FEDERAL POWER COMMISSION
WASHINGTON, D.C. 20426
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Mr. Daniel R. Muller
Assistant Director for
Environmental Projects
Directorate of Licensing
U. S. Atomic Energy Commission
Washington, D. C. 20545

Dear Mr. Muller:

This is in response to your letter dated November 21, 1972, requesting comments on the AEC Draft Environmental Statement related to the issuance of construction permits jointly to the Southern California Edison Company and the San Diego Gas & Electric Company for construction of the San Onofre Nuclear Generating Station Units 2 and 3 (Docket Nos. 50-361 and 50-362).

Pursuant to the National Environmental Policy Act of 1969, and the April 23, 1971, Guidelines of the Council on Environmental Quality, these comments are directed to a review of the need for the facilities as concerns the adequacy and reliability of the affected bulk power systems and matters related thereto.

In preparing these comments, the Federal Power Commission's Bureau of Power staff has considered the AEC Draft Environmental Statement; the Applicant's Environmental Report and Supplements thereto; related reports made in response to the Commission's Statement of Policy on Adequacy and Reliability of Electric Service (Order No. 383-2); and the staff's analysis of these documents together with related information from other FPC reports. The staff of the Bureau of Power generally bases its evaluation of the need for a bulk power facility upon long term considerations as well as the load-supply situation for the peak load period immediately following the availability of the facility. The useful life of the San Onofre facilities is expected to be 30 years or more. During that period, these units will make a significant contribution to the adequacy and reliability of power supply in the Applicants' service areas.

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Need for the Facility

The San Onofre Nuclear Generating Station is located entirely within the Camp Joseph H. Pendleton Naval Reservation on the shore of the Pacific Ocean about 62 miles southeast of Los Angeles and 51 miles northwest of San Diego, California. The 429-megawatt nuclear unit No. 1 has been in operation at this site since 1967. The two units now proposed for construction are scheduled to start commercial operation in June 1978 and June 1979, respectively. The Applicants will share the output of each of the 1,140-megawatt units with 80 percent or 912 megawatts, to the Southern California Edison Company (SEC) and 20 percent, or 228 megawatts, to the San Diego Gas and Electric Company (SDG&E).

The owners of the San Onofre Nuclear Generating Station are members of the Western Systems Coordinating Council (WSCC) and together with the Metropolitan Water District of Southern California and the California Department of Water Resources and a number of other utilities comprise the systems serving the Pacific Southwest Sub-Areas A and B of WSCC, which extend over the southern half of California and the southern half of Nevada. The Applicants' systems account for the major portion of the electric resources of the sub-areas. The WSCC region, which extends over 12 states and part of Canada, is a winter-peaking area; however, the sub-areas served by the Applicants are summer-peaking with little seasonal diversity. Winter and summer peak loads are approximately equal. Both the WSCC region and the Applicant's sub-areas have projected growth rates of 7.3 percent. Consequently the annual peak load is expected to double in the 1970-1980 period. To meet this projected demand, the Applicants have been expanding their baseload generating capacity with fossil and nuclear generating units. Temperature inversions, common in the southern California area, result in heavy smog conditions caused principally by combustion of fossil fuels. Local air quality regulations will have a strong influence in shaping the region's fuel choices for generating electric power.

The capacity expansion program for both Applicants' systems is tabulated below:

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Station/Unit	Owner	Capacity (MW)	Type 1/	In-Service Date
Mohave 1 (rerate)	SCE (Share)	174	F	January 1973
Ormond Beach No. 2	SCE	790	F	June 1973
Mohave 1 & 2	SCE (Share)	34	F	July 1973
Encina No. 4	SDGE	287	F	June 1973
Various G/T	SDGE	150	F	June 1974
Various G/T	SCE	40	F	June 1974
Combined Cycle A	SCE	160	F	August 1974
Combined Cycle B	SCE	160	F	April 1975
Combined Cycle C	SCE	300	F	June 1975
Encina No. 5	SDGE	303	F	June 1975
Combined Cycle D	SCE	80	F	October 1975
Combined Cycle E	SCE	68	F	June 1976
Oil and Gas No. 1	SCE	790	F	June 1976
Various G/T	SDGE	150	F	June 1976
Oil and Gas No. 2	SCE	790	F	June 1977
Various G/T	SCE	320	F	June 1977
Various G/T	SDGE	253	F	June 1977
San Onofre No. 2	SDGE (Share)	228	N	June 1978
San Onofre No. 2	SCE (Share)	912	N	June 1978
Thermal A	SCE (Share)	500	F	June 1978
Thermal A	SDGE (Share)	300	F	June 1978
Piru Creek No. 1	SCE	200	PS	July 1978
Piru Creek No. 3	SCE	200	PS	January 1979
San Onofre No. 3	SCE (Share)	912	N	June 1979
San Onofre No. 3	SDGE (Share)	228	N	June 1979
Thermal B	SCE	500	F	June 1979
Thermal B	SDGE	300	F	June 1979
Piru Creek No. 5	SCE	200	PS	July 1979
	TOTAL	9,329 MW		

1/ Types: F - Fossil, N - Nuclear, PS - Pumped Storage.

In addition to the new capacity planned by the Applicants, other electric systems located in Sub-areas A and B have planned 1,770 megawatts of new hydroelectric capacity, 1,319 megawatts of new fossil-fueled capacity and 500 megawatts of new nuclear capacity.

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The following tabulations show the electric system loads to be served by the Applicants' systems and the Sub-Areas A and B of the Pacific Southwest Power Area, and the relationship of the electric power output of the San Onofre Units 2 and 3 to the projected available reserve capacities on these systems at the time of the 1978 and 1979 summer peak loads. These are the anticipated initial service periods of the new units, but the units will be depended upon to supply power to meet future demands over a period of many years beyond the initial service needs discussed in this report.

1978 SUMMER PEAK LOAD - SUPPLY SITUATION

	SCE	SDG&E	Pacific S.W. Sub-Area A&B
Conditions With San Onofre Unit 2 (1,140 Megawatts) 1/			
Net Total Capability - Megawatts	18,126	3,632	31,669 2/
Net Peak Load - Megawatts	14,900	2,669	25,140
Reserve Margin - Megawatts	3,226	963	6,529 3/
Reserve Margin - Percent of Peak Load	21.7	36.1	26.0
Reserve Margin - Based on 20 Percent of Peak Load - Megawatts 4/	2,980	534	5,028
Conditions Without San Onofre Unit 2			
Net Total Capability - Megawatts	17,214	3,404	30,529 2/
Net Peak Load - Megawatts	14,900	2,669	25,140
Reserve Margin - Megawatts	2,314	735	5,389
Reserve Margin - Percent of Peak Load	15.5	27.5	21.4
Reserve Deficiency - Megawatts 5/	666	--	--

1/ SCE share - 912 megawatts; SDG&E share - 228 megawatts.
2/ Includes net purchase of 3,433 megawatts.
3/ Includes scheduled maintenance of 1,257 megawatts.
4/ FPC staff estimate of reserve needed for acceptable reliability.
5/ Based on staff estimate of needed reserve.

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1979 SUMMER PEAK LOAD - SUPPLY SITUATION

	SCE	SDG&E	Pacific S.W. Sub-Area A&B
Conditions With San Onofre Unit 3 (1,140 Megawatts) 1/			
Net Total Capability - Megawatts	19,938	4,172	34,896 2/
Net Peak Load - Megawatts	15,990	2,888	26,959
Reserve Margin - Megawatts	3,948	1,284	7,937 3/
Reserve Margin - Percent of Peak Load	24.7	44.5	29.4
Reserve Margin Needs - Based on 20 Percent of Peak Load - Megawatts 4/	3,198	578	5,392
Conditions Without San Onofre Unit 3			
Net Total Capability - Megawatts	19,026	3,944	33,756
Net Peak Load - Megawatts	15,990	2,888	26,959
Reserve Margin - Megawatts	3,036	1,056	6,797 3/
Reserve Margin - Percent of Peak Load	19.0	36.6	25.2
Reserve Deficiency - Megawatts 5/	162	--	--
Conditions Without San Onofre Units 2 and 3			
Net Total Capability - Megawatts	18,114	3,716	32,616
Net Peak Load - Megawatts	15,990	2,888	26,959
Reserve Margin - Megawatts	2,124	828	5,659 3/
Reserve Margin - Percent of Peak Load	13.3	28.7	21.0
Reserve Deficiency - Megawatts 5/	1,074	578	--

1/ SCE share - 912 megawatts; SDG&E share - 228 megawatts.
2/ Includes net purchases of 1,431 megawatts.
3/ Includes scheduled maintenance of 2,266 megawatts.
4/ FPC staff estimate of reserve needed for acceptable service.
5/ Based on staff estimate of needed reserve.

The Applicants state that they use minimum reserve margin criteria for acceptable system reliability of:

A. An installed capacity margin after maintenance of at least 15 percent of the annual peak demand.

B. An installed capacity after deducting scheduled maintenance sufficient to allow loss of the larger of (1) the two largest risks (generating unit or interconnection), or (2) 7 percent of system demand plus the largest risk.

C. A reliability criterion based on probability calculations (SCE only).

In general, satisfying all three criteria is considered necessary to assure that a level of reliability be maintained sufficient to provide service consistent with accepted practice throughout the industry. For the conditions encountered in the period of this study, the reliability criterion based on probability calculations is considered the most stringent and, therefore, the governing criterion. The Criteria A and B, above, are those used for acceptable system reliability for the southern California sub-area. The installed capacity margin of at least 15 percent in the above criteria refers to reserve margin after allowance for scheduled maintenance and hence does not represent the total gross reserve margin needed for system reliability.

The availability of the San Onofre Unit 2 for the 1978 summer peak period would provide the SCE system with an expected reserve margin of 3,226 megawatts, or 21.7 percent of the system peak load, and the SDG&E system with an expected reserve margin of 963 megawatts or 36.1 percent of the system peak load. If Unit 2 should be delayed beyond the 1978 summer peak period, the SCE system reserve margin would be reduced to 2,314 megawatts or 15.5 percent of system peak load and the SDG&E system would be reduced to 735 megawatts or 27.5 percent of system peak load. The availability of the San Onofre Unit 3 for the 1979 summer peak period would provide the SCE system with an expected reserve margin of 3,948 megawatts, or 24.7 percent of system peak load and the SDG&E system with an expected reserve margin of 1,284 megawatts or 44.5 percent of system peak load. If Unit 3 should be delayed beyond the 1979 summer peak period the SCE system reserve margin would be reduced to 3,036 megawatts, or 19.0 percent of system peak load and the SDG&E system reserve margin would be reduced to 1,056 megawatts or 36.6 percent of the system peak load.

The Pacific Southwest Sub-areas A and B project a reserve margin for the 1978 summer peak period of 6,529 megawatts, or 26.0 percent of the peak load; if Unit 2 should be delayed beyond this period, the reserve

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margin would be reduced to 5,389 megawatts or 21.4 percent of the peak load. The sub-areas project a reserve margin for the 1979 summer peak period of 7,937 megawatts, or 29.4 percent of peak load; if Unit 3 should be delayed beyond this peak period, the reserve margin would be reduced to 6,797 megawatts, or 25.2 percent of the peak load.

The adequacy and reliability of the Applicants' system will be dependent upon satisfactory completion of a large amount of new capacity scheduled for commercial service prior to the 1979 summer peak load period. The Applicants' capacity expansion program and those of other systems in Sub-areas A and B indicate a total of 12,918 megawatts of new capacity must be placed in commercial operation on schedule to provide the reserve margins indicated. The reserve margins mentioned in the foregoing paragraphs are gross and must provide for scheduled outages of equipment for maintenance, slippage in availability dates of new generating capacity, forced outages of generating equipment, errors in load fore-casting, derating of equipment, exceptional weather and operating reserves normally required on interconnected bulk power systems. For the Pacific Southwest Sub-Area A and B, scheduled maintenance during the 1978 summer peak period will total 1,257 megawatts which reduced the available reserve capacity to 5,272 megawatts, or 21.0 percent of peak load, and for the 1979 summer peak period scheduled maintenance will total 2,266 megawatts reducing the available capacity reserves to 5,671 megawatts, or 21.0 percent of peak load.

The planned reserves on the Applicants' systems and that of the sub-areas would appear ample at this time to serve the needs of the sub-areas. However, the Western Systems Coordinating Council area is served by a highly interconnected system spread over a very large area. In the neighboring sub-area to the north, the Pacific Gas and Electric Company has recently withdrawn its application for the 2,260-megawatt nuclear Mendocino Power Plant whose units were scheduled for commercial operation in 1978 and 1979, the same years as the San Onofre Units No. 2 and 3. It is unlikely that these commercial operating dates could be met by any alternative that may be chosen for the Mendocino plant. The expansion programs for the Applicants' systems indicate that plants Thermal A and B, both of 800 megawatts of capacity, are also planned for commercial operation in 1978 and 1979. These units are the proposed coal-fired Kaiparowits units located in Southern Utah and their availability for the 1978-1979 period is considered very doubtful by the Applicants.

The South Coast Air Basin is an area in which air pollution appears to be of serious public concern. The combustion of fossil fuels for electric power generation in the Los Angeles area is encountering strong opposition. The curtailment of further development of fossil-fueled generating facilities or emergency curtailment of existing facilities in

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the Los Angeles-San Diego area could result in a severe area-wide deficiency of generating capacity. The San Onofre nuclear units would not be subject to curtailment of operations or shut-down to alleviate air quality conditions since no particulates or gaseous combustion products are emitted.

Transmission Facilities

Three additional overhead transmission lines are planned to integrate the San Onofre Units 2 and 3 into the Applicants' existing transmission systems. One double-circuit 220-kilovolt line will extend from the plant switchyard generally north-northwest along the existing right-of-way from the plant to the existing Santiago Substation, near Santa Ana, California, a distance of about 28.4 miles, to serve the SCE system. The lines will be mounted on steel-latticed towers and on modern esthetically designed structures near the plant. A second 230-kilovolt line will extend from the plant switchyard generally southeast about 25 miles to the existing Encina Substation near Carlsbad, California to serve the SDG&E system. A third 230-kilovolt line will extend from the plant switchyard initially northwest a distance of 7 miles to the existing Telega Substation, then easterly 27 miles to the proposed Pala Substation and then southerly a distance of 17 miles to the existing Escondido Substation near San Marcos, California to serve the SDG&E system. These two lines serving the SDG&E system will be mounted on steel-latticed towers. The rights-of-way will traverse essentially rural areas but will pass near and in some cases through residential areas. Some segments of the rights-of-way will be located on Federally-owned land in the Camp Pendleton reserve. The Applicants state that the lines will comply with the environmental criteria established by the Federal Power Commission and the U. S. Department of the Interior and U. S. Department of Agriculture with few exceptions. Multiple use of rights-of-way will minimize the impact of the new lines on the area.

Alternatives and Costs

The Applicants in determining the need for additional generation to meet their projected system demands considered in addition to the purchase of firm power, a number of other alternatives, such as alternate locations, plant types, fuels, environmental effects and economics. The Applicants considered twenty sites in the original selection of the San Onofre site for Unit 1. The Applicants considered an alternate site for Units 2 and 3 on Point Conception in Santa Barbara County; however, environmental considerations in that area led to the selection of the San Onofre site where the existing Unit 1 was located and in operation. Undeveloped hydroelectric capacity of 11,908 megawatts was stated in the Federal Power Commission's 1968 survey to be available in the State of California. However, this undeveloped capacity is located well outside the Applicants'

service areas. The only viable thermal alternative plant was considered to be two 790-megawatt oil and gas fired units and two 121-megawatt gas turbine generators at a site near Boron, California. With a total capacity of 1,824 megawatts, such a plant would be equivalent to the SCE share of the output of the San Onofre Units 2 and 3. A coal-fired alternative plant at the proposed Kaiparowits site in southern Utah could not be considered an available alternative to the Applicants because of environmental objections of local residents of the area. The Applicants' final choice between the nuclear-fueled and oil and gas-fired plant rested upon the reduced environmental impact and superior fuel economics of the nuclear plant and the reduced capacity (by 450 megawatts) of the oil and gas-fueled alternative plant. The Applicants reported capital costs of $840 million for the nuclear-fueled plant and $570 million for the oil and gas-fueled plant resolve to $368 and $250 per kilowatt of capacity, respectively. The Applicant did not report estimated fuel costs for the nuclear-fueled plant or the oil and gas-fueled alternative plant. The staff of the Bureau of Power finds the capital costs to be within the range of similar costs reported by the industry.

A geothermal source equivalent to the San Onofre nuclear units would have to provide energy averaging approximately 15,960,000 megawatt-hours annually for 30 years at a rate of 2,280 MW. Sources of geothermal energy are known to exist in the Applicants' service area, although it has not been reliably ascertained that the energy flow needed in this instance is available. In addition to decisions regarding the significant environmental aspects of the exploitation of geothermal sources, a number of engineering tests, evaluations and decisions would be required before engineering design of the plant could be undertaken. The Bureau of Power staff is of the opinion that the geological, environmental and engineering studies, the design effort, and the construction activity required to produce a reliable geothermal plant of the size required, could not be completed by the June 1978 and 1979 dates scheduled for commercial operation of the San Onofre nuclear units.

Conclusions

The staff of the Bureau of Power concludes that, although some slippage might be tolerated without severe results if a large number of other new units are completed and in service on schedule, the electric power output of the San Onofre Nuclear Generating Station Units 2 and 3 will likely be needed to meet the projected loads of the Southern California area by their planned dates of operation and to provide the reserve margins for adequacy and reliability of electric service on the Applicants' systems and the Pacific Southwest Sub-areas A and B of the Western Systems Coordinating Council area. The two San Onofre units are the only planned thermal baseload units for the 1978-1980 periods which will not cause further

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deterioration of the air quality in the South Coast Air Basin, or cause further inroads into critically short supplies of oil and gas fuels. The 1,140 megawatt San Onofre Units 2 and 3, planned for commercial operation prior to the 1978 and 1979 summer peak load period, respectively, are the two largest units of the 12,918 megawatts of new capacity planned in the area. The timely commercial operation of these units and other planned capacity additions is needed to attain the capacity reserves to provide adequate reliability on the Applicants' systems.

Very truly yours,

T. A. Phillips
Chief, Bureau of Power