Southern California Edison Company

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W. G. HUGHES, JR.
MANAGER OF INSURANCE

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(213) 572-1079

March 29, 1982

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Mr. Jerome Saltzman
Chief, Antitrust & Indemnity Group
Nuclear Reactor Regulation
Nuclear Regulatory Commission
Washington, D.C. 20555

Re: Docket No. 50-206

Dear Mr. Saltzman:

In compliance with Section 140.21 of 10 CFR Part 140, the following materials are submitted on behalf of Southern California Edison Company, San Diego Gas and Electric Company, and the cities of Anaheim and Riverside for their ownership interests in San Onofre Nuclear Generating Station, Units 1 and 2:

1. One copy of Annual Report to the Securities and Exchange Commission (Form 10-K) for the fiscal year ended December 31, 1981.

2. Cash Flow Statement for the fiscal year ended December 31, 1981.

Sincerely,

WGH:JR
Enclosures
cc: Messrs. H. Fred Christie
Michael L. Noel
Charles R. Kocher
Craig Hubble
David E. Sparks

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SOUTHERN CALIFORNIA EDISON COMPANY

1981 Internal Cash Flow Projection For
San Onofre Nuclear Generating Station Units 1 & 2
(Dollars in Thousands)

	1981 Actual	1982 Projected
Net Income After Taxes	$489,912	$ *
Less Dividends Paid	336,546	*
Retained Earnings	$153,336	*
Adjustments:		
Depreciation & Amortization	$202,182	$246,000
Deferred Investment Tax Credits	47,386	56,000
Allowance for Funds Used During Construction	(232,552)	(220,000)
Total Adjustments	$ 17,016	$ 82,000
Internal Cash Flow	$170,352	*
Average Quarterly Cash Flow	$ 42,588	*

Percentage Ownership in All Operating Nuclear Units	Unit #1	80%	Southern California Edison Company
		20%	San Diego Gas & Electric Company
	Unit #2	75.05%	SCE
		20.00%	SDG&E
		3.16%	City of Anaheim
		1.79%	City of Riverside
Maximum Total Contingent Liability		$ 20,000	

* Company policy prohibits disclosure of financial data which will enable unauthorized persons to forecast earnings or dividends, unless assured confidentiality. The Net Estimated Cash Flow for 1982 is expected to be comparable to the Actual Cash Flow for 1981.

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SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 1981 | **Commission file number 1-2313**

SOUTHERN CALIFORNIA EDISON COMPANY

(Exact name of registrant as specified in its charter)

California	**95-1240335**
(State or other jurisdiction of incorporation or organization)	**(IRS Employer Identification No.)**

2244 Walnut Grove Avenue Rosemead, California	**91770**	**(213) 572-1212**
(Address of principal executive offices)	**(Zip Code)**	**(Registrant's telephone number, including area code)**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class		Name of each exchange on which registered
Capital Stock		
Original Preferred		American and Pacific
Cumulative Preferred		American and Pacific
4.08% Series	5.80% Series	
4.24% Series	8.85% Series	
4.32% Series	9.20% Series	
4.78% Series		
$100 Cumulative Preferred		American and Pacific
7.58% Series	8.96% Series	
8.54% Series	12.00% Series	
8.70% Series		
Preference		American and Pacific
5.20% Convertible Series		
Common		New York, Pacific and London
First and Refunding Mortgage Bonds		American
Series I through Series S, Series Y through Series CC, Series FF through Series JJ, Series MM through Series PP and Series RR		

Securities registered pursuant to Section 12(g) of the Act: None

The aggregate market value of registrant's voting stock held by non-affiliates was approximately $3,228,421,975 on or about February 26, 1982, based upon prices reported in The Wall Street Journal. The market value of certain series of $100 Cumulative Preferred and Preference Stock, private placements for which market prices are not available, were derived by dividing the annual dividend rate of each such series of stock by the average yield of all of the Company's Cumulative Preferred and $100 Cumulative Preferred Stock outstanding. The approximate market value of each of the various classes of voting stock were as follows: ORIGINAL PREFERRED STOCK $12,343,263; CUMULATIVE PREFERRED STOCK $120,383,527; $100 CUMULATIVE PREFERRED STOCK $270,674,245; PREFERENCE STOCK $20,336,144; COMMON STOCK $2,804,684,796.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes √. No __.

At March 17, 1982 there were 93,231,641 shares of Common Stock outstanding.

The following documents are incorporated by reference in the part of the report designated herein: (1) 1981 Annual Report to Shareholders (only portions of which are incorporated by reference) — Part II; (2) Proxy Statement filed with the Securities and Exchange Commission by the registrant on March 2, 1982 — Part III.

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Part I

PART I

Item 1. Business

Southern California Edison Company ("Company") was incorporated in 1909 under California law and is a public utility primarily engaged in the business of supplying electric energy to a 50,000 square-mile area of central and southern California, excluding the City of Los Angeles and certain other cities. This area includes some 800 cities and communities and a population of more than eight million people. As of December 31, 1981, the Company had 14,569 employees. During the year ended December 31, 1981, 28% of the Company's total operating revenues was derived from residential customers, 27% from commercial customers, 26% from industrial customers, 8% from public authorities and 11% from other sources, primarily resale.

General problems of the industry

The electric utility industry in general is currently experiencing problems relating to (i) high costs of fuel, wages and materials, (ii) vast capital outlays and longer construction periods for the larger and more complex new generating units needed to meet current and future service requirements of customers, (iii) increasing levels of allowance for funds used during construction ("AFUDC"), which are non-cash earnings, resulting from such increased capital outlays and longer construction periods, (iv) greater reliance on capital markets with high costs of both equity and borrowed capital, (v) effects of compliance with numerous regulatory and environmental requirements, and (vi) difficulties and delays in obtaining needed rate increases. The Company is, to varying degrees, currently experiencing all of these problems.

Regulation

The retail operations of the Company are subject to regulation by the California Public Utilities Commission ("CPUC"), which has the authority to regulate, among other things, retail rates, issuances of securities and accounting and depreciation practices. The Company's resale operations are subject to regulation by the Federal Energy Regulatory Commission ("FERC") as to rates on sales for resale, as well as other matters, including accounting and depreciation practices.

The Company is subject to the jurisdiction of the Nuclear Regulatory Commission ("NRC") with respect to nuclear power plants. NRC regulations govern the granting of licenses for the construction and operation of nuclear power plants and subject such power plants to continuing review and regulation.

The Company's plant construction, planning and siting are subject to the jurisdiction of the California Energy Commission. The Company is subject to rules and regulations promulgated by the California Air Resources Board and local air pollution control districts with respect to the emission of pollutants into the atmosphere, and the regulatory requirements of the California State Water Resources Control Board and regional boards with respect to the discharge of pollutants into waters of the state. The Company is also subject to regulation by the Environmental Protection Agency ("EPA"), which administers certain federal statutes relating to environmental matters, and to certain other federal, state and local laws and regulations relating to environmental protection and land use.

The Department of Energy has regulatory authority over certain aspects of energy conservation, solar energy development, power plant fuel use, coal conversion, public utility regulatory policy and natural gas pricing.

Rate matters

Retail rates

On December 18, 1981, the Company filed with the CPUC a general rate application designed to increase annual revenues by approximately $1.247 billion based on a 1983 test year, which should afford the Company a reasonable opportunity to earn an average rate of return on common equity of 19% for the 1983-84 period. The application also requests a general rate increase effective January 1, 1984 designed to produce additional annual revenues of approximately $169,000,000 to offset higher costs expected to be incurred in 1984. On March 4, 1982 the Company withdrew from further consideration in the application items amounting to approximately $284,000,000 of revenues. The Company made this withdrawal based on changed circumstances and conditions and more current information. Withdrawal of approximately $77,000,000 was contingent upon these items being considered in other proceedings. Withdrawal of approximately $64,000,000 related to the sales forecast for 1983 and was based on the CPUC adopting a revenue adjustment mechanism similar to the procedure authorized by the CPUC in other general rate increase applications. This rate request does not reflect revenue requirements associated with the operation of San Onofre Units 2 and 3.

On February 18, 1982, the Company filed with the CPUC an application to establish a Major Additions Adjustment Clause ("MAAC") to recover the expenditures associated with major generating projects where (1) it is not possible to trend certain expenses due to a lack of operating experience; and/or (2) it is not possible to anticipate the operating date of the projects with sufficient certainty to include them in a general rate case. In this application, the Company requested an annualized revenue increase of approximately $361,565,000, effective August 15, 1982, to recover the costs of owning, operating and maintaining San Onofre Unit 2, excluding Energy Cost Adjustment Clause ("ECAC") related fuel costs. In addition, the Company requested an equal reduction in net ECAC revenues to become effective August 15, 1982.

On January 1, 1982, the Company's base rates were increased to recover an additional $92,000,000 in annual revenues. This adjustment was in compliance with the CPUC's order in the Company's 1981 test year rate case, which order granted a $92,000,000 attrition allowance for the year 1982.

Energy cost adjustment clause

The Company's ECAC provides for adjustments in rates, subject to CPUC approval, to reflect changes in energy costs. The ECAC procedure provides for two ECAC rates. The Energy Cost Adjustment Billing Factors ("ECABF") recover 98% of certain energy costs for which a balancing account has been established. The accumulated over or undercollections in the balancing account are reflected in succeeding rate adjustment applications which are filed to become effective on January 1, May 1, and September 1 of each year. On February 28, 1982, the balance in the ECAC balancing account, representing net overcollections and accrued interest, was $54,500,000.

The ECAC also provides for an Annual Energy Rate ("AER") to reflect certain costs associated with (i) investment in fuel oil inventory, (ii) facility charges and underlift payments relating to fuel oil purchases, (iii) the remaining two percent of the Company's fuel and purchased power costs, and (iv) gains and losses on the sale of fuel oil. The AER is subject to revision each May 1.

On March 1, 1982, the Company filed an ECAC application proposing a net annualized decrease in ECAC revenues of $254,000,000, to become effective on May 1, 1982. This request includes a proposed annualized decrease in AER revenues of $3,800,000, and a proposed annualized decrease in ECABF revenues of $250,200,000.

The proposed decrease of $250,200,000 in ECABF revenues represents the expected implementation of a Rate Stabilization Plan proposed by the Company to provide for constant total rate levels through 1982, with an increase in base rates on January 1, 1983. The Plan is intended to operate by combining authorized changes in all adjustment clause rates with equal and opposite changes in the ECAC rates so that the effective total rate levels being charged the Company's customers remain stable. If the Plan is not implemented as proposed, the estimated net annualized decrease in ECABF revenue, beginning May 1, 1982, calculated in accordance with the current ECAC procedure, would be approximately $870,400,000.

Resale rates

Pursuant to FERC procedures, on August 4, 1974, February 1, 1976, August 16, 1979 and July 16, 1981, increases in the Company's resale rates became effective, subject to refund with interest to the extent that any of the increases are subsequently determined to be inappropriate.

An August 1, 1979 FERC decision affirmed the August 4, 1974 resale rate increase with respect to cost of service. The decision provided that the rate increase remain subject to refund pending resolution of an anti-competitive "price squeeze" issue raised by intervenors. On September 15, 1981, the FERC affirmed the administrative law judge's ruling granting the Company's motion for summary disposition in the "price squeeze" proceedings relating to the August 4, 1974 rate increase. That FERC decision is final.

An August 22, 1979 FERC decision on the February 1, 1976 rate increase required the Company to file a revised cost of service which reduced the annual increase in revenues. Revenues billed in excess of the revised cost of service had previously been deferred and the related interest accrued. The August 22, 1979 decision also found that the Company's resale customers had established a prima facie case of a "price squeeze" and provided that the case would be remanded to an Administrative Law Judge for hearings to determine the extent of such "price squeeze," if any, with respect to the filed revised rates. If a "price squeeze" is determined to exist, a further rate reduction may be imposed, which could result in additional refunds. Both the Company and intervenors filed petitions with the Court of Appeals for review of the August 22, 1979 decision. On December 11, 1981, the Court of Appeals denied both the Company's and intervenors' petitions and affirmed the FERC ruling in this case. This FERC decision could adversely affect the pending antitrust litigation instituted in federal district court on March 2, 1978 by five of the Company's resale customers (see "Antitrust Litigation" under Item 3).

By letter dated November 16, 1981 the FERC notifed the Company that its latest compliance filing relating to the February 1, 1976 rate increase was not in compliance with FERC opinions and required the Company to file a revised cost of service and revised rates. By this letter the FERC also required the Company to make refunds with appropriate interest of amounts collected in excess of those produced by the compliance rates filed. On December 16, 1981, the Company filed with the FERC, pursuant to the letter dated November 16, 1981, a revised cost of service which would further reduce the filed rates by $135,000. Revenues billed in excess of this revised cost of service had previously been deferred and the related interest accrued. In accordance with this letter the Company has refunded a total of $18,500,000 to FERC jurisdiction customers. The intervenors have made two subsequent objections to the Company's December 16, 1981 compliance filing and a February 3, 1982 refund request. One objection, concerning the calculation of interest on refunds, was acknowledged by the Company, and additional refunds were made on March 10, 1982. The other objection is before the FERC for resolution.

An Administrative Law Judge issued an initial decision on November 6, 1981 regarding the August 16, 1979 increase, in which the Judge disallowed the majority of the increase. Based on preliminary estimates, the Company believes that any amounts which would be required to be refunded would not have a material financial effect on the Company. On January 21, 1982, the Company filed a brief with the FERC contesting the Administrative Law Judge's decision, and on March 11, 1982, opposing briefs were filed.

The Company's July 16, 1981 rate increase included an adjustment in resale rates proposed to be effective when San Onofre Unit 2 becomes operational. The effective date for such resale rate increase would be suspended under the FERC order until five months after the date of commercial operation. The Company filed a voluntary notice of withdrawal on this portion of the filing on August 10, 1981. On August 20, 1981, intervenors filed a response which requested that such withdrawal by the Company be subject to the condition that any new rate filing the Company might make not allow for an earlier date for inclusion of San Onofre Unit 2 in rates than the effective date established under the July 16, 1981 FERC order. On January 4, 1982, the FERC denied the intervenors' request and granted the unconditional withdrawal of the proposed rate increase adjustment.

As of February 28, 1982, approximately $587,700,000 had been billed subject to refund. The Company believes that any amounts which the FERC may require the Company to refund as a result of the above proceedings should not have a material financial effect on the Company.

Fuel supply

Fuel and purchased power costs amounted to approximately $2.6 billion in 1981, 27% higher than for the year 1980. Sources of energy and unit costs of fuel for 1977 through 1981 were as follows:

	Sources of Energy					Average Cost Per Million BTU's(1)				
	Year Ended December 31,					Year Ended December 31,				
	1977	1978	1979	1980	1981	1977	1978	1979	1980	1981
Oil	56%	43%	44%	28%	21%	$2.54	$2.91	$3.40	$5.31	$7.10
Natural gas	15	18	23	30	34	1.85	2.05	2.39	3.33	3.77
Coal	14	10	11	12	12	.41	.53	.71	.69	.81
Nuclear(2)	3	3	4	1	1	.34	.36	.43	.82	—
All fuels	88	74	82	71	68	2.00	2.24	2.58	3.58	4.20
Hydroelectric(3)	2	9	8	9	6					
Purchased and interchanged power	10	17	10	20	26					
	100%	100%	100%	100%	100%					

(1) British Thermal Unit ("BTU") — The standard unit of measure for the heat content of fuels. It is the amount of heat required to raise the temperature of one pound of water, at 39.1 degrees Fahrenheit, by one degree Fahrenheit.

(2) San Onofre Unit 1 was not in service for a significant portion of 1981, therefore no comparable average cost is available.

(3) There are no fuel costs associated with the Company's hydroelectric generation.

The prices for oil now under contract are subject to various adjustments based on, among other factors, specified foreign prices for crude oil (including prices established by OPEC nations), import license fees and duties, royalties, taxes and transportation charges.

Average fuel costs, expressed in cents per kilowatt-hour for the year ended December 31, 1981 were: Oil 6.733¢; natural gas 4.046¢ and coal .953¢.

Natural gas and fuel oil supply

A number of the Company's major steam electric generating units are designed to burn oil or natural gas as a primary boiler fuel. Although increased supplies of natural gas have become available to the Company and natural gas is expected to be the Company's principal fuel during the next several years, the extent of the Company's use of natural gas as boiler fuel is dependent upon the amount of gas available from the Company's primary gas supplier as well as upon applicable federal and state laws and regulations. To the extent the Company's use of natural gas is restricted, it will be forced to rely more heavily on fuel oil, with resulting increases in fuel expenses.

Air pollution control laws and regulations applicable to the Company's oil- and gas-fired steam electric generating units have required the Company to depend on more costly 0.25% low-sulphur fuel oil when adequate natural gas supplies are unavailable. Based upon current projections of gas availability, the Company now has under contract sufficient 0.25% low sulphur fuel oil to meet its estimated requirements through 1986. To the extent that oil demand in this period exceeds current forecasts, additional supplies are expected to be available from purchases made on the spot market, under short-term contracts or through flexibility in existing long-term contracts. However, in the event that the Company were unable to purchase enough low-sulphur fuel oil to meet its fuel oil requirements in the future, it might still be able to acquire higher-sulphur fuel oil. The Company's ability to burn such higher-sulphur fuel oil would be dependent upon obtaining variances under air pollution control regulations.

As of December 31, 1981, the Company had in inventory approximately 13,153,000 barrels of low-sulphur fuel oil which, depending on utilization of other fuel sources, will supply the Company's oil-burning facilities for at least 90 days. Because of the availability of other less expensive fuel and energy sources and the resultant increase in fuel storage levels, the Company, since 1980, has occasionally sold excess quantities of fuel oil. In addition, since 1980 the Company has from time to time been unable to take delivery of all its contracted-for fuel oil and thereby has incurred underlift charges for fuel oil. Due to the unexpected availability of fuels other than oil and of purchasd power, negotiations for the possible modification of some oil contracts are underway.

The Powerplant and Industrial Fuel Use Act of 1978 was amended in 1981 to eliminate the limitation originally imposed upon the use of natural gas in existing powerplants. However, provisions of that Act continue to preclude the use of natural gas and petroleum in new powerplants unless exemptions are obtained.

Nuclear fuel supply

The Company has contractual arrangements covering 100% of the nuclear fuel cycle for San Onofre through the years indicated below:

	Unit 1	Units 2 & 3
Mining and milling to produce concentrates(1)	1986	1985
Conversion	1990	1990
Enrichment	2014	2009
Fabrication	1993	1985
Spent fuel storage(2)	1994	1994

(1) The Company has contracted for approximately 68% of the uranium concentrates required for San Onofre Units 1, 2 and 3 from 1986 through 1990. Approximately 58% of the Company's uranium concentrate requirements for the period 1982 through 1990 are expected to be provided by a mine and mill in which Mono Power Company, a wholly-owned subsidiary of the Company, has a 50% partnership interest.

(2) The dates indicated assume full utilization of the capacities for on-site storage now existing and under construction and normal operation of these Units, including interpool transfers. If additional storage or permanent disposal is unavailable when storage limits are reached, other arrangements will be required, the availability or cost of which the Company cannot predict at this time.

Participants in the Palo Verde Nuclear Generating Station have renegotiated contractual commitments for the supply of uranium concentrates and conversion services. Uranium concentrates supply commitments have been renegotiated through 1983 to provide the participants greater flexibility in scheduling supplies and to permit future purchases on the open market. Contracts to provide conversion services have been renegotiated to cover requirements through 1987. The Company is currently investigating the possibility of furnishing its share of uncommitted uranium concentrates requirements beyond 1983 for this project from inventories or purchases on the open market, independent of arrangements made by the other participants.

Although the Palo Verde participants have no commitments for off-site storage of fuel discharged from reactors, on-site storage for spent fuel is being planned to accommodate normal operation through 1989 for Unit 1 and through later dates for Units 2 and 3. The timing and extent of off-site storage requirements cannot be accurately projected at this time.

Coal supply

Coal supplies for the operation of the Mohave and Four Corners Projects are obtained pursuant to purchase contracts which extend over the expected useful lives of those projects and provide for the purchase of low-sulphur coal to support anticipated levels of operation during such periods.

Environmental matters

Legislation and regulation

Legislative and regulatory activities in the areas of air pollution, water pollution, waste management, noise abatement, land use, aesthetics and nuclear control continue to result in the imposition of numerous restrictions on the operation by the Company of its existing facilities and on the timing, cost, location, design, construction and operation by the Company of new facilities required to meet its future load requirements. These activities substantially affect future planning and will continue to require modifications of the Company's existing facilities and operating procedures. They also increase the risk of forced abandonment of construction projects with a resultant loss of design, engineering and construction costs and the payment of cancellation charges which in the aggregate could be substantial.

The two principal federal environmental statutes are the Clean Air Act, as amended, and the Clean Water Act. Both regulatory schemes are administered by the EPA in conjunction with state and local governments.

The Clean Air Act provides the statutory framework to implement a program for achieving national ambient air quality standards and provides for maintenance of air quality in areas exceeding such standards. As a result, the Company may incur additional expenses in reducing or eliminating emissions at existing facilities and in constructing new facilities.

Regulations under the Clean Water Act require the obtaining of permits for the discharge of certain pollutants into the waters of the United States. Under the Act, the EPA issues effluent limitation guidelines, pretreatment standards and new source performance standards for the control of certain pollutants. Individual states may impose still more stringent limitations. In order to comply with guidelines and standards applicable to steam electric power plants, the Company is incurring additional expenses and capital expenditures. Additional regulations will be issued but the Company is unable to predict the extent to which such additional regulations will affect its operations and capital expenditure requirements. The Company presently has discharge permits for all applicable facilities. However, on January 29, 1982 a federal district court held that man-made dams are sources which should be regulated under the National Pollution Discharge Elimination System and required that the EPA develop regulations to control discharges from man-made dams within 90 days. It is not known at this time what effect any new EPA regulations will have on the Company's hydroelectric generating facilities.

The State of California has adopted a policy discouraging the use of fresh water for plant cooling purposes at inland locations. Such a policy, when taken in conjunction with existing federal and state water quality regulations and coastal zone land use restrictions, could substantially increase the difficulty of siting new generating plants anywhere in California.

The Resource Conservation and Recovery Act provides the statutory authority for the EPA to implement a regulatory program for the safe treatment, recycling, storage and disposal of solid and hazardous wastes. The EPA controls hazardous wastes with regulations on their generation, handling, storage and disposal. Thus far, these regulations have had only a minimal economic impact on expenditures.

Individual states may implement their own EPA-approved hazardous waste programs in place of the federal scheme and may impose more stringent controls. The State of California has obtained interim EPA authorization to administer its own program. Furthermore, additional regulations are expected to be promulgated by the EPA. As a consequence of the uncertainty in the future of the regulatory program, it is difficult to assess the extent to which operations and capital expenditures will be affected.

The Toxic Substance Control Act and accompanying regulations govern the manufacturing, processing, distribution in commerce, use, and disposal of polychlorinated biphenyls, a toxic substance used in certain electrical equipment. Certain aspects of the regulations pertaining to the use of polychlorinated biphenyls in electrical transformers and capacitors have been the subject of litigation and negotiation. Rulemaking on these disputed issues is to take place within the next year. It will be difficult to assess the economic impact of such regulations until such time as the rulemaking is completed.

Currently pending environmental rulemaking and compliance proceedings and litigation involving the Company are discussed in "Environmental litigation and administrative proceedings" under Item 3. The effect of the Company's use of low-sulphur fuel oil required by air quality regulations is discussed in *"Natural gas and fuel oil supply"* under "Fuel supply."

Environmental expenditures

The Company's capitalized expenditures for environmental protection for the years 1969 through 1981 and its currently estimated capital expenditures for such purposes for the years 1982 through 1986 are as follows:

(Thousands of Dollars)

Years	Total	Air Pollution Control	Water Pollution Control	Solid Waste Disposal	Noise Abatement	Aesthetics	Additional Plant Capacity	Miscellaneous
1969-1981	$997,784	$ 57,067	$ 24,074	$ 2,757	$ 4,607	$707,748	$ 3,746	$197,785
1982	311,231	124,103	21,696	—	357	125,374	—	39,701
1983	231,012	92,237	7,522	—	536	119,578	—	11,139
1984	208,906	72,919	—	63	1,233	118,418	—	16,273
1985	131,187	—	—	—	85	130,671	—	431
1986	152,422	—	21	—	26	146,400	—	5,975

These estimates include budgeted and forecast plant expenditures responsive to currently effective legislation and do not include potential costs associated with certain environmental proceedings. (See "Environmental litigation and administrative proceedings" under Item

3.) Projected capital expenditures for environmental protection are subject to continuous review and periodic revisions because of escalation in engineering and construction costs, additions and deletions of planned facilities, changes in technology, evolving environmental regulatory requirements and other factors beyond the Company's control. The Company believes that costs incurred for these environmental purposes will be recognized by the CPUC and the FERC as reasonable and necessary costs of service for rate purposes.

Item 2. Properties

Existing generating facilities

The Company owns and operates 13 oil- and gas-fueled electric generating plants, one diesel-fueled generating plant, 36 hydroelectric plants and Unit 1 (80% Company-owned) at the San Onofre Nuclear Generating Station ("San Onofre"), located in central and southern California. In addition, construction of San Onofre Unit 2 (75.05% Company-owned) has been completed and the Unit is presently undergoing fuel loading and low power testing, and San Onofre Unit 3 (75.05% Company-owned) and Palo Verde Nuclear Generating Station Units 1, 2 and 3 ("Palo Verde") (15.8% Company-owned) are under construction. The Company also owns two small fossil-fueled electric generating units in Arizona and a 48% undivided interest (768 megawatts ("MW")) in Four Corners 4 and 5, a coal-fueled steam electric generating plant in New Mexico ("Four Corners Project"), all of which are operated by another utility. The Company also operates and owns a 56% undivided interest (885 MW) in two coal-fueled steam electric generating units in Clark County, Nevada ("Mohave Project"). The Company also operates certain hydroelectric generating units owned by others in Arizona. Of the existing Company-owned generating capacity, approximately 78% is dependent on gas and oil fuel, 12% on coal, 3% on nuclear fuel and 7% is hydroelectric.

San Onofre, the Four Corners Project, certain of the Company's substations and certain portions of its transmission, distribution and communication systems are located on lands of the United States or others under (with minor exceptions) licenses, permits, easements or leases or on public streets or highways pursuant to franchises. Certain of such documents obligate the Company, under specified circumstances, at its expense to relocate transmission, distribution and communication facilities located on lands owned or controlled by federal, state or local governments.

With certain exceptions, major and certain minor hydroelectric plants, with related reservoirs, having an effective operating capacity of 871 MW and located in whole or in part on lands of the United States, are owned and operated under governmental licenses which expire at various times between 1982 and 2009. Such licenses impose numerous restrictions and obligations on the Company, including the right of the United States to acquire the project upon payment of specified compensation. When original licenses expire, the FERC has authority to issue new licenses to third parties, but only upon payment of specified compensation to the Company. Any new licenses issued to the Company are expected to be issued upon terms and conditions less favorable than those of the expired licenses. Applications of the Company for the relicensing of certain of the hydroelectric plants referred to above with an aggregate effective operating capacity of 11 MW are pending, and until such proceedings are completed, the Company expects to be issued annual license renewals for such projects.

The record peak area demand experienced on the Company's system through December 31, 1981, was 13,738 MW on August 27, 1981. At the time of the peak, the total area system operating capacity available to the Company was approximately 15,592 MW.

Substantially all of the properties of the Company are subject to the lien of a trust indenture securing First and Refunding Mortgage Bonds, of which $3,295,830,000 principal amount was outstanding at December 31, 1981. Such lien and the Company's title to its properties are subject to the terms of franchises, licenses, easements, leases, permits, contracts and other instruments under which properties are held or operated, certain statutes and governmental regulations, liens for taxes and assessments, the lien of another trust indenture to the extent referred to below, and liens of the trustees under such indentures. In addition such liens and the Company's title to its properties are subject to certain other liens, prior rights and other encumbrances, none of which, with minor or unsubstantial exceptions, affects the Company's right to use such properties in its business, unless the matters with respect to the Company's interest in the Four Corners Project and the related easement and lease referred to below may be so considered.

The properties acquired by the Company pursuant to the merger in 1963 with California Electric Power Company, together with all substitutions, replacements, additions, alterations, improvements and enlargements to, of, or upon such properties are, with certain exceptions, also subject to the prior lien of another trust indenture securing $60,000,000 principal amount of First Mortgage Bonds originally issued by that company and outstanding at December 31, 1981.

The Company's rights in the Four Corners Project, which is located on land of The Navajo Tribe of Indians under an easement from the United States and a lease from The Navajo Tribe, may be subject to possible defects, including possible conflicting grants or encumbrances not ascertainable because of the absence of or inadequacies in the applicable recording law and the record system of the Bureau of Indian Affairs and The Navajo Tribe, the possible inability of the Company to resort to legal process to enforce its rights against The Navajo Tribe without Congressional consent and, in the case of the lease, possible impairment or termination under certain circumstances by Congress or the Secretary of the Interior. The Company cannot predict what effect, if any, such possible defects may have on its interest in the Four Corners Project.

Construction program and capital expenditures

The Company presently anticipates that it will need approximately 5,860 MW of additional energy resources to serve its projected customer needs through 1990. Approximately 2,230 MW of new nuclear generating facilities are either under construction or undergoing low power testing, and the Company plans to obtain approximately 1,420 MW from sources outside its service territory. The Company intends to pursue the accelerated development of alternate and renewable energy resources (i.e., hydroelectric, co-generation, geothermal, solar, wind, and fuel cells) to meet a portion of its future energy resource requirements. The Company's present goal is to obtain substantially all of its remaining energy resource requirements from alternate and renewable energy resources.

The major generating facilities under construction at December 31, 1981 were the following nuclear plants being built jointly with other utilities:

				Company's share of			
Facility	Location	Percent completed as of December 31, 1981	Initial Full Power	Facility	Net capacity (MW)	Estimated total cost(1) (000)	Recorded costs as of December 31, 1981(1) (000)
San Onofre 2, 3	San Clemente, CA	96	1982-1983	75.05%	1,651	$2,625,000	$2,239,933
Palo Verde 1, 2 & 3	Wintersburg, AZ	74	1983-1984 & 1986	15.8 %	579	1,077,000	526,450

(1) Exclusive of fuel and related off-site transmission facilities. Estimates are subject to revision because of numerous factors, some of which are beyond the Company's control.

The Company's construction program and related expenditures are continuously reviewed and periodically revised because of changes in estimated system load growth, rates of inflation, receipt of adequate and timely rate relief, the availability and timing of environmental, siting and other regulatory approvals, the scope of modifications required by regulatory agencies, the availability and costs of external sources of capital, the development of new technology and other factors beyond the Company's control.

Funds required by the Company for its construction expenditures totaled $674,147,000 in 1979, $781,510,000 in 1980 and $956,763,000 in 1981. Construction expenditures for the 1982-1986 period are estimated (as of December 17, 1981, the date of the Company's latest approved budget) as follows:

	(Millions of Dollars)					
	1982	1983	1984	1985	1986	Total
Electric generating plants	$ 740	$ 477	$ 353	$ 353	$ 373	$2,296
Electric transmission lines and substations	67	144	148	114	126	599
Electric distribution lines and substations	241	267	313	348	388	1,557
Other expenditures	45	46	42	30	28	191
Total construction additions	1,093	934	856	845	915	4,643
Less allowance for funds used during construction	220	130	80	80	85	595
Funds required for construction expenditures	$ 873	$ 804	$ 776	$ 765	$ 830	$4,048

Approximately 42% of the total electric generating plant expenditures for the years 1982 through 1986 are related to the construction of the new nuclear units at San Onofre and Palo Verde. The Company's share of the total cost of construction for these units is estimated to be $2.6 billion and $1.1 billion, respectively, of which approximately $2.2 billion and $526,000,000, respectively, had been expended through December 31, 1981.

Due to the high level of construction work in progress (primarily related to the construction of San Onofre Units 2 and 3), a significant portion of the Company's net income in recent years has been attributable to AFUDC which does not contribute to the current cash flow of the Company. AFUDC constituted approximately 34%, 51% and 47% of net income in 1979, 1980 and 1981, respectively. AFUDC is expected to decline significantly when San Onofre Units 2 and 3 are placed in commercial operation with a resulting reduction in this non-cash portion of net income. Assuming the costs associated with the operation of such Units receive appropriate and timely rate treatment, sufficient additional cash income is expected to be received to offset this decline in AFUDC.

To provide funds required for construction expenditures for the five fiscal years through 1986, as shown in the above table, and to meet long-term debt maturities and preferred stock sinking fund requirements aggregating $796,000,000 during such years, the Company estimates that approximately $2.9 billion, or 60%, of such expenditures, will be required from external sources. The balance of funds required for these purposes is expected to be obtained from internal sources, primarily during the latter part of such period, with a substantial majority of construction funds in 1982 projected to be obtained from external sources.

The Company's estimates of funds available from internal sources assume the receipt of adequate and timely general rate relief, the timely inclusion of the new San Onofre Units and Palo Verde Units in its rate base and the realization of its assumptions regarding cost increases, including the cost of capital. The Company's estimates and underlying assumptions are subject to continuous review and periodic revision.

The timing, type and amount of additional external financing are dependent upon market conditions, rate relief and other factors, including restrictions imposed by the Company's Articles of Incorporation and trust indenture.

Nuclear power developments

As a result of evaluations of the accident at Three Mile Island Nuclear Power Plant ("TMI"), a facility in which the Company has no ownership or other interest, the NRC required a review of the design and operating procedures of all operating or planned nuclear power plants. San Onofre Unit 1, of which the Company's share is 349 MW, has been operating under a provisional operating license since 1968. Although Unit 1 is different in design and manufacture from TMI, the Company has been ordered to implement certain design and operating procedure changes to allow continued operations. Certain of these modifications were made during outages in 1980 and 1981. The Company has informed the NRC that other modifications, are being made during the current outage described below. The Company's share of the total cost of TMI-related modifications to Unit 1 is currently estimated at $30,000,000. Certain design modifications for San Onofre Units 2 and 3 also have been or will be completed as a result of the TMI accident. The Company believes that these currently required modifications could be accomplished without delaying the construction of Unit 3 or the operational schedule for Unit 2.

Unit 1 has been operated at approximately 90% of its full power rating after insertion in 1981 of sleeves in steam generator tubes that had deteriorated. This reduced power operation was to aid the Company in determining the effect of reduced temperature on conditions which led to the deterioration in the steam generator tubes. Pursuant to a requirement of the NRC, the Unit was shut down on February 27, 1982 for an inspection of the steam generators and for various plant modifications. A decision will be made regarding increasing the power level at which the Unit will be operated based upon the results of the inspection.

The NRC has requested specific information related to the Company's projections of the effect of radiation on the material properties of the Unit 1 reactor vessel. This information has been requested of the operators of eight of the older reactors in the country and is part of the NRC's continuing review of the effects of radiation on the material properties of the reactor vessels. This review may necessitate corrective actions in the form of plant or procedural modifications. Analyses by the Company demonstrate that the operational life of the Unit is at least 18 more years, and that no modifications are required. These analyses are being reviewed by the NRC.

The NRC's Systematic Evaluation Program ("SEP") provides for evaluating, against current criteria, eleven older operating nuclear units, including San Onofre Unit 1. In connection with the SEP, the Company has reinitiated a program to seismically reevaluate safety-related structures, systems and equipment. The Company's cost of structural modifications required as a result of the seismic reevaluation and currently in progress amounts to $30,000,000. Additional modifications may be required, and a full-term operating license will not be issued until completion of the SEP.

Pursuant to recent NRC requirements, the operators of nuclear generating facilities throughout the country, including the Company, have been required to demonstrate by June 30, 1982 compliance with recently adopted requirements for assuring the ability of safety-related electrical equipment to remain operable during postulated post-accident conditions. The Company has commenced analysis of such equipment at San Onofre Unit 1. Although the Company believes that the safety-related electrical equipment at Unit 1 will remain operable during postulated post-accident conditions and has previously demonstrated such fact to the satisfaction of the NRC, it foresees difficulty in demonstrating compliance with the recently adopted requirements due to the NRC's application of current criteria and record-keeping requirements which were not in effect at the time that Unit 1 was built. Strict compliance with present NRC requirements may result in the need for plant modifications.

The operators of nuclear generating facilities throughout the country have also been required by the NRC to comply with additional fire protection requirements. San Onofre Units 2 and 3 are in substantial compliance with these requirements, and the Company has completed some of the modifications to Unit 1 with others underway. However, it is seeking an extension of time to submit plans and schedules for certain other modifications. If the extension is not granted and court challenges by other utilities to the NRC fire protection requirements are unsuccessful, Unit 1 could be shut down pending completion of such modifications.

On January 11, 1982, the Atomic Safety and Licensing Board ("ASLB") rendered a favorable decision on San Onofre Units 2 and 3 seismic issues and low power licensing issues. Intervenors who participated in the original hearings filed exceptions to and moved for a stay of this decision in January 1982. The Company cannot predict what effects, if any, these actions will have on the projected licensing schedule. The Company received a low power operating license from the NRC for Unit 2 on February 16, 1982. The low power license allows the Company to load fuel and conduct low power testing up to 5% of the reactor's thermal rating. The Company projects that Unit 2 will be operational in the summer of 1982. Unit 3 is scheduled to be operational approximately one year later. The projected operation of Unit 2 is based upon receipt of a full power operating license in the second quarter of 1982.

The City of Anaheim has purchased an additional 1.5% share of San Onofre Units 2 and 3, reducing the Company's share to 75.05%. This transfer has been approved by the NRC and the CPUC.

Although higher energy costs will be incurred for alternative generating capacity during the periods that the San Onofre Units are not in operation, substantially all such costs will be included in future ECAC filings. The Company cannot predict what other effects, if any, legislative or regulatory actions may have upon it or upon the construction, licensing or future operation of the San Onofre or Palo Verde Units or the extent of any additional costs it may incur as a result thereof.

Effect of governmental utilities and utility districts

Under various acts of Congress, federal power projects have been constructed in California and neighboring states. Municipally-owned utilities, cooperative utilities and other public bodies have certain preference over investor-owned utilities in the purchase of electric power provided by federally funded power projects and, in addition, have certain preference over investor-owned utilities in connection with the acquisition of licenses to build hydroelectric power plants on federal lands. Any energy which is or may be generated at these projects and transmitted for the account of such other utilities and public bodies over present or future government or utility-owned lines into the territory or markets served by the Company would result in a loss of sales by the Company.

Under the laws of California, utility districts may be formed and may include incorporated as well as unincorporated territory. Such districts, as well as municipalities, have the right to construct, purchase or condemn and operate electric facilities. In addition, when a city owning an electric system annexes adjacent unincorporated territory which the Company has previously served, the Company may experience a loss of customers.

The Company's construction permits for San Onofre Units 2 and 3 contain certain conditions, the terms of which require the Company (i) to permit privately- or publicly-owned utilities, including the Company's resale customers, within or adjacent to the Company's service area, on timely notice, to participate on mutually agreeable terms in future nuclear units initiated by the Company, and (ii) to interconnect and coordinate reserves with, furnish emergency service to, sell to and purchase bulk power from, and provide certain transmission services for, such utilities.

The Company has also entered into agreements with certain of its resale customers which contemplate their possible participation in jointly-owned generating projects initiated by the Company, and the integration of power sources acquired by each such customer, including the dispatching, reserve sharing, partial power supply requirements and transmission services required in conjunction with such integrated operations. Pursuant to these agreements, two resale customers exercised an option to participate in the Company's ownership entitlement in San Onofre Units 2 and 3. The Company sold an undivided 3.45% interest in San Onofre Units 2 and 3 to these two resale customers for approximately $90,000,000. A further 1.5% interest in Units 2 and 3 was sold to one of these resale customers for approximately $50,000,000. The foregoing conditions and agreements involve the potential additional loss of generation and transmission capacity and sales of power. The Company is unable to determine what effect these losses will have on its business and operations.

Item 3. Legal Proceedings

Antitrust litigation

In March 1978, five resale customers filed a suit against the Company in Federal court alleging violation of certain antitrust laws. The complaint seeks damages in excess of $23,000,000, consequential damages and a trebling of such damages and certain injunctive relief, and alleges that the Company (i) is engaging in anti-competitive behavior by charging more for wholesale electricity sold to the resale customers than the Company charges certain classes of its retail customers, and (ii) has taken actions alone and in concert with other utilities to prevent or limit such resale customers from obtaining bulk power supplies from other sources to reduce or replace the resale customers' wholesale purchases from the Company. Trial is scheduled to commence on April 19, 1983. The foregoing proceedings involve complex issues of law and fact and, although the Company is unable to predict their final outcome or the possible effect of the August 22, 1979 FERC decision (discussed in *"Resale rates"* under "Rate matters") on the proceedings, it has categorically denied the allegations of these resale customers.

Department of Water and Power ("DWP") service to California Department of Water Resources ("DWR")

In October 1979 DWP advised DWR that DWP would terminate service under a Suppliers Contract and would cease supplying energy under that contract. The Suppliers Contract provides that DWP and other suppliers, including the Company, will furnish energy at the fixed rate of three mills per kilowatt-hour. The Company, on November 6, 1979, sought and received a preliminary injunction enjoining DWP from terminating service.

If DWP were to prevail with its defense at the coming trial and be successful in unilaterally terminating its obligations to supply energy to DWR under the Suppliers Contract, and DWR were to prevail in its position that the Company must furnish 43% of DWP's obligation at the fixed three mills per kilowatt-hour price, the additional revenue deficiency from the Company's share of DWP's obligation up to the 1983 termination date of the Suppliers Contract is estimated to be approximately $57,000,000, based on supply figures prepared by DWP.

Environmental litigation and administrative proceedings

Four Corners Project

A revised New Mexico sulphur dioxide ("SO_2") emission rule requires that Units 4 and 5 of the Four Corners Project achieve a 72% SO_2 removal rate by December 31, 1984. This rule has been approved by the EPA as part of the State Implementation Plan in accordance with the Clean Air Act.

Installation of SO_2 removal equipment will be in addition to the installation of the equipment now being constructed to meet the requirements of a New Mexico particulate emissions rule. Arizona Public Service Company has estimated that the cost for control of both pollutants will be $564,000,000. The Company's share of such estimated costs will be approximately $270,000,000.

Oxides of Nitrogen Rules

All of the Company's conventional oil- and gas-fueled generating plants which are located in the South Coast Air Basin were subject to oxides of nitrogen rules ("NOx Rules") promulgated by the Air Resources Board ("ARB") for the South Coast Air Quality Management District ("SCAQMD") and the Ventura County Air Pollution Control District on December 18, 1980. The NOx Rules were designed to achieve an 80% reduction in oxides of nitrogen emissions from conventional generating units by December 31, 1989.

The NOx Rules could have required the Company to make substantial expenditures (up to $500 million in 1982 dollars) for pollution control equipment designed to effect such reduction. A Company suit against the air pollution regulatory agencies regarding the NOx Rules has been settled on terms which require about a 60% reduction in NOx through 1990. Based on its current resource plan, the Company anticipates that it will be able to achieve these reductions without any costs to the Company above those to which the Company is already committed by its resource plan.

Alamitos and Redondo Generating Stations

In April 1979, the Company stipulated to orders of the SCAQMD to implement measures designed to reduce emissions of particulates from the Company's Alamitos and Redondo Generating Stations. Compliance with the orders involved the expeditious refitting of certain of the power plants' machinery and equipment with more corrosion-resistant materials, and the early implementation of fuel additive injection and of specific stack washing and boiler cleaning techniques. The cost for implementation is currently estimated at $22,000,000. The Company will complete a final test of these particulate reduction measures by March 31, 1982. If the implemented measures are accepted by the SCAQMD, the orders will be lifted in April 1983. The Company would then be required to maintain the effectiveness of such measures.

Tax litigation

The Navajo Tribal Council has adopted, but not yet implemented, a possessory interest tax, a business activity tax and a sulphur emissions tax which could apply to the Four Corners Project. The validity of these taxes is currently being litigated by participants in the Project. The Company cannot predict the ultimate effect of these taxes, if implemented, upon future costs associated with the Four Corners Project or their effect upon costs of power or fuel derived from certain other Arizona and New Mexico operations.

Item 4. Submission of Matters to a Vote of Security Holders

Inapplicable.

Pursuant to General Instruction G, the following information is included as an additional item in Part I:

Executive Officers of the Registrant

Executive Officer	Age at December 31, 1981	Company Position	Effective Date
William R. Gould	62	Chairman of the Board, Chief Executive Officer and Director	July 1, 1980
Howard P. Allen	56	President and Director	July 1, 1980
H. Fred Christie	48	Executive Vice President and Chief Financial Officer	July 1, 1980
David J. Fogarty	54	Executive Vice President	January 1, 1982
A. Arenal	56	Vice President (Engineering and Construction)	January 1, 1980
Glenn J. Bjorklund	49	Vice President (System Development)	August 1, 1979
John R. Bury	54	Vice President and General Counsel	January 1, 1982
Robert Dietch	43	Vice President (Nuclear Engineering and Operations)	January 1, 1980
C. E. Hathaway	47	Vice President (Human Resources)	January 1, 1980
Joe T. Head, Jr.	60	Vice President (Power Supply)	November 21, 1974
P. L. Martin	52	Vice President (Customer Service)	September 1, 1978
A. L. Maxwell	60	Vice President and Comptroller	July 17, 1975
Edward A. Myers, Jr.	58	Vice President (Conservation, Communications and Revenue Services)	August 19, 1971
Michael L. Noel	40	Vice President and Treasurer	July 1, 1980
Lawrence T. Papay	45	Vice President (Advanced Engineering)	January 1, 1980
William H. Seaman	64	Vice President (Fuel Supply)	July 17, 1969
Robert E. Umbaugh	44	Vice President (Administration)	September 1, 1976
Honor Muller	53	Secretary	November 1, 1979

None of the Company's executive officers are related to each other by blood or marriage. All of the executive officers have been actively engaged in the business of the Company for more than five years. Those officers who have not held their present position for the past five years had the following business experience during that period:

William R. Gould	President and Director	February 1978 to June 1980
	Executive Vice President	December 1973 to January 1978
Howard P. Allen	Executive Vice President	December 1973 to June 1980
H. Fred Christie	Senior Vice President and Chief Financial Officer	January 1977 to June 1980
David J. Fogarty	Senior Vice President	September 1977 to December 1981
	Vice President — Customer Service	September 1976 to August 1977
A. Arenal	Vice President — Advanced Engineering	August 1979 to December 1979
	Vice President — System Development	September 1976 to July 1979
Glenn J. Bjorklund	Division Vice President — Eastern Division	May 1978 to July 1979
	Administrator of Department Operations — Customer Service Staff	May 1975 to April 1978
John R. Bury	General Counsel	September 1978 to December 1981
	Assistant General Counsel	December 1973 to August 1978
Robert Dietch	Division Manager — Southeastern Division	August 1979 to December 1979
	Assistant Division Manager — Southeastern Division	October 1978 to July 1979
	Manager of Projects — Project Management Organization	January 1978 to September 1978
	Manager of Engineering Design Organization	January 1976 to December 1977
C. E. Hathaway	Division Vice President — Eastern Division	August 1979 to December 1979
	Division Vice President — Southeastern Division	September 1978 to July 1979
	Division Vice President — Central Division	January 1978 to August 1978
	Assistant Division Manager — Central Division	May 1975 to December 1977
P. L. Martin	Division Vice President — Southeastern Division	September 1977 to August 1978
	Division Manager — Southeastern Division	December 1973 to August 1977
Michael L. Noel	Treasurer	August 1976 to June 1980
Lawrence T. Papay	General Superintendent — Power Supply	October 1978 to December 1979
	Director of Research and Development	August 1970 to September 1978
Honor Muller	Assistant Secretary	December 1978 to October 1979
	Executive Secretary	February 1959 to December 1978

PART II

Item 5. Market for the Registrant's Common Equity and Related Stockholder Matters

Information responding to Item 5 was included in the Company's Annual Report to Shareholders for the year ended December 31, 1981 ("Annual Report") under "Capital Stock — Dividend Price Information" on page 31 and is incorporated by reference pursuant to General Instruction G. Additional information concerning the market for the Company's Common Stock is set forth on the cover page.

Item 6. Selected Financial Data

Information responding to Item 6 was included in the Annual Report under "Selected Financial Data 1971-1981" on pages 34-35 and is incorporated herein by reference pursuant to General Instruction G.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Information responding to Item 7 was included in the Annual Report under "Management's Discussion and Analysis of Financial Condition and Results of Operations" on pages 32-33 and is incorporated herein by reference pursuant to General Instruction G.

Item 8. Financial Statements and Supplementary Data

Certain information responding to Item 8 is set forth after Item 13 in Part IV. Other information responding to Item 8 was included in the Annual Report on pages 16-31 and is incorporated herein by reference pursuant to General Instruction G.

Item 9. Disagreements on Accounting and Financial Disclosure

Inapplicable.

PART III

Item 10. Directors and Executive Officers of the Registrant

Information concerning executive officers of the Company is set forth in Part I, pursuant to Instruction 3 to Item 401 of Regulation S-K. Other information responding to Item 10 was included in a proxy statement filed by the Company on or about March 2, 1982 with the Commission pursuant to Regulation 14A ("Proxy Statement") on pages 2-4 and is incorporated herein by reference pursuant to General Instruction G.

Item 11. Management Remuneration and Transactions

Information responding to Item 11 was included in the Proxy Statement on pages 6-9 and is incorporated herein by reference pursuant to General Instruction G.

Item 12. Security Ownership of Certain Beneficial Owners and Management

Information responding to Item 12 was included in the Proxy Statement on pages 5-6 and 13-14 and is incorporated herein by reference pursuant to General Instruction G.

PART IV

Item 13. Exhibits, Financial Statement Schedules and Reports on Form 8-K

13(a)(1) Financial Statements

Incorporated by reference to the Annual Report:

Responsibility for Financial Statements

Report of Independent Public Accountants

Statements of Income — Years Ended December 31, 1981, 1980 and 1979

Balance Sheets — December 31, 1981 and 1980

Statements of Sources of Funds Used for Construction Expenditures — Years Ended December 31, 1981, 1980 and 1979

Statements of Earnings Reinvested in the Business and Statements of Additional Paid-in Capital — Years Ended December 31, 1981, 1980 and 1979

Statements of Capital Stock — December 31, 1981 and 1980

Statements of Long-term Debt — December 31, 1981 and 1980

Notes to Financial Statements

Supplementary Information to Disclose the Effects of Changing Prices (Unaudited)

Management's Discussion and Analysis of Financial Condition and Results of Operations

13(a)(2) Report of Independent Public Accountants and Schedules Supporting Financial Statements

Included after Item 13 in Part IV.

The tax information Required by Schedule X was included in the Annual Report on pages 25-26. The amounts of depreciation and maintenance expense appear on the Statements of Income. Royalties paid and advertising costs included in other expenses are less than 1% of revenue.

Schedules I to XIII, inclusive, except those referred to above, are omitted as not required or not applicable.

13(a)(3) Exhibits

See Exhibit Index on page 32.

13(b) Reports on Form 8-K

None

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS ON SUPPORTING SCHEDULES

To Southern California Edison Company:

In connection with our examination of the financial statements included in the 1981 Annual Report to Shareholders of Southern California Edison Company and incorporated by reference in this Form 10-K, we have also examined the supporting schedules listed in the index herein. Our examination was made for the purpose of forming an opinion on the basic financial statements taken as a whole. The supporting schedules are presented for purposes of complying with the Securities and Exchange Commission's rules and regulations under the Securities and Exchange Act of 1934 and are not otherwise a required part of the basic financial statements. The supporting schedules have been subjected to the auditing procedures applied in the examination of the basic financial statements and, in our opinion, fairly state in all material respects the financial data required to be set forth therein in relation to the basic financial statements taken as a whole.

ARTHUR ANDERSEN & CO.

Los Angeles, California,
February 5, 1982.

SOUTHERN CALIFORNIA EDISON COMPANY

SCHEDULE V — PROPERTY, PLANT AND EQUIPMENT

FOR THE YEAR ENDED DECEMBER 31, 1981

(Thousands of Dollars)

Classification	Balance at Beginning of Period	Additions at Cost	Add (Deduct) Retirements	Add (Deduct) Other Changes	Balance at End of Period
Steam Production	$1,357,301	$ 23,948	$ (1,115)	$ 83	$1,380,217
Nuclear Production	169,779	87,783	(768)	—	256,794
Hydro Production	234,723	1,897	(162)	—	236,458
Other Production	354,637	3,891	(1)	—	358,527
Transmission	1,236,762	23,572	(2,323)	(283)	1,257,728
Distribution	2,215,891	204,920	(23,650)	206	2,397,367
General	169,803	14,397	(2,204)	(6)	181,990
Plant Held for Future Use	25,781	2,197	(2,103)	—	25,875
Experimental Electric Plant Unclassified	14,283	(38)	—	—	14,245
Other Utility Plant	6,240	78	(35)	—	6,283
Subtotal — Utility Plant	$5,785,200	$ 362,645	$ (32,361)	$ —	$6,115,484
Construction Work in Progress	2,600,460	823,139	(3,831)	(42,124) (a)	3,377,644
Nuclear Fuel	45,938	8,521	—	(4,628) (a)	49,831
Gross Utility Plant	$8,431,598	$1,194,305	$ (36,192)	$ (46,752)	$9,542,959
Nonutility Property	$ 9,183	$ 2,618	$ (3,329)	$ —	$ 8,472

(a) Represents the cost of the interest in San Onofre Nuclear Generating Station Units 2 and 3 which was sold to the Cities of Anaheim and Riverside.

SOUTHERN CALIFORNIA EDISON COMPANY

SCHEDULE V — PROPERTY, PLANT AND EQUIPMENT

FOR THE YEAR ENDED DECEMBER 31, 1980

(Thousands of Dollars)

Classification	Balance at Beginning of Period	Additions at Cost	Add (Deduct) Retirements	Add (Deduct) Other Changes	Balance at End of Period
Steam Production	$1,340,840	$ 18,427	$ (1,966)	$ —	$1,357,301
Nuclear Production	156,027	13,903	(151)	—	169,779
Hydro Production	216,809	18,130	(223)	7	234,723
Other Production	354,680	230	(2)	(271)	354,637
Transmission	1,186,035	49,977	(2,759)	3,509	1,236,762
Distribution	2,069,431	168,898	(22,148)	(290)	2,215,891
General	146,821	27,829	(1,892)	(2,955)	169,803
Plant Held for Future Use	26,069	(286)	(2)	—	25,781
Experimental Electric Plant Unclassified	107	14,176	—	—	14,283
Other Utility Plant	6,165	78	(3)	—	6,240
Subtotal — Utility Plant	5,502,984	311,362	(29,146)	—	5,785,200
Construction Work in Progress	2,058,958	622,206	(1,441)	(79,263) (a)	2,600,460
Nuclear Fuel	40,616	12,050	—	(6,728) (a)	45,938
Gross Utility Plant	$7,602,558	$ 945,618	$ (30,587)	$ (85,991)	$8,431,598
Nonutility Property	$ 9,209	$ 737	$ (763)	$ —	$ 9,183

(a) Represents the cost of the interest in San Onofre Nuclear Generating Station Units 2 and 3 which was sold to the cities of Anaheim and Riverside.

SOUTHERN CALIFORNIA EDISON COMPANY

SCHEDULE V — PROPERTY, PLANT AND EQUIPMENT

FOR THE YEAR ENDED DECEMBER 31, 1979

	(Thousands of Dollars)				
			Add (Deduct)		
Classification	Balance at Beginning of Period	Additions at Cost	Retirements	Other Changes	Balance at End of Period
Steam Production	$1,323,603	$ 18,515	$ (1,278)	$ —	$1,340,840
Nuclear Production	145,565	10,493	(31)	—	156,027
Hydro Production	215,647	1,333	(161)	(10)	216,809
Other Production	350,002	4,678	—	—	354,680
Transmission	1,164,523	30,276	(6,628)	(2,136)	1,186,035
Distribution	1,930,266	158,939	(19,576)	(198)	2,069,431
General	139,374	7,496	(2,999)	2,950	146,821
Plant Held for Future Use	28,373	1,615	(1,636)	(2,283)	26,069
Experimental Electric Plant Unclassified	217	107	—	(217)	107
Other Utility Plant	6,176	1,019	(10)	(1,020)	6,165
Subtotal — Utility Plant	5,303,746	234,471	(32,319)	(2,914)	5,502,984
Construction Work in Progress	1,493,573	564,504	881	—	2,058,958
Nuclear Fuel	36,353	4,263	—	—	40,616
Gross Utility Plant	$6,833,672	$ 803,238	$ (31,438)	$ (2,914)	$7,602,558
Nonutility Property	$ 7,182	$ 4,438	$ (2,411)	$ —	$ 9,209

SOUTHERN CALIFORNIA EDISON COMPANY

SCHEDULE VI — ACCUMULATED DEPRECIATION AND AMORTIZATION OF PROPERTY, PLANT AND EQUIPMENT(a)

FOR THE YEAR ENDED DECEMBER 31, 1981

(Thousands of Dollars)

Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Add (Deduct) Retirements	Add (Deduct) Other Changes(b)	Add (Deduct) Salvage	Balance at End of Period
Steam Production	$ 614,860	$ 41,107	$ (1,115)	$ (70)	$ 33	$ 654,815
Nuclear Production	48,595	12,313	(768)	686	—	60,826
Hydro Production	91,481	3,471	(175)	(21)	1	94,757
Other Production	72,875	16,263	(2)	—	—	89,136
Transmission	272,536	37,760	(2,184)	(407)	991	308,696
Distribution	699,969	82,919	(23,409)	(8,157)	7,037	758,359
General	41,590	8,399	(2,238)	193	286	48,230
Experimental Electric Plant Unclassified	1,019	3,050	—	—	—	4,069
Retirement Work in Progress	(3,860)	—	1,361	(3,016)	538	(4,977)
Other Utility Plant Reserves	1,168	168	(35)	—	—	1,301
Subtotal	1,840,233	205,450	(28,565)	(10,792)	8,886	2,015,212
Nuclear Fuel Amortization	25,289	—	—	—	—	25,289
Total Utility Plant Reserves	$1,865,522	$205,450	$(28,565)	$(10,792)	$ 8,886	$2,040,501
Nonutility Property Reserves	$ 972	$ 92	$ (830)	$ 783	$ —	$ 1,017

(a) Depletion is not applicable.

(b) Includes removal costs related to facilities retired, damage claims and relocation costs collected from others, and various other adjustments of depreciation and amortization.

SOUTHERN CALIFORNIA EDISON COMPANY

SCHEDULE VI — ACCUMULATED DEPRECIATION AND AMORTIZATION OF PROPERTY, PLANT AND EQUIPMENT(a)

FOR THE YEAR ENDED DECEMBER 31, 1980

(Thousands of Dollars)

Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Add (Deduct) Retirements	Add (Deduct) Other Changes(b)	Add (Deduct) Salvage	Balance at End of Period
Steam Production	$ 578,032	$ 38,947	$ (1,949)	$ (186)	$ 16	$ 614,860
Nuclear Production	39,169	9,455	(9)	(27)	7	48,595
Hydro Production	88,109	3,570	(225)	(7)	34	91,481
Other Production	57,647	15,229	(2)	1	—	72,875
Transmission	240,888	33,010	(2,007)	(501)	1,146	272,536
Distribution	639,263	81,730	(21,420)	(7,698)	8,094	699,969
General	35,792	7,412	(1,959)	225	120	41,590
Experimental Electric Plant Unclassified	6	1,013	—	—	—	1,019
Retirement Work in Progress	(3,766)	—	(2,279)	(449)	2,634	(3,860)
Other Utility Plant Reserves	1,008	164	(3)	(1)	—	1,168
Subtotal	1,676,148	190,530	(29,853)	(8,643)	12,051	1,840,233
Nuclear Fuel Amortization	24,888	401	—	—	—	25,289
Total Utility Plant Reserves	$1,701,036	$190,931	$(29,853)	$ (8,643)	$ 12,051	$1,865,522
Nonutility Property Reserves	$ 951	$ 105	$ (798)	$ 714	$ —	$ 972

(a) Depletion is not applicable.

(b) Includes removal costs related to facilities retired, damage claims and relocation costs collected from others, and various other adjustments of depreciation and amortization.

SOUTHERN CALIFORNIA EDISON COMPANY

SCHEDULE VI — ACCUMULATED DEPRECIATION AND AMORTIZATION OF PROPERTY, PLANT AND EQUIPMENT(a)

FOR THE YEAR ENDED DECEMBER 31, 1979

(Thousands of Dollars)

Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Add (Deduct) Retirements	Add (Deduct) Other Changes(b)	Add (Deduct) Salvage	Balance at End of Period
Steam Production	$ 540,254	$ 38,876	$ (1,140)	$ 11	$ 31	$ 578,032
Nuclear Production	30,205	9,009	(30)	(15)	—	39,169
Hydro Production	84,979	3,322	(172)	(40)	20	88,109
Other Production	42,409	15,250	—	(12)	—	57,647
Transmission	212,944	32,026	(6,265)	(760)	2,943	240,888
Distribution	579,316	76,292	(19,453)	(4,120)	7,228	639,263
General	31,399	6,719	(2,877)	(240)	791	35,792
Experimental Electric Plant Unclassified	1	5	—	—	—	6
Retirement Work in Progress	(3,207)	—	774	(1,560)	227	(3,766)
Other Utility Plant Reserves	874	143	(9)	(1)	1	1,008
Subtotal	1,519,174	181,642	(29,172)	(6,737)	11,241	1,676,148
Nuclear Fuel Amortization	22,781	2,107	—	—	—	24,888
Total Utility Plant Reserves	$1,541,955	$ 183,749	$ (29,172)	$ (6,737)	$ 11,241	$1,701,036
Nonutility Property Reserves	$ 1,267	$ 78	$ (872)	$ 478	$ —	$ 951

(a) Depletion is not applicable.

(b) Includes removal costs related to facilities retired, damage claims and relocation costs collected from others, and various other adjustments of depreciation and amortization.

SOUTHERN CALIFORNIA EDISON COMPANY

SCHEDULE VIII — VALUATION AND QUALIFYING ACCOUNTS

FOR THE YEAR ENDED DECEMBER 31, 1981

(Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
Group A:					
Uncollectible Accounts					
Customers	$ 3,666	$12,548	$ —	$ 9,465	$ 6,749
All Other	4,339	672	—	1,078	3,933
Total	$ 8,005	$13,220	$ —	$10,543(a)	$10,682
Group B:					
Pensions and Benefits	$21,586	$ 6,090	$10,405(b)	$16,015(c)	$22,066
Insurance, Casualty and Other	18,351	21,929	—	23,123(d)	17,157
Total	$39,937	$28,019	$10,405	$39,138	$39,223

(a) Accounts written off, net.

(b) Principally, charges are to various plant and expense accounts as a payroll additive for employees' paid absences.

(c) Includes pension payments to retired employees, amounts paid to active employees during periods of illness and the funding of certain pension benefits.

(d) Principally charges from work orders closed and amounts charged to operations that were not covered by insurance.

SOUTHERN CALIFORNIA EDISON COMPANY

SCHEDULE VIII — VALUATION AND QUALIFYING ACCOUNTS

FOR THE YEAR ENDED DECEMBER 31, 1980

	(Thousands of Dollars)				
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
Group A:					
Uncollectible Accounts					
Customers	$ 2,263	$ 7,806	$ —	$ 6,403	$ 3,666
All Other	6,233	(37)	—	1,857	4,339
Total	$ 8,496	$ 7,769	$ —	$ 8,260(a)	$ 8,005
Group B:					
Pensions and Benefits	$17,739	$ 9,348	$ 9,756(b)	$15,257(c)	$21,586
Insurance, Casualty and Other	14,809	30,151	—	26,609(d)	18,351
Total	$32,548	$39,499	$ 9,756	$41,866	$39,937

(a) Accounts written off, net.

(b) Principally, charges are to various plant and expense accounts as a payroll additive for employees' paid absences.

(c) Includes pension payments to retired employees, amounts paid to active employees during periods of illness and the funding of certain pension benefits.

(d) Principally charges from work orders closed and amounts charged to operations that were not covered by insurance.

SOUTHERN CALIFORNIA EDISON COMPANY

SCHEDULE VIII — VALUATION AND QUALIFYING ACCOUNTS

FOR THE YEAR ENDED DECEMBER 31, 1979

(Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
Group A:					
Uncollectible Accounts					
Customers	$ 2,059	$ 4,770	$ —	$ 4,566	$ 2,263
All Other	3,549	3,565	—	881	6,233
Total	$ 5,608	$ 8,335	$ —	$ 5,447(a)	$ 8,496
Group B:					
Pensions and Benefits	$15,536	$ 5,728	$ 8,705(b)	$12,230(c)	$17,739
Insurance, Casualty and Other	11,089	23,282	—	19,562(d)	14,809
Total	$26,625	$29,010	$ 8,705	$31,792	$32,548

(a) Accounts written off, net.

(b) Principally, charges are to various plant and expense accounts as a payroll additive for employees' paid absences.

(c) Includes pension payments to retired employees, amounts paid to active employees during periods of illness and the funding of certain pension benefits.

(d) Principally charges from work orders closed and amounts charged to operations that were not covered by insurance.

SOUTHERN CALIFORNIA EDISON COMPANY

SCHEDULE IX — SHORT-TERM BORROWINGS

	Balance at End of Period	Weighted Average Interest Rate	Maximum Amount Outstanding During the Period	Average Amount Outstanding During the Period	Weighted Average Interest Rate During the Period
	(000)		(000)	(000) (A)	(B)
December 31, 1981					
Notes Payable to banks	$ 28,687	12.625%	$ 59,778	$ 31,685	16.15%
Payable to holders of Commercial Paper	266,500	12.75 %	396,500	199,352	16.10%
December 31, 1980					
Notes Payable to banks	19,998	16.875%	45,996	20,296	12.79%
Payable to holders of Commercial Paper	164,975	15.29 %	489,395	299,873	11.85%
Bankers Acceptances	—	—	30,860	7,723	17.35%
December 31, 1979					
Notes Payable to banks	19,840	13.75 %	20,078	20,052	11.01%
Payable to holders of Commercial Paper	134,340	13.73 %	184,340	65,057	11.08%

(A) Average amount outstanding during the period is computed by dividing the total of daily outstanding principal balances by 365 for 1981, 366 for 1980 and 360 for 1979.

(B) Weighted average interest rate during the year is computed by dividing the total interest expense by the average amount outstanding.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this Annual Report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Rosemead, and State of California.

SOUTHERN CALIFORNIA EDISON COMPANY

By J. B. GREENE

(J. B. Greene,
Assistant Treasurer)

Date: March 19, 1982

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report on Form 10-K has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
Principal Executive Officer:		
William R. Gould*	Chairman of the Board, Chief Executive Officer and Director	March 19, 1982
Principal Financial Officer:		
H. Fred Christie*	Executive Vice President and Chief Financial Officer	March 19, 1982
Controller or Principal Accounting Officer:		
A. L. Maxwell*	Vice President and Comptroller	March 19, 1982
Directors:		
Howard P. Allen*	President and Director	March 19, 1982
Roy A. Anderson*	Director	March 19, 1982
N. Barker, Jr.*	Director	March 19, 1982
Edward W. Carter*	Director	March 19, 1982
Warren Christopher*	Director	March 19, 1982
Walter B. Gerken*	Director	March 19, 1982
Joan C. Hanley*	Director	March 19, 1982
J. K. Horton*	Director	March 19, 1982
F. G. Larkin, Jr.*	Director	March 19, 1982
T. M. McDaniel, Jr.*	Director	March 19, 1982
John V. Newman*	Director	March 19, 1982
Henry T. Segerstrom*	Director	March 19, 1982
E. L. Shannon, Jr.*	Director	March 19, 1982
H. Russell Smith*	Director	March 19, 1982

*By J. B. GREENE

(J. B. Greene, Attorney-in-Fact)

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation by reference of our report (the Report of Independent Public Accountants) appearing on Page 16 of the 1981 Annual Report to Shareholders of Southern California Edison Company (Exhibit 13 included herein) in the Annual Report on Form 10-K for the year ended December 31, 1981 of Southern California Edison Company.

We further consent to the incorporation by reference of the above-mentioned Report of Independent Public Accountants, incorporated by reference in the annual report on Form 10-K, and to the incorporation by reference of our report (the Report of Independent Public Accountants on Supporting Schedules), appearing on Page 19 in the Annual Report on Form 10-K, in the Registration Statement on Form S-16 which became effective on April 7, 1980 (File No. 2-66939), in the Post-Effective Amendments No. 2 to the Registration Statements on Form S-8 (File Nos. 2-63711 and 2-65941) which became effective on March 25, 1981, and in the Registration Statement on Form S-8 filed on March 18, 1982 (File No. 2-76230).

ARTHUR ANDERSEN & CO.

Los Angeles, California
March 19, 1982

EXHIBIT INDEX

3.1	Restated Articles of Incorporation as amended through April 23, 1981 (File No. 1-2313)*
3.2	Bylaws as revised effective January 1, 1982
4.1	Trust Indenture, dated as of October 1, 1923 (Registration No. 2-1369)*
4.2	Supplemental Indenture, dated as of March 1, 1927 (Registration No. 2-1369)*
4.3	Second Supplemental Indenture, dated as of April 25, 1935 (Registration No. 2-1472)*
4.4	Third Supplemental Indenture, dated as of June 24, 1935 (Registration No. 2-1602)*
4.5	Fourth Supplemental Indenture, dated as of September 1, 1935 (Registration No. 2-4522)*
4.6	Fifth Supplemental Indenture, dated as of August 15, 1939 (Registration No. 2-4522)*
4.7	Sixth Supplemental Indenture, dated as of September 1, 1940 (Registration No. 2-4522)*
4.8	Seventh Supplemental Indenture, dated as of January 15, 1948 (Registration No. 2-7369)*
4.9	Eighth Supplemental Indenture, dated as of August 15, 1948 (Registration No. 2-7610)*
4.10	Ninth Supplemental Indenture, dated as of February 15, 1951 (Registration No. 2-8781)*
4.11	Tenth Supplemental Indenture, dated as of August 15, 1951 (Registration No. 2-7968)*
4.12	Eleventh Supplemental Indenture, dated as of August 15, 1953 (Registration No. 2-10396)*
4.13	Twelfth Supplemental Indenture, dated as of August 15, 1954 (Registration No. 2-11049)*
4.14	Thirteenth Supplemental Indenture, dated as of April 15, 1956 (Registration No. 2-12341)*
4.15	Fourteenth Supplemental Indenture, dated as of February 15, 1957 (Registration No. 2-13030)*
4.16	Fifteenth Supplemental Indenture, dated as of July 1, 1957 (Registration No. 2-13418)*
4.17	Sixteenth Supplemental Indenture, dated as of August 15, 1957 (Registration No. 2-13516)*
4.18	Seventeenth Supplemental Indenture, dated as of August 15, 1958 (Registration No. 2-14285)*
4.19	Eighteenth Supplemental Indenture, dated as of January 15, 1960 (Registration No. 2-15906)*

4.20 Nineteenth Supplemental Indenture, dated as of August 15, 1960 (Registration No. 2-16820)*

4.21 Twentieth Supplemental Indenture, dated as of April 1, 1961 (Registration No. 2-17668)*

4.22 Twenty-First Supplemental Indenture, dated as of May 1, 1962 (Registration No. 2-20221)*

4.23 Twenty-Second Supplemental Indenture, dated as of October 15, 1962 (Registration No. 2-20791)*

4.24 Twenty-Third Supplemental Indenture, dated as of May 15, 1963 (Registration No. 2-21346)*

4.25 Twenty-Fourth Supplemental Indenture, dated as of February 15, 1964 (Registration No. 2-22056)*

4.26 Twenty-Fifth Supplemental Indenture, dated as of February 1, 1965 (Registration No. 2-23082)*

4.27 Twenty-Sixth Supplemental Indenture, dated as of May 1, 1966 (Registration No. 2-24835)*

4.28 Twenty-Seventh Supplemental Indenture, dated as of August 15, 1966 (Registration No. 2-25314)*

4.29 Twenty-Eighth Supplemental Indenture, dated as of May 1, 1967 (Registration No. 2-26323)*

4.30 Twenty-Ninth Supplemental Indenture, dated as of February 1, 1968 (Registration No. 2-28000)*

4.31 Thirtieth Supplemental Indenture, dated as of January 15, 1969 (Registration No. 2-31044)*

4.32 Thirty-First Supplemental Indenture, dated as of October 1, 1969 (Registration No. 2-34839)*

4.33 Thirty-Second Supplemental Indenture, dated as of December 1, 1970 (Registration No. 2-38713)*

4.34 Thirty-Third Supplemental Indenture, dated as of September 15, 1971 (Registration No. 2-41527)*

4.35 Thirty-Fourth Supplemental Indenture, dated as of August 15, 1972 (Registration No. 2-45046)*

4.36 Thirty-Fifth Supplemental Indenture, dated as of February 1, 1974 (Registration No. 2-50039)*

4.37 Thirty-Sixth Supplemental Indenture, dated as of July 1, 1974 (Registration No. 2-59199)*

4.38 Thirty-Seventh Supplemental Indenture, dated as of November 1, 1974 (Registration No. 2-52160)*

4.39 Thirty-Eighth Supplemental Indenture, dated as of March 1, 1975 (Registration No. 2-52776)*

4.40 Thirty-Ninth Supplemental Indenture, dated as of March 15, 1976 (Registration No. 2-55463)*

4.41 Fortieth Supplemental Indenture, dated as of July 1, 1977 (Registration No. 2-59199)*

4.42 Forty-First Supplemental Indenture, dated as of November 1, 1978 (Registration No. 2-62609)*

4.43 Forty-Second Supplemental Indenture, dated as of June 15, 1979 (Registration No. 1-2313)*

4.44 Forty-Third Supplemental Indenture, dated as of September 15, 1979 (Registration No. 1-2313)*

4.45 Forty-Fourth Supplemental Indenture, dated as of October 1, 1979 (Registration No. 2-65493)*

4.46 Forty-Fifth Supplemental Indenture, dated as of April 1, 1980 (Registration No. 2-66896)*

4.47 Forty-Sixth Supplemental Indenture, dated as of November 15, 1980 (Registration No. 2-69609)*

4.48 Forty-Seventh Supplemental Indenture, dated as of May 15, 1981 (Registration No. 2-71948)*

4.49 Forty-Eighth Supplemental Indenture, dated as of August 1, 1981 (Registration No. 1-2313)*

4.50 Forty-Ninth Supplemental Indenture, dated as of December 1, 1981 (Registration No. 2-74339)*

4.51 Fiftieth Supplemental Indenture, dated as of January 16, 1982

4.52 First Mortgage Indenture, dated October 1, 1943, between California Electric Power Company and The International Trust Company and Leo A. Steinhardt as Trustees (Registration No. 2-18234)*

4.53 Second Supplemental Indenture, dated June 1, 1946, between California Electric Power Company and The International Trust Company and Leo A. Steinhardt as Trustees (Registration No. 2-18234)*

4.54 Third Supplemental Indenture, dated June 1, 1948, between California Electric Power Company and The International Trust Company and Leo A. Steinhardt as Trustees (Registration No. 2-18234)*

4.55 Fourth Supplemental Indenture, dated June 1, 1950, between California Electric Power Company and The International Trust Company and Leo A. Steinhardt as Trustees (Registration No. 2-18234)*

4.56 Sixth Supplemental Indenture, dated May 1, 1954, between California Electric Power Company and The International Trust Company and Elmer W. Johnson as Trustees (Registration No. 2-18234)*

4.57 Seventh Supplemental Indenture, dated September 1, 1955, between California Electric Power Company and The International Trust Company and Elmer W. Johnson as Trustees (Registration No. 2-18234)*

4.58 Eighth Supplemental Indenture, dated October 1, 1956, between California Electric Power Company and The International Trust Company and Elmer W. Johnson as Trustees (Registration No. 2-18234)*

4.59	Ninth Supplemental Indenture, dated April 1, 1957, between California Electric Power Company and The International Trust Company and Elmer W. Johnson as Trustees (Registration No. 2-18234)*
4.60	Tenth Supplemental Indenture, dated March 1, 1958, between California Electric Power Company and The International Trust Company and Elmer W. Johnson as Trustees (Registration No. 2-18234)*
4.61	Eleventh Supplemental Indenture, dated May 1, 1960, between California Electric Power Company and The First National Bank of Denver and Elmer W. Johnson as Trustees (Registration No. 2-18234)*
4.62	Twelfth Supplemental Indenture, dated July 1, 1961, between California Electric Power Company and The First National Bank of Denver and Elmer W. Johnson as Trustees (Registration No. 2-22056)*
4.63	Thirteenth Supplemental Indenture, dated as of December 31, 1963, by and between Southern California Edison Company and The First National Bank of Denver and Elmer W. Johnson as Trustees (Registration No. 2-22056)*
10.1	Executive Supplemental Benefit Program (File No. 1-2313)*
10.2	Deferred Compensation Agreement
11.	Computation of Fully Diluted Earnings Per Share
13.	Annual Report to Shareholders for year ended December 31, 1981 (except for those portions which are expressly incorporated herein by reference, such Annual Report is furnished for the information of this Commission and is not deemed to be "filed" herein)
24.	Consent of Independent Public Accountants (See page 31 hereof.)
25.	Power of Attorney and Authorizing Resolution
28.1	Form 11-K for the Company's Employee Stock Purchase Plan
28.2	Form 11-K for the Company's Employee Stock Ownership Plan

* Incorporated by reference pursuant to Rule 12b-32.

Exhibit 11

SOUTHERN CALIFORNIA EDISON COMPANY

COMPUTATION OF FULLY DILUTED EARNINGS PER SHARE

	(Thousands of Dollars)		
	Year Ended December 31,		
	1981	1980	1979
Net Income	$ 489,912	$ 317,536	$ 346,219
Less: Preferred and Preference dividend requirements	69,342	62,284	54,967
Add: Original Preferred dividends	1,454	1,334	1,229
Add: Convertible Preference dividend requirements	812	1,149	1,592
Add: Interest on 3⅛% Convertible Debentures	—	—	2,341
Less: Tax effect of interest on 3⅛% Convertible Debentures(A)	—	—	1,190
Adjusted amount available	$ 422,836	$ 257,735	$ 295,224
Weighted average shares —			
Original Preferred	480,000	480,000	480,000
Common(B)	85,222,970	72,864,813	63,887,178
Common shares reserved for conversion of:			
3⅛% Convertible Debentures	—	—	2,024,380
Preference Stock, 5.20% Convertible Series	430,268	612,230	796,088
Total weighted average shares	86,133,238	73,957,043	67,187,646
Fully diluted earnings per share(C)	$4.91	$3.48	$4.39

Notes:

(A) Composite tax rate	—	—	50.86%

(B) Includes Common Stock equivalents and Common Stock issued due to conversions during 1981, 1980 and 1979 adjusted as if they were outstanding at the beginning of the year.

(C) Adjusted amount available divided by total weighted average shares.