acceptance
24 of it by any regulatory commission shall not be deemed in
25 any respect to constitute a finding by such commission or
26 an admission by Anza or Edison that any allegation or

1 contention urged by the other party in any previous or .
2 pending proceeding is true or valid.

3 8.2 This Agreement is conditioned expressly upon
4 the approval or acceptance by the FERC of all of its
5 terms and conditions without additional terms or
6 conditions unacceptable to either Party. If this Agree-
7 ment is not so approved or accepted, either Party shall
8 have the right to terminate this Agreement by giving
9 written notice of such termination to the other Party.

10 "Approval or acceptance" as used in this Agreement
11 refers to a final order of the FERC no longer subject to
12 judicial review.

13 8.3 All services, including but not limited to
14 sales of electricity for resale and transmission
15 service, rendered by Edison to Anza shall be pursuant to
16 the rates and subject to the rules of Edison on file
17 with the FERC and no provision of this Agreement shall
18 in any manner affect Edison's right, except as provided
19 in Sections 15.1.4, 15.1.5, 15.1.6, 15.2, 15.3, 16.3,
20 21.3, 21.4, 21.5, 21.6, 21.7, 21.8, 21.9, and 21.10 of
21 the Integrated Operations Agreements referred to in
22 Section 3.4 of this Settlement Agreement, to change
23 such rates or rules or to file new rates or rules
24 applicable to service rendered to Anza, pursuant to
25 Section 205(d) of the Federal Power Act, which rates or
26 rules shall become effective pursuant to Section 205(e)

1 of the Federal Power Act. Anza shall have the right to.
2 oppose or seek the modification of any such rates or
3 rules in accordance with the provisions of the Federal
4 Power Act except that Anza shall not base such opposi-
5 tion or request for modification upon matters covered by
6 Section 6 or the release set forth in Section 7.

7 8.4 This Agreement is made upon the express under-
8 standing that it constitutes a negotiated settlement and
9 that all offers of settlement and discussions relating
10 thereto are and shall be privileged and shall be without
11 prejudice to the position of either Party and that if
12 any commission having jurisdiction over this Agreement
13 does not by order approve or accept this Agreement, it
14 shall be deemed withdrawn and shall not constitute a
15 part of the record in any proceeding or be used for any
16 other purpose.

17 8.5 Commitments made and services offered herein
18 shall be subject to interruption or curtailment in case
19 of force majeure.

20 8.6 Any undertaking by one Party to the other
21 Party under this Agreement shall not constitute the
22 dedication of the electric system or any portion thereof
23 of any Party, to the public or to the other Party, nor
24 affect the status of any Party as an independent
25 electric system.

26 8.7 This Agreement shall be governed by,

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interpreted, and construed under the laws of the State of California or the laws of the United States as applicable, as if executed and to be performed wholly within the State of California.

8.8 The signatories hereto represent that they have been appropriately authorized to enter into this Agreement on behalf of the Party for whom they sign.

Executed this 8th day of JUNE, 1978.

ATTEST:

SOUTHERN CALIFORNIA EDISON COMPANY

J. C. Bohak
Secretary

By [Signature]
Vice President

ATTEST:

ANZA ELECTRIC COOPERATIVE, INC.

[Signature]
Secretary

By [Signature]
President

APPROVED AS TO FORM:
ROLLIN E. WOODBURY
Vice President & General Counsel
By [Signature]
Assistant Counsel
6/1, 1978

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Before Commissioners: John N. Nassikas, Chairman;
Albert B. Brooke, Jr., and Rush Moody, Jr.

Southern California Edison Company) Docket No. E-7618

OPINION NO. 654

OPINION AND ORDER FIXING
JUST AND REASONABLE RATES

(Issued March 19, 1973)

NASSIKAS, Chairman:

This proceeding involves a proposed rate increase filed by Southern California Edison on March 23, 1971, for both resale service (R-1) and large resale service (R-2). On May 27, 1971, 1/ the Commission suspended the proposed rate increases for five months, provided for a hearing, and denied the motion to reject of the Cities of Anaheim, Riverside, and Banning (Cities) that Edison was precluded from filing such rate changes under Sierra-Mobile. 2/ On July 28, 1971, the Commission denied Cities' motion for reconsideration of our prior order. 3/ Thereafter, Cities filed a petition for review of the Commission orders of May 27 and July 28, 1971. 4/

1/ 45 FPC 1021.

2/ F.P.C. v. Sierra Pacific Power Co., 350 U.S. 348 (1956);
United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350
U.S. 332 (1956).

3/ 46 FPC 238.

4/ City of Anaheim, et al. v. F.P.C., D. C. Cir., No. 71-1652.
By later court orders the briefing schedule in that case
has been postponed. On January 19, 1972, the court denied
the Commission's motion to dismiss that petition for review.

FILED FPC NO.	19.3
DATE 11-14-75	FILED 6 23
3-19-73	LOUKE E 7618
FPC NO.	19.4
FPC NO.	12-2-73

On June 12, 1972, the Commission consolidated, for the limited purpose of discovery on antitrust issues, Docket No. E-7618 and Project Nos. 67 and 120, to which the Cities raised antitrust allegations in both proceedings.

On August 17, 1972, a Settlement Agreement, entered into by Cities and Edison, was filed and on November 1, 1972, was noticed. On November 6, 1972, Commission staff recommended a remand to the Administrative Law Judge for the elicitation of on the record testimony concerning the settlement and on November 14, 1972, staff identified six subject areas which should be explored in the remand.

On January 10, 1973, the Commission referred the August 17 settlement to the Administrative Law Judge for an expedited hearing, the latter having subsequently been held on February 13, 1973. On February 2, 1973, proposed additional settlements were noticed for other R-1 and R-2 customers and on February 13, 1973, a settlement agreement with Anza Electric Cooperative, Inc. was noticed.

Settlement Agreement

Once a settlement proposal has been presented, we are under a duty to consider it. 5/ However, irrespective of the unanimity of parties to the settlement, the Commission is still required to make findings of fact and conclusions of law based upon the record in support of the settlement. 6/ Moreover, the Commission is not precluded from considering the settlement proposal as a basis for disposition of the case on its merits, as distinct from a settlement. 7/

5/ Michigan Consolidated Gas Co. v. F.P.C., 283 F.2d 204, 224 (D.C. Cir.), cert. denied 364 U.S. 913 (1960).

6/ Cf. Permian Basin Area Rate Cases, 390 U.S. 747, 792 (1968); Alabama Power Co. v. F.P.C., 405 F.2d 716, 721 (D.C. Cir. 1971). See Colorado-Wyoming Gas Co. v. F.P.C., 324 U.S. 626, 634 (1945).

7/ Michigan Consolidated, supra at 224.

FILED	19 3
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3 19 73	E 7618
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FILED NO.	12-7-73

We state these basic precepts at the outset because of our action upon this settlement. As detailed infra we will not, nor cannot, accept the settlement carte blanche. 8/ We will, however, accept portions of the settlement as a resolution on the merits as supported by the evidentiary record below. 9/ Disposition on the merits is herein made of those matters within our jurisdiction. However, certain of the settlement provisions are either contrary to prior orders in this proceeding or outside our responsibilities under the Federal Power Act. We recognize the express intentions of the parties to the settlement that it is conditioned upon approval of all the terms and conditions contained therein. 10/ However, rather than remand a proceeding involving rate changes filed two years ago, we will dispose of the proceeding on the record before us, recognizing that no party below has objected to those portions of the settlement which we resolve herein.

Rates

The basic rates agreed to by the parties are contained in Exhibit H to the August 17, 1972 settlement which outline the R-2 rate schedules for the Cities. 11/ The R-1 rate schedules, agreed to by the parties, are described in both the January 29 and February 5, 1973 settlements. 12/

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- 8/ Scenic Hudson Preservation Conference v. F.P.C., 354 F.2d 603, 620 (2nd Cir. 1965), cert. denied 384 U.S. 941 (1966). Cf. Udall v. F.P.C., 387 U.S. 428, 450 (1965); EDF v. Ruckelshaus, 439 F.2d 584, 595-98 (D.C. Cir. 1971).
- 9/ Compare Hugoton-Anadarko Area Rate Case, 466 F.2d 974 (10th Cir. 1972); Pennsylvania Gas and Water Co. v. F.P.C., 463 F.2d 1242 (D.C. Cir. 1972).
- 10/ Article 5.2 of the Settlement Agreement of August 17, 1972. Also, Cities accepted the cost data presented only for purposes of settlement. Tr. 197-98.
- 11/ As supplemented by the January 29, 1973 settlement adding Azusa, Cotton, Vernon and Southern California Water Company.
- 12/ There was some dispute as to whether or not the settlement with respect to Anza was within the scope of this proceeding. Tr. 208-09. Because of our ruling on the underlying settlement, we will dispose of Anza in this order also.

For 1972, the present rates would produce revenues of about \$508,000 under the R-1 schedule and about \$32,313,000 under the R-2 schedule. The proposed rates would produce revenues of \$597,000 and \$36,319,000 under the R-1 and R-2 schedules, respectively (Tr. 266). Based upon updated data through June 1971, the proposed rates would yield rates of of return of about 4.3-4.7 percent for R-2 customers and 5.9 percent for R-1 customers (Tr. 230-31). Counsel for Cities indicated he could "accept Edison's cost of service as showing that the settlement rates will not produce an unreasonable or excessive rate of return." (Tr. 324) Numerous exhibits were introduced in support of the proposed rates, rate of return, and including depreciation, cost of plant, and taxes. 13/ Such evidentiary presentations were introduced without substantive objections at the February 13, 1973 hearing. The rates proposed in the settlements for both the R-1 and R-2 service are just and reasonable and the rate of return upon which such rates are based is within the zone of reasonableness. 14/ Our determinations in this respect are based upon the uncontradicted record evidence and the cost-of-service and other evidence in support of the proposed rates and the rate of return.

We will also accept as just and reasonable and in the public interest those other provisions of the settlement pertaining to rates, including:

X Article 2 in its entirety which includes voltage discounts and a moratoria on future rate filings until June 1, 1973.

Sections 5.3-5.5, 5.7-5.11 of Article 5 concerning filing of rate schedules.

Other Terms and Conditions

Cities has alleged anticompetitive conduct on the part of Edison (Tr. 325-26) and Edison has agreed to changes in terms and conditions of electric service to meet such

13/ E.g. Exhibits 17-31.

14/ See Union Electric Co., 47 FPC 144, 155-62 (1972), wherein a 7.625 percent overall rate of return was found to be just and reasonable.

11-14-71	SHEET 9 OF 23
3-19-73	DOCKET NO. E-7618
FPC NO. 79-4	DATE 12-7-73

Docket No. E-7618

- 5 -

allegations (Tr. 272-73, 354-55). The following services which Edison agrees to render Cities are summarized in Article 4 of the August 17, 1972 settlement, and include:

- 4.1.1 - integration of operations between Cities and Edison including dispatching, sharing of reserves and transmission.
- 4.1.2 - partial requirements service.
- 4.1.3-.5 - availability of transmission service on Edison's 220 kV network and outside that network.

We find nothing inconsistent with the public interest in the above-referenced sections of Article 4 as they relate to Exhibit A (Integrated Operation Agreement), Exhibit B (Partial Requirements Service), and Exhibits C-E (Transmission Service) in the August 17 settlement. The implementation of many of such services envision future filings with this Commission or other appropriate regulatory authorities and we can rule on the merits of such schedules and service agreements as filed with us.

Our finding that the proposed services in Sections 4.1.1-4.1.5 of Article 4 of the settlement agreement are not inconsistent with the public interest is in no way a determination, one way or the other, on the merits of the anticompetitive allegations raised by Cities which are outside our jurisdiction. However, the merits of alleged anticompetitive conduct within our responsibilities have been resolved and agreed to by the parties to this proceeding and are supported by those provisions of the settlement and the evidence adduced thereon. ^{15/} We realize that there was extensive discovery and some 30,000 documents were obtained on the anticompetitive issues, whether or not this Commission can grant the appropriate remedial relief, and which the parties purport to resolve by this settlement. Irrespective of such allegations, the proposed services to be rendered are not inconsistent with the public interest.

^{15/} Cf. City of Lafayette v. F.P.C., 454 F.2d 941 (D.C. Cir. 1971); Northern Natural Gas Co. v. F.P.C., 399 F.2d 953 (D.C. Cir. 1968).

Disposition of Collateral Proceedings

Article I of the settlement provides that Cities will (1) withdraw their objections in the relicensing proceedings in Project Nos. 67 and 120, (2) withdraw their intervention before the California Public Utilities Commission in Application No. 52976 concerning a high voltage transmission line, (3) withdraw their objections in licensing proceedings of San Onofre Units 2 and 3 before the Atomic Energy Commission in Docket Nos. 50-361 and 50-362, 15/ and (4) withdraw their petition for review of the Commission orders of May 27 and July 28, 1971, supra. Article 1.5 provides that Edison will pay Cities \$3.1 million, allegedly to withdraw their petition for review of the Sierra-Mobile question, and an additional \$25,000 for "antitrust claims" (Tr. 298-99, 316). This \$3.125 million is a negotiated amount for liquidated damages (Tr. 301-02).

Our order of January 10, 1973, referring the settlement back for an evidentiary hearing, specifically requested information on "whether the \$3,100,000 payment provided for in the Settlement Agreement is [was] in the best interests of the public." It is contended that if Cities should prevail on the Sierra-Mobile question, Edison would be liable for \$5 million; therefore, the \$3.1 million would represent a refund of those rates collected unlawfully from November 14, 1971, until the expiration of the contracts with Cities in 1973-1974 (Tr. 289-93). 16/ Assuming the \$3.1 million is solely for consideration of Cities' withdrawal of their appeal concerning Sierra-Mobile, we refuse to place our imprimatur upon such damages. To do so would be to concede we erred

16/ Article 4.1.7 of the settlement concerns participation by Cities in ownership of these nuclear units.

17/ There appears to be some ambiguity as to whether some or all of the \$3.1 million is related to anticompetitive allegations (Tr. 316).

SEARCHED	INDEXED	FILED	1973
11-14-71	11-14-71	11-14-71	23
3-11-73	3-11-73	3-11-73	E-7618
			19.2
			11.4 DATE 12-7-73

in our original findings that Edison was not prohibited from making the unilateral rate increase under Sierra-Mobile. Moreover, inasmuch as Cities, and no other R-2 customers, would be the beneficiaries of such "refunds", they would effectively be paying a lower and preferential rate (Tr. 296-97). Assuming that the \$3.125 million is compensation for the settlement of alleged anticompetitive conduct, the appropriate forum to determine the damage issue, by settlement or otherwise, is the U.S. District Court. The \$3.1 million, as well as the \$25,000 represent liquidated damages, 17/ which this Commission has no jurisdiction to adjudicate, as recognized by Cities' counsel (Tr. 335). 18/

As for the other contentions, Cities is free to withdraw their interventions in Project Nos. 67 and 120 by making the appropriate filings. With respect to Cities' position before the California Public Utilities Commission in Application No. 52976, Cities may pursue whatever avenue it desires, subject to the procedures and jurisdiction of that state regulatory commission.

We take official notice of the antitrust review letter of the Department of Justice 19/ which was sent to the AEC concerning the joint application of Southern California Edison Company and San Diego Gas and Electric Company in Docket Nos. 50-361 and 50-362. Justice therein recommended

18/ Cf. Allied Air Freight, Inc. v. Pan American, 393 F.2d 441 (2nd Cir. 1968); TWA v. Hughes, 332 F.2d 602 (2nd Cir. 1964).

19/ The \$3.125 million would apparently be treated as a "below-the-line" non-utility deduction (Account 426.5), subject to a future rate proceeding wherein "above-the-line" treatment could be urged. Tr. 274-76. We do not resolve the merits of this issue except to find that no portion of the \$3.125 million is, or shall be included, in the rate of Edison approved by this order.

20/ July 12, 1971. 36 Fed. Reg. 17886 (1971).

11-14-71	19.3
3-19-73	12 OF 23
	DOCKET NO. E-7618
	19.2
	19.4 DATE 12-7-73

aring based upon alleged violations of Sections 1 and 2 of the Sherman Act by Edison. This liaison between Justice and the AEC arises from the 1970 Amendments to the Atomic Energy Act 20/ which, inter alia, requires the AEC to send all Section 103 licenses to Justice for antitrust review, if Justice requests a hearing within six months the AEC is required to hold one, and the AEC has the authority to condition any licenses to correct potential antitrust abuses. While Justice has not intervened nor presented any position before us in Docket No. E-7618, Cities represents that if we approve Article 1.4 of the settlement, they will so advise Justice so that the latter would in turn recommend that the AEC issue licenses for San Onofre Units 1 and 2. We refuse to rule on this provision of the settlement. The AEC clearly has the primary jurisdiction to adjudicate this provision and the parties should resolve such matters before the AEC. 21/

The Commission further finds and orders that:

- (A) The settlement rates for the R-1 and R-2 services are just and reasonable.
- (B) To the extent not otherwise so found to be in the public interest, those provisions of the settlement agreements (Articles 1,3,4.1.6,4.17,4.2,4.3,5.1,5.2,5.12-5.16) either require premature approval or are outside our jurisdiction.
- (C) The \$3.125 million in liquidated damages is not properly the subject of a settlement agreement before the Federal Power Commission and is outside our jurisdiction.
- (D) The rate schedules contained in Exhibits 34 and 35 for R-1 and R-2 service are accepted for filing and approved with an effective date of November 14, 1971.

By the Commission.

(S E A L)

Kenneth F. Plumb,
Secretary.

42 U.S.C. §2132, et seq.

45 FPC 1153 (1971).

EDULE FPC NO.	193
DATE 11-14-71	SHEET 13 OF 23
3-19-73	DOCKET NO. E7618
FPC NO.	19.2
FPC NO.	194 DATE 12-7-73

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

ELECTRIC RATES: Settlement and
Withdrawal

Before Commissioners: Don S. Smith, Acting Chairman;
Georgiana Sheldon, Matthew Holden, Jr.,
and George R. Hall.

Pacific Gas & Electric Company)	Docket No. E-7777
)	(Phase II)
Pacific Power & Light Company, et al.)	Docket No. E-7796

ORDER APPROVING SETTLEMENT AND
ALLOWING WITHDRAWAL

(Issued February 23, 1979)

On June 16, 1978, Anza Electric Cooperative, Inc. (Anza), tendered for filing in these proceedings a proposed Settlement Agreement and a Motion for Certification and Approval of the Settlement Offer. Anza also tendered for filing a motion for withdrawal from the present proceedings. Public notice of the certification to the Commission was issued on November 3, 1978, with comments required to be filed on or before November 15, 1978. No comments were received from any party to these proceedings.

Anza is a non-profit membership corporation engaged in the retail distribution of electric energy to rural customers in and around the Town of Anza, California. Anza currently purchases all of its power from Southern California Edison Company (Edison).

By Order issued March 14, 1974 in Docket No. E-7777 (Phase II), the Commission ^{1/} instituted an investigation under Section 206 of the Federal Power Act into the justness and reasonableness of various contracts executed by Pacific

^{1/} This proceeding began before the FPC. Pursuant to the Department of Energy Organization Act, it is now before this Commission effective as of October 1, 1977. The term "Commission" when used in the context of an action taken prior to October 1, 1977, refers to the FPC; when used otherwise the reference is to the FERC.

Gas and Electric Company (PG&E) which were alleged to be restrictive and anticompetitive. 2/ On June 24, 1974, Anza filed a petition to intervene in Docket No. E-7777 (Phase II). On May 12, 1975, the Commission issued an Order granting Anza's intervention and designated Edison as a party respondent to the proceedings.

On July 23, 1974, Anza filed a petition to intervene in Docket No. E-7796, which was denied on February 7, 1977. On March 7, 1977, Anza renewed its petition to intervene, alleging that the so-called Seven Party Agreement prevented Anza from sharing in excess power that may become available from the Pacific Northwest and may hinder Anza in marketing any power that may become available to it from other sources. Anza's renewed petition was granted by order of April 5, 1977.

On December 28, 1978, the Commission issued an order consolidating the cases in Docket Nos. E-7777 and E-7796.

Among other items, the Settlement Agreement provides that 1) Anza may seek capacity and energy resources from sources other than Edison; 2) Edison will make available services to Anza to enable Anza to utilize such alternate resources; 3) Edison will provide Anza with services similar to those provided by Edison to the Cities of Anaheim and Riverside pursuant to "Integrated Operations Agreements". The Commission finds that the Settlement is in the public interest and accepts and approves it as hereinafter ordered and conditioned.

2/ The PG&E contracts at issue are with: San Diego Gas & Electric and Southern California Edison Company (FPC Rate Schedule No. 27); United State Bureau of Reclamation (FPC Electric Tariff Original Volume No. 9); Sacramento Municipal Utility District (FPC Rate Schedule No. 45); and Southern California Edison, San Diego Gas and Electric, Portland General Electric Company, Puget Sound Power & Light Company, The Washington Water Power Company, and Pacific Power & Light Company, (Seven Party Rate Agreement)(FPC Rate Schedule No. 105).

Docket Nos. E-7777
(Phase II) and E-7796

- 3 -

The Commission orders:

(A) The Proposed Settlement Agreement filed with the Commission is hereby accepted, incorporated by reference herein and approved.

(B) Anza Electric Cooperative, Inc. is hereby authorized to withdraw as a party to the proceedings in Docket Nos. E-7777 (Phase II) and E-7796.

(C) This order is made without prejudice to any findings or orders which have been made or which will hereafter be made by the Commission with respect to any person still party to the proceedings now pending in Docket Nos. E-7777 (Phase II) and E-7796, and further, this order shall not be construed to affect any rights, claims, or interests of any other party or parties to the present proceedings.

(D) The Secretary shall cause prompt publication of this order to be made in the Federal Register.

By the Commission.

(S E A L)

Kenneth F. Plumb,
Secretary.

3

~~1000-2-100~~

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D. C. 20426

Docket Nos. ER78-250; ER78-253

Southern California Edison Company
Attention: Mr. Ronald Daniels
Manager of Revenue Requirements
Post Office Box 800
2244 Walnut Grove Avenue
Rosemead, California 91770

JUN 7 1979

Dear Mr. Daniels:

By letters dated March 8 and June 20, 1978, you submitted for filing separate undated Integrated Operations Agreements with the City of Riverside and the City of Anaheim, California. The filings submitted by your company have been accepted for filing, to become effective July 24, 1978 (30 days after filing), and have been designated as shown on the Enclosure.

Invocation of Section 15.1.3, Section 16.1.4, Section 18.6.2 and Appendixes B, C, D, and E of the above agreements will constitute a change in rate and will require timely filing pursuant to Section 35.13 of the Commission's Regulations.

Notice of the filings was issued on March 17, 1978, with comments, protests, or petitions to intervene due on or before April 3, 1978. On April 3, 1978, the Cities of Riverside and Anaheim filed comments and petitions to intervene in the above dockets. Petitioners support the above filings and request Commission acceptance. The Cities of Riverside and Anaheim are hereby granted intervenor status.

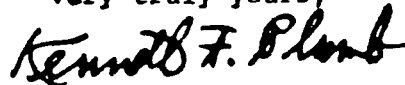
This acceptance for filing does not constitute approval of any service, rate, charge, classification, or any rule, regulation, contract, or practice affecting such rate or service provided for in the Enclosure; nor shall such acceptance be deemed as recognition of any claimed

Southern California Edison Company

contractual right or obligation affecting or relating to such service or rate; and such acceptance is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against your company.

This acceptance for filing terminates Docket Nos. ER78-250 and ER78-253.

Very truly yours,

A handwritten signature in black ink, appearing to read "Kenneth F. Plumb". The signature is written in a cursive style with some capital letters.

Secretary

Enclosure

cc: City of Riverside
City of Anaheim
George Spiegel, Esquire

Southern California Edison Company

Rate Schedule Designations:

Instrument Date: (1) November 11, 1977; (2) - (5) Undated
Filing Date : June 22, 1978
Effective Date : July 24, 1978

<u>Designations</u>	<u>Instrument</u>	<u>Other Party</u>
(1) Rate Schedule FERC No. 94	Integrated Operations Agreement	City of Riverside, California
(2) Supplement No. 1 to Rate Schedule FERC No. 94	Appendix A - Certificated Service AREA MAP	"
(3) Supplement No. 2 to Rate Schedule FERC No. 94	Appendix B - Monthly Dispatching Charges	"
(4) Supplement No. 3 to Rate Schedule FERC No. 94	Appendix C - Transmission Service Agreement	"
(5) Supplement No. 4 to Rate Schedule FERC No. 94	Appendix D - Network Transmission Service (TN)	"
(6) Supplement No. 5 to Rate Schedule FERC No. 94	Appendix E - Point to Point Transmission Service	"

Southern California Edison Company

Rate Schedule Designations:

Instrument Date: (1) November 11, 1977; (2) - (5) Undated
Filing Date : March 13, 1978
Effective Date : July 24, 1978

<u>Designations</u>	<u>Instrument</u>	<u>Other Party</u>
(1) Rate Schedule FERC No. 95	Integrated Operations Agreement	City of Anaheim
(2) Supplement No. 1 to Rate Schedule FERC No. 95	Appendix A - Certificated Service AREA MAP	"
(3) Supplement No. 2 to Rate Schedule FERC No. 95	Appendix B - Monthly Dispatching Charges	"
(4) Supplement No. 3 to Rate Schedule FERC No. 95	Appendix C - Transmission Service Agreement	"
(5) Supplement No. 4 to Rate Schedule FERC No. 95	Appendix D - Network Transmission Service (TN)	"
(6) Supplement No. 5 to Rate Schedule FERC No. 95	Appendix E - Point to Point Transmission Service	"

Southern California Edison Company

Rate Schedule Designations

Instrument Date: (1) November 11, 1977; (2)-(5) Undated
 Filing Date : June 22, 1978
 Effective Date : July 24, 1978

<u>Designations</u>	<u>Instrument</u>	<u>Other Party</u>
(1) Rate Schedule FERC No. 94	Integrated Operations Agreement	City of Riverside, California
(1a) *Exhibit A to Rate Schedule FERC No. 94	Letter of June 9, 1978, correcting typographical error	"
(2) Supplement No. 1 to Rate Schedule FERC No. 94	Appendix A - Certified Service AREA MAP	"
(3) Supplement No. 2 to Rate Schedule FERC No. 94	Appendix B - Monthly Dispatching Charges	"
(4) Supplement No. 3 to Rate Schedule FERC No. 94	Appendix C - Transmission Service Agreement	"
(5) Supplement No. 4 to Rate Schedule FERC No. 94	Appendix D - Network Transmission Service (TN)	"
(6) Supplement No. 5 to Rate Schedule FERC No. 94	Appendix E - Point to Point Transmission Service	"

* New designation

Southern California Edison Company

Rate Schedule Designations

Instrument Date: (1) November 29, 1977; (2)-(5) Undated
 Filing Date : March 13, 1978
 Effective Date : July 24, 1978

<u>Designations</u>	<u>Instrument</u>	<u>Other Party</u>
(1) Rate Schedule FERC No. 95	Integrated Operations Agreement	City of Anaheim
(1a) *Exhibit A to Rate Schedule FERC No. 95	Letter of June 9, 1978, correcting typographical error	"
(2) Supplement No. 1 to Rate Schedule FERC No. 95	Appendix A - Certified Service AREA MAP	"
(3) Supplement No. 2 to Rate Schedule FERC No. 95	Appendix B - Monthly Dispatching Charges	"
(4) Supplement No. 3 to Rate Schedule FERC No. 95	Appendix C - Transmission Service Agreement	"
(5) Supplement No. 4 to Rate Schedule FERC No. 95	Appendix D - Network Transmission Service (TN)	"
(6) Supplement No. 5 to Rate Schedule FERC No. 95	Appendix E - Point to Point Transmission Service	"

* New designation

Attachment A

SUNDESERT PROJECT TRANSMISSION FACILITY NEGOTIATIONS

Status as of March 14, 1978

NEGOTIATION ITEMS
(Listed by system elements and contractual considerations)

PARTICIPANTS/SDG&E
NEGOTIATING TEAM
CURRENT POSITION

SOUTHERN CALIFORNIA
EDISON STAFF
CURRENT POSITION

A. Palo Verde-Devers-Sundesert
500 kv Loop-in

1. Ownership	SCE ----->	SAME
2. Facility Design	SCE ----->	SAME
3. Construction:		
Performance	SCE ----->	SAME
Initial Cost	Allocated between Participants SDG&E and SCE in proportion to benefits. ----->	SAME
4. Use	SCE ----->	SAME
5. Operation:		
Performance	(1) SCE ----->	SAME
Cost	Shared in proportion to the benefits. ----->	SAME
6. Maintenance:		
Performance	(1) SCE ----->	SAME
Cost	Shared in proportion to the benefits. ----->	SAME

Footnotes: (1) Operation and maintenance of Loop-in to be coordinated with SDG&E/Participants.

*** CONTINUED ON NEXT PAGE ***

Attachment A

SUNDESERT PROJECT TRANSMISSION FACILITY NEGOTIATIONS

Status as of March 14, 1978

NEGOTIATION ITEMS
(listed by system elements and
contractual considerations)

PARTICIPANTS/SDG&E
NEGOTIATING TEAM
CURRENT POSITION

SOUTHERN CALIFORNIA
EDISON STAFF
CURRENT POSITION

A. Palo Verde-Devers-Sundesert
500 kv Loop-in (CONTINUED)

7. Licensing

Coordinated SCE/SDG&E and
Participants----->

SAME

8. R-0-W Acquisition

(2) SCE/SDG&E Coordinated effort.

~~SAME~~ SCE

9. Initial Operation

April 1, 1982

(?)

Footnotes: (2) Party(s) to acquire R-0-W remains to be decided.

Attachment A

SUNDESERT PROJECT TRANSMISSION FACILITY NEGOTIATIONS

Status as of March 14, 1978

NEGOTIATION ITEMS
(Listed by system elements and contractual considerations)

PARTICIPANTS/SDG&E
NEGOTIATING TEAM
CURRENT POSITION

SOUTHERN CALIFORNIA
EDISON STAFF
CURRENT POSITION

B. Sundesert 500 kv Switchyard
(Includes loop-in terminating facilities)

NEGOTIATION ITEMS	PARTICIPANTS/SDG&E NEGOTIATING TEAM CURRENT POSITION	SOUTHERN CALIFORNIA EDISON STAFF CURRENT POSITION
1. Ownership	Participants/SDG&E (except SCE to own its loop-in terminating facilities). ----->	SAME
2. Facility Design	SDG&E ----->	SAME
3. Construction:		
Performance	SDG&E ----->	SAME
Cost	SDG&E/Participants/SCE -- in proportion to OWNERSHIP. ----->	SAME
4. Use	SDG&E/Participants/SCE ----->	SAME
5. Operation:		
Performance	SDG&E with consideration of scheduling requirements of SCE/Participants ----->	SAME
Cost	SDG&E -- Reimbursed by Participants and SCE in proportion to OWNERSHIP. ----->	SAME
6. Maintenance:		
Performance	SDG&E with consideration of scheduling requirements of SCE/Participants ----->	SAME
Cost	SDG&E -- Reimbursed by Participants and SCE in proportion to OWNERSHIP. ----->	SAME
7. Initial Operation	April 1, 1982	(?)

Attachment A

SUNDESERT PROJECT TRANSMISSION FACILITY NEGOTIATIONS

Status as of March 14, 1978

NEGOTIATION ITEMS
(Listed by system elements and contractual considerations)

PARTICIPANTS/SDG&E
NEGOTIATING TEAM
CURRENT POSITION

SOUTHERN CALIFORNIA
EDISON STAFF
CURRENT POSITION

C. Line No. 1, Palo Verde-Devers
500 kv Line. (Sundesert-
Devers section)

1. Ownership (Facilities)	SCE ----->	SAME
2. Facility Design	SCE -- Coordinated with SDG&E ----->	SAME
3. Construction:		
Performance	SCE -- Coordinated with SDG&E ----->	SAME
Cost	SCE ----->	SAME
4. Use	SCE ----->	SAME
5. Operation:		
Performance	(1) SCE ----->	SAME
Cost	SCE ----->	SAME
6. Maintenance:		
Performance	(1) SCE ----->	SAME
Cost	SCE ----->	SAME

Footnotes: (1) Operation and maintenance of Line 1 and Line 2 to be coordinated with SDG&e/Participants.

*** CONTINUED ON NEXT PAGE ***

Attachment A

SUNDESERT PROJECT TRANSMISSION FACILITY NEGOTIATIONS

Status as of March 14, 1978

NEGOTIATION ITEMS
(Listed by system elements and contractual considerations)

PARTICIPANTS/SDG&E
NEGOTIATING TEAM
CURRENT POSITION

SOUTHERN CALIFORNIA
EDISON STAFF
CURRENT POSITION

C. Line No. 1, Palo-Verde-Devers
500 kv Line. (Sundesert-
Devers Section (CONTINUED))

7. Licensing	SCE ----->	SAME
8. R.O.W.:		
Acquisition	(2) SCE ----->	SAME
Ownership	SCE ----->	SAME
9. Initial Operation	SAME	<----- January, 1982

Footnotes: (2) Acquisition of private lands for two 500 kv lines with contemplated transfer of 50% to SDG&E.

Attachment A

SUNDESERT PROJECT TRANSMISSION FACILITY NEGOTIATIONS

Status as of March 14, 1978

NEGOTIATION ITEMS
(Listed by system elements and
contractual considerations)

PARTICIPANTS/SDG&E
NEGOTIATING TEAM
CURRENT POSITION

SOUTHERN CALIFORNIA
EDISON STAFF
CURRENT POSITION

D. Line No. 2, Sundesert-
Devers 500 kv Line

1. Ownership	(1) Participants ----->	SAME
2. Facility Design	SDG&E -- Coordinated with SCE ----->	SAME
3. Construction		
Performance	SDG&E/Participants -- Coordina- ted with SCE. ----->	SAME
Cost	(1) Participants ----->	SAME
4. Use	(1) Participants ----->	SAME
5. Operation:		
Performance	(1) (2) (3) SDG&E/Participants ----->	SAME
Cost	(1) Participants ----->	SAME
6. Maintenance:		
Performance	(2) (3) SDG&E/Participants ----->	SAME
Cost	(1) Participants ----->	SAME

Footnotes: (1) SDG&E may need interest in Line No. 2.
(2) SCE willing to consider.
(3) Operation and maintenance of line No. 1 and Line No. 2
to be coordinated with SCE/Participants.

*** CONTINUED ON NEXT PAGE ***

Attachment A

SUNDESERT PROJECT TRANSMISSION FACILITY NEGOTIATIONS

Status as of March 14, 1978

NEGOTIATION ITEMS
(Listed by system elements and contractual considerations)

PARTICIPANTS/SDG&E
NEGOTIATING TEAM
CURRENT POSITION

SOUTHERN CALIFORNIA
EDISON STAFF
CURRENT POSITION

D. Line No. 2 Sundesert-Devers
500 kv Line (CONTINUED)

7. Licensing

SDG&E as a part of the
Sundesert Project ----->

SAME

8. R.O.W.

Acquisition

(4) SCE ----->

SAME

Ownership

SDG&E/Participants ----->

SAME

9. Initial Operation

January, 1986 ----->

(?)

Footnotes: (4) Acquisition of private lands for two 500 kv lines
with contemplated transfer of 50% to SDG&E.

Attachment A

SUNDESERT PROJECT TRANSMISSION FACILITY NEGOTIATIONS

Status as of March 14, 1978

NEGOTIATION ITEMS
(Listed by system elements and contractual considerations)

PARTICIPANTS/SDG&E
NEGOTIATING TEAM
CURRENT POSITION

SOUTHERN CALIFORNIA
EDISON STAFF
CURRENT POSITION

E. Devers-Valley 500 kv Line (1)

1. Ownership (facilities)	SDG&E	SCE
2. Facility Design	SDG&E	SCE
3. Construction:		
Performance	SDG&E	SCE
Cost	SDG&E	SCE
4. use	SDG&E	SCE
5. Operation:		
Performance	SDG&E	SCE
Cost	SDG&E	SCE
6. Maintenance:		
Performance	SDG&E	SCE
Cost	SDG&E	SCE

Footnotes: (1) SDG&E willing to own, construct, use, operate, maintain and license the complete line.
SDG&E willing to share ownership, use, etc. with participants and/or SCE between Devers-Valley.

Attachment A

SUNDESERT PROJECT TRANSMISSION FACILITY NEGOTIATIONS

Status as of March 14, 1978

NEGOTIATION ITEMS
(Listed by system elements and
contractual considerations)

PARTICIPANTS/SDG&E
NEGOTIATING TEAM
CURRENT POSITION

SOUTHERN CALIFORNIA
EDISON STAFF
CURRENT POSITION

E. Devers-Valley 500 kv Line (CONTINUED)

NEGOTIATION ITEMS	PARTICIPANTS/SDG&E NEGOTIATING TEAM CURRENT POSITION	SOUTHERN CALIFORNIA EDISON STAFF CURRENT POSITION
7. Licensing	(1) SDG&E	SCE
8. R.O.W. Acquisition	SDG&E	SCE
9. Initial Operation	April, 1984	(?)

Footnotes: (1) SDG&E willing to own, construct, use, operate, maintain and license the complete line.
SDG&E willing to share ownership, use, etc. with participants and/or SCE between Devers-Valley.

Attachment A

SUNDESERT PROJECT TRANSMISSION FACILITY NEGOTIATIONS

Status as of March 14, 1978

NEGOTIATION ITEMS (Listed by system elements and contractual considerations)	PARTICIPANTS/SDG&E NEGOTIATING TEAM CURRENT POSITION	SOUTHERN CALIFORNIA EDISON STAFF CURRENT POSITION
<hr/>		
F. Valley-Rainbow 500 kv Line (1)		
<hr/>		
1. Ownership (facilities)	SDG&E ----->	SAME
2. Facility Design	SDG&E ----->	SAME
3. Construction:		
Performance	SDG&E ----->	SAME
Cost	SDG&E ----->	SAME
4. Use	SDG&E ----->	SAME
5. Operation:		
Performance	SDG&E ----->	SAME
Cost	SDG&E ----->	SAME
6. Maintenance:		
Performance	SDG&E ----->	SAME
Cost	SDG&E ----->	SAME

Footnotes: (1) SDG&E willing to own, construct, use, operate, maintain and license the complete line.
SDG&E willing to share ownership, use, etc. with participants and/or SCE.

Attachment A

SUNDESERT PROJECT TRANSMISSION FACILITY NEGOTIATIONS

Status as of March 14, 1978

NEGOTIATION ITEMS
(Listed by system elements and
contractual considerations)

PARTICIPANTS/SDG&E
NEGOTIATING TEAM
CURRENT POSITION

SOUTHERN CALIFORNIA
EDISON STAFF
CURRENT POSITION

G. Sundesert-Miguel 500 kv Line

1. Ownership (facilities)	SDG&E ----->	SAME
2. Facility Design	SDG&E ----->	SAME
3. Construction:		
Performance	SDG&E ----->	SAME
Cost	SDG&E ----->	SAME
4. Use	SDG&E ----->	SAME
5. Operation:		
Performance	SDG&E ----->	SAME
Cost	SDG&E ----->	SAME
6. Maintenance:		
Performance	SDG&E ----->	SAME
Cost	SDG&E ----->	SAME
7. Licensing	SDG&E ----->	SAME
8. R.O.W. Acquisition	SDG&E ----->	SAME
9. Initial Operation	January, 1984	(?)

Attachment A

SUNDESERT PROJECT TRANSMISSION FACILITY NEGOTIATIONS

Status as of March 14, 1978

NEGOTIATION ITEMS
(Listed by system elements and contractual considerations)

PARTICIPANTS/SDG&E
NEGOTIATING TEAM
CURRENT POSITION

SOUTHERN CALIFORNIA
EDISON STAFF
CURRENT POSITION

H. Devers-500 kv Substation

1. Ownership of Terminating Facilities for Lines No. 1 and No. 2 and Rainbow Line

Participants own Line 2 Terminating Facilities.

SCE to have 100% ownership of all Devers Substation Facilities.

SCE own Line No. 1 Terminating Facilities. ----->

SAME

Participants/SDG&E own Valley Line Terminating Facilities.

SCE

SAME

2. Facility Design

SCE

3. Construction:

Performance

SCE ----->

SAME

Cost

In proportion to OWNERSHIP of Facilities.

Should be in proportion to USE of the Facility.

4. Operation:

Performance

SCE with consideration of scheduling requirements of SDG&E/Participants ----->

SAME

Cost

In proportion to OWNERSHIP of Facilities.

Should be in proportion to USE of the Facility.

5. Maintenance:

Performance

SCE with consideration of scheduling requirements of SDG&E/Participants ----->

SAME

Cost

In proportion to OWNERSHIP of Facilities.

Should be in proportion to USE of the Facility.

DERIVATION OF CONTRACT ENERGY COST
November 1978 - Anaheim

FC = 297¢/M² BTU

Liquid Fuel Beginning Inventory	<u>Total M² BTU</u>	<u>Total Cost</u>	<u>Weighted Average Cost ¢/M² BTU</u>
<u>Low Sulfur Oil Plants</u>			
Alamitos	8,374,385	\$ 25,047,429.89	
Redondo Beach	2,333,660	6,960,479.80	
Huntington Beach	3,696,828	11,108,043.00	
El Segundo	2,129,327	6,320,031.15	
Etiwanda	2,531,278	7,583,376.92	
System Storage	31,313,125	93,505,021.41	
Mandalay	2,162,650	6,077,156.78	
Ormond Beach	9,012,683	25,136,486.78	
Port Huenele	357,519	997,126.04	
Coolwater	1,234,384	3,982,871.31	
Highgrove	392,825	816,135.54	
San Bernardino	753,460	2,282,859.86	
Long Beach	472,014	1,106,408.20	
	<u>64,764,138</u>	<u>\$190,923,426.68</u>	<u>\$ 294.80</u>
<u>Combined Cycle Plants</u>			
Long Beach	844,401	\$ 2,892,907.31	
Coolwater	2,766,282	9,551,771.54	
System	295,718	1,018,953.37	
	<u>3,906,401</u>	<u>\$ 13,443,632.22</u>	<u>\$ 344.14</u>
<u>Jet Fuel Plants</u>			
Etiwanda	114,138	\$ 310,495.52	
Alamitos	101,034	274,945.08	
Huntington Beach	110,802	300,944.43	
Mandalay	110,325	299,386.01	
Ellwood	45,209	122,683.00	
	<u>481,508</u>	<u>\$ 1,308,454.04</u>	<u>\$ 271.74</u>
Total Liquid Fuel Inventory	<u>69,152,047</u>	<u>\$205,675,512.04</u>	<u>\$ 297.42</u>

2LOE050.C(1)
1/21/80

DERIVATION OF CONTRACT ENERGY COST
November 1978 - Anaheim

HR = 9,974 BTU/KWH
OC = 1.22 Mills/KWH

Source: F.P.C. Form No. 1, 1977

(1) Plant	(2) Net Generation Exclusive of Plant Use KWH x 10 ³	(3) Average BTU/KWH of Net Generation	(4) BTU x 10 ⁶ Col. (2) x Col. (3)	Other Costs \$		
				Total, Accts. 500 - 514	Acct. 501 (Fuel)	Accts. 500 - 514 Less Acct. 501
Long Beach	888,569	10,688	9,497,025	\$ 28,444,728	\$ 22,438,737	\$ 6,005,991
Redondo Beach	6,586,901	10,161	66,929,501	167,112,849	157,105,181	10,007,668
Huntington Beach	4,551,948	9,820	44,700,129	112,442,384	105,369,788	7,072,596
Mandalay	2,478,682	9,603	23,802,783	56,202,045	53,524,120	2,677,925
Ormond Beach	7,313,450	9,620	70,355,389	179,802,066	174,200,920	5,601,146
Alamitos	10,316,757	9,833	101,444,672	263,840,963	254,882,747	8,958,216
El Segundo	5,308,266	9,864	52,360,736	128,262,633	124,301,158	3,961,475
Etiwanda	5,361,704	9,989	53,558,061	132,543,460	125,189,293	7,354,167
Coolwater	1,094,470	10,093	11,046,486	26,569,867	25,461,176	1,108,691
Highgrove	42,872	13,497	578,643	1,963,209	1,296,950	666,259
San Bernardino	801,988	10,163	8,150,604	18,487,430	17,007,837	1,479,593
Ellwood	167,230	33,026	5,522,938	62,719	13,587	49,132
Total	<u>44,912,837</u>		<u>447,946,967</u>	<u>\$1,115,734,353</u>	<u>\$1,060,791,494</u>	<u>\$54,942,859</u>

$$\text{Heat Rate (HR)} = \frac{447,946,967 \text{ BTU} \times 10^6}{44,912,837 \text{ KWH} \times 10^3} = 9,973.6956 \text{ BTU/KWH; round to } 9,974 \text{ BTU/KWH}$$

$$\text{Other Costs (OC)} = \frac{54,942,859 \text{ Mills} \times 10^3}{44,912,837 \text{ KWH} \times 10^3} = 1.223 \text{ Mills/KWH; round to } 1.22 \text{ Mills/KWH}$$

2LOE050.C(2)

DERIVATION OF CONTRACT ENERGY COST
November 1978 - Anaheim

L = 1.31%
CEC = 30.02 Mills/KWH

(1) Plant	(2) Mileage From Plant to Lewis	(3) Network Loss Factor, % Per Mile	(4) Percent Loss From Plant To Lewis (Col. (3) x Col. (4))	(5) Net Generation Exclusive of Plant Use KWH x 10 ³	(6) % x (KWH x 10 ³) Col. (4) x Col. (5)
Long Beach	32.4	0.023	0.7452	888,569	662,162
Redondo Beach	33.5	0.023	0.7705	6,586,901	5,075,207
Huntington Beach	21.9	0.023	0.5037	4,551,948	2,292,816
Mandalay	151.3	0.023	3.4799	2,478,682	8,625,565
Ormond Beach	142.9	0.023	3.2867	7,313,450	24,037,116
Alamitos	20.4	0.023	0.4692	10,316,757	4,840,622
El Segundo	36.6	0.023	0.8418	5,308,266	4,468,498
Etiwanda	34.8	0.023	0.8004	5,361,704	4,291,508
Coolwater	117.8	0.023	2.7094	1,094,470	2,965,357
Highgrove	41.3	0.023	0.9500	42,872	40,728
San Bernardino	52.0	0.023	1.1960	801,988	959,178
Ellwood	184.4	0.023	4.2412	167,230	709,256
				<u>44,912,837</u>	<u>58,968,013</u>

Weighted transmission loss from plant to Lewis (L) = $\frac{58,968,013}{44,912,837} = 1.3129\%$; round to 1.31%

$$\begin{aligned}
 \text{Contract Energy Cost} &= \left[(\text{FC} \times \text{HR}) + \text{OC} \right] \times \frac{100}{100-L} \\
 &= \left[(297 \times 9,974) + 1.22 \right] \times \frac{100}{100-1.31} \\
 &= \left[2,962,278 + 1.22 \right] \times \frac{100}{98.69} \\
 &= 296,227,922 \div 98.69 \\
 &= 30.01600 \text{ Mills/KWH, round to } 30.02 \text{ Mills/KWH}
 \end{aligned}$$

2LOE050.C(3)

Referring to Page 3, if Coolwater and Highgrove are omitted, and assuming the Long Beach mileage is correct:

Total of Col. 5 = 43,775,495

Total of Col. 6 = 55,961,928

Weighted transmission loss
from plant to Lewis (L) = $\frac{55,961,928}{43,775,495} = 1.27838\%$, round to 1.28%

$$\begin{aligned} \text{CEC} &= \left[(297 \times 9,974) + 1.22 \right] \times \frac{100}{100-1.28} \\ &= \left[2,962,278 + 1.22 \right] \times \frac{100}{98.72} \\ &= 296,227,922 \div 98.72 \\ &= 30.00688 \text{ Mills/KWH, round to } 30.00 \text{ Mills/KWH} \end{aligned}$$

2LOE050.C(4)

DERIVATION OF CONTRACT ENERGY COST
December 1978 - Anaheim

FC = 287¢/M² BTU

<u>Liquid Fuel</u> <u>Beginning Inventory</u>	<u>Total M² BTU</u>	<u>Total Cost</u>	<u>Weighted Average Cost</u> <u>¢/M² BTU</u>
<u>Low Sulfur Oil Plants</u>			
Alamitos	6,976,119	\$ 19,957,592.72	
Redondo Beach	2,705,228	7,539,020.41	
Huntington Beach	1,708,847	4,903,215.66	
El Segundo	2,732,261	7,735,415.69	
Etiwanda	2,582,592	7,400,528.06	
System Storage	24,773,349	70,918,921.85	
Mandalay	1,847,603	5,157,615.95	
Ormond Beach	5,389,644	15,015,793.60	
Port Hueneme	324,717	904,676.44	
Coolwater	728,951	2,362,042.36	
Highgrove	793,623	2,027,646.47	
San Bernardino	447,664	1,366,599.48	
Long Beach	472,014	1,106,408.20	
	<u>51,482,612</u>	<u>\$146,395,476.89</u>	<u>\$ 284.36</u>
<u>Combined Cycle Plants</u>			
Long Beach	679,941	\$ 2,280,267.07	
Coolwater	1,657,164	5,617,935.45	
System	296,112	1,000,410.20	
	<u>2,633,217</u>	<u>\$ 8,898,612.72</u>	<u>\$ 337.94</u>
<u>Fuel Plants</u>			
Etiwanda	115,658	\$ 326,192.35	
Alamitos	102,655	289,623.48	
Huntington Beach	101,304	285,256.34	
Mandalay	115,807	325,808.42	
Ellwood	45,073	126,807.26	
	<u>480,497</u>	<u>\$ 1,353,687.85</u>	<u>\$ 281.73</u>
Total Liquid Fuel Inventory	<u>54,596,326</u>	<u>\$156,647,777.46</u>	<u>\$ 286.92</u>

2LOE050.C(5)

Heat Rate (HR) = 9,974 BTU/KWH See Page 2 of November 1978 Derivation
 Other Costs (OC) = 1.22 Mills/KWH
 (L) = 1.31% See Page 3 of November 1978 Derivation

$$\begin{aligned}
 \text{Contract Energy Cost} &= (\text{FC} \times \text{HR}) + \text{OC} \times \frac{100}{100-L} \\
 &= [(287 \times 9,974) + 1.22] \times \frac{100}{100-1.31} \\
 &= [2,862,538 + 1.22] \times \frac{100}{98.69} \\
 &= 286,253,922 \div 98.69 \\
 &= 29.00536 \text{ Mills/KWH, round to } 29.00 \text{ Mills/KWH}
 \end{aligned}$$

If, as in Page 4, Coolwater and Highgrove and omitted, and assuming the Long Beach mileage is correct, L = 1.28%

$$\begin{aligned}
 \text{CEC} &= 286,253,922 \div 98.72 \\
 &= 28.99655, \text{ round to } 29.00 \text{ Mills/KWH}
 \end{aligned}$$

2LOE050.C(6)

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JAN 7 1980



Department of the Interior
United States Department of the Interior

IN REPLY REFER

BUREAU OF LAND MANAGEMENT

ARIZONA STATE OFFICE

2400 VALLEY BANK CENTER

PHOENIX, ARIZONA 85073

January 2, 1980

A-9878 (920
CA-4163

To Persons Interested in the Palo Verde-Devers 500kV Transmission Line:

After analyzing the information in the final environmental statement for the proposed Palo Verde-Devers 500kV transmission line, the Bureau of Land Management (BLM) has identified its preferred route for the line, which is highlighted on the attached map.

BLM considered the following major points in identifying the preferred route:

1. Making the best use of existing roads and utility rights-of-way, thereby reducing the impacts of road construction and opening of new areas to vehicle access;
2. Avoiding, or reducing as much as possible, land use, social, and economic impacts on private lands and;
3. Avoiding direct impacts on proposed and established wilderness study areas.
4. Avoiding critical Bighorn sheep habitat.

BLM will deal with other potential impacts, such as effects on vegetation and cultural resources, as the specific tower sites and access roads are located on the ground.

BLM will work with Southern California Edison (SCE) and the U.S. Fish and Wildlife Service (FWS) to examine this route in detail, allowing SCE to do the ground site location and survey work required to perfect their right-of-way applications.

The following steps will be taken in completing this project:

1. BLM, FWS and SCE will conduct field review of the preferred route.
2. SCE will submit a preliminary survey of centerline and aerial strip maps and will flag potential disturbance areas.

3. SCE will apply to the Arizona State Siting Committee for approval of the segments of the line that have changed since the committee originally gave its approval.

4. BLM, SCE, and other affected parties will conduct field walk-through inspections of critical areas.


5. SCE will submit a perfected application to BLM, including cultural and botanical surveys. SCE will make a separate application to the FWS for that segment of the line across the KOFA National Wildlife Refuge.

6. BLM will issue a right-of-way grant for all areas except the segment crossing the KOFA National Wildlife Refuge, for which the U. S. Fish and Wildlife Service will grant the right-of-way. The Fish and Wildlife Service will impose such terms and conditions as are necessary, including siting, to protect the Refuge resources.

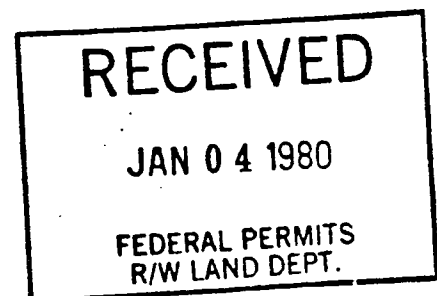
7. BLM and FWS will work with SCE in preconstruction activities and will closely monitor the entire construction process for compliance with the stipulations included in the right-of-way grants.

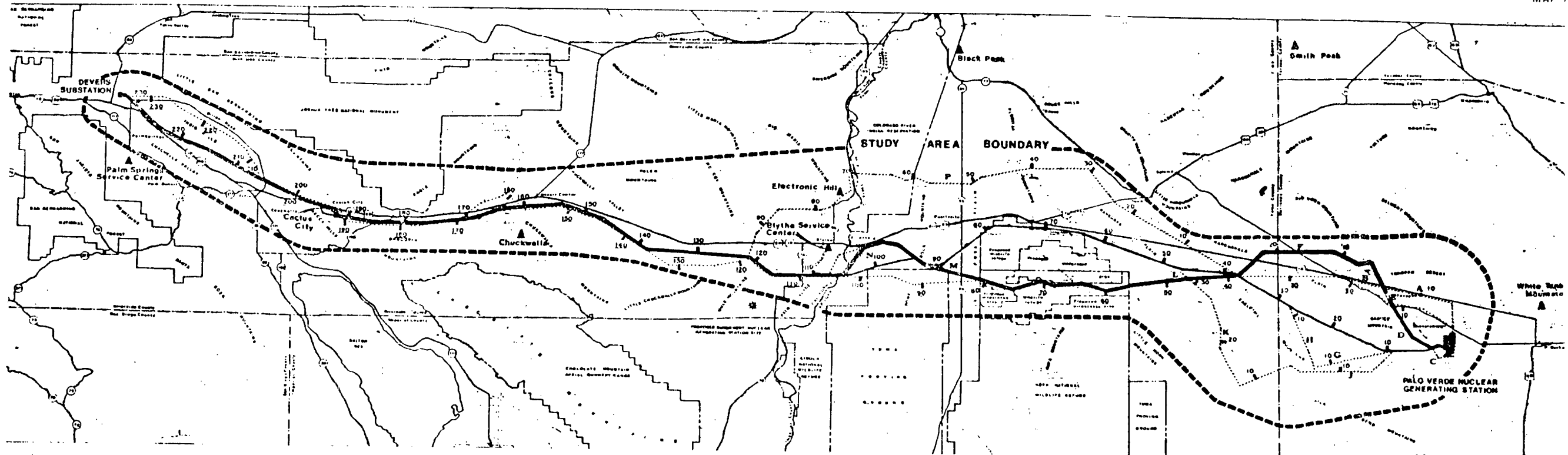
I hope that this brief summary will bring you up to date on the actions taken by BLM and those that we anticipate taking in the future in meeting BLM's responsibilities in this project.

Sincerely,


Glendon E. Collins
Acting State Director

Enclosure
Map





LEGEND

MILEPOSTS

- | BRENDA
- | KOFA
- | SUBALTERNATES

TELECOMMUNICATION SITES

- ▲ OUTSIDE STUDY AREA
- ▲ IN STUDY AREA

- STUDY AREA BOUNDARY
- STATE HIGHWAY
- INTERSTATE HIGHWAY
- FEDERAL HIGHWAY
- COUNTY LINES
- STATE LINE

UNITED STATES
 DEPARTMENT OF THE INTERIOR
 BUREAU OF LAND MANAGEMENT
 PROPOSED
 PALO VERDE-DEVERS 500KV TRANSMISSION LINE

STUDY AREA

ENVIRONMENTALLY PREFERRED ROUTE

ROUTES UNDER STUDY
 BRENDA
 KOFA
 SUBALTERNATES

SOURCE: BLM TEAM & APPLICANT