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AUTH. NAME	AUTHOR AFFILIATION
TURLEY, K. L.	Arizona Nuclear Power Project (formerly Arizona Public Serv
DE MICHELE, O. M.	Arizona Nuclear Power Project (formerly Arizona Public Serv
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161-00502-JGH/NEM
September 14, 1987

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

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Dears Sirs:

Subject: Palo Verde Nuclear Generating Station (PVNGS)
Units 1, 2 and 3
Submittal of 1986 Annual Reports
File: 87-056-026; 87-017-404

Pursuant to 10 CFR 50.71(b), please find attached copies of the 1986 Annual Reports for the Participants who jointly own the Palo Verde Nuclear Generating Station. These Participants are Arizona Public Service Company, Salt River Project Agricultural Improvement and Power District, El Paso Electric Company, Southern California Edison Company, Public Service Company of New Mexico, Southern California Public Power Authority and Los Angeles Department of Water and Power.

If you have any questions, please contact Mr. W. F. Quinn of my staff.

Very truly yours,

J G Haynes

J. G. Haynes
Vice President
Nuclear Production

JGH/NEM/ls
Attachments

cc: O. M. De Michele (w/o)
E. E. Van Brunt, Jr. (w/o)
G. W. Knighton (w/o)
J. B. Martin (w/a)
E. A. Licitra (w/o)
G. Fiorelli (w/a)
A. C. Gehr (w/o)

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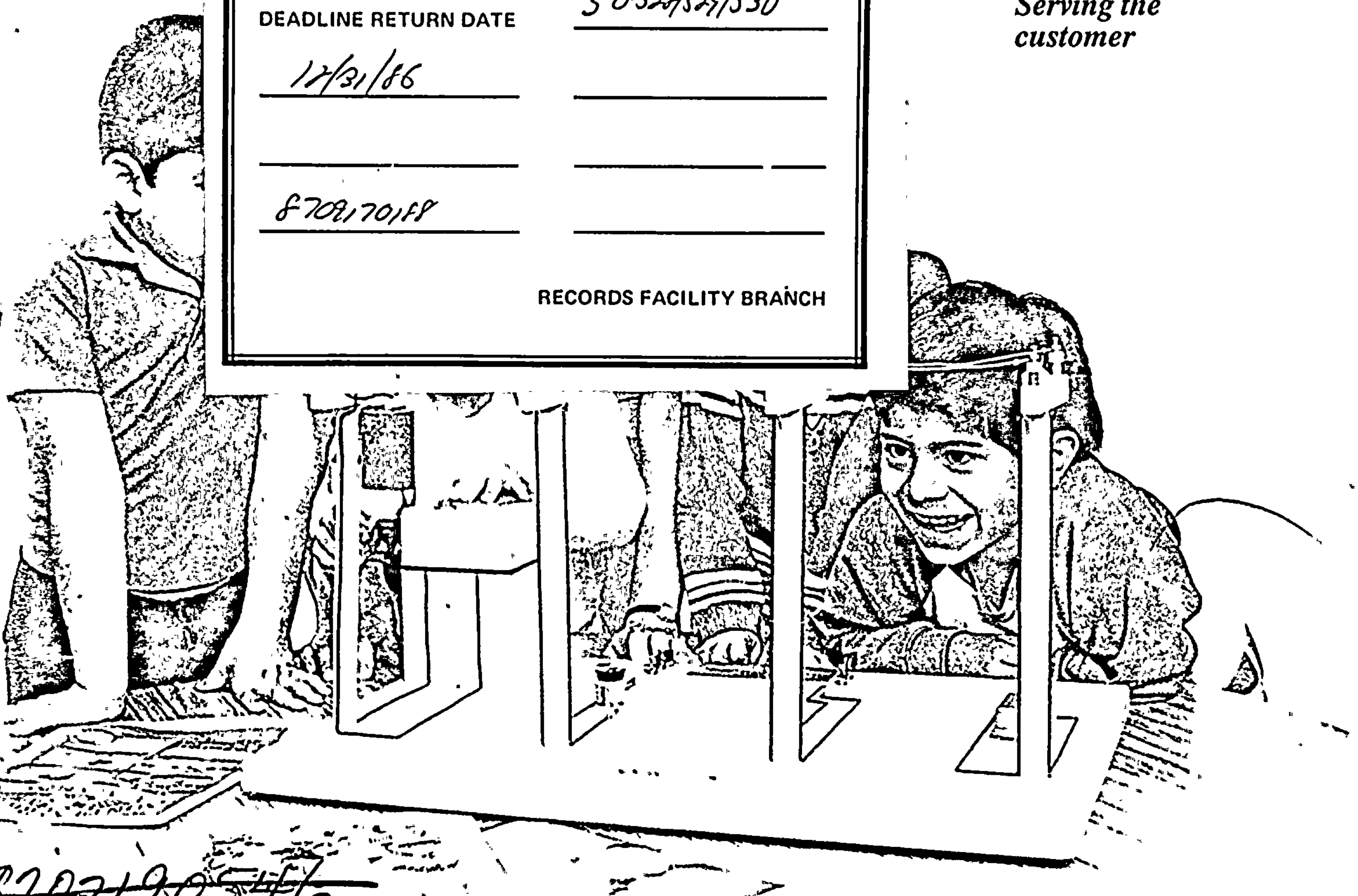
Los Angeles Department of Water and Power 1985-1986 Annual Report

City of
Los Ange
Board of
Water and
Commissi

Serving the customer



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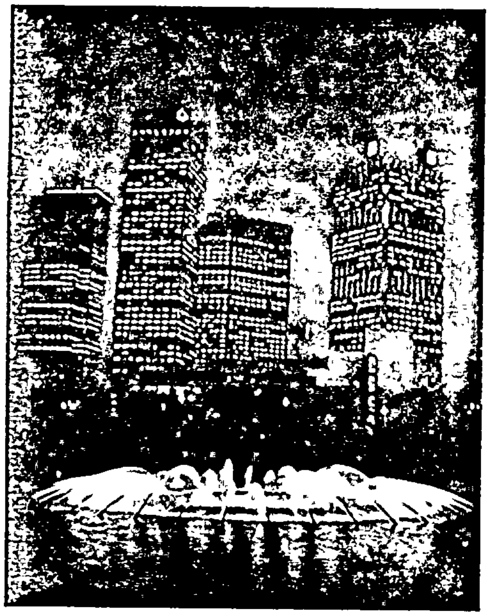


Water and electricity have been vital elements in the growth of Los Angeles, one of the world's great cities.

Front Cover: Youngsters at Sunrise Elementary School learn the basics of power generation with the aid of a DWP exhibit. The Department furnishes a broad range of educational materials to Los Angeles schools.

Tom Bradley
Mayor of
Los Angeles

Los Angeles City Council‡
Pat Russell, Sixth District
President, City Council
Joel Wachs, Second District
Joy Picus,* Third District
John Ferraro, Fourth District
Zev Yaroslavsky,* Fifth District
Ernani Bernardi, Seventh District
Robert C. Farrell, Eighth District
Gilbert W. Lindsay, Ninth District
Marvin Braude, Eleventh District
Hal Bernson, Twelfth District
Michael Woo, Thirteenth District
Richard Alatorre, Fourteenth District
Joan Milke Flores, Fifteenth District

*Member, City Council's Energy and Natural Resources Committee
‡First and Tenth council district seats are vacant

City Controller
Rick Tuttle

City Attorney
James Kenneth Hahn

The Department in Brief

The Los Angeles Department of Water and Power (DWP) is the largest municipally owned utility in the United States.

A unit of the Los Angeles city government, the DWP has more than 10,600 employees serving the 3.1 million residents of the second most populous American city in a 464-square-mile area.

The Department's operations are financed solely by the sale of water and electricity; they are not tax supported.

The DWP is administered by the Board of Water and Power Commissioners, whose five members are appointed by the mayor and confirmed by the City Council for terms of five years. The Board establishes the DWP's rates, subject to approval by the council.

Los Angeles obtains about 75 percent of its water from the Owens River and other sources in the Eastern Sierra Nevada via the Los Angeles Aqueduct, 15 percent from the San Fernando Valley and other local groundwater basins, and 10 percent from the Metropolitan Water District of Southern California, whose water comes from the Colorado River and the State Water Project.

A vast network of power stations and transmission facilities, some located outside California, supplies electrical energy to DWP customers. Power sources include coal, hydroelectric, steam, oil and natural gas. Nuclear power, imported from Arizona, became available to the DWP for the first time in fiscal 1986.

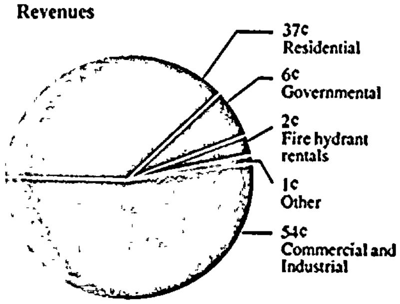
Comparative Highlights

SERVICE	WATER Fiscal Year 1986	WATER Fiscal Year 1985	POWER Fiscal Year 1986	POWER Fiscal Year 1985
Sales	204.3 billion gallons	203.4 billion gallons	20.3 billion kilowatt hours	19.9 billion kilowatt hours
Average number of customers	630,105	630,353	1,261,972	1,251,206
FINANCIAL (in thousands)				
Revenue from water and electric sales, and other income—Net	$234,195	$220,440	$1,386,118	$1,319,943
Operation costs of the water and electric systems*	133,674	118,697	991,260	907,963
Net income	61,844	63,322	193,585	213,630
Transferred to City of Los Angeles reserve fund	10,415	9,885	64,353	58,867

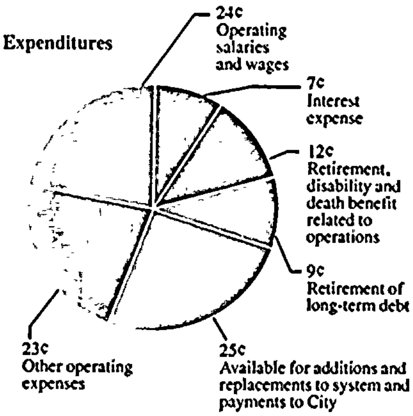
*Excluding depreciation expense

The 1985-86 Water Dollar

Revenues

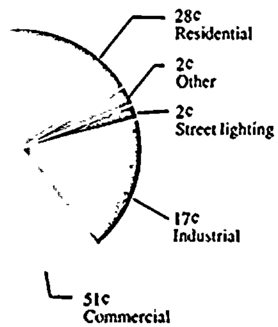


Expenditures

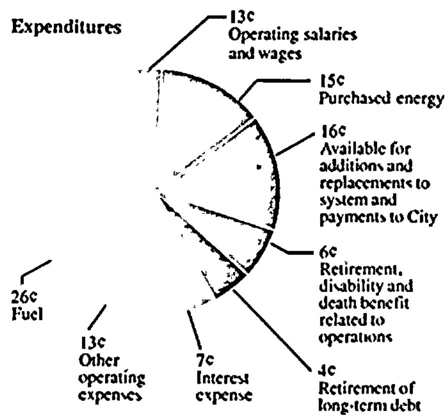


The 1985-86 Power Dollar

Revenues



Expenditures



The City of Los Angeles
Honorable Tom Bradley, Mayor
Honorable Members of the City Council

We take great pleasure in transmitting this 85th annual report which reviews the accomplishments and progress of the Department of Water and Power during the 1985–86 fiscal year, in accordance with the City Charter.

As the gateway to the Pacific, the setter of trends and the center for a growing and diverse population, the City of Los Angeles is dynamic and ever-changing. It is a constant challenge to meet the water and electrical needs of residents, businesses and industries.

We have been successful in this endeavor through proper planning and reliable service at reasonable rates. We take pride in our accomplishments, but know each year we must renew our efforts to continue meeting customers' needs.

Water and electricity have helped Los Angeles grow into a modern metropolis. Today, we serve a population of more than 3.1 million while keeping an eye toward the needs of the future. This year we contributed more than $74 million to the city's general reserve fund in addition to meeting all operating expenses.

We are grateful for the support and cooperation received from you and the City Council. Our appreciation is also extended to other elected city officials and boards and managements of other city departments. We also commend the efforts of our own management and personnel for their continued service and dedication.

Rick J. Caruso
President
Board of Water and Power Commissioners

Rick J. Caruso
President

Jack W. Leeney
Vice President

Angel M. Echevarria

Carol Wheeler

Walter A. Zelman

General Manager's Report

Fiscal 1986 was an especially significant year for the Department. I am pleased to report that we completed several long-term projects that will make a profound impact on our operations in three critical areas: the improvement of water quality, the improvement of customer service, and the development of cost-saving power sources as alternatives to oil and natural gas.

The highlights for the year were as follows:

Water System Developments

—Construction neared completion on the $150 million Los Angeles Aqueduct Filtration Plant, the largest of its type in the country. The plant will remove turbidity from all water delivered through the aqueduct—about 75 percent of the city's supply.

—We greatly expanded our water conservation activities.

—We continued programs to protect water in the San Fernando Valley Groundwater Basin from further contamination and to clean up existing contamination.

—We also continued an intensive program to repair and replace older water lines, pumping stations and reservoirs. This involved an outlay of $52 million during the year.

—We made significant progress in our work with Inyo County to protect and enhance the environment of Owens Valley, our principal water source. In addition, we continued to defend the city's Mono Basin water rights in various lawsuits.

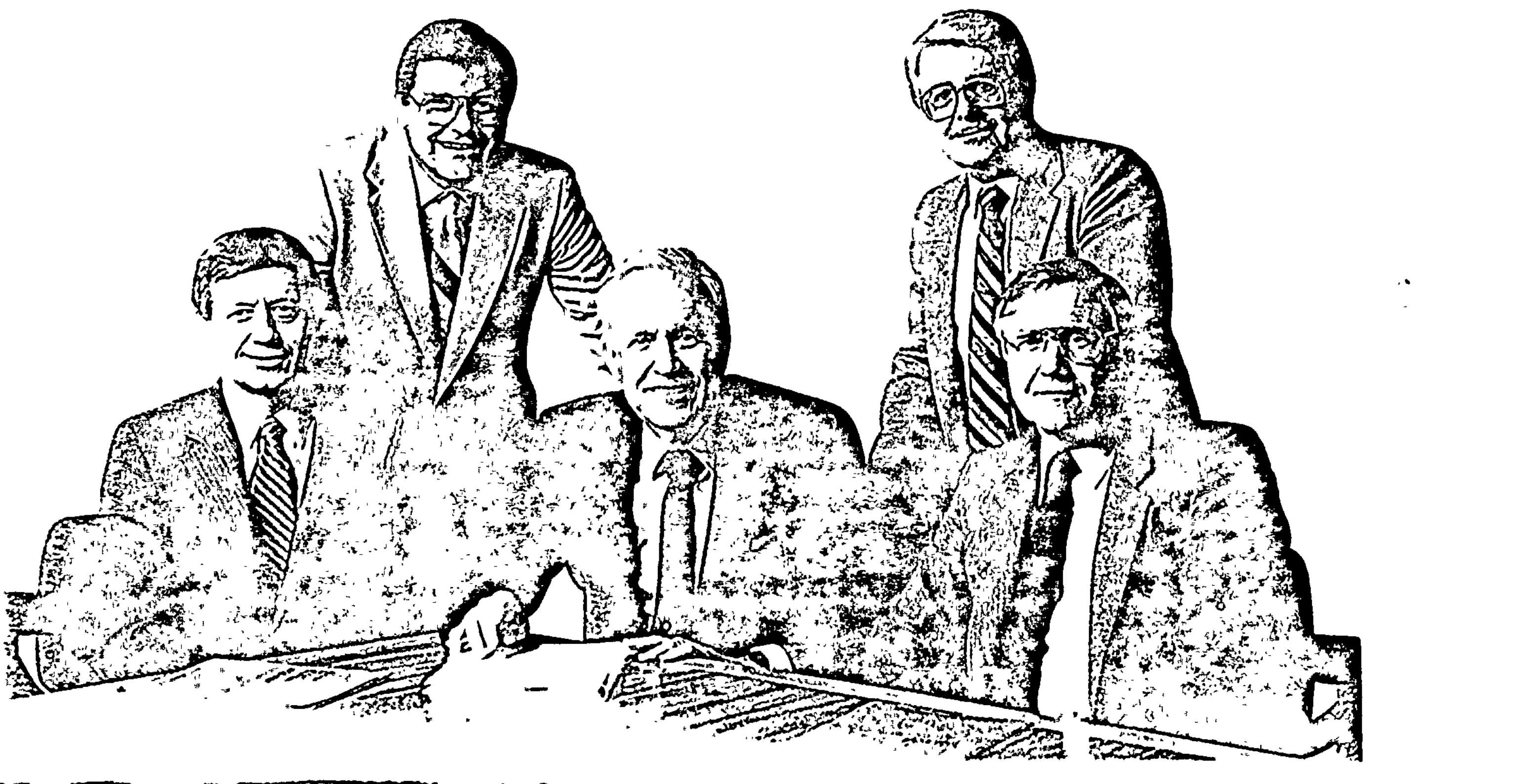
Power System Developments

—The Palo Verde Nuclear Generating Station, a 3,800-megawatt facility in Arizona became an important source of power for Los Angeles when the first of its three units began commercial operation in fiscal 1986. The Department exchanged its 30 percent ownership in a coal-fueled plant, also in Arizona, for an approximately 6 percent interest in the larger Palo Verde facility.

—The 1,600-megawatt Intermountain Power Project (IPP), a $5 billion coal-fueled plant in Utah for which the DWP served as project designer and construction manager, also went on-line, with Unit 1 and the Northern and Southern Transmission Systems being placed in service. Under a long-term contract, we will operate the facility and receive about 45 percent of the project's output.

IPP and Palo Verde represent major steps toward one of the Department's key objectives, to become less dependent on oil and natural gas to produce electricity.

DWP top management: Duane L. Georgeson, assistant general manager—water; Daniel W. Waters, assistant general manager—external affairs; Paul H. Lane, general manager and chief engineer; Norman J. Powers, chief financial officer; and Norman E. Nichols, assistant general manager—power.



Administration and Personnel

—We installed a state-of-the-art, $2.5 million telephone system in the headquarters building to handle customer inquiries faster. The system has increased our efficiency and significantly reduced customer complaints about long delays, enabling us to be more responsive to our customers' needs.

—Computer operations were upgraded with the addition of a $4.5 million mainframe computer that increases our processing capacity 45 percent.

—There were four major executive appointments during the year.

Daniel W. Waters, who began his career with us as a civil engineer in the Power System in 1962, was appointed to the new position of assistant general manager—external affairs. His responsibilities include public affairs, management services, legislative affairs and executive office administration.

Eldon A. Cotton, a 20-year veteran of the Department who had headed the Power System's System Development Division for four years, succeeded Mr. Waters as assistant chief electrical engineer.

Vernon L. Pruett, who joined the DWP in 1963, succeeded Mr. Cotton. In his previous assignment, he served as assistant project director for the Intermountain Power Project.

Lloyd B. Dennis, former senior vice president and director of public affairs for First Interstate Bank of California, was named to the new post of executive director of public affairs. His appointment reflects the increasing importance the Department attaches to effective organizational communications.

Financial Results

—Sales of water and electric power attained record levels, although net income for both the Water System and the Power System declined from the previous year's all-time highs owing to increased expenses. The financial condition of both units is very strong; their combined total assets at year-end stood at $4.8 billion, with all obligations amply covered.

Our operating budget for fiscal 1987 is $2.4 billion. Transfers to the city reserve fund will amount to a record $79 million (5 percent of the 1985-86 fiscal year gross revenues.)

In other internal matters, we increased emphasis on improving our safety record, our affirmative action program continued to produce good results as more women and minority group members gained employment and promotion, and we expanded our supplier relationships with female and minority businesses.

I wish to thank Mayor Bradley, the City Council, and the Board of Water and Power Commissioners for their counsel and support. Their assistance has been most valuable to the DWP, not only in the past year but over a period of many years. I also would like to express my appreciation to my fellow employees for their excellent, dedicated work.

All of us in the Department look forward to expanding and improving our service to the people of Los Angeles during fiscal 1987.

Paul H. Lane

Paul H. Lane
General Manager
and Chief Engineer

The Water System

A Prime Objective: Improving Water Quality

Chief among the Department's concerns in its water-related activities in fiscal 1986 as it probably will be for at least several more years, was improving water quality. There were notable accomplishments in this area.

Additionally, we undertook important environmental programs in the Owens Valley, continued our efforts to resolve water rights litigation, expanded our conservation activities, and continued an intensive program to repair and replace older water facilities.

Filtration Plant Nears Completion

Construction on the Los Angeles Aqueduct Filtration Plant, a landmark project for the Department, was substantially completed. After three years of construction, testing is now underway, and the plant is scheduled to begin full-scale operation next spring.

Located in Sylmar in the north San Fernando Valley, the plant will treat up to 600 million gallons of water daily. This constitutes the entire flow of the two Los Angeles aqueducts, which bring water some 340 miles to Los Angeles from the Owens Valley and Mono Basin. The plant forms the terminus of the aqueduct system and the beginning of the water distribution system.

The plant, built at a cost of $150 million, is one of the largest and most advanced water treatment facilities in the world. Filtration will remove turbidity, or cloudiness, found naturally in surface water supplies, making the water clearer and more easily disinfected.

Ozone will be added as an aid to filtration. It will also provide the benefits of superior disinfection, reduced color, improved taste and odor, and a reduction in the formation of chlorinated organic compounds.

Protecting San Fernando Valley Groundwater

A Precious Source. The San Fernando Valley Groundwater Basin, made up of layers of clay, sand and gravel, naturally contains large quantities of water. About 15 percent of the Los Angeles water supply is drawn from wells located in this basin. It normally serves about 500,000 people, but because of its storage capacity it can supply 1 million people during a drought or emergency.

Several years ago, when sensitive monitoring equipment became available for water testing, trace amounts of two industrial solvents, trichloroethylene (TCE) and perchloroethylene (PCE), were found in a sizable number of the basin's wells. These contaminants probably had been present for many years but previously were undetectable.

Los Angeles municipal pools rely on water supplied by the DWP.

While water consumption by DWP customers is safe, the spread of contamination in the San Fernando Basin is reducing the number of wells available for use.

The Department has minimized the potential risks posed by these chemicals through two measures: shutting down certain wells, and blending contaminated water with clean water so that the contamination level is below permissible state and federal levels.

While water consumed by DWP customers is safe, the spread of contamination in the San Fernando Basin is reducing the number of wells available for use. We are moving on several fronts to control this situation.

Working With the EPA. The Department signed an agreement with the U.S. Environmental Protection Agency (EPA) to conduct a study on how best to clean up the San Fernando Valley groundwater and prevent further contamination. We estimate the study will cost about $4 million and take two years to complete.

Four well fields within the San Fernando Valley Basin have been placed on the EPA's national priorities list for hazardous waste cleanup and are eligible for EPA Superfund financing. Because these funds have not yet been made available, the DWP plans to proceed with the first stage of the study using $300,000 of its own money.

Aeration Tower Approved. A major element in our groundwater protection plan is an aeration tower to be built in the San Fernando Valley community of North Hollywood. The 48-foot-high tower would remove trace levels of contaminants, mainly TCE and PCE, from the water.

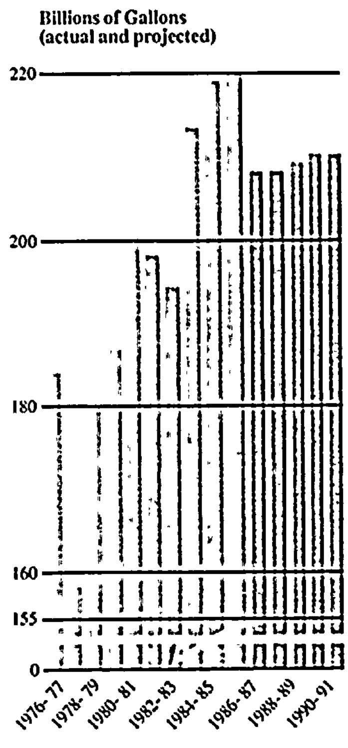
A lengthy process of governmental review and public hearings on the environmental effects of the tower was completed. With the necessary permits for the $2.5 million project in hand, construction will begin early in 1987. The facility will be in operation by late 1987.

In the aeration process, contaminated underground water is pumped through pipes to the top of the tower. As the water falls by gravity through packing material in the tower, it is blasted with air. This causes the contaminants, volatile organic compounds, to separate and vaporize. Granular activated carbon filters, added to the end of this treatment process, will remove the contaminants from the air emissions.

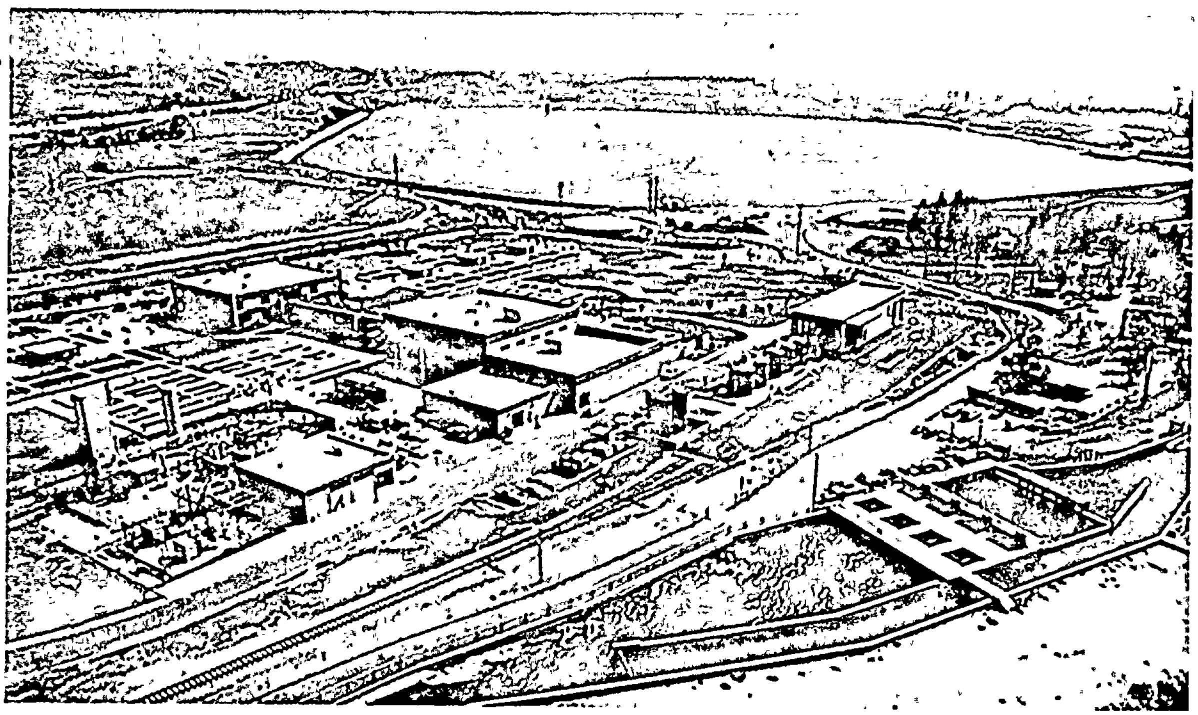
The aeration facility proposal was the product of a two-year study of groundwater management in the San Fernando Valley that the Department completed in 1983 under an EPA grant. Other measures recommended in that study that are now being carried out include educating the public on toxic waste, monitoring toxic waste storage facilities, eliminating certain septic disposal systems, and increasing enforcement of hazardous waste disposal laws.

Protecting and Enhancing the Owens Valley Environment. In 1984 Inyo County and Los Angeles, in an attempt to resolve their long-standing differences over water rights, entered into an agreement to set aside litigation and to jointly conduct vegetation and ground-

Water Use Deliveries



The Los Angeles Aqueduct Filtration Plant, located at Sylmar in the San Fernando Valley, begins full-scale operation in December 1986. The $150 million complex is one of the world's most advanced water treatment facilities.



water studies, implement several enhancement and beautification projects in the Owens Valley, and develop a long-term groundwater management plan.

At present, various projects ranging from revegetation, to providing wildlife habitat, to the creation of recreation areas are under way. Other programs will be implemented in the future.

A major element in our groundwater protection plan is an aeration tower to be built in the San Fernando Valley community of North Hollywood.

Last year saw the culmination of the most ambitious of these programs—the $750,000 Lower Owens River Project—which established a warm water fishery and wildlife habitat along the normally dry riverbed. On June 5, water was released from the Los Angeles Aqueduct into a 25-mile section of the river that had been essentially dry since the early 1900s.

Using about 18,000 acre-feet of water annually from the aqueduct, the project will provide a continuous flow of water from Black Rock Springs downstream to Owens Lake. New wells under construction elsewhere in the valley will replace the diverted water.

In addition to reviving the river, the project will sustain water fowl habitat in five small lakes and ponds. The new fishery will support such warm-water species as largemouth bass, bluegill, catfish, and carp. In the next few years, the DWP will work with the state Department of Fish and Game to develop a wildlife management plan for the Lower Owens River area.

Water Rights Litigation

The Department is involved in a number of court cases in which our long-standing water rights in the Mono Basin are being challenged. We are defending ourselves vigorously in these matters. Mono Basin is of great importance to the DWP since it supplies about 17 percent of our water supply and large amounts of hydroelectric power.

Following is a brief summary of the suits that proceeded in fiscal 1986:

—Mono Lake. This suit was filed by the Audubon Society in 1979, challenging our rights to the entire Mono Basin water supply. Separate appeals, relating to the site of an eventual trial,

The DWP conducts a rigorous testing program to help ensure the high quality of its water supply.

were filed by the society and California and have delayed resolution of this issue.

—Lower Rush Creek. The environmental groups are seeking to have the DWP maintain a trout fishery that developed in the normally dry creek during several years of unusually heavy run-off in the Mono Basin. Additional studies ordered by the court will be conducted over the next two years.

Conservation Efforts Increased

DWP completed a sweeping plan designed to increase water conservation in Los Angeles. Designated as the Urban Water Management plan, it was prepared in response to 1983 state legislation.

The plan includes numerous conservation measures that will be expanded or newly implemented to promote efficient water usage in the city through the year 2010. The plan was compiled over two years with the assistance of environmental organizations, community groups, water conservation agencies, and other groups and individuals knowledgeable about conservation.

Key measures under the plan include:

—Seasonal water rates implemented in December 1985.

—A pilot program to distribute free conservation kits, including low-volume shower heads, to 110,000 lifeline customers.

—Participation in the Large Turf Audit program of the state Department of Water Resources, which is aimed at increasing the efficiency of irrigation for areas such as golf courses and cemeteries. This effort can be significant, since landscaping accounts for almost one-fourth of all water use in Los Angeles.

—Distributing thousands of lawn watering guides to residential customers.

—Speaking programs to promote residential conservation.

—A biannual business and industry water conservation awards program.

Major Computer System Set for Start-Up

A $15 million computer system that will monitor and control DWP water distribution facilities from our headquarters building neared completion. Under design and development for more than three years, the system, scheduled to begin operating early in 1987, will improve the Water System's reliability as well as substantially reduce its operating costs.

Initially, we will be able to monitor reservoir levels, water flow and pressure, and the condition of pumps and valves at 77 locations throughout the Water System. That number eventually will rise to 250.

The new equipment will enable us to flag minor problems and correct them before they escalate to cause major damage or service interruptions. We also will be able to assess the effects of earthquake tremors on our facilities.

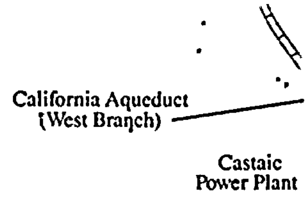
An important attribute of the system is that it will allow better regulation of power usage by wells and pumping stations, thus significantly reducing our electricity costs. The system includes two identical computers, either of which can perform all critical tasks if the other is down.

A DWP representative gives conservation and water energy efficiency advice to a customer at her home. This service is provided free on request to all residential customers.

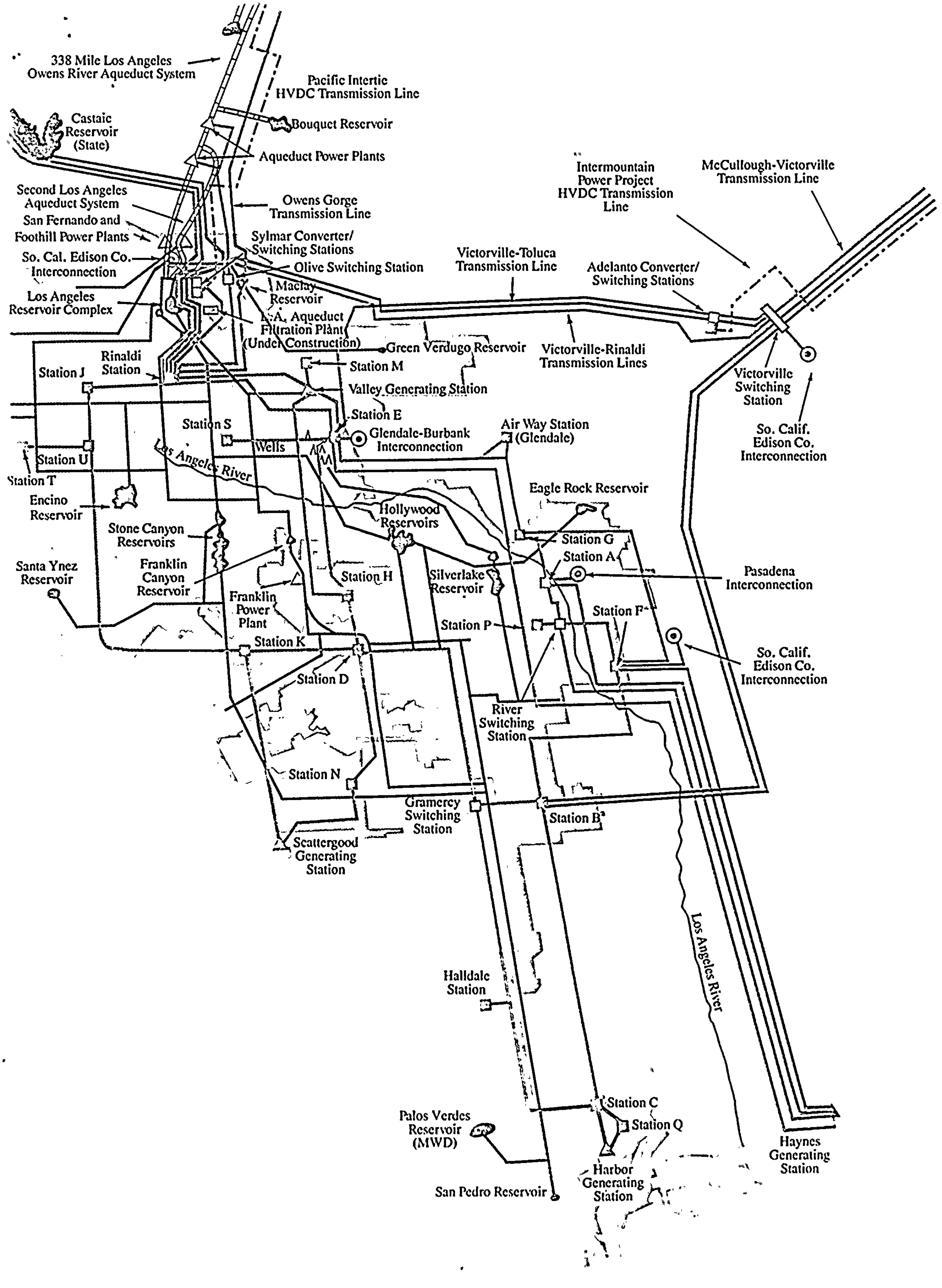
Water System Facts in Brief

	1985-86	1984-85
Use of Water		
Average Los Angeles population served*	3,214,000	3,103,000
Average daily use per capita, gallons	187.2	193.6
Water sales for fiscal year, billion gallons	204.3	203.4
Maximum daily demand, million gallons	915.2	882.9
Water Supply to City Area		
From local supply, cu. ft. per second (c.f.s.)	144.5	164.8
From DWP Aqueduct, c.f.s.	671.8	709.3
From Metropolitan Water District, c.f.s. (California Aqueduct and Colorado River Aqueduct)	123.9	64.8
Gross supply, c.f.s.	940.2	938.9
Diversion from (to) local storage, c.f.s.	(6.6)	(6.4)
Net supply to distribution systems, c.f.s.	933.6	932.5

*Includes 28,000 people in certain areas, contiguous to Los Angeles which are served by the Water System. Excludes 2,000 residents of the City not served by the Water System.



The City of Los Angeles encompasses 464 square miles and has a population of 3.1 million. A vast network of facilities is in place to serve customers with a reliable supply of water and electricity. Water is imported from hundreds of miles away and brought to Los Angeles through aqueducts. Generating facilities in other western states are playing a larger role in the City's power supply income.


338 Mile Los Angeles Owens River Aqueduct System
Pacific Intertie HVDC Transmission Line
Castaic Reservoir (State)
Bouquet Reservoir
Aqueduct Power Plants
Intermountain Power Project HVDC Transmission Line
McCullough-Victorville Transmission Line
Second Los Angeles Aqueduct System
Owens Gorge Transmission Line
San Fernando and Foothill Power Plants
Sylmar Converter/ Switching Stations
So. Cal. Edison Co. Interconnection
Olive Switching Station
Victorville-Toluca Transmission Line
Adelanto Converter/ Switching Stations
Los Angeles Reservoir Complex
Maclay Reservoir
L.A. Aqueduct Filtration Plant (Under Construction)
Green Verdugo Reservoir
Victorville-Rinaldi Transmission Lines
Rinaldi Station
Station J
Station M
Valley Generating Station
Victorville Switching Station
Station E
So. Calif. Edison Co. Interconnection
Station S
Glendale-Burbank Interconnection
Air Way Station (Glendale)
Wells
Station U
Los Angeles River
Station T
Encino Reservoir
Eagle Rock Reservoir
Hollywood Reservoirs
Stone Canyon Reservoirs
Station G
Station A
Santa Ynez Reservoir
Franklin Canyon Reservoir
Station H
Silverlake Reservoir
Pasadena Interconnection
Franklin Power Plant
Station F
Station P
Station K
So. Calif. Edison Co. Interconnection
Station D
River Switching Station
Station N
Gramercy Switching Station
Station B
Scattergood Generating Station
Los Angeles River
Halldale Station
Station C
Station Q
Palos Verdes Reservoir (MWD)
Haynes Generating Station
Harbor Generating Station
San Pedro Reservoir

The Power System

Developing New Energy Sources

In pursuing its overall goal of supplying Los Angeles with energy that is clean, safe, reliable and economical, the Department has several interrelated, long-term objectives.

For reasons both of economy and stability of supply, we continuously seek to develop new fuel sources other than oil or natural gas. The long-term price increases of both oil and gas probably will exceed the inflation rate, and both the price and availability of our oil supplies depend on unpredictable world economic and political developments.

Therefore coal, which is abundant domestically and relatively inexpensive, figures importantly in our energy future. Similarly, but to a lesser degree, nuclear power will be part of that future energy mix.

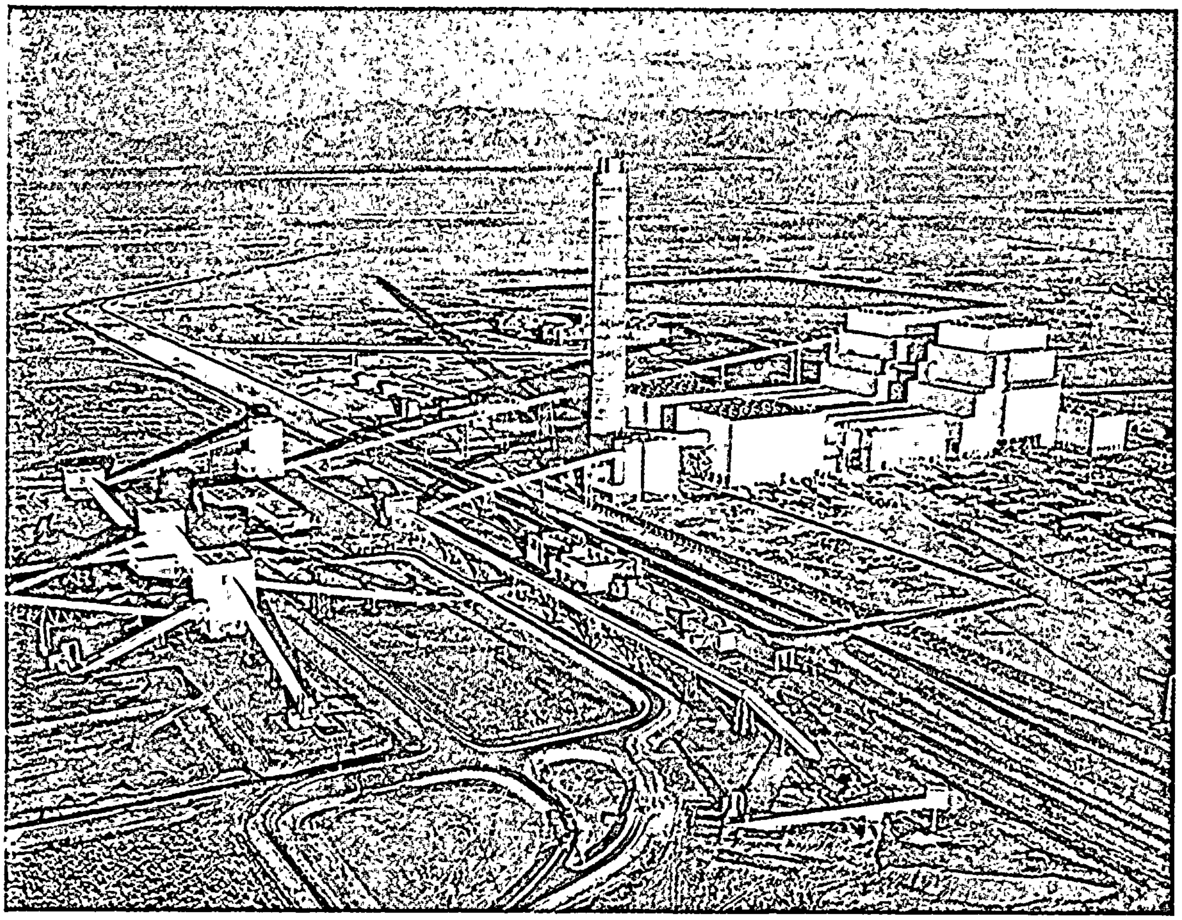
During the early 1970s, the Department produced about 80 percent of its energy from oil and natural gas-fueled generators in the Los Angeles Basin. By contrast, in fiscal 1986 those sources accounted for only 31.5 percent of our energy, with DWP-owned hydroelectric (5.4 percent), Hoover Dam power (11.2 percent), coal (26.1 percent), purchased energy (25.3 percent), and nuclear (.5 percent) making up the rest of the supply.

Intermountain Power Project Comes On-Line

A major new source of clean and economical energy became available to Los Angeles last spring when the first of two generators of the Intermountain Power Project (IPP) near Delta, Utah, began commercial production.

A 1,600-megawatt, coal-fueled facility owned by the Intermountain Power Agency (IPA), a Utah public authority, IPP will distribute power to 36 project participants in Utah, Nevada, Wyoming, Idaho, and Southern California.

The DWP is by far the largest buyer of IPP output. Initially we will purchase more than 62



The Intermountain Power Project, a huge coal-fueled power plant in Utah, began supplying electricity to Los Angeles last spring.

Like IPP, Palo Verde constitutes an important step in the Department's efforts to develop alternative fuel resources.

percent of the project's power, although our long-term entitlement is about 45 percent. Our power will be delivered through one of the major components of the project, the 490-mile long Southern Transmission System, to our converter station at Adelanto, California, 100 miles northeast of Los Angeles, in the Mojave Desert.

All IPP facilities, except the Southern Transmission System, have been financed by the sale of IPA bonds and commercial paper. The transmission system was funded by bonds issued by the Southern California Public Power Authority (SCPPA), of which DWP is the largest member.

The start-up of the first IPP generating unit—ahead of schedule and well below budget—marked an extraordinary achievement by the Department, which has served as the project's manager since its inception in the 1970s.

DWP employees have been deeply involved in the $5 billion project since it was first conceived. At one time, as many as 4,200 people (including a small DWP contingent) worked on the construction site at IPP, one of the largest and most complex power projects undertaken in the United States in many years. About 70 Department employees were assigned to the project as of last year.

In addition to the two generating units (Unit 2 is scheduled to go on-line next summer), which include state-of-the-art air quality control devices, IPP comprises two transmission systems, converter facilities, a microwave communication and control system, and a railcar service center in Provo, Utah.

The plant, whose fuel requirements will average 4 million tons of coal a year, is highly automated. It is the first power plant to use decentralized computers to run all major operations. Each computer controlling a major system has a back-up to assure that system's reliability.

DWP Acquires Interest in Nuclear Plant

After ten years of planning, designing, construction, and testing, the Palo Verde Nuclear Generating Station, located about 50 miles west of Phoenix, Arizona, began producing commercial power for utilities in Arizona, Texas, New Mexico, and California last winter.

Los Angeles will be a beneficiary of the $5.9 billion facility (this figure excludes financing costs), since the DWP has a 5.7 percent ownership—equivalent to about 217 megawatts—in it.

According to a 1977 agreement between the Department and the Salt River Project, an Arizona agency, we exchanged our 30 percent interest in the coal-fueled Coronado power plant, located near St. Johns, Arizona, for equivalent electrical capacity in the new Palo Verde facility when it went on-line.

In addition to that entitlement, the DWP will receive an energy and capacity interest of almost 4 percent, or about 151 megawatts, though SCPPA.

Like IPP, Palo Verde constitutes an important step in the Department's efforts to develop alternative fuel resources. When fully operational, it should supply about 8 percent of our power requirements.

Palo Verde, a joint venture of six public utilities, is comprised of three identical 1,270-megawatt generating units. Unit 1 went into operation in January 1986. The project will be completed when Unit 3 begins service next year. The plant is expected to generate about 23 million megawatt-hours annually by the early 1990s.

This store and thousands of other facilities in Los Angeles depend on electricity furnished by the Department.

Expansion of Transmission System

The Department spent about $39 million improving and expanding the high voltage transmission system in fiscal 1986. The most important of these projects was the award of a contract to expand the electrical capacity of the Sylmar Converter Station, the southern terminus of the 846-mile Pacific Intertie Transmission System, which is a major power link between Southern California and the Pacific Northwest.

The $171 million expansion, scheduled for completion in 1989, will increase the transmission system's capacity 55 percent, to 3,100 megawatts. It calls for the construction of parallel valve groups, converter valve halls, a control building and related equipment.

Work also began on the new Victorville-to-Rinaldi Transmission Line, a 500-kilovolt, single-circuit line that will be used to transmit power from coal-fueled generating stations in the southwest. Expected to be completed next July, the 86-mile project represents a $67 million investment, including the purchase of rights-of-way.

In the Future: Alternative Energy

In addition to relying on a variety of conventional energy sources, the Department also is seeking to develop alternative sources such as geothermal, solar and biomass energy and other emerging technologies to address the future power needs of Los Angeles.

Although these methods are not now technically or economically feasible for our operations, they hold promise for the future. Last year we spent $5.4 million on alternative energy research and development.

Geothermal Projects. The Department continued its development of geothermal power (underground steam or hot water) in the China Lake region of the Coso Range in Inyo County. We began exploring the Coso Known Geothermal Resource Area in 1981, when we acquired leases to 6,825 acres located a few miles from DWP transmission lines.

Three exploratory wells were drilled in 1985 with favorable results, and more wells will be drilled to define the reservoir. Our long-range plans call for a demonstration plant to be operating in the early 1990s, and for commercial units to operate later in that decade.

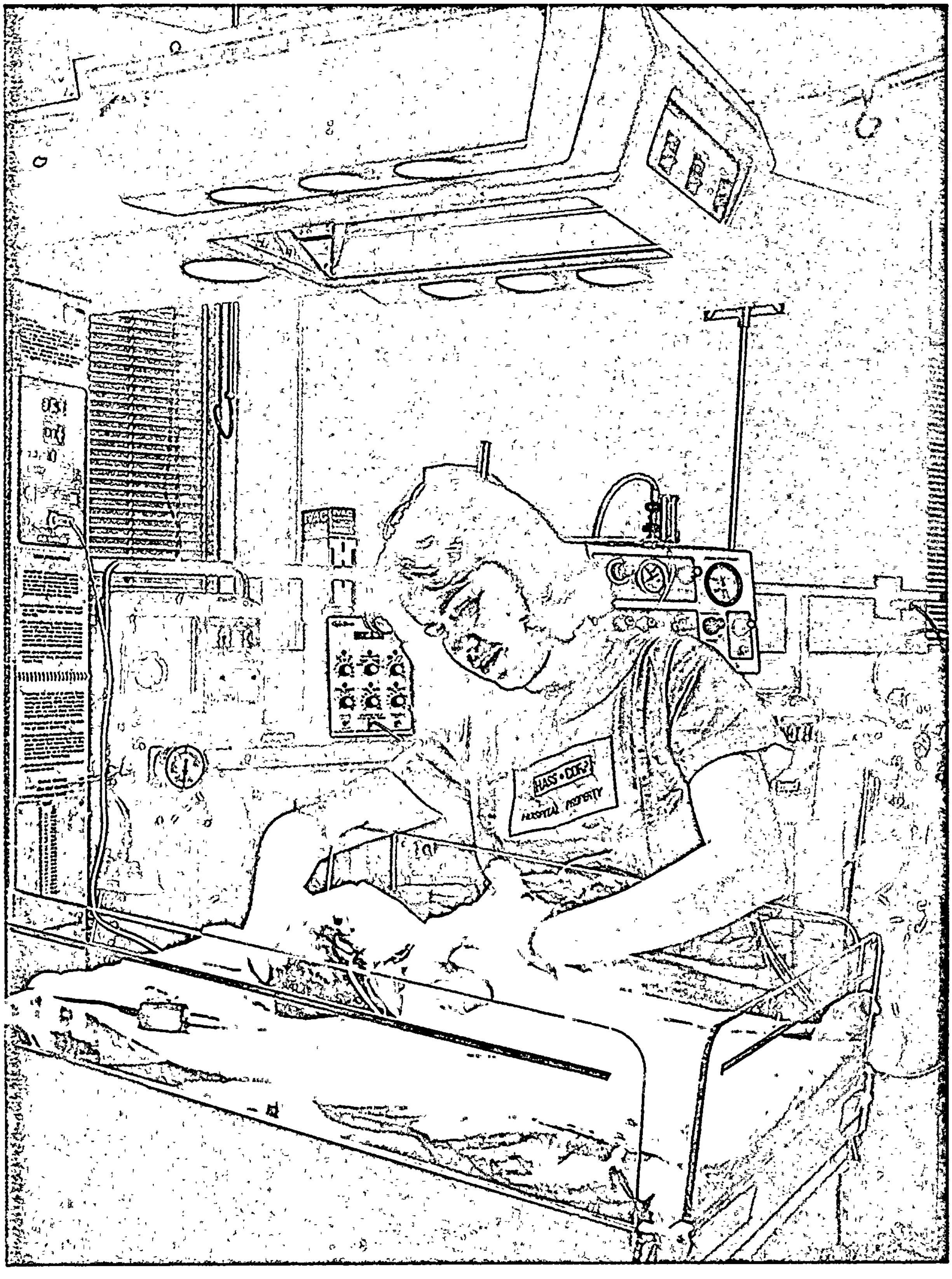
Geothermal is a proven technology. Commercial plants have been operating in the United States and other countries for many years.

White Pine County Power Project. To be located near Ely, Nevada, the White Pine Power Project is a proposed coal-fueled generating station that would be jointly owned by White Pine County and two Nevada power companies. Development work on White Pine continued last year. Under current plans, the DWP will acquire a portion of the project's output.

Hydroelectric. Environmentally clean and reliable, hydroelectric power has long been an important element in the Department's energy sources. Under a recent agreement, the city will continue to receive power from Hoover Dam for the next 30 years.

The DWP was a close partner of the federal Bureau of Reclamation in conceiving and building the dam, which was the main source of power for Los Angeles for many years. The Department, which has been operating 13 of the dam's 17 huge generators for the Bureau since 1935, began phasing out of its involvement in this work last year.

Landfill Gas Recovery. The Department has tested a 40-kilowatt fuel cell powered by landfill gas to produce electricity and heat. The DWP and Southern California Edison were joint participants in this project, part of a program sponsored by the federal Department of



A reliable supply of energy can be a matter of life and death as well as routine convenience. At California Hospital, this newborn is warmed and protected by DWP electricity.

Energy and the Gas Research Institute that is testing more than 40 fuel cells in the United States and Japan. The program was highly successful.

We continue to use landfill gas as supplemental boiler fuel at our Valley Generating Station. Landfill gas is recovered at a nearby landfill and piped to the station.

Conservation Programs Continue

Besides the activities cited above, the Department has operated a comprehensive energy conservation program since 1971. At present, these efforts mainly comprise free, customer-requested audits for both residential and business customers designed to improve energy efficiency, and a broad education campaign for both customer groups.

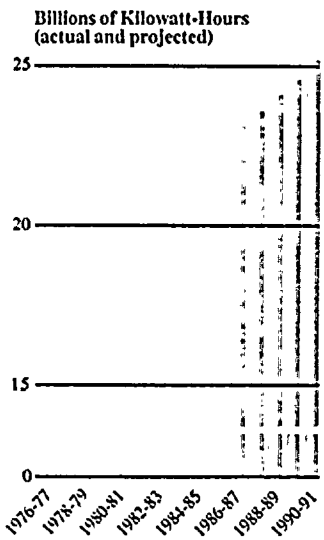
Largely as a result of these programs, Los Angeles has one of the lowest per capita energy consumptions of any California city.

In the seven years that the Department has been surveying business and industrial establishments, which consume about 80 percent of the energy used in the city, about 800 audits have been completed through the year-end. These saved an estimated 250 million kilowatt hours.

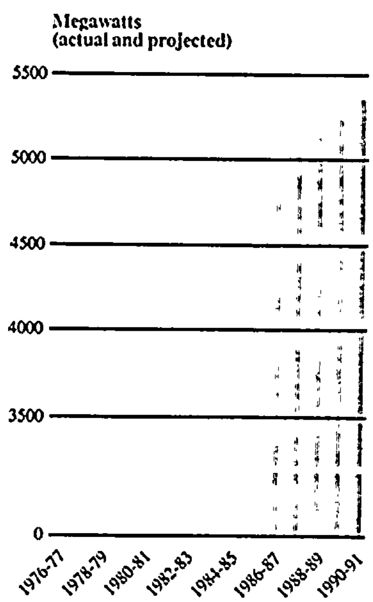
Through our conservation loan program, 119 loans totaling $539,000 were granted during fiscal 1986 for solar and heat pump installations and master-meter conversions. Since its inception, the program has provided $4.3 million in loans to residential customers.

The Department presented awards to 167 businesses for their achievements in energy efficiency management during the year.

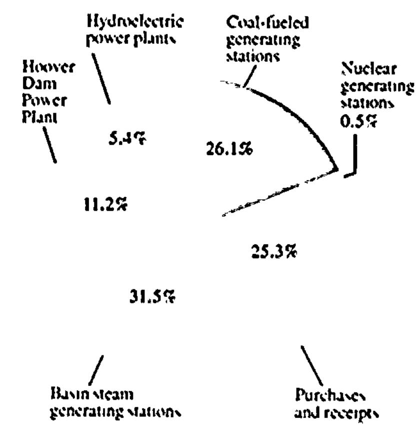
Electric Energy Requirements



Power System Peak Demand Forecasts



Electric Energy Sources



Power System Facts in Brief

Power production in kilowatt-hours (including all generation of Hoover units connected to DWP system)

	1985-86	1984-85
Power Use		
Domestic Customers	1,078,074	1,069,622
Commercial Customers	157,484	155,176
Industrial Customers	20,233	20,434
Total Customers—All Classes	1,261,972	1,251,206
Sales to Ultimate Consumers—Kilowatt-hours	20,034,676,000	19,554,854,000
Sales to Other Utilities—Kilowatt-hours	215,819,000	337,857,000
Average Annual Kilowatt-hours per Domestic Customer	5,102	5,185
Status of System		
Utility Plant (Less Accumulated Provision for Depreciation)	$2,943,900,000	$2,656,056,000
Generating Stations—Net Dependable Capability, Kilowatts	7,309,000*	6,534,000*

*Includes purchased capacity; does not deduct short-term sales of excess capacity.

Customer Service

The Year Sees Important Advances

The continuing, paramount objective of the Department is to provide ever-improving service to our customers, the people of Los Angeles. Last year we achieved much in that regard.

A New Telephone System Is Installed

A highly advanced telephone system that will provide much faster response to customer calls for service and information went into operation last spring.

The computer-controlled system, which cost about $2.5 million, does something our previous electro-mechanical system could not: It assures that customers get first-call, first-served treatment. It also can answer a call immediately and place a customer on hold until a service representative is available to take the call.

The new equipment also continuously provides our service supervisors with information such as call length, volume and location which enables them to manage the system more efficiently.

In order to implement the new system, the telephone service operations of our Van Nuys and headquarters offices were consolidated, and the new unit was relocated to a remodeled area of the headquarters building lobby floor.

The telephone service staff consists of about 175 representatives, including about 40 who work part-time during high volume periods and 12 "leads," or supervisors. These people handle, on average, a total of 7,000 to 8,000 calls a day.

Computer Services Improved

In most large business and governmental organizations, there is an important, if sometimes indirect, relationship between the quality of the enterprise's computer services and the quality of its end product. This is the case with the DWP.

A very large, sophisticated computer services operation—the operating budget is about $33 million—enhances all aspects of the Department's administrative work, and that, in turn, is reflected in improved customer service.

Last year we purchased a powerful mainframe computer which increased our processing capacity by about 45 percent. The new machine, which cost about $4.5 million, processes information at the rate of 30 million instructions per second—twice as fast as the larger of our two older mainframes. Department personnel operating more than 1,600 remote terminals access these computers to carry out myriad administrative tasks.

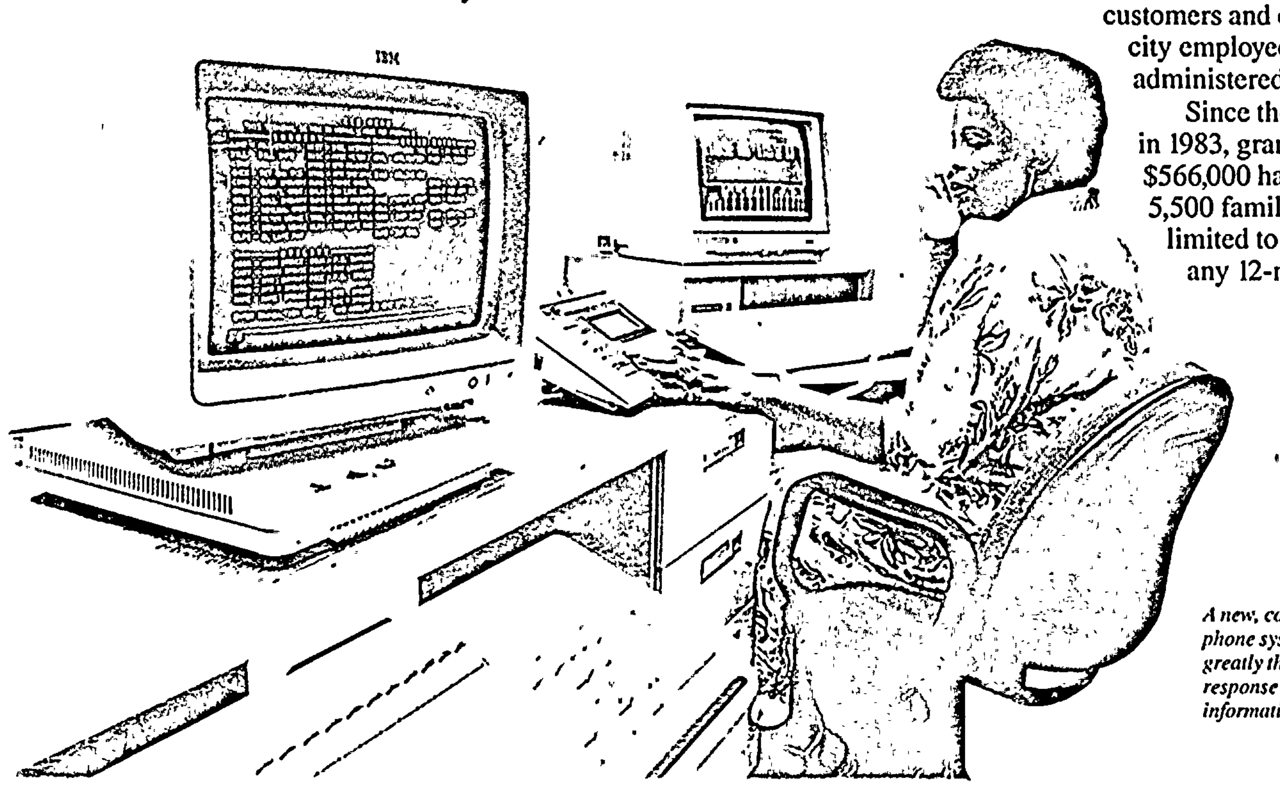
In 1983, the Department initiated a program to train and assist employees in using personal computers. About 90 PCs were installed throughout the DWP last year, bringing the total at year-end to about 230. Each of these machines is used by a cluster of employees.

Assisting Low-Income Customers

Project ANGEL, the Department's program to assist customers who because of hardship cannot pay their DWP bills, distributed more than $130,000 during the year.

Funding for Project ANGEL, an acronym for Assist Neighbors by Giving Energy for Living, comes from contributions by DWP customers and employees and other city employees. The program is administered by the United Way.

Since the program's inception in 1983, grants of more than $566,000 have been made to some 5,500 families. Assistance is limited to $150 per family in any 12-month period.



A new, computerized telephone system has improved greatly the Department's response to service and information calls.

DWP People

Developing Our Most Important Asset

Among the more important responsibilities of the DWP are safeguarding the on-the-job welfare and nurturing the talents and capabilities of the more than 10,600 men and women comprising the workforce. Last year the Human Resources Division began several major new programs to help accomplish those ends.

Management Development Program Launched

Working with a consulting firm, we completed the first phase of the most comprehensive management training program the Department has ever undertaken.

The task was a complex one, involving more than 350 managers representing the entire Department. Surveys, focus groups and individual interviews were analyzed to determine the program's major areas of concentration.

The findings of this study will help us both identify the needs of individual managers and chart the course for a complete management development program for the Department.

In a related development, we also introduced a formal performance evaluation and development system for all engineering management personnel.

The system seeks to promote regular, open communication between superiors and subordinates on job performance, with a view toward developing better performance by the subordinate and increasing the job satisfaction and professional growth of both parties. This program was developed with the help of many of our engineering personnel at various levels.

Dealing With Substance Abuse

Recognizing that drug and alcohol abuse among DWP employees can pose serious health risks for them as well as create hazardous working conditions which could affect the public, we instituted a firm policy on the use of these substances.

The policy, which was agreed to by our various employee unions, is aimed at maintaining safe and efficient working conditions that are alcohol and drug free. It also provides employees involved in substance abuse with a full opportunity for rehabilitation. Referral of employees through the Department's Employee Assistance Program to a variety of community-based rehabilitation programs is an integral part of the policy.

The Department has provided extensive training to more than 1,700 supervisors in recognizing the signs of drug use and in the referral techniques necessary for rehabilitation.

Safety Record Improves

The Department expanded its safety programs considerably in fiscal 1986.

Department-wide recognition of outstanding safety records occurred with the establishment and first presentation of the General Manager's Safety Awards, which will be presented annually. The General Services, Water Operating, and Power Distribution Divisions won the awards for reducing their serious accidents by 25 percent to 34 percent.

We also established an Industrial Hygiene unit that is responsible for assuring that DWP operations involving hazardous chemicals are conducted safely and in compliance with government regulations. The unit developed and presented "right-to-know" training for 7,000 DWP field employees. It is now monitoring Department worksites and preparing evaluations for operating managers.

Additionally, we invested substantial sums in new safety equipment, carried out employee tests under Occupational Safety and Health Administration (OSHA) standards, and expanded our safety awareness programs.

DWP crews demonstrate electrical safety practices to students at Los Angeles schools.

Finances

Operations for fiscal year 1985-86 produced increases of .5 percent in water sales and 1.8 percent in the sales of electric energy.

Operating revenues of the Department's Water and Power Systems totaled more than $1.58 billion, a gain of $88 million over the previous fiscal year. The Water System accounted for $18 million of the increase due primarily to higher energy and purchased water costs billed to customers. The Power System added $70 million to the total. This came mainly from an increase in energy costs billed to customers combined with the November 1985 rate increase.

Higher Water System operating revenues partially offset by an increase in operating and maintenance expenses resulted in net income of $61.8 million.

A total of $112.8 million was spent by the Water System on capital construction, most of which went towards the improvement of the water distribution system and continued construction of the Los Angeles Aqueduct Filtration Plant project. Water filtration is necessary to comply with federal and state drinking water quality regulations.

The operating revenue of the Power System increased by 5.4 percent from 1984-85 to a total of $1.36 billion. Net income amounted to $193.6 million.

The Power System invested $404.4 million in capital construction for the year. Major expenditures were for additions and modifications to the electrical distribution system in Los Angeles, additions and improvements to transmission facilities, and the Coronado/Palo Verde power generation project.

Two $50 million issues of Power System revenue bonds were sold during the year. Interest rates for these issues averaged 8.6 percent. The Water System sold two advance refunding bond issues for almost $67 million. Proceeds of the sales were pledged to retire the higher-interest cost Water Works Revenue Bond issues of 1982 and 1984. This transaction will ultimately yield interest cost savings in excess of $18 million over the life of the refunding issues.

Outstanding bonds, notes and revenue certificates on June 30, 1986, totaled $1.63 billion for the Power System and $324.4 million for the Water System. Both systems met their maturing payments on bonds and notes.

Totaled assets of the Department at June 30, 1986, were approximately $4.84 billion. Of this amount, $3.70 billion was recorded in the Power System and the remainder in the Water System.

In accordance with its basic fiscal policy, the Department pays all costs of operation, debt service and part of the cost of capital improvements from current revenues. The remainder of the cost of capital improvements is met through sales of revenue bonds or notes and from contributions in aid of construction.

Besides meeting all costs of operation from current revenues, the Department paid more than $74 million into the Reserve Fund of the city in support of general city government. Almost 90 percent of that amount came from the Power Revenue Fund. Operations of the Water and Power Systems are entirely self-supporting and no financial obligation or tax burden is placed on the citizens of Los Angeles.

Water System Statement of Income

(In Thousands)	1986	1985	1984
	Year ended June 30		
Operating revenues:			
Sales of water	$220,433	$203,042	$180,851
Fire hydrant rentals	4,042	4,015	3,926
Other operating revenues	1,544	1,243	965
Total operating revenues	226,019	208,300	185,742
Operating expenses:			
Purchased water	17,192	9,139	6,775
Purchased energy	8,050	7,524	6,006
Purchased water and energy costs	25,242	16,663	12,781
Other operation	78,715	72,308	69,107
Maintenance	27,145	27,351	25,919
Provision for depreciation	22,983	21,844	20,956
Taxes on property outside the City	2,572	2,375	2,342
Total operating expenses	156,657	140,541	131,105
Operating income	69,362	67,759	54,637
Other income—net	8,176	12,140	7,715
Income before debt expenses	77,538	79,899	62,352
Debt expenses:			
Interest on debt	23,239	23,254	18,263
Allowance for borrowed funds used during construction	(7,545)	(6,677)	(2,392)
Net debt expenses	15,694	16,577	15,871
Income before nonrecurring credit	61,844	63,322	46,481
Nonrecurring credit related to accounting changes	—	—	11,962
Net income	$ 61,844	$ 63,322	$58,443

Statement of Retained Income Reinvested in the Business

	1986	1985	1984
Balance at beginning of year	$357,757	$304,320	$253,673
Net income for the year	61,844	63,322	58,443
	419,601	367,642	312,116
Less—Payments to the reserve fund of the City	10,415	9,885	7,796
Balance at end of year	$409,186	$357,757	$304,320

The accompanying notes are an integral part of these financial statements.

Water System Balance Sheet

(In Thousands)	June 30 1986	1985
Assets		
Utility plant, at original cost:		
Source of water supply	$ 223,350	$ 220,698
Pumping	23,656	22,489
Purification	9,654	9,323
Distribution	904,277	864,406
General	97,614	83,793
	1,258,551	1,200,709
Less—Accumulated provision for depreciation	453,695	429,510
	804,856	771,199
Construction work in progress	183,941	131,048
	988,797	902,247
Long-term receivables	1,076	1,573
Current assets:		
Deposits with City Treasurer—		
Revenue fund	64,227	103,514
Bond redemption and interest funds	2,772	6,837
Cash on hand and revolving funds	556	249
Customer and other accounts receivable, less $600 allowance for losses	35,009	32,231
Accrued unbilled revenue	17,890	15,817
Materials and supplies, at average cost	13,423	13,304
Prepayments and other current assets	13,826	2,289
	147,703	174,241
Unamortized debt expenses	409	846
	$1,137,985	$1,078,907
Liabilities and Equity		
Equity:		
Retained income reinvested in the business, per accompanying statement	$ 409,186	$ 357,757
Contributions in aid of construction	302,946	284,884
	712,132	642,641
Long-term debt, excluding advance refunding bonds:		
Revenue bonds	296,546	309,242
Revenue notes	27,861	34,801
	324,407	344,043
Less—Long-term debt due within one year (see below)	19,370	19,450
	305,037	324,593
Current liabilities:		
Long-term debt due within one year (see above)	19,370	19,450
Accrued interest	6,746	6,226
Accounts payable and accrued expenses	66,873	61,281
Customer deposits	27,827	24,716
	120,816	111,673
	$1,137,985	$1,078,907

The accompanying notes are an integral part of these financial statements.

Water System Statement of Changes in Financial Position

(In Thousands)	Year ended June 30 1986	1985	1984
Financial resources provided by:			
Operations—			
Net income	$ 61,844	$ 63,322	$ 58,443
Charges and credits to income not affecting working capital—			
Depreciation	26,291	25,793	25,270
Other, net	748	570	489
Resources provided by operations	88,883	89,685	84,202
Sale of revenue bonds and notes	—	34,706	49,471
Sale of advance refunding bonds	65,928	18,597	—
Amount received from escrow account	13,025	20,600	—
Contributions in aid of construction	18,062	18,945	15,890
	185,898	182,533	149,563
Financial resources used for:			
Expenditures for plant and equipment	112,841	101,482	90,788
Reduction of long-term debt	19,370	19,450	12,375
Amount deposited in escrow accounts and offset against advance refunding bonds (Note B)	65,928	18,597	—
Long-term debt redeemed, including call premium	13,025	20,600	—
Payments to the reserve fund of the City	10,415	9,885	7,796
	221,579	170,014	110,959
Increase (decrease) in working capital	$ (35,681)	$ 12,519	$ 38,604
Increase (decrease) in components of working capital:			
Deposits with City Treasurer—			
Revenue fund	$ (39,287)	$ 19,712	$ 40,673
Bond redemption and interest funds	(4,065)	5,219	(497)
Cash on hand and revolving funds	307	21	(159)
Customer and other accounts receivable	2,778	4,853	4,664
Accrued unbilled revenue	2,073	647	15,170
Materials and supplies	119	2,350	805
Deferred purchased water costs	—	—	(2,024)
Prepayments and other current assets	11,537	(153)	592
Net change in current assets	(26,538)	32,649	59,224
Long-term debt due within one year	80	(7,075)	250
Accrued interest	(520)	(144)	2
Accounts payable and accrued expenses	(5,592)	(10,110)	(16,727)
Customer deposits	(3,111)	(2,801)	(4,145)
Net change in current liabilities	(9,143)	(20,130)	(20,620)
Increase (decrease) in working capital	$ (35,681)	$ 12,519	$ 38,604

The accompanying notes are an integral part of these financial statements.

Water System Notes to Financial Statements

NOTE A—Summary of significant accounting policies:

The Department—The Department of Water and Power of the City of Los Angeles exists under and by virtue of the City Charter enacted in 1925 as a separate proprietary agency of the City. The Water System is responsible for delivering water to the City's inhabitants.

Financial statement presentation—The financial statements of the Water System are presented in conformity with generally accepted accounting principles, and substantially in conformity with accounting principles prescribed by the California Public Utilities Commission except for the method of accounting for contributions in aid of construction described below. The Department is not subject to regulations of such commission.

Utility plant and depreciation—The costs of additions to utility plant and replacements of retired units of property are capitalized. Costs include labor, materials and allocated indirect charges such as engineering, supervision, transportation and construction equipment, retirement plan contributions and other fringe benefits, and certain administrative and general expenses.

For projects over a specified dollar amount, the Water System also capitalizes an allowance for funds used during construction equivalent to the cost of long-term debt incurred to finance plant under construction. Research and development costs directly related to current and future construction projects are capitalized and all other such costs are expensed as incurred. The cost of relatively minor replacements is included in maintenance expense. The original cost of property retired, together with removal cost, less salvage, is charged to accumulated depreciation when property is removed from service.

Utility plant depreciation is provided by the straight-line method based on estimated service lives. The depreciation expense was 2.28%, 2.28% and 2.36% of average depreciable plant for the years ended June 30, 1986, 1985 and 1984.

Deposits with City Treasurer—Of the deposits with the City Treasurer, $57,584,000 and $101,396,000 at June 30, 1986 and 1985, were invested in short-term securities under the City Treasurer's pooled investment program, whereby available funds of the City and its independent operating departments are invested on a combined basis. These investments are valued at cost, which approximates market.

Contributions in aid of construction—Under the provisions of the City Charter, amounts received from customers and others for constructing utility plant are combined with retained income reinvested in the business to represent equity for purposes of computing the Water System's borrowing limits. Accordingly, contributions in aid of construction are shown in the accompanying balance sheet as an equity account and are not offset against utility plant; depreciation provided for the related utility plant is expensed.

Revenues—The Water System's rates are fixed by the Department and approved by the City Council. Revenues include amounts resulting from a purchased water cost adjustment formula designed to permit full recovery of purchased water costs. The Department projects these costs to establish the purchased water cost recovery component of customer billings. Any difference between amounts billed and actual purchased water costs results in over- or under-recovered purchased water costs, which are adjusted in subsequent billings.

Under the rate ordinance approved August 30, 1983, the Water System changed its method of recognizing purchased water costs to expense and bill these costs in the period incurred; previously, billable purchased water costs were deferred until actually billed. To provide a better matching of costs and revenues, effective June 30, 1984, the Water System changed its accounting policy for recognizing revenue to a method which provides for accruing estimated unbilled revenues for water sold but not billed at the end of a fiscal period; previously, revenues were recognized when billed. At June 30, 1984, as required by the rate ordinance, deferred purchased water costs of $3,208,000 were charged to expense. The net effect of the two changes was to increase net income for the year ended June 30, 1984 by $11,962,000.

Under a rate ordinance approved November 24, 1985, to be effective January 1, 1986, the Water System will recover all energy purchased as part of the purchased water cost recovery rates. Previously, purchased energy was recovered through base rate billings. This change had no significant effect on net income for the year ended June 30, 1986.

The Water System sells water to other departments of the City at regular rates provided in the ordinance.

Shared operating expenses—The Water System shares certain administrative functions with the Department's Power System. Generally, the cost of these functions is allocated on the basis of benefits provided to the Systems.

Debt expenses—Debt premium, discount, and issue expenses are deferred and amortized to income over the lives of the related issues.

Payments to the reserve fund of the City—Under the provisions of the City Charter, the Water System transfers funds at its discretion to the reserve fund of the City. Such payments are not in lieu of taxes and are recorded as distributions of retained income.

NOTE B—Long-term debt:

Long-term debt outstanding at June 30, 1986, consisted of revenue bonds and notes due serially in varying annual amounts through 2024. Interest rates, which vary among individual maturities, averaged approximately 7.14% and 7.59% at June 30, 1986 and 1985. The revenue bonds are callable generally ten years after issuance. Scheduled principal maturities during the five years succeeding June 30, 1986 are $19,370,000, $19,560,000, $20,270,000, $20,180,000, and $12,460,000, respectively

In fiscal years ended June 30, 1986, 1985 and 1977, the Water System sold advance refunding bonds totaling $66,585,000, $18,785,000 and $33,625,000, respectively. Until the bonds to be refunded are called, interest on the advance refunding bonds is payable from interest earned on securities of the United States government purchased out of the proceeds of the sales and held in escrow accounts with Citibank, N.A., New York. At June 30, 1986 and 1985, $85,370,000 and $31,810,000 of these escrow accounts have been offset against the advance refunding bonds in the accompanying balance sheet ($12,650,000 face value was redeemed during the year ended June 30, 1986). After the monies in the escrow accounts are applied to redeem the bonds to be called ($82,890,000 face value to be redeemed through 1994), the advance refunding bonds will be payable from Water System revenues.

NOTE C—Shared operating expenses:

Operating expenses shared with the Power System were $216,276,000, $197,265,000 and $165,089,000 for the years ended June 30, 1986, 1985 and 1984, of which $74,347,000, $67,139,000 and $51,033,000 were allocated to the Water System.

NOTE D—Employees' retirement plan:

The Department has a funded contributory retirement, disability and death benefit insurance plan covering substantially all of its employees. The Water System was allocated approximately 26% of the plan's total costs for the years ended June 30, 1986, 1985 and 1984 amounting to $32,247,000, $29,156,000 and $30,618,000. These costs include amortization of prior service costs generally over a 30-year period ending June 30, 2003. The Department funds retirement plan costs in accordance with the recommendations of the plan's independent actuary. In 1986, no significant amendments were made to the plan.

The actuarially computed present value of accumulated retirement plan benefits attributable to the Water System aggregated $461,000,000 and $434,000,000 at June 30, 1986 and 1985, of which $459,000,000 and $433,000,000 were vested. An assumed rate of return of 8% was used in determining these actuarially computed values. The retirement plan's assets at market value allocated to the Water System were $397,000,000 and $313,000,000 at such dates.

NOTE E—Commitments and contingencies:

Capital program and other—The Department's budget for the year ending June 30, 1987 provides for capital expenditures of approximately $114,000,000 in the Water System. Also, the Department has budgeted payments of $11,301,000 for the year ending June 30, 1987 from the Water System's revenue fund to the reserve fund of the City.

Litigation—A number of claims and suits are pending against the Department for alleged damages to persons and property and for other alleged liabilities arising out of its operations. In the opinion of management, the uninsured liability under these actions would not materially affect the Water System's financial position as of June 30, 1986.

Report of Independent Accountants

To the Board of Water
and Power Commissioners
Department of Water
and Power
City of Los Angeles

We have examined the balance sheet of the Water System of the Department of Water and Power of the City of Los Angeles as of June 30, 1986 and 1985, and the related statements of income, of retained income reinvested in the business and of changes in financial position for each of the three years in the period ended June 30, 1986. Our examinations were made in accordance with generally accepted auditing standards and accordingly included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

As more fully described in Note A to the financial statements, effective June 30, 1984, the Water System of the Department changed its method of accounting for unbilled revenues and the method of recognizing purchased water costs.

In our opinion, the financial statements examined by us present fairly the financial position of the Water System of the Department of Water and Power of the City of Los Angeles at June 30, 1986 and 1985, and the results of its operations and the changes in its financial position for each of the three years in the period ended June 30, 1986, in conformity with generally accepted accounting principles consistently applied during the period except for the changes, with which we concur, referred to in the preceding paragraph.

Price Waterhouse
Simpson & Simpson

Los Angeles, California
October 10, 1986

Power System Statement of Income

(In Thousands)	Year ended June 30 1986	1985	1984
Operating revenues:			
Sales of electric energy	$1,349,579	$1,280,632	$1,170,953
Other operating revenues	8,555	7,335	6,516
Total operating revenues	1,358,134	1,287,967	1,177,469
Operating expenses:			
Fuel for generation	348,069	347,591	313,850
Purchased power	203,116	181,961	169,615
Energy costs	551,185	529,552	483,465
Other operation	288,954	240,090	232,525
Maintenance	142,461	129,425	110,598
Provision for depreciation	107,419	105,483	98.521
Taxes on property outside the City	8,660	8,896	10,965
Total operating expenses	1,098,679	1,013,446	936,074
Operating income	259,455	274,521	241,395
Other income—net	27,984	31,976	22,032
Income before debt expenses	287,439	306,497	263,427
Debt expenses:			
Interest on debt	97,464	96,075	98,548
Allowance for borrowed funds used during construction .	(3,610)	(3,208)	(575)
Net debt expenses	93,854	92,867	97,973
Net income	$ 193,585	$ 213,630	$ 165,454

Statement of Retained Income Reinvested in the Business

Balance at beginning of year	$1,432,156	$1,277,393	$1,167,259
Net income for the year	193,585	213,630	165,454
	1,625,741	1,491,023	1,332,713
Less—Payments to the reserve fund of the City	64,353	58,867	55,320
Balance at end of year	$1,561,388	$1,432,156	$1,277,393

The accompanying notes are an integral part of these financial statements.

Power System Balance Sheet

(In Thousands)	June 30 1986	1985
Assets		
Utility plant, at original cost:		
Production	$1,379,279	$1,483,086
Transmission	501,453	508,148
Distribution	1,571,148	1,471,489
General	235,012	210,213
	3,686,892	3,672,936
Less—Accumulated provision for depreciation	1,157,138	1,106,040
	2,529,754	2,566,896
Construction work in progress	383,904	89,160
Nuclear fuel, at amortized cost	30,242	—
	2,943,900	2,656,056
Current assets:		
Deposits with City Treasurer—		
Revenue fund	355,565	283,118
Bond redemption and interest funds	17,226	40,872
Cash on hand and revolving funds	1,166	1,222
Customer and other accounts receivable, less $3,300 and $2,900 allowance for losses	140,043	148,752
Accrued unbilled revenue	83,729	57,483
Materials and supplies, at average cost	61,820	57,149
Fuel for generation	61,819	83,851
Deferred energy costs	26,784	40,537
Prepayments and other current assets	9,397	9,569
	757,549	722,553
Unamortized debt expenses	1,045	2,118
	$3,702,494	$3,380,727
Liabilities and Equity		
Equity:		
Retained income reinvested in the business, per accompanying statement	$1,561,388	$1,432,156
Contributions in aid of construction	84,708	79,625
	1,646,096	1,511,781
Long-term debt, excluding advance refunding bonds:		
Revenue bonds	1,512,710	1,465,200
Revenue notes	24,955	60,000
	1,537,665	1,525,200
Less—Long-term debt due within one year (see below)	61,526	84,996
	1,476,139	1,440,204
Current liabilities:		
Long-term debt due within one year (see above)	61,526	84,996
Revenue certificates	90,000	90,000
Accrued interest	26,504	23,746
Accounts payable and accrued expenses	315,519	209,934
Over-recovered energy costs	69,261	13,102
Extension and other deposits	17,449	6,964
	580,259	428,742
	$3,702,494	$3,380,727

The accompanying notes are an integral part of these financial statements.

Power System Statement of Changes in Financial Position

(In Thousands)	1986	1985	1984
	Year ended June 30		
Financial resources provided by:			
Operations—			
Net income	$ 193,585	$213,630	$165,454
Charges and credits to income not affecting working capital—			
Depreciation	115,599	113,328	104,832
Amortization of nuclear fuel	925	—	—
Other, net	(32)	385	582
Resources provided by operations	310,077	327,343	270,868
Sale of revenue bonds	98,566	49,586	—
Amount received from escrow account	72,920	88,786	—
Contributions in aid of construction	5,083	15,489	4,576
	486,646	481,204	275,444
Financial resources used for:			
Expenditures for plant and equipment	404,368	177,674	150,926
Reduction of long-term debt	61,526	84,996	79,126
Long-term debt redeemed, including call premium	72,920	88,786	—
Payments to the reserve fund of the City	64,353	58,867	55,320
	603,167	410,323	285,372
Increase (decrease) in working capital	$(116,521)	$ 70,881	$ (9,928)
Increase (decrease) in components of working capital:			
Deposits with City Treasurer—			
Revenue fund	$ 72,447	$ 71,000	$ 35,038
Bond redemption and interest funds	(23,646)	32,534	(7,273)
Cash on hand and revolving funds	(56)	(5)	318
Customer and other accounts receivable	(8,709)	44,738	1,054
Accrued unbilled revenue	26,246	(4,397)	61,880
Materials and supplies	4,671	1,919	1,515
Fuel for generation	(22,032)	6,174	(14,242)
Deferred energy costs	(13,753)	(10,481)	(59,213)
Prepayments and other current assets	(172)	475	207
Net change in current assets	34,996	141,957	19,284
Long-term debt due within one year	23,470	(5,870)	(7,315)
Accrued interest	(2,758)	(169)	8,399
Accounts payable and accrued expenses	(105,585)	(49,352)	(28,909)
Over-recovered energy costs	(56,159)	(13,102)	—
Extension and other deposits	(10,485)	(2,583)	(1,387)
Net change in current liabilities	(151,517)	(71,076)	(29,212)
Increase (decrease) in working capital	$(116,521)	$ 70,881	$ (9,928)

The accompanying notes are an integral part of these financial statements.

Power System Notes to Financial Statements

NOTE A—Summary of significant accounting policies:

The Department—The Department of Water and Power of the City of Los Angeles exists under and by virtue of the City Charter enacted in 1925 as a separate proprietary agency of the City. The Power System is responsible for delivering electric power to the City's inhabitants.

Financial statement presentation—The financial statements of the Power System are presented in conformity with generally accepted accounting principles, and substantially in conformity with accounting principles prescribed by the Federal Energy Regulatory Commission and the California Public Utilities Commission except for the method of accounting for contributions in aid of construction described below. The Department is not subject to regulations of such commissions.

Utility plant and depreciation—The costs of additions to utility plant and replacements of retired units of property are capitalized. Costs include labor, materials and allocated indirect charges such as engineering, supervision, transportation and construction equipment, retirement plan contributions and other fringe benefits, and certain administrative and general expenses.

For projects over a specified dollar amount, the Power System capitalizes an allowance for funds used during construction equivalent to the cost of long-term debt incurred to finance plant under construction. Research and development costs directly related to current and future construction projects are capitalized and all other such costs are expensed as incurred. The cost of relatively minor replacements is included in maintenance expense. The original cost of property retired, together with removal cost, less salvage, is charged to accumulated depreciation when property is removed from service.

Utility plant depreciation is provided for a large portion of the facilities by the 5% sinking fund method based on the estimated service lives. The straight-line method is used for major projects completed after July 1, 1973 and for all office and shop structures, related furniture and equipment, and transportation and construction equipment. The aggregate provision was 3.27%, 3.24% and 3.13% of average depreciable plant for the years ended June 30, 1986, 1985 and 1984. Nuclear fuel is amortized and charged to Fuel for Generation on the basis of actual thermal energy produced relative to total thermal energy expected to be produced over the life of the fuel. A contract has been entered into with the United States Department of Energy for the disposal of the spent fuel.

Nuclear decommissioning—Decommissioning of the Palo Verde Nuclear Generating Station (PVNGS) is projected to commence in approximately 35 to 40 years. The Power System is providing for estimated future decommissioning costs over the life of the PVNGS through annual charges to expense.

Deposits with City Treasurer—Of the deposits with the City Treasurer, $337,034,000 and $279,025,000 at June 30, 1986 and 1985 were invested in short-term securities under the City Treasurer's pooled investment program, whereby available funds of the City and its independent operating departments are invested on a combined basis. These investments are valued at cost, which approximates market.

Fuel for generation—Coal inventories are stated at average cost. Fuel oil inventories are stated at cost, using the last-in, first-out method.

Contributions in aid of construction—Under the provisions of the City Charter, amounts received from customers and others for constructing utility plant are combined with retained income reinvested in the business to represent equity for purposes of computing the Power System's borrowing limits. Accordingly, contributions in aid of construction are shown in the accompanying balance sheet as an equity account and are not offset against utility plant; depreciation provided for the related utility plant is expensed.

Revenues—The Power System's rates are fixed by the Department and approved by the City Council. Revenues include amounts resulting from an energy cost adjustment formula designed to permit the full recovery of energy costs. The Department projects these costs to establish the energy cost recovery component of customer billings. Any difference between amounts billed and actual energy costs results in over- or under-recovery of energy costs, which are adjusted in subsequent billings.

Under the rate ordinance approved August 30, 1983, the Power System changed its method of recognizing energy costs to expense and bill these costs in the period incurred; previously, billable energy costs were deferred until actually billed. Also, to provide a better matching of costs and revenues, effective June 30, 1984, the Power System changed its accounting policy for recognizing revenue to a method which provides for accruing estimated unbilled revenues for energy sold but not billed at the end of a fiscal period; previously, revenues were recognized when billed. At June 30, 1984, as required by the rate ordinance, an amount of deferred energy cost equal to the accrued unbilled revenues was charged to expense and, therefore, has no effect on net

income. Deferred energy costs will be billed in future periods.

The Power System sells electric energy to other departments of the City at regular rates provided in the ordinance.

Shared operating expenses—The Power System shares certain administrative functions with the Department's Water System. Generally, the cost of these functions is allocated on the basis of benefits provided to the Systems.

Debt expenses—Debt premium, discount, and issue expenses are deferred and amortized to income over the lives of the related issues.

Payments to the reserve fund of the City—Under the provisions of the City Charter, the Power System transfers funds at its discretion to the reserve fund of the City. Such payments are not in lieu of taxes and are recorded as distributions of retained income.

NOTE B—Revenue certificates:

At June 30, 1986 and 1985, the average interest rate of revenue certificates outstanding was 4.55% and 4.80% with maturities ranging from 19 to 152 days and 34 to 180 days, respectively. The Department has an unsecured standby line of credit of $90,000,000 which can be used if the certificates cannot be refinanced as they mature.

NOTE C—Jointly-owned electric utility plant:

The Power System has an undivided interest in several electrical generating stations and transmission systems which are jointly-owned with various utilities. Each participant provides its own construction financing. The Power System's proportionate share of construction and improvement costs is included in the appropriate categories of utility plant. The Power System will incur certain minimum operating costs on jointly-owned facilities, whether or not it is able to take delivery of its share of energy generated. The proportionate share of these expenses incurred is included in the appropriate categories of operating expenses. At June 30, 1986 and 1985, the Power System's investment in such projects totaled $853,748,000 and $671,917,000.

NOTE D—Long-term debt:

Long-term debt outstanding at June 30, 1986, consisted of revenue bonds and notes due serially in varying annual amounts through 2026. Interest rates, which vary among individual maturities, averaged approximately 6.56% and 6.29% at June 30, 1986 and 1985. The revenue bonds are callable generally ten years after issuance. Scheduled principal maturities during the five years succeeding June 30, 1986 are $61,526,000, $67,916,000, $53,545,000, $51,930,000, and $53,180,000, respectively.

In the fiscal year ended June 30, 1977, the Power System sold advance refunding bonds totaling $161,700,000. Until the bonds to be refunded were called, interest on the advance refunding bonds was payable from interest earned on securities of the United States Government purchased out of the proceeds of the sales and held in escrow accounts with Citibank, N.A., New York. At June 30, 1986, all refunded bonds had been called and the related escrow accounts liquidated; the advance refunding bonds are now payable from Power System revenues. During the years ended June 30, 1986 and 1985, $70,800,000 and $86,200,000 face value of the refunded bonds were redeemed.

NOTE E—Shared operating expenses:

Operating expenses shared with the Water System were $216,276,000, $197,265,000 and $165,089,000 for the years ended June 30, 1986, 1985 and 1984, of which $141,929,000, $130,126,000 and $114,056,000 were allocated to the Power System.

NOTE F—Employees' retirement plan:

The Department has a funded contributory retirement, disability and death benefit insurance plan covering substantially all of its employees. The Power System was allocated approximately 74% of the plan's total costs for the years ended June 30, 1986, 1985 and 1984 amounting to $90,677,000, $82,983,000 and $86,744,000. These costs include amortization of prior service costs generally over a 30-year period ending June 30, 2003. The Department funds retirement plan costs in accordance with the recommendations of the plan's independent actuary. In 1986, no significant amendments were made to the plan.

The actuarially computed present value of accumulated retirement plan benefits attributable to the Power System aggregated $1,151,000,000 and $1,084,000,000 at June 30, 1986 and 1985, of which $1,147,000,000 and $1,080,000,000 were vested. An assumed rate of return of 8% was used in determining these actuarially computed values. The retirement plan's assets at market value allocated to the Power System were $992,000,000 and $783,000,000 at such dates.

NOTE G—Commitments and contingencies:

Capital program and other—The Department's budget for the year ending June 30, 1987 provides for capital expenditures of approximately $478,000,000 in the Power System. Also, the Department has budgeted payments of $67,913,000 for the year ending June 30, 1987 from the Power System's revenue fund to the reserve fund of the City.

Long-term purchased power and transmission contracts—The Department has entered into a number of energy and capacity contracts which involve substantial commitments. These include an agreement with the Intermountain Power Agency (IPA), a Utah State Agency, and two agreements with the Southern California Public Power Authority (SCPPA), a California Public Authority. Under the IPA agreement, as amended, the Power System has committed to purchase 62.8%, of which 44.6% is a "take or pay" obligation, of the energy gen-

erated by the Intermountain Power Project (IPP), a coal-fueled generating station that became operational July 1, 1986. At June 30, 1986, IPA had issued $5,120,142,000 of Power Supply Revenue Bonds and had made expenditures of approximately $2,592,000,000. Subsequent to June 30, 1986, IPA issued an additional $1,635,000,000 of Special Obligation Crossover Bonds, the proceeds of which will be used to redeem $1,532,000,000 of Power Supply Revenue Refunding Bonds.

Under a power sales agreement with SCPPA, the Power System will purchase 67% of SCPPA's entitlement to the Palo Verde Nuclear Project. At June 30, 1986, SCPPA had issued $1,033,000,000 of Power Project Bond Anticipation Notes and Power Project Revenue Bonds and had made expenditures of approximately $584,873,000.

Under a transmission service contract with SCPPA, the Power System is to purchase 59.5% of the capacity of the Southern Transmission System, a 500kV DC transmission line, which will transmit energy from IPP to Southern California. At June 30, 1986, SCPPA had issued $1,058,000,000 of Transmission Project Bond Anticipation Notes and Transmission Project Revenue Bonds and had made expenditures of approximately $636,706,000.

All these agreements require the Power System to make certain minimum payments whether or not power is produced or it is able to take delivery of the power. Minimum payments are based upon debt service requirements plus production costs and, therefore, cannot presently be determined.

Litigation—A number of claims and suits are pending against the Department for alleged damages to persons and property and for other alleged liabilities arising out of its operations. In the opinion of management, the uninsured liability under these actions would not materially affect the Power System's financial position as of June 30, 1986.

Report of Independent Accountants

To the Board of Water
and Power Commissioners
Department of Water
and Power
City of Los Angeles

We have examined the balance sheet of the Power System of the Department of Water and Power of the City of Los Angeles as of June 30, 1986 and 1985, and the related statements of income, of retained income reinvested in the business and of changes in financial position for each of the three years in the period ended June 30, 1986. Our examinations were made in accordance with generally accepted auditing standards and accordingly included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

As more fully described in Note A to the financial statements, effective June 30, 1984, the Power System of the Department changed its method of accounting for unbilled revenues and the method of recognizing energy costs. Adoption of these new accounting policies, with which we concur, had no effect on net income for 1984.

In our opinion, the financial statements examined by us present fairly the financial position of the Power System of the Department of Water and Power of the City of Los Angeles at June 30, 1986 and 1985, and the results of its operations and the changes in its financial position for each of the three years in the period ended June 30, 1986, in conformity with generally accepted accounting principles consistently applied.

Price Waterhouse
Simpson & Simpson

Los Angeles, California
October 10, 1986

Water Sales

	Residential	Commercial & Industrial	Irrigation	Power System	City Governmental	Other Governmental	All Classes Combined
Revenue from sales of water:							
Year ended June 30-							
1986	$ 84,147,000	$122,917,000	$305,000	$ 783,000	$5,321,000	$6,960,000	$220,433,000
1985	78,960,000	111,082,000	324,000	651,000	5,880,000	6,145,000	203,042,000
Increase (decrease)	5,187,000	11,835,000	(19,000)	132,000	(559,000)	815,000	17,391,000
Percent increase (decrease)	6.57	10.65	(5.86)	20.28	(9.51)	13.26	8.57
Unit of 100 cubic feet sold:							
Year ended June 30-							
1986	102,935,903	150,414,530	783,087	1,001,851	8,789,111	9,178,955	273,103,437
1985	104,339,796	146,600,867	920,556	889,851	10,081,941	9,055,702	271,888,713
Increase (decrease)	(1,403,893)	3,813,663	(137,469)	112,000	(1,292,830)	123,253	1,214,724
Percent increase (decrease)	(1.35)	2.60	(14.93)	12.59	(12.82)	1.36	0.45
Average billing price per 100 cubic feet:							
Year ended June 30-							
1986	0.8175	0.8172	0.3895	0.7816	0.6054	0.7583	0.8071
1985	0.7568	0.7577	0.3520	0.7316	0.5832	0.6786	0.7468
Increase (decrease)	0.0607	0.0595	0.0375	0.0500	0.0222	0.0797	0.0603
Percent increase (decrease)	8.02	7.85	10.65	6.83	3.81	11.74	8.07
Average number of customers (calculated on no. of billings):							
Year ended June 30-							
1986	455,553	169,388	32	366	3,031	1,735	630,105
1985	462,384	162,631	35	404	3,719	1,180	630,353
Increase (decrease)	(6,831)	6,757	(3)	(38)	(688)	555	(248)
Percent increase (decrease)	(1.48)	4.15	(8.57)	(9.41)	(18.50)	47.03	(0.04)
Average annual consumption per customer (in units of 100 cubic feet):							
Year ended June 30-							
1986	226	888	24,471				
1985	226	901	26,302				
Increase (decrease)	0	(13)	(1,831)				
Percent increase (decrease)	0.00	(1.44)	(6.96)				

Power Sales

	Residential	Commercial	Industrial	Public Street and Highway Lighting	Water System	Other Electric Utilities	All Classes Combined
Revenue from sales of electric energy:							
Year ended June 30-							
1986	$379,488,000	$691,897,000	$240,290,000	$22,120,000	$8,050,000	$ 7,734,000	$1,349,579,000
1985	372,959,000	629,013,000	230,187,000	21,595,000	7,524,000	19,354,000	1,280,632,000
Increase (decrease)	6,529,000	62,884,000	10,103,000	525,000	526,000	(11,620,000)	68,947,000
Percent increase (decrease)	1.75	10.00	4.39	2.43	6.99	(60.04)	5.38
Kilowatt hours sold (in thousands):							
Year ended June 30-							
1986	5,499,851	10,279,185	3,818,084	308,167	129,389	215,819	20,250,495
1985	5,545,726	9,754,748	3,818,476	309,679	126,225	337,857	19,892,711
Increase (decrease)	(45,875)	524,437	(392)	(1,512)	3,164	(122,038)	357,784
Percent increase (decrease)	(0.83)	5.38	(0.01)	(0.49)	2.51	(36.12)	1.80
Average billing price per kilowatt hour:							
Year ended June 30-							
1986	0.0690	0.0673	0.0629	0.0718	0.0622	0.0358	0.0666
1985	0.0673	0.0645	0.0603	0.0697	0.0596	0.0573	0.0644
Increase (decrease)	0.0017	0.0028	0.0026	0.0021	0.0026	(0.0215)	0.0022
Percent increase (decrease)	2.53	4.34	4.31	3.01	4.36	(37.52)	3.42
Average number of customers (calculated on no. of billings):							
Year ended June 30-							
1986	1,078,074	157,484	20,233	5,806	369	6	1,261,972
1985	1,069.622	155,176	20,434	5,595	372	7	1,251,206
Increase (decrease)	8,452	2,308	(201)	211	(3)	(1)	10,766
Percent increase (decrease)	0.79	1.49	(0.98)	3.77	(0.81)	(14.29)	0.86
Average annual consumption per customers (in kilowatt hours):							
Year ended June 30-							
1986	5,102	65,271	188,706				
1985	5,185	62,862	186,869				
Increase (decrease)	(83)	2,409	1,837				
Percent increase (decrease)	(1.60)	3.83	0.98				

1 9 8 6 ANNUAL REPORT

ARIZONA PUBLIC SERVICE COMPANY

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APS

About the Company

Arizona Public Service Company (the "Company" or "APS") is engaged principally in the generation and sale of electricity. APS, a successor to a series of small utility operations originating in 1886, was incorporated in 1920 under the laws of Arizona and has operated under its present name since 1952. The Company's electric service reaches approximately 1,508,400 people, or about 45 percent of the state's population, in an area that includes all or part of 11 of Arizona's 15 counties.

All the shares of common stock of the Company are owned by AZP Group, Inc. ("AZP"), which became the Company's corporate parent, effective in April 1985, pursuant to a corporate restructuring. The restructuring did not affect the Company's preferred stock or any of its outstanding debt securities, all of which remain obligations of the Company. As part of the restructuring, the Company sold and transferred to AZP all the capital stock of three of its non-utility subsidiaries: Malapai Resources Company, SunCor Development Company (formerly Energy Development Company), and El Dorado Investment Company. APS Finance Company N.V., Bixco, Inc., and APS Fuels Company remain as wholly-owned subsidiaries of the Company.

Annual Report

This report is published to provide general information concerning the Company and not in connection with any sale, offer for sale, or solicitation of an offer to buy, any securities.

Annual Meeting of Stockholders

All stockholders are invited to attend the Company's sixty-seventh annual meeting. It will be held on Thursday, April 23, 1987 in the Grand Ballroom of the Phoenix Hilton, 111 North Central Avenue, Phoenix, Arizona. AZP will begin its Annual Meeting at 10:00 a.m., and immediately following will be the APS Annual Meeting.

APS Officers

O. Mark De Michele, 53, President and Chief Operating Officer
Walter F. Ekstrom, 49, Vice President, Electric Operations
Karl Eller, 58, Chairman of the Executive Committee
David W. Ellis, 48, Vice President, Marketing and Energy Management
Kathryn A. Forbes, 36, General Auditor
Joseph A. Gelinas, 42, Vice President, Employee Relations
B. Paul Hart, 63, Vice President, Rates and Regulation
Jerry G. Haynes, 52, Vice President, Nuclear Production
Russell D. Hulse, 59, Vice President, Resources Planning
Jerry Human, 56, Vice President, Customer Services, State Region
Charles D. Jarman, 51, Vice President, Construction
Donald B. Karner, 35, Vice President, Engineering
Sally F. Kur, 42, Assistant Secretary
Guy W. Lunt, Jr., 53, Vice President, Customer Services, Metro Region
Jaron B. Norberg, 49, Executive Vice President and Chief Financial Officer
John C. Ogden, 41, Vice President, Customer and Administrative Services
William J. Post, 36, Vice President and Controller
Shirley A. Richard, 40, Vice President, Corporate Relations and Marketing
Keith L. Turley, 63, Chairman and Chief Executive Officer
Edwin E. Van Brunt, Jr., 55, Executive Vice President, Arizona Nuclear Power Project
Faye Widenmann, 38, Secretary
Paul A. Williams II, 41, Vice President and Treasurer

(Age on Annual Meeting date, April 23, 1987)

To Our APS Preferred Shareholders:

Last year, we reported that APS was entering a new era of competition; an era requiring greater innovation, creativity and flexibility to maintain our standing as Arizona's number one utility. We're happy to report that, through 1986, we met that challenge head on.

Throughout our organization, management and employees joined together to find new and better ways of doing business. We even changed our way of thinking — from thinking of ourselves as a regulated utility, to thinking and operating like the dynamic, market-driven company we've become.

This new philosophy has permeated every area of our business. We've formed a new sales team to work with homebuilders in promoting total electric homes, we've expanded our economic development program to maintain and attract new businesses to our service territory, we've enhanced programs designed to help our customers control their electric bills, and we've instilled in employees a deep appreciation for the value of top-quality customer service.

We recognize our long-term success does not depend on short-term priorities and quick fixes. Our success depends on our overall credibility with customers, regulators and shareholders; on our continuing commitment to be a socially responsible community member; and on our overriding mission to provide quality, reasonably priced service.

By continuing to strive for these goals, we feel confident APS will not only meet the challenges of 1987 and beyond, we will emerge as a strong, financially healthy utility. This, in turn, assures that the energy future of Arizona is secure.

Thanks for the support and interest many of you have shown during the past year. We hope you'll take time to review the comprehensive financial information contained in the following pages, as well as the more detailed annual report from our parent company, AZP Group, Inc. That report will be sent to you in the near future.

Sincerely,

Keith L. Turley
Chairman of the Board and
Chief Executive Officer

O. Mark De Michele
President and
Chief Operating Officer

ARIZONA PUBLIC SERVICE COMPANY

SELECTED CONSOLIDATED FINANCIAL DATA

	1986	1985	1984	1983	1982
	(Dollars in Thousands, Except Per Share Amounts)				
Electric Operating Revenues	$ 1,249,912	$ 1,174,502	$ 994,967	$ 871,875	$ 866,486
Electric Operating Expenses:					
Operation and maintenance	541,108	447,985	358,665	349,150	349,975
Depreciation and amortization	139,541	99,221	87,494	83,707	79,676
Taxes*	294,942	320,312	285,548	185,606	173,736
Total	975,591	867,518	731,707	618,463	603,387
Operating Income	274,321	306,984	263,260	253,412	263,099
Other Income*	188,406	190,047	190,818	134,459	83,040
Interest Deductions - Net	188,607	171,608	156,508	118,819	117,838
Income from Continuing Operations	274,120	325,423	297,570	269,052	228,301
Income (Loss) from Discontinued Operations	—	—	(26,503)	(4,255)	2,742
Net Income	274,120	325,423	271,067	264,797	231,043
Preferred Stock Dividend Requirements	39,279	44,412	48,375	43,741	34,816
Earnings for Common Stock	$ 234,841	$ 281,011	$ 222,692	$ 221,056	$ 196,227
Total Assets	$ 5,595,883	$ 5,251,327	$ 4,653,774	$ 4,386,312	$ 3,888,536
Long-term Debt and Redeemable Preferred Stock	$ 2,107,219	$ 2,425,361	$ 1,967,486	$ 1,892,477	$ 1,610,486
Common Stock Data:					
Book value per share	$ 25.76	$ 25.42	$ 24.18	$ 23.78	$ 22.94
Earnings (loss) per average common share outstanding:					
Continuing Operations	$ 3.30	$ 3.96	$ 3.65	$ 3.53	$ 3.25
Discontinued Operations	—	—	(0.39)	(0.07)	0.05
Total	$ 3.30	$ 3.96	$ 3.26	$ 3.46	$ 3.30
Dividends declared per share	$ 2.94	$ 2.73	$ 2.60	$ 2.56	$ 2.40
Common shares outstanding:					
Year-end	71,264,947	71,264,947	70,128,329	66,710,852	62,894,490
Average	71,264,947	71,031,228	68,308,131	63,865,210	59,549,685
Number of common shareholders	1**	1**	124,274	127,387	120,623

* Federal and State income taxes are included in Taxes and in Other Income. Total income tax expense was as follows (thousands of dollars): 1986, $156,820; 1985, $165,279; 1984, $137,072; 1983, $93,930; 1982, $93,100.

** See Note 2 of Notes to Consolidated Financial Statements for a description of the corporate restructuring.

OTHER FINANCIAL AND OPERATING STATISTICS

	1986	1985	1984	1983	1982
		(Dollars in Thousands, Except Per Hour Amounts)			
Capitalization:					
Common equity	$ 1,835,616	$ 1,811,405	$ 1,695,923	$ 1,586,671	$ 1,442,639
Non-redeemable preferred stock	218,561	218,561	218,561	218,561	168,561
Redeemable preferred stock	178,728	219,421	282,740	237,400	241,220
Long-term debt	1,928,491	2,205,940	1,684,746	1,655,077	1,369,266
Total	$ 4,161,396	$ 4,455,327	$ 3,881,970	$ 3,697,709	$ 3,221,686
Utility Plant—gross	$ 5,851,880	$ 5,712,507	$ 5,088,243	$ 4,761,265	$ 4,198,466
Utility Plant—net	$ 4,904,325	$ 4,873,823	$ 4,344,083	$ 4,033,400	$ 3,551,949
Number of employees at year-end	8,966	8,324	7,358	7,642	7,047
Average wage per hour	$ 15.23	$ 14.48	$ 13.61	$ 13.11	$ 12.27
Electric resources (kw)	3,592,100	3,570,800	3,425,900	3,528,400	3,532,900
Peak load (kw)	3,194,600	3,197,800	2,970,600	2,899,000	2,898,700
Electric sales—total (mwh)	13,863,473	13,971,314	13,054,987	12,753,542	12,950,727
Number of customers at year-end	545,018	521,567	499,751	468,768	449,244

OPERATING REVENUES

	1986	1985	1984	1983	1982
			(Thousands of Dollars)		
Electric					
Residential	$ 466,816	$ 438,265	$ 378,536	$ 314,404	$ 294,498
Commercial	441,236	401,439	343,971	296,364	286,262
Industrial	141,729	135,254	126,187	122,184	128,464
Irrigation	21,547	22,853	25,540	15,113	23,391
Other	80,671	97,728	86,394	90,118	92,490
Total	1,151,999	1,095,539	960,628	838,183	825,105
Transmission for others	19,692	16,602	13,023	12,555	11,104
Miscellaneous services	78,221	62,361	21,316	21,137	30,277
Total Operating Revenues	$ 1,249,912	$ 1,174,502	$ 994,967	$ 871,875	$ 866,486

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Liquidity and Capital Resources

The Company has capital requirements for its ongoing construction program (see Note 12 of Notes to Consolidated Financial Statements) and for the refunding of maturing securities. Its reliance on external financing to meet those requirements is detailed in Notes 4, 5 and 6 of Notes to Consolidated Financial Statements. The Company has a degree of flexibility in adjusting its construction program to its financing capability. However that flexibility is limited and the Company's long-term liquidity will depend on its access to the capital markets, which in turn will depend on sufficiency of the Company's rates to provide adequate coverages on its senior securities, and an adequate rate of return on common stock equity. Adequate earnings and coverages are critical to the maintenance of satisfactory credit ratings on the Company's senior securities and, as calculated in accordance with the governing instruments, are prerequisite to the Company's legal ability to issue such securities.

See page 3 with respect to the Company's capitalization at December 31, 1986. The Company regards common stock equity as its most expensive form of permanent financing, but it intends to maintain that category at approximately the 40% level in order to support the credit ratings on its senior securities. If interest and dividend rates on new issues of long-term debt and preferred stock rise in the future, the Company's average cost of capital will rise accordingly.

In August and December, 1986, the Company entered into sale and leaseback transactions under which it sold approximately 42% of its 29.1% undivided ownership interest in Unit 2 ("Unit 2") of the Palo Verde Nuclear Generating Station ("Palo Verde"). The leases are being accounted for as operating leases and, accordingly, are not reflected in the Company's capitalization. See Note 9 of Notes to Consolidated Financial Statements.

See Note 7 of Notes to Consolidated Financial Statements with respect to short-term borrowings available to the Company (there being a statutory limitation on the amount of such borrowings that can be outstanding without consent from the Arizona Corporation Commission ("ACC")). The funds available from operations after the payment of dividends, although less than the amount considered appropriate by management, have increased in the last few years (see Consolidated Statements of Changes in Financial Position). This situation is expected to continue to improve as the Company's construction expenditures decline, assuming that the costs of Palo Verde Units 2 and 3 are recovered through revenues. In addition, the Company's retention of funds from operations has been affected by its policy of increasing common stock dividends periodically.

On October 9, 1986, the ACC issued an order (the "Order") in the "Phase II" hearings of the rate case in which the Company requested an increase in annual retail rates premised upon Palo Verde Unit 1 ("Unit 1") being fully included in the Company's rate base. The Order granted the Company a $1,600,000 retail rate increase, effective November 1, 1986, and provided that those revenues attributable to the inclusion of $210,000,000 of the capital costs of Unit 1 (representing approximately 25% of total Unit 1 costs) are to be deemed "interim or temporary in nature until further Order of the Commission." As a result, the Company estimates that up to $40,000,000 per year of revenues attributable to Unit 1 costs included in the Company's rate base may be deemed "interim or temporary" pending the outcome of the prudence audit of Palo Verde (See Note 3 of Notes to Consolidated Financial Statements).

The Order also stated that, for ACC purposes, Unit 1 attained commercial operation on January 1, 1986, rather than on February 13, 1986, as previously reported by the Company. The Company began expensing the ACC portion of the cost of owning, operating and maintaining its 29.1% share of Unit 1 on that date.

In addition, the Order granted the Company's request that, for rate-making and accounting purposes, the facilities common to all three Palo Verde units (the "Common Facilities") be treated as being transferred to plant-in-service in three equal installments, each tied to the commercial operation date of a Palo Verde unit. Consequently, the Company ceases to accrue a carrying charge on, and begins expensing the cost of owning, operating, and maintaining the ACC portion of its share of the Common Facilities in one-third increments.

The Company considers Unit 2 to have commenced commercial operation on September 19, 1986, although the ACC will definitively establish the Unit 2 commercial operation date in the rate case pending before the ACC in which the Company has requested an increase in annual retail rates premised upon Unit 2 being fully included in the Company's rate base. On December 5, 1986, the ACC issued an accounting and rate-making order allowing the Company to defer substantially all costs relating to, and accrue a carrying charge equivalent to an allowance for funds used during construction ("AFC") on, its share of Unit 2 and one-third of the Common Facilities for the period of time between the commercial operation date of Unit 2 and the effective date of new rates to cover the costs of Unit 2. If the ACC does not grant adequate rate relief with respect to Unit 2, the Company expects its future earnings to be adversely affected.

Palo Verde Unit 3 ("Unit 3") is currently scheduled to commence commercial operation during the third quarter of 1987. The Company is currently evaluating various rate-making and accounting alternatives with respect to Unit 3. At a minimum, the Company will request an accounting and rate-making order for Unit 3, similar to that granted relative to Unit 2, which would allow the Company to defer substantially all costs until the effective date of new rates to cover Unit 3. Failure to grant such accounting and rate-making order or rate relief for Unit 3 would adversely affect the Company's net income approximately $10,000,000 per month from the date that Unit 3 commences commercial operation.

Operating Results

The largest single factor in the decline in net income for 1986 compared to 1985 was the Palo Verde Unit 1 rate case.

Total operating revenues reflect the effects of rate increases and adjustment clauses on prices of units sold. Operating revenues also reflect volume changes in unit sales. The foregoing factors contributed to annual increases in electric operating revenues over the preceding calendar year as follows:

	Year Ended December 31,		
	1986	1985	1984
	(Thousands of Dollars)		
Energy related:			
Volume increases (1)	$ 3,742	$ 71,169	$ 29,216
Price increases (2)	52,718	63,742	93,229
Non-energy related:			
Revenue increases (3)	18,950	44,624	647
Total increase	$75,410	$179,535	$123,092

(1) Calculated by summing the products derived by multiplying the year-to-year increases in units sold in each customer class by the weighted average of the applicable rate levels in effect for the prior year.

(2) Calculated by summing the products derived by multiplying the year-to-year increases in the weighted average of rate levels in each customer class times the applicable number of units sold in the current year. Relative contributions by rate increases and by effects of the Company's fuel adjustment clauses vary according to the timing of general rate proceedings and the extent to which accumulated effects of the adjustment clauses are incorporated in new rates.

(3) Includes revenues for miscellaneous services and transmission for others.

The volume-related increase in electric revenues in 1986 was primarily due to higher sales in the residential and commercial customer classes, partially offset by lower sales to resale customers. The sales increases in the residential and commercial classes were primarily due to customer growth. In 1985, the increase in volume-related electric revenues was also primarily due to higher sales in the residential and commercial classes, reflecting customer growth and warm weather conditions during the summer of 1985. Volume-related electric revenue increased in 1984 primarily due to customer growth in the residential and commercial classes and humid weather conditions, partially offset by decreased industrial and resale sales. Conservation efforts by customers in response to higher energy costs have affected unit sales, are expected to continue to do so, and are being aided by the Company's own load-management programs. The year-to-year changes in non-energy related electric revenues reflect changes in the capacity sold to other utilities.

Unit fuel costs decreased in 1986 due to lower unit fuel costs associated with the commercial operation of Units 1 and 2 and due to lower gas fuel prices. In 1986, fuel expenses decreased due to the availability of nuclear generation which displaced higher cost gas and coal generation. In 1985, increases in fuel expenses were primarily due to increased gas generation.

Variations in purchased power and interchange reflect varying degrees of availability of relatively low-priced power from other sources including energy available from testing of the Company's nuclear generating units, the needs of the Company to augment its own generating sources from time to time, and the Company's ability to sell energy to neighboring utilities. In 1986, the increase in purchased power and interchange was primarily due to the operation of the

Company's Purchased Power and Fuel Adjustment Mechanism ("PPFAM") (See Note 1d of Notes to Consolidated Financial Statements), partially offset by reduced purchased power due to the availability of energy from Units 1 and 2, the availability of low cost interchange and reduced system energy requirements. A portion of the increase associated with the PPFAM is due to the disallowance of certain under-collected fuel and purchased power costs ordered by the ACC (See Note 3 of Notes to Consolidated Financial Statements). In 1985, increases in purchased power and interchange-net were due to increased purchases and reduced interchange sales to other utilities, which were partially offset by the operation of the Company's PPFAM.

See "Effects of Inflation" below in regard to maintenance expense, which is also a function of the size of the Company's utility plant and is affected by the timing of major overhauls. The increase in operations excluding fuel expense in 1986 was due primarily to increased expenses resulting from the start of commercial operation of Units 1 and 2.

Depreciation and amortization expenses and ad valorem taxes increase with the size of the Company's utility plant. See Note 13 of Notes to Consolidated Financial Statements for both ad valorem and sales taxes (the latter being a function of operating revenues), which are the principal components of other taxes.

The Tax Reform Act of 1986 significantly overhauled the nation's tax system. The major impact of this law on the Company will result from longer depreciation lives, loss of investment tax credits, capitalization of construction related expenses and a lower corporate tax rate. The Company might also be subjected in the future to the new alternative minimum tax. These changes will result in a reduction of internal cash flow provided by deferred taxes. Additionally, the lower tax rate has been reflected in the Company's Unit 2 rate request. Although these changes will reduce cash flow, the new tax law is expected to have little impact on earnings.

The aggregate amount of AFC, shown as other income and a credit to interest deductions, is primarily a function of the amount of construction work in progress during any given period and ceases to accrue on those portions of construction work in progress that are placed in service. See Note 1e of Notes to Consolidated Financial Statements for changes in AFC rates.

The increase in interest on long-term debt in recent years reflects new borrowings partially offset in 1986 by the effect of refinancing high coupon debt at lower rates. See "Liquidity and Capital Resources" above and Note 6 of Notes to Consolidated Financial Statements. The decreased level of interest on short-term borrowings in 1985 and 1986 as compared to 1984 resulted primarily from lower interest rates, but includes the effects of decreased borrowings.

Consolidated net income represents a composite of cash and non-cash items (see Consolidated Statements of Changes in Financial Position) and, in part, reflects accounting practices unique to regulated public utilities.

Effects of Inflation

In contrast to the analysis of increases in operating revenues in the table at the beginning of "Operating Results," it is sometimes difficult, in the case of operation and maintenance expenses, to distinguish between effects of volume increases and rises in unit costs (which, for purposes of this discussion, are all attributed to inflationary pressures).

Certain inflationary effects, such as those on costs of generating fuel, are passed through to customers pursuant to rate adjustment procedures. Nevertheless, the Company attempts to minimize such effects by means that include increasing the availability of its nuclear and coal-fired units to result in a more economical fuel mix. This increase has been achieved by an intensive maintenance program, the cost of which is not covered by the adjustment clauses. There are a number of other major expense items that are also beyond the scope of the adjustment clauses. Inflationary pressures on these items have given rise to a significant earnings attrition between general rate increases.

ARIZONA PUBLIC SERVICE COMPANY

CONSOLIDATED BALANCE SHEETS

ASSETS

	December 31, 1986	December 31, 1985
	(Thousands of Dollars)	
Utility Plant (Notes 6, 8 and 9):		
Electric plant in service and held for future use	$4,807,226	$2,970,368
Less accumulated depreciation and amortization	947,555	838,684
Total	3,859,671	2,131,684
Construction work in progress	979,733	2,742,139
Nuclear fuel, net of amortization of $28,555,000	64,921	—
Utility Plant—net	4,904,325	4,873,823
Investments and Other Assets:		
Investments in and receivables from affiliates	16,513	16,513
Other investments and notes receivable (Note 14)	24,179	5,991
Total Investments and Other Assets	40,692	22,504
Current Assets:		
Cash	6,770	7,871
Special deposits and working funds (Note 6)	167,212	3,342
Accounts receivable:		
Service customers	76,555	84,533
Other	35,143	43,415
Allowance for doubtful accounts	(2,060)	(1,395)
Materials and supplies (at average cost)	65,283	41,525
Fossil fuel (at average cost)	30,006	30,433
Deferred fuel (Note 3)	23,994	74,335
Other	8,060	3,873
Total Current Assets	410,963	287,932
Deferred Debits:		
Deferred income taxes	94,246	13,573
Palo Verde cost deferral (Note 3)	63,694	—
Unamortized costs of reacquired debt	31,002	2,887
Unamortized debt issue costs	17,563	16,705
Other	33,398	33,903
Total Deferred Debits	239,903	67,068
Total	$5,595,883	$5,251,327

See Notes to Consolidated Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY

CONSOLIDATED BALANCE SHEETS

LIABILITIES

	December 31, 1986	December 31, 1985
	(Thousands of Dollars)	
Capitalization (Notes 2, 4, 5 and 6):		
Common stock	$ 178,162	$ 178,162
Premiums and expenses—net	1,040,084	1,040,909
Retained earnings	617,370	592,334
Common stock equity	1,835,616	1,811,405
Non-redeemable preferred stock	218,561	218,561
Redeemable preferred stock	178,728	219,421
Long-term debt less current maturities	1,928,491	2,205,940
Total Capitalization	4,161,396	4,455,327
Current Liabilities:		
Commercial paper	37,000	18,000
Current maturities of long-term debt (Note 6)	312,554	17,456
Accounts payable	70,313	87,113
Accrued taxes	91,792	52,976
Accrued interest	52,498	72,678
Other	48,331	29,635
Total Current Liabilities	612,488	277,858
Deferred Credits and Other:		
Deferred income taxes	373,646	230,553
Deferred investment tax credit	203,066	174,503
Unamortized gain—sale of utility plant (Note 9)	141,786	—
Unamortized credit related to sale of tax benefits (Note 10)	41,958	43,645
Customers' advances for construction	23,852	23,991
Other	37,691	45,450
Total Deferred Credits and Other	821,999	518,142
Commitments and Contingencies (Notes 3 and 12)		
Total	$5,595,883	$5,251,327

ARIZONA PUBLIC SERVICE COMPANY

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	1986	1985	1984
	(Dollars in Thousands, Except Per Share Amounts)		
Electric Operating Revenues	$ 1,249,912	$ 1,174,502	$ 994,967
Fuel Expenses:			
Fuel for electric generation	178,814	219,575	186,276
Purchased power and interchange - net	107,066	16,789	6,647
Total	285,880	236,364	192,923
Operating Revenues Less Fuel Expenses	964,032	938,138	802,044
Other Operating Expenses:			
Operations excluding fuel expenses	157,196	122,751	97,535
Maintenance	98,032	88,870	68,207
Depreciation and amortization	139,541	99,221	87,494
Income taxes (Note 10)	171,349	216,036	191,100
Other taxes (Note 13)	123,593	104,276	94,448
Total	689,711	631,154	538,784
Operating Income	274,321	306,984	263,260
Other Income (Deductions):			
Allowance for equity funds used during construction.	93,734	143,612	134,359
Palo Verde cost deferral (Note 3)	63,788	—	—
Income taxes (Note 10)	14,529	50,757	54,028
Other - net	16,355	(4,322)	2,431
Total	188,406	190,047	190,818
Income Before Interest Deductions	462,727	497,031	454,078
Interest Deductions:			
Interest on long-term debt	214,029	209,220	191,079
Interest on short-term borrowings	6,973	6,951	12,281
Debt discount, premium and expense	5,851	3,613	2,465
Allowance for borrowed funds used during construction	(38,246)	(48,176)	(49,317)
Total	188,607	171,608	156,508
Income From Continuing Operations	274,120	325,423	297,570
Loss From Disposal and Operation of Discontinued Gas System, Net of Tax (Note 14)	—	—	(26,503)
Net Income	274,120	325,423	271,067
Preferred Stock Dividend Requirements	39,279	44,412	48,375
Earnings for Common Stock	$ 234,841	$ 281,011	$ 222,692
Average Common Shares Outstanding	71,264,947	71,031,228	68,308,131
Earnings (Loss) per Average Share of Common Stock Outstanding:			
Continuing operations	$ 3.30	$ 3.96	$ 3.65
Discontinued operations	—	—	(0.39)
Total	$ 3.30	$ 3.96	$ 3.26
Dividends Declared per Share of Common Stock	$ 2.94	$ 2.73	$ 2.60

See Notes to Consolidated Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

	Year Ended December 31,		
	1986	1985	1984
	(Thousands of Dollars)		
Retained earnings at beginning of year	$592,334	$505,414	$459,962
Add—Net income	274,120	325,423	271,067
Total	866,454	830,837	731,029
Deduct—Dividends:			
Common stock (Notes 4, 5 and 6)	209,805	194,091	177,240
Preferred stock (see below)	39,279	44,412	48,375
Total	249,084	238,503	225,615
Retained earnings at end of year	$617,370	$592,334	$505,414
Dividends on preferred stock:			
$1.10 preferred	$ 172	$ 172	$ 172
$2.50 preferred	258	258	258
$2.36 preferred	94	94	94
$4.35 preferred	326	326	326
Serial preferred:			
$2.40 Series A	576	576	576
$2.625 Series C	630	630	630
$2.275 Series D	455	455	455
$3.25 Series E	1,040	1,040	1,040
$8.50 Series G	—	96	401
$10.00 Series H	994	1,459	3,147
$10.70 Series I	942	2,300	2,595
$8.32 Series J	4,160	4,160	4,160
$8.80 Series K	3,033	3,407	5,280
$9.70 Series L	3,880	4,656	4,656
$11.95 Series M	426	1,235	2,330
$12.90 Series N	4,773	4,773	4,773
$3.58 Series O	7,160	7,160	7,160
Adjustable Rate Series P	1,250	1,250	1,250
Adjustable Rate Series Q	3,360	4,615	5,223
$11.50 Series R	5,750	5,750	3,849
Total	$ 39,279	$ 44,412	$ 48,375

See Consolidated Statements of Income for dividends per share of common stock.

See Notes to Consolidated Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY

CONSOLIDATED STATEMENTS OF CHANGES IN FINANCIAL POSITION

	Year Ended December 31,		
	1986	1985	1984
	(Thousands of Dollars)		
Source of Funds:			
Funds from operations:			
Continuing operations:			
Income from continuing operations	$ 274,120	$ 325,423	$297,570
Principal non-fund charges (credits) to income:			
Depreciation and amortization	139,541	99,221	87,494
Nuclear fuel amortization	21,762	—	—
Allowance for equity funds used during construction	(93,734)	(143,612)	(134,359)
Deferred income taxes—net	62,420	106,158	43,464
Deferred investment tax credit—net	28,563	36,383	56,002
Palo Verde cost deferral	(63,788)	—	—
Other	(11,499)	31,361	(385)
Total funds from continuing operations	357,385	454,934	349,786
Funds from discontinued gas system-net	—	—	(3,093)
Total funds from operations	357,385	454,934	346,693
Funds from external sources:			
Funds from sale/leaseback of Palo Verde Unit 2	487,296	—	—
Proceeds from sale of gas system	—	—	114,657
Common stock	—	28,562	63,800
Preferred stock	—	—	50,000
Long-term debt	521,738	745,030	264,179
Short-term borrowings—net	19,000	(141,800)	73,492
Other items—net	21,416	(160)	(3,916)
Total funds from external sources	1,049,450	631,632	562,212
Total source of funds	$1,406,835	$1,086,566	$908,905
Application of Funds:			
Funds used for capital expenditures:			
Continuing operations	$ 459,257	$ 494,105	$377,278
Discontinued operations	—	—	31,657
Investments and other assets	18,188	(44,777)	(13,299)
Repayment and reacquisition of long-term debt	537,114	275,421	275,833
Redemption of redeemable preferred stock	40,693	63,319	4,660
Dividends on preferred and common stock	249,084	238,503	225,615
Increase in working capital*	102,499	59,995	7,161
Total application of funds	$1,406,835	$1,086,566	$908,905
Increase (Decrease) in Working Capital*:			
Cash, special deposits and working funds	$ 162,769	$ 309	$ (25,704)
Accounts receivable	(16,915)	22,098	(2,216)
Materials, supplies and fossil fuel	23,331	(1,147)	(1,420)
Deferred fuel and other assets	(46,154)	71,245	(4,191)
Accounts payable and accrued liabilities	(1,377)	(38,846)	32,881
Other liabilities	(19,155)	6,336	7,811
Net increase	$ 102,499	$ 59,995	$ 7,161

*Excluding short-term borrowings—net and current maturities of long-term debt.

See Notes to Consolidated Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies.

a. System of accounts—The accounting records of Arizona Public Service Company (the "Company") are maintained in accordance with the uniform system of accounts prescribed by the Federal Energy Regulatory Commission ("FERC").

b. Consolidation—The consolidated financial statements include the accounts of the Company and those of its wholly-owned subsidiaries, APS Finance Company N.V. ("Finance"), organized to serve as a financing corporation to raise funds outside the United States, and APS Fuels Company, organized to manage investments in certain fuel resources. All significant intercompany balances and transactions have been eliminated.

c. Plant and depreciation—Property is stated at original cost as defined for regulatory purposes. The cost of additions to utility plant and replacements of retirement units is capitalized. Replacements of minor items of property are charged to expense as incurred. In addition to direct costs, capitalized items include the present value of certain future lease payments (see Note 6), research and development expenditures pertaining to construction projects, indirect charges for engineering, supervision, transportation and similar costs, and an allowance for funds used during construction. Costs of depreciable units of plant retired are eliminated from plant accounts and such costs plus removal expenses less salvage are charged to accumulated depreciation. Contributions in aid of construction are credited to plant cost.

Depreciation on utility property is provided on a straight-line basis at rates authorized by the Arizona Corporation Commission ("ACC") annually. The applicable rates for 1984 through 1986 ranged from 0.68% to 9.86% for Electric Plant.

d. Revenues and fuel costs—Operating revenues are recognized when billed on a monthly cycle billing basis. Retail rate schedules include adjustment clauses which permit recovery of costs of certain fuel and purchased power. Regulatory hearings are held periodically to adjust the rates applicable under fuel adjustment clauses to more nearly match actual fuel costs. Temporary net under or over-recoveries of costs resulting from application of the adjustment clauses are recognized as a deferred fuel asset or liability, respectively, with an offsetting amount recognized in purchased power and interchange expense.

e. Allowance for funds used during construction—In accordance with the regulatory accounting practice prescribed by the FERC and the ACC, the Company capitalizes an allowance for the cost of funds used to finance its construction program ("AFC"). AFC, which does not represent current cash earnings, is defined as the net cost during the period of construction of borrowed funds and a reasonable rate of return on equity funds so used. The calculated amount is capitalized as a part of the cost of utility plant.

AFC has been calculated using composite rates of 12.75% from January 1984 through October 1986 and 11.25% thereafter. The Company compounds AFC semi-annually and records the borrowed funds portion on a "net of tax" basis through charges to income taxes—operating expense and credits to income taxes—other income. AFC ceases to accrue on those portions of construction work in progress placed in service.

f. Income taxes—The Company uses accelerated depreciation methods for income tax purposes. As prescribed by the ACC, deferred income taxes are provided for certain timing differences arising from the recording, for income tax and financial reporting purposes, of depreciation of property placed in service after January 1, 1977. In accordance with an ACC order, the Company defers amounts equal to the change in income taxes arising from substantially all other timing differences, which prior to October 1983 were reflected currently in

income. At December 31, 1986 the Company had flowed through to income currently approximately $260,000,000 of income tax benefits arising from income tax timing differences for which deferred taxes have not been provided.

In compliance with an ACC order, the Company defers amounts equal to the reduction in Federal income taxes arising from investment tax credits and amortizes these amounts to other income over the estimated life of the related assets.

g. Research and development costs—The Company expenses research and development costs on a current basis, except that costs which may result in additions to utility plant are deferred for subsequent inclusion in plant or to be written off if the applicable project is abandoned.

h. Reacquired debt costs—In accordance with the regulatory accounting practices prescribed by the ACC, the Company defers the excess of the reaquisition price of reacquired debt over the net carrying amount and amortizes these amounts to expense over the remainder of the original life of the issues reacquired.

i. Nuclear fuel and decommissioning costs—Pursuant to the Nuclear Waste Policy Act of 1982 ("Act"), contracts have been entered into with the U.S. Department of Energy for disposal of spent nuclear fuel. The Act provides for an assessment of one mil per kilowatt-hour of nuclear generation. This amount is charged to nuclear fuel expense and recovered through the Company's fuel adjustment clauses.

The Company has made no provision for decommissioning costs for the Palo Verde Nuclear Generating Station ("Palo Verde") pending ACC action in its current rate case filing. Total decommissioning costs for all three Palo Verde units are currently estimated at approximately $615,000,000 (in 1986 dollars) of which the Company's share (29.1%) is approximately $179,000,000.

2. Corporate Restructuring.

On April 18, 1985, the Company's shareholders approved a plan for corporate restructuring to provide financial and organizational flexibility by separating regulated utility operations from other activities. Effective April 29, 1985, APS became a subsidiary of a holding company, AZP Group, Inc. ("AZP").

As part of the restructuring, the Company sold to AZP, at book value of $34,703,000, the common stock of three of its wholly-owned subsidiaries, Malapai Resources Company, SunCor Development Company (formerly Energy Development Company) and El Dorado Investment Company. Prior to the sale, the results of operations and net assets of these subsidiaries were included in Other income — net and Investments in and receivables from affiliates.

The corporate restructuring had no effect on the ownership of preferred stock or on debt securities.

3. ACC Matters.

On September 4, 1986, the ACC issued an order establishing a new format for a prudence audit of Palo Verde construction costs. Previously, the prudence audit was controlled by the four state utility regulatory commissions having jurisdiction over the regulated participants in Palo Verde. The prudence audit will hereafter be controlled by the ACC, paid for by the Company, and limited in scope to the Company. Ernst & Whinney, a national accounting firm, will oversee the prudence audit, which is expected to be completed in 1988. The order provides that the Company may submit for review up to ten areas in which it believes its performance in the construction of Palo Verde exceeds the prudence audit standard of "reasonableness". Costs ultimately deemed by the ACC to have been imprudently incurred will be recognized as a loss by

the Company at such time as it becomes probable that the costs will be disallowed for rate-making purposes. Although the Company is unable to predict the ultimate outcome of this matter, management believes that overall Palo Verde was constructed in a prudent manner.

On July 24, 1986, the ACC issued an order disallowing recovery of approximately $24.4 million of under-collected fuel and purchased power costs which had been deferred as of December 31, 1985. As a result the disallowed costs were charged to fuel expenses.

As an incentive to complete construction and commence operation of Palo Verde, the ACC in a November 1984 order, placed a $2.86 billion cap on total construction costs. Amounts expended in excess of the cap are presumed to be imprudent under the ACC's order. The most recent estimate of the Company's share of Palo Verde construction costs is $2.76 billion.

On October 9, 1986, the ACC issued an order (the "Phase II Order") providing that revenues attributable to the inclusion of $210,000,000 of the capital costs of Palo Verde Unit 1 ("Unit 1") (approximately 25% of total Unit 1 costs) are to be deemed "interim and temporary in nature until further Order of the Commission." The Company estimates that up to $40,000,000 per year of revenues attributable to Unit 1 costs included in rate base may be deemed "interim or temporary" pending the outcome of the prudence audit. The Phase II Order also permitted deferral of depreciation, ad valorem taxes and a return on that portion of common facilities associated with Palo Verde Units 2 and 3 from January 1, 1986 until the commercial operation dates of each unit.

On December 5, 1986, the ACC issued an accounting and rate-making order (the "Phase III Order") allowing deferral of substantially all retail costs associated with Palo Verde Unit 2 ("Unit 2"), including its portion of common facilities, for the period of time between Unit 2 going into commercial operation and new rates going into effect to cover these costs. As an incentive to control expenses related to Unit 2, the Phase III Order placed a deferral cap of $25,213,000 annually on operation and maintenance expenses. The Company considers the commercial operation date to be September 19, 1986. On December 19, 1986, the Company updated a request to recover its share of the costs of commercial operation of Unit 2. The Company proposed that the costs of owning and operating Unit 2 be phased in over the next three years. The hearing date for the Unit 2 case has been set for March 19, 1987.

ARIZONA PUBLIC SERVICE COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

4. Common and Non-Redeemable Preferred Stock.

The balances at December 31, 1986 and 1985 of common stock and of preferred stock, which is not redeemable except pursuant to call by the Company at its option, are as follows.

	Number of Shares			Par Value			Call
		Outstanding at December 31,			Outstanding at December 31,		Price Per
	Authorized	1986	1985	Per Share	1986	1985	Share(a)
					(Thousands of Dollars)		
Common Stock	100,000,000	71,264,947(b)	71,264,947(b)	$ 2.50	$178,162	$178,162	—
Non-Redeemable Preferred Stock (cumulative):							
$1.10 preferred	160,000	155,945	155,945	$ 25.00	$ 3,898	$ 3,898	$ 27.50
$2.50 preferred	105,000	103,254	103,254	50.00	5,163	5,163	51.00
$2.36 preferred	120,000	40,000	40,000	50.00	2,000	2,000	51.00
$4.35 preferred	150,000	75,000	75,000	100.00	7,500	7,500	102.00
Serial preferred	1,000,000						
$2.40 Series A		240,000	240,000	50.00	12,000	12,000	50.50
$2.625 Series C		240,000	240,000	50.00	12,000	12,000	51.00
$2.275 Series D		200,000	200,000	50.00	10,000	10,000	50.50
$3.25 Series E		320,000	320,000	50.00	16,000	16,000	51.00
Serial preferred	4,000,000(c)						
$8.32 Series J		500,000	500,000	100.00	50,000	50,000	(d)
Adjustable rate Series Q		500,000	500,000	100.00	50,000	50,000	(e)
Serial preferred	10,000,000						
$3.58 Series O		2,000,000	2,000,000	25.00	50,000	50,000	(f)
Total		4,374,199	4,374,199		$218,561	$218,561	

(a) In each case plus accrued dividends.

(b) As a result of the corporate restructuring described in Note 2, these shares are now held by AZP.

(c) This authorization also covers outstanding redeemable preferred shares shown in Note 5, as well as the non-redeemable shares indicated above.

(d) At $105.50 through August 31, 1987; at $103.00 through August 31, 1992; and at $101.00 thereafter.

(e) Bears dividends at a rate, adjusted on a quarterly basis, 2% below the rate borne by certain United States Treasury Securities, but in no event less than 6% per annum, or greater than 12% per annum. Redeemable on or after March 1, 1988 at the option of the Company at $103.00 through February 28, 1993; and at $100.00 thereafter.

(f) Not redeemable prior to June 1, 1987 through certain refunding operations that would result in a lower cost to the Company than the dividend rate on the shares to be redeemed; otherwise at $28.58 through May 31, 1987; at $27.39 through May 31, 1992; at $26.19 through May 31, 1997; and at $25.00 thereafter.

The holders of preferred stock are entitled to one vote for each share held of record. Special requirements for favorable votes of holders of preferred stock, voting by the classes respectively prescribed for the several purposes, pertain to (i) certain conversions or exchanges of outstanding preferred stock, (ii) the authorization of any stock ranking prior to the preferred stock, (iii) making any change in the terms and provisions of preferred stock that would adversely affect the rights and preferences of the holders thereof, (iv) the issuance of any additional shares of preferred stock except under prescribed circumstances or (v) a merger, consolidation or sale of substantially all the assets of the Company. The foregoing voting rights attach to both redeemable and non-redeemable preferred stock, as do the rights that would arise out of dividend arrearages as discussed in Note 5.

Common and non-redeemable preferred stock sales and changes in premiums and expenses during each of the three years in the period ended December 31, 1986 are as follows (dollars in thousands):

	Common Stock		Non-Redeemable Preferred Stock (cumulative)		Premiums and
Description	Number of Shares	Par Value Amount	Number of Shares	Par Value Amount	Expenses Net*
Balance, December 31, 1983	66,710,852	$166,777	4,374,199	$218,561	$ 959,932
Common Stock	3,417,477	8,544	—	—	55,256
Balance, December 31, 1984	70,128,329	175,321	4,374,199	218,561	1,015,188
Common Stock	1,136,618	2,841	—	—	25,721
Balance, December 31, 1985	71,264,947	178,162	4,374,199	218,561	1,040,909
Premiums and Expenses - Net	—	—	—	—	(825)
Balance, December 31, 1986	71,264,947	$178,162	4,374,199	$218,561	$1,040,084

*Premiums and expenses — net also includes those of redeemable preferred stock issues (see Note 5).

5. Redeemable Preferred Stock.

The balances at December 31, 1986 and 1985 of preferred stock which is redeemable at the option of the holders or pursuant to sinking fund obligations, in addition to being callable by the Company, are as follows.

	Number of Shares Outstanding at December 31,			Par Value Outstanding at December 31,		
	1986	1985	Per Share	1986	1985	Call Price Per Share(a)
				(Thousands of Dollars)		
Redeemable Preferred Stock (cumulative) serial preferred: (b)						
$10.00 Series H	88,677	104,677	$100.00	$ 8,868	$ 10,468	(c)
$10.70 Series I	—	209,934	100.00	—	20,993	
$8.80 Series K	344,600	344,600	100.00	34,460	34,460	(d)
$9.70 Series L	384,000	480,000	100.00	38,400	48,000	(e)
$11.95 Series M	—	85,000	100.00	—	8,500	
$12.90 Series N	370,000	370,000	100.00	37,000	37,000	(f)
Adjustable Rate Series P	100,000	100,000	100.00	10,000	10,000	(g)
$11.50 Series R	500,000	500,000	100.00	50,000	50,000	(h)
Total	1,787,277	2,194,211		$178,728	$219,421	

(a) In each case plus accrued dividends.

(b) See Note 4 for authorized number of shares.

(c) Redeemable at $105.76 through September 1, 1987, and thereafter declining by $0.36 per year to par after September 1, 2002. Applicable sinking fund provisions require the redemption of 16,000 shares at par annually (representing annual payments of $1,600,000).

(d) Redeemable at $106.00 through February 28, 1989; at $103.00 through February 28, 1994; and thereafter declining in steps to $101.00. Applicable sinking fund provisions require the redemption of 22,500 shares at par annually (representing annual payments of $2,250,000). The Company may, but is not required to, redeem an additional 22,500 shares at par on March 1 in any year. At December 31, 1985, the Company had met the 1986 sinking fund requirement.

(e) Redeemable at the option of the Company at $103.23 through February 28, 1987, declining by $1.08 per year to $101.07 after March 1, 1988. Applicable sinking fund provisions require the redemption of 96,000 shares at par annually (representing annual payments of $9,600,000).

(f) Redeemable after June 1, 1992 at the option of the Company at $106.11 through June 1, 1993, declining by $0.68 per year to $100.00 after June 1, 2001. Applicable sinking fund provisions require the redemption between 1988 and 2002 of all shares according to a predetermined schedule.

(g) Bears a dividend of $12.50 per share through December 1, 1987 and a dividend thereafter to be fixed by a formula related to the average prime interest rate in 1987. Redeemable at par on or after December 1, 1987 at the option of the Company. Applicable sinking fund provisions require the redemption of 20,000 shares at par each December 1 beginning in 1988 (representing annual payments of $2,000,000). All shares then outstanding are required to be redeemed on December 1, 1992.

(h) Redeemable after June 1, 1994 at the option of the Company at $105.45, declining each year by a predetermined amount to $100.00 after June 1, 2004. Applicable sinking fund provisions require the redemption between 1990 and 2004 of all shares according to a predetermined schedule.

If there were to be any arrearage in dividends on any of its preferred stock or in the sinking fund requirements applicable to any of its redeemable preferred stock (each such dividend being cumulative and of equal ranking with other such dividends, and each such requirement being cumulative and of equal ranking with other such requirements), the Company could not pay dividends on its common stock or acquire any shares thereof for consideration. If any such dividend arrearage was to equal six or more quarterly dividends, the holders of preferred stock, in addition to their other voting rights and voting by the classes prescribed for this purpose, could elect a total of six directors (all series of serial preferred stock, regardless of par value and whether redeemable or non-redeemable, comprising one such class and being entitled to elect two of the six directors). See Note 4 in regard to other voting rights of holders of preferred stock.

The combined aggregate amount of redemption requirements for the above issues each year through 1991 are as follows: $13,450,000 in 1987; $18,040,000 in 1988; $18,040,000 in 1989; $21,472,000 in 1990; and $11,873,000 in 1991.

Redeemable preferred stock transactions during each of the three years in the period ended December 31, 1986 are as follows (dollars in thousands):

Description	Number of Shares	Par Value Amount
Balance, December 31, 1983	2,374,000	$237,400
$11.50 Series R	500,000	50,000
Retirements:		
$8.50 Series G	(15,600)	(1,560)
$10.00 Series H	(16,000)	(1,600)
$10.70 Series I	(15,000)	(1,500)
Balance, December 31, 1984	2,827,400	282,740
Retirements:		
$8.50 Series G	(38,400)	(3,840)
$10.00 Series H	(199,323)	(19,932)
$10.70 Series I	(30,066)	(3,007)
$8.80 Series K	(255,400)	(25,540)
$11.95 Series M	(110,000)	(11,000)
Balance, December 31, 1985	2,194,211	219,421
Retirements:		
$10.00 Series H	(16,000)	(1,600)
$10.70 Series I	(209,934)	(20,993)
$9.70 Series L	(96,000)	(9,600)
$11.95 Series M	(85,000)	(8,500)
Balance, December 31, 1986	1,787,277	$178,728

ARIZONA PUBLIC SERVICE COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

6. Long-Term Debt.

Details of long-term debt outstanding at December 31, 1986 and 1985 are as follows:

	December 31, 1986	December 31, 1985
	(Thousands of Dollars)	
First Mortgage Bonds:		
Maturing through 1990:		
5.125% due October 1, 1987	$ 15,000	$ 15,000
4.7% due March 1, 1989	20,000	20,000
Maturing 1991 through 1995 - 4.40% to 12%	225,000	325,000
Maturing 1996 through 2000 - 6.25% to 12.875%	467,311	269,977
Maturing 2001 through 2005 - 6.20% to 9.95%	185,000	185,000
Maturing 2006 through 2010 - 6% to 13.25%	127,000	202,000
Maturing 2011 through 2016 - 11% to 11.5%	350,000	450,000
Unamortized discount and premium	(1,487)	(2,413)
Total first mortgage bonds	1,387,824	1,464,564
Pollution Control Indebtedness:		
Maturing August 2, 2009 (a)	106,980	106,980
Less securities held by trustee (b)	—	(1,572)
Maturing December 1, 2009 (c)	147,000	147,000
Less securities held by trustee (b)	(10,336)	(15,071)
Maturing May 1, 2013 (c)	65,750	65,750
Maturing May 1, 2014 (d)	55,200	55,200
Maturing February 1, 2015 (a)	49,400	49,400
Less securities held by trustee (b)	(2,353)	(2,444)
Total pollution control indebtedness	411,641	405,243
Debentures:		
16.25% guaranteed due February 1, 1989 (e)	—	75,000
16% guaranteed due February 15, 1989 (e)	—	25,000
11.75% guaranteed due January 15, 1990 (e)	60,000	60,000
12.5% due February 15, 1992	75,000	75,000
Total debentures	135,000	235,000
Unsecured notes payable due 1987 (f)	70,000	70,000
Revolving credit agreements (g)	110,000	—
Term loan due June 1990 (LIBOR plus ¼%)	80,000	—
Capitalized lease obligation (h)	45,222	46,907
Other	1,536	1,975
Unamortized discount	(178)	(293)
Total long-term debt	2,241,045	2,223,396
Less current maturities:		
5.125% first mortgage bonds due October 1, 1987	15,000	—
11.50% first mortgage bonds due June 1, 2015 (i)	150,000	—
Unsecured notes payable due 1987 (f)	70,000	—
11.75% guaranteed debentures due January 15, 1990 (e)	60,000	—
Sinking fund requirements on first mortgage bonds	15,333	15,333
Capitalized lease obligation (h)	1,748	1,685
Other	473	438
Total current maturities	312,554	17,456
Total long-term debt less current maturities	$1,928,491	$2,205,940

(a) Adjustable-rate annual tender pollution control revenue refunding bonds supported by a long-term irrevocable letter of credit issued by a bank. The bonds bear an interest rate, determined annually, which will cause the bonds to have a market value which approximates, as nearly as possible, their par value.

(b) Representing pollution control funds deposited with a revenue bond trustee to be disbursed as needed to pay the costs of acquiring, constructing, reconstructing, improving, maintaining, equipping or furnishing the facilities financed.

(c) Consisting of borrowings from a governmental authority which has funded that amount through issuance of a series of par value demand bonds supported by a long-term irrevocable letter of credit issued by a bank. These bonds bear interest at such rate, determined weekly, as will cause the bonds to have a market value which approximates, as nearly as possible, their par value.

(d) On May 15, 1985 the Company borrowed from a governmental authority the proceeds of a $55,200,000 issue of adjustable-rate annual tender pollution control revenue refunding bonds for the purpose of refunding $55,200,000 in aggregate principal amount of previously issued pollution control bonds due April 1, 1986. The new issue is supported by a long-term irrevocable letter of credit issued by a bank. The bonds bear an interest rate, determined annually, which will cause the bonds to have a market value which approximates, as nearly as possible, their par value.

(e) The 16.25% debentures due February 1, 1989 and 16% debentures due February 15, 1989 were redeemed on February 1, 1986 and February 15, 1986, respectively, with the proceeds of a $100,000,000 issue of first mortgage bonds. The debentures were redeemed at 101% plus accrued interest.

The 11.75% debentures due January 15, 1990 were redeemed on January 15, 1987 at 101½% plus accrued interest.

(f) Consisting of two bank loans of $50,000,000 and $20,000,000 bearing interest at the CD Rate plus .55% and the CD Rate plus ⅝%, respectively.

(g) Represents borrowings under a $120,000,000 Eurocommercial paper program agreement among the company and various financial institutions and is supported by a revolving credit agreement which expires in 1991. At December 31, 1986, the outstanding balance consisted of $100,000,000 of Eurocommerical paper and $10,000,000 on the revolving credit agreement. Interest rates on the Eurocommercial paper are negotiated at the time of borrowing. Interest rates applicable to borrowings under the revolving credit agreement are LIBOR plus .30% to .45% with commitment fees of .15% on the unused credit line.

(h) Represents the present value of future lease payments (discounted at the interest rate of 7.48%) on a combined cycle plant sold and leased back from the independent owner-trustee formed to own the facility. The lease requires semi-annual payments of $2,582,000 through June 2001, and includes renewal and purchase options based on fair market value. This plant is included in plant in service at its original cost of $54,405,000; accumulated depreciation at December 31, 1986 was $23,664,000.

(i) The 11.50% first mortgage bonds were redeemed on January 27, 1987, at par, with proceeds from the Palo Verde Unit 2 sale and leaseback transactions. At December 31, 1986, such proceeds were included in Special deposits and working funds in the Consolidated Balance Sheet.

During February 1987, the Company issued $150,000,000 of 9% First Mortgage Bonds due February 1, 2017.

Aggregate annual payments due on long-term debt and for sinking fund requirements through 1991 are as follows: 1987, $312,554,000; 1988, $17,795,000; 1989, $37,985,000; 1990, $18,193,000; and 1991, $53,365,000. See Note 5 for sinking fund requirements and redemptions at the option of the holders of redeemable preferred stock.

Substantially all utility plant, other than nuclear fuel, transportation equipment and the combined cycle plant mentioned above, is subject to the lien of the first mortgage bonds. The indenture respecting the first mortgage bonds includes provisions which would restrict the payment of dividends on common stock under certain conditions which did not exist at December 31, 1986.

7. Lines of Credit and Compensating Balances.

The Company's lines of credit at December 31, 1986 and 1985 are summarized below. No amounts were outstanding under the lines at December 31, 1986 and 1985.

	1986	1985
	(Thousands of Dollars)	
Commercial paper backup lines:		
Domestic banks	$175,000	$125,000
Foreign banks	—	50,000
Other domestic bank lines	240,000(a)	245,000(a)
Total	$415,000	$420,000

(a) Including $200,000,000 available under a credit agreement between the Company and various banks which carries a commitment fee of ¼% per annum.

The commitment fees for the commercial paper backup lines with domestic banks were ⅜% per annum in 1986 and 1985. Compensating balances required (but which were not legally restricted) for the other domestic banks lines (exclusive of the credit agreement referred to in (a) above) were generally 7½% of the lines plus 5% of borrowings in 1986 and 1985.

By statute the Company's short-term borrowings cannot exceed 7% of total capitalization without the consent of the ACC.

8. Jointly-Owned Facilities.

At December 31, 1986, the Company owned interests in jointly-owned electric generating and transmission facilities are as follows (dollars in thousands):

	Percent owned by Company	Plant in Service	Accumulated Depreciation	Net Plant in Service	Construction Work in Progress
Generating Facilities:					
Palo Verde Nuclear Generating Station - Units 1, 2 and 3	(a)	$1,585,059	$ 32,396	$1,552,663	$740,519
Four Corners Steam Generating Plant - Units 4 and 5	15.0%	124,176	23,730	100,446	2,749
Navajo Steam Generating Plant - Units 1, 2 and 3	14.0%	122,033	42,060	79,973	1,108
Transmission Facilities:					
ANPP Transmission System	35.8%(b)	61,273	2,241	59,032	4,359
Navajo Southern Transmission System	31.4%(c)	28,226	9,892	18,334	99
Palo Verde-Yuma 500KV System	23.9%(d)	15,596	972	14,624	—
Total		$1,936,363	$111,291	$1,825,072	$748,834

(a) The Company owns 29.1% of Units 1 and 3 and approximately 17% of Unit 2 (see Note 9).

(b) Weighted average of interests varying from 34.6% to 43.95%.

(c) Weighted average of interests varying from 14% to 100%.

(d) Weighted average of interests varying from 11% to 100%.

The foregoing dollar amounts correlate to the Company's percentage interest in each facility. The Company's share of related operating and maintenance expenses is included in Operating Expenses.

9. Leases

In August and December, 1986, the Company entered into sale and leaseback transactions under which it sold approximately 42% of its 29.1% share of Palo Verde Unit 2 resulting in net proceeds of $487,296,000. The resulting gain of approximately $140,220,000 has been deferred and is being amortized to operations expense over the original lease term. The leases require semi-annual payments of approximately $22,021,000 through June 1997 and $26,778,000 through December 2015 and include options to renew the leases for two additional years and to purchase the property at fair market value at the end of the lease term. The leases are being accounted for as operating leases. Lease expense for 1986 amounted to $13,126,000 and was deferred as allowed by the Phase III Order (see Note 3).

10. Income Tax Expense.

The components of income tax expense—continuing operations for each of the three years in the period ended December 31, 1986 are as follows:

	Year Ended December 31,		
	1986	1985 (Thousands of Dollars)	1984
Currently payable:			
Federal	$ 46,463	$ 10,095	$ 14,578
State	17,951	10,664	16,340
Other	1,643	2,861	3,606
Total current	66,057	23,620	34,524
Deferred:			
Depreciation—net	62,347	57,273	26,276
Taxes, pension costs and other—net	86,237	49,690	18,367
Deferred gain—sale of utility plant	(84,697)	—	—
Investment tax credit—net	28,563	36,383	59,592
Total deferred	92,450	143,346	104,235
Amortization of tax benefits sold	(1,687)	(1,687)	(1,687)
Total	$156,820	$165,279	$137,072

In 1981 the Company sold to another corporation certain federal income tax benefits in exchange for cash. The Company, pursuant to an order of the ACC, has recorded the proceeds of the sale as a deferred credit and is amortizing the amount of such proceeds on a straight-line basis over approximately 30 years.

The difference between income tax expense—continuing operations and the amount obtained by multiplying income before income taxes by the statutory federal income tax rate for each of the three years in the period ended December 31, 1986 are as follows:

	Year Ended December 31,		
	1986	1985 (Thousands of Dollars)	1984
Federal income tax expense at statutory rate	$198,232	$225,723	$199,935
Increases (reductions) in tax expense resulting from:			
Tax under book depreciation	18,855	16,431	14,165
Allowance for funds used during construction	(60,711)	(88,222)	(84,491)
Palo Verde cost deferral	(11,505)	—	—
Investment tax credit amortization	(5,975)	(2,955)	(2,827)
State income tax—net of Federal income tax benefit	13,239	11,815	11,172
Other	4,685	2,487	(882)
Total provision for Federal and State income tax expense	$156,820	$165,279	$137,072

11. Pension Plan and Other Benefits.

The Company's pension plan, a defined benefit plan, covers virtually all employees. The benefits are based on years of service and compensation utilizing the final average pay plan benefit formula. It is the Company's policy to fund the plan on a current basis to the extent deductible under existing tax regulations. Pension cost, including administrative cost, for 1986, 1985, and 1984 was approximately $2,751,000, $15,458,000, and $16,370,000, respectively, of which

approximately $602,000, $5,081,000, and $6,512,000, respectively was charged to expense; the remainder was either capitalized as a component of construction costs or billed to participants of jointly owned facilities. Plan assets consist primarily of common stocks, U.S. obligations and bonds.

In 1986, the Company adopted Statement of Financial Accounting Standards ("SFAS") No. 87, Employers Accounting for Pensions. Net periodic pension cost under SFAS No. 87 is made up of the components listed below as determined using the projected unit credit actuarial cost method. For prior years, the Company's net periodic pension cost (pension expense) was normal cost as determined using the aggregate actuarial cost method.

Net periodic pension cost for 1986 (thousands of dollars):

Service cost-benefits earned during the period	$10,253
Interest cost on projected benefit obligation	18,587
Return on plan assets	(54,441)
Net amortization and deferral	26,171
Net periodic pension cost	$ 570

The discount rate and rate of increase in future compensation levels used in determining the actuarial present value of the projected benefit obligation were 8% and 5.5%, respectively. The expected long-term rate of return on assets was 10.15%.

The following table sets forth the plan's funded status and amounts recognized in the Company's balance sheets (thousands of dollars):

	1986	1985
Actuarial present value of benefit obligation, including vested benefits of $152,884 and $119,883	$173,825	$131,965
Effect of projected future compensation increases	68,319	59,854
Projected benefit obligation	242,144	191,819
Plan assets, at fair value	294,934	252,650
Plan assets in excess of projected benefit obligation	52,790	60,831
Unrecognized net loss from past experience different from that assumed	4,241	—
Unrecognized net asset at January 1, 1986 being recognized over 20.2 years	(62,005)	(65,235)
Accrued pension liability included in other deferred credits	$ (4,974)	$ (4,404)

In addition to providing pension benefits, the Company provides certain health care and life insurance benefits for active and retired employees. Life insurance benefits are provided through an insurance company whereas health care costs are paid as expenses are incurred under a self-insured plan. The cost of providing those benefits for both active and retired employees amounted to approximately $18,591,000, $14,509,000 and $13,786,000, of which approximately $6,285,000, $5,825,000 and $5,689,000 was charged to expense in 1986, 1985 and 1984, respectively. Remaining amounts were either capitalized as a component of construction costs or billed to participants of jointly owned facilities. The cost of providing such benefits solely to retired employees is not significant.

12. Commitments and Contingencies.

Nuclear Insurance

The Price-Anderson Act ("Act") currently limits the public liability payments resulting from a nuclear incident to a maximum amount of $695,000,000 as of December 31, 1986 for each licensed nuclear facility. Private insurance for this exposure has been purchased by the participants in Palo Verde, including the Company in the maximum available amount, presently $160,000,000, with the balance to be provided by secondary financial protection required by the Nuclear Regulatory Commission (NRC). Under the agreement with the NRC, the Company could be assessed retrospective premium adjustments of up to $2,910,000 per year for each of its operating reactors in the event of nuclear incidents involving any licensed reactor in the United States.

The Act is scheduled to expire in August 1987 and Congress is currently considering several alternatives. The Company is unable to predict Congress' ultimate action and what effect such action may have on the Company's liability.

As of December 31, 1986, the Company purchased $1,160,000,000 of decontamination liability and property damage insurance for the participants in Palo Verde. Several of these policies are provided through mutual insurance companies owned by utilities with nuclear facilities. If losses at any nuclear facility covered by the arrangement were to exceed the accumulated funds available for these insurance programs, the Company could be assessed retrospective premium adjustments of up to $3,100,000 per year.

Litigation

The Company is a party to various claims, legal actions and complaints arising in the ordinary course of business, including a lawsuit seeking to invalidate the Company's contract with various municipalities for the purchase of effluent to be used as cooling water for Palo Verde. In the opinion of management, the ultimate disposition of these matters will not have a material adverse effect on the operations or financial position of the Company.

Purchase Commitments

The Company has significant purchase commitments in connection with its continuing construction program. Construction expenditures in 1987 have been estimated at $345,000,000.

13. Supplementary Income Statement Information.

Other taxes charged to operations during each of the three years in the period ended December 31, 1986 are as follows:

	Year Ended December 31,		
	1986	1985	1984
	(Thousands of Dollars)		
Ad valorem	$ 55,798	$ 45,554	$42,581
Sales	58,606	51,438	45,495
Other	9,189	7,284	6,372
Total other taxes	$123,593	$104,276	$94,448

14. Discontinued Operations.

Effective November 1, 1984 (the "Closing Date") the Company sold its gas distribution system to Southwest Gas Corporation ("Southwest"). The sale resulted in a non-recurring loss of approximately $26,470,000, net of an income tax benefit of $7,094,000, (approximately $0.39 per average share of common stock) in 1984.

The Company agreed to fund a portion of the costs associated with the accelerated replacement of certain gas pipe included in the gas distribution system acquired by Southwest by purchasing, under certain conditions, up to $50,000,000 in aggregate par value of cumulative preference stock (the "Stock") of Southwest. As of December 31, 1986, the Company had purchased 160,000 shares of the Stock at a cost of $16,000,000 which is included in Other investments and notes receivable in the Consolidated Balance Sheet. Any additional purchases would be made by the Company within approximately three years following the Closing Date. The Stock yields an annual dividend of between 3% and 16% (payable quarterly) based on a formula relating to the operating performance of the gas distribution system. The Stock is also redeemable by Southwest, at its option, on any dividend payment date (at the issue price plus accrued dividends), but must be redeemed no later than seven years after the issuance date as to any issue.

Revenue from the Company's discontinued gas operations for 1984 was $174,728,000.

15. Selected Quarterly Financial Data (Unaudited).

Quarter	Operating Revenues	Operating Income	Net Income	Earnings for Common Stock	Earnings Per Share of Common Stock
	(Dollars in Thousands, Except Per Share Amounts)				
1986					
First	$274,530	$ 61,283	$ 59,263	$ 48,682	$0.68
Second	295,452	60,012	53,689	43,662	0.61
Third	391,738	95,581	102,223	92,874	1.30
Fourth	288,192	57,445	58,945	49,623	0.70
1985					
First	$243,552	$ 49,452	$ 59,019	$ 46,921	$0.67
Second	276,697	68,330	73,185	62,443	0.88
Third	368,129	118,286	114,473	103,641	1.45
Fourth	286,124	70,916	78,746	68,006	0.95

ACCOUNTANTS' OPINION

Arizona Public Service Company:

We have examined the consolidated balance sheets of Arizona Public Service Company and its subsidiaries as of December 31, 1986 and 1985 and the related consolidated statements of income, retained earnings and changes in financial position for each of the three years in the period ended December 31, 1986. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

In our opinion, such consolidated financial statements present fairly the financial position of Arizona Public Service Company and its subsidiaries at December 31, 1986 and 1985 and the results of their operations and the changes in their financial position for each of the three years in the period ended December 31, 1986, in conformity with generally accepted accounting principles applied on a consistent basis.

Deloitte Haskins & Sells

Phoenix, Arizona
February 19, 1987

Shareholder Information

Stock Listing

The $3.58 cumulative preferred stock, Series O (Symbol ARPO); and the adjustable cumulative preferred stock, Series Q (Symbol ARPQ) are listed for trading on the New York Stock Exchange. The common stock of the Company is wholly-owned by AZP and as a result is not listed for trading on any stock exchange. Prior to April 29, 1985 the Company's common stock was publicly held and was traded on the New York and Pacific Stock Exchanges. At the close of business on April 28, 1985 the Company's common stock was held by 123,776 shareholders.

The chart below sets forth the common stock price ranges for the first two quarters of 1985. The second quarter common stock price ranges for 1985 reflect the price ranges to April 29, 1985, the date on which AZP became the sole shareholder of the Company's common stock. The chart below also sets forth the dividends per share paid on the Company's common stock for each of the four quarters for 1986 and 1985.

Common Stock Price Ranges and Dividends

1986	High	Low	Dividend Per Share
1st Quarter	—	—	$.72
2nd Quarter	—	—	.72
3rd Quarter	—	—	.74
4th Quarter	—	—	.76
1985			
1st Quarter	22⅞	20⅝	$.65
2nd Quarter	24⅞	22¼	.68
3rd Quarter	—	—	.69
4th Quarter	—	—	.71

Transfer Agent

First Interstate Bank of Arizona, N.A.
Corporate Trust Operations
Dept. 958, P.O. Box 29715
Phoenix, Arizona 85038
(602) 271-1620

Registrars

First Interstate Bank of Arizona, N.A.
Phoenix, Arizona

The Valley National Bank of Arizona,
Phoenix, Arizona

General Counsel

Snell & Wilmer, Phoenix, Arizona

Auditors

Deloitte Haskins & Sells,
Phoenix, Arizona

AZP Stock Purchase and Dividend Reinvestment Plan

A Prospectus describing this plan is available upon request. Write: Office of the Secretary, Sta. 1891, at the address below.

Form 10-K

A copy of our Annual Report to the Securities and Exchange Commission, Form 10-K, will be available after March 31, 1987, without charge, upon written request of shareholders. Write: Office of the Secretary, Sta. 1891, at the address below.

Statistical Report

A detailed Statistical Report for Financial Analysis 1976-1986 will be available by mid-April on request. Write: Office of the Treasurer, Sta. 1820, at the address below.

MAILING ADDRESS:

P.O. Box 53999
Phoenix, Arizona 85072-3999

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APS DIRECTORS

Joe Acosta, 63, founder, Acosta, Cordova & Pittman, C.P.A.s, P.A., Phoenix, Arizona

Dino DeConcini, 53, attorney at law, Phoenix, Arizona

[1] O. Mark De Michele, 53, president and chief operating officer of APS, Phoenix, Arizona

[1] Karl Eller, 58, chairman of the board, The Circle K Corporation, Phoenix, Arizona

[1] William T. Garland, 70, president of Garland Land Co. (land development), Sedona, Arizona

Pamela Grant, 48, president and chief executive officer, Goldwaters, Division of May Department Stores Company, Scottsdale, Arizona

Jack M. Morgan, 63, attorney at law and state senator, Farmington, New Mexico

Marvin R. Morrison, 63, farmer, cattle feeder and dairyman, Morrison Brothers Ranch, Higley, Arizona

[2] Jaron B. Norberg, 49, executive vice president and chief financial officer of APS, Phoenix, Arizona

[3] John R. Norton III, 58, chairman and chief executive officer, J. R. Norton Co. (agricultural production), Phoenix, Arizona

John J. Rhodes, 70, former member of the U.S. House of Representatives and counsel in the law firm of Hunton & Williams, Washington, D.C.

Wilma W. Schwada, 60, civic leader and homemaker, Phoenix, Arizona

[1] Richard Snell, 56, chairman of the board and president, Ramada Inc., Phoenix, Arizona

[1] Donald N. Soldwedel, 62, president, Western Newspapers, Inc., Yuma, Arizona

[1] Maurice R. Tanner, 65, chairman of the board and chief executive officer, The Tanner Companies (construction and materials supply), Phoenix, Arizona

[1] Keith L. Turley, 63, chairman of the board and chief executive officer of APS; chairman of the board and president of AZP, Phoenix, Arizona

[1] Douglas J. Wall, 60, member of the law firm of Mangum Wall Stoops & Warden, Flagstaff, Arizona

Morrison F. Warren, 63, professor emeritus of education, Arizona State University, Tempe, Arizona

Ben F. Williams, Jr., 57, mayor of the City of Douglas and attorney at law, Douglas, Arizona

Thomas G. Woods, Jr., 60, formerly executive vice president for the Arizona Nuclear Power Project (Retired 2/85), Phoenix, Arizona

(Age on Annual Meeting date, April 23, 1987)

[1] Member of Executive Committee

[2] Mr. Norberg was elected to the board on July 25, 1986.

[3] Mr. Norton was reelected to the board February 20, 1986 effective March 1, 1986. He had resigned from the board in May 1985 to accept a position as U.S. Deputy Secretary of Agriculture.

Henry B. Sargent, Jr., and James P. Simmons served to July 25, 1986 and June 9, 1986, respectively.

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Los Angeles
Vernon
Anaheim
Banning

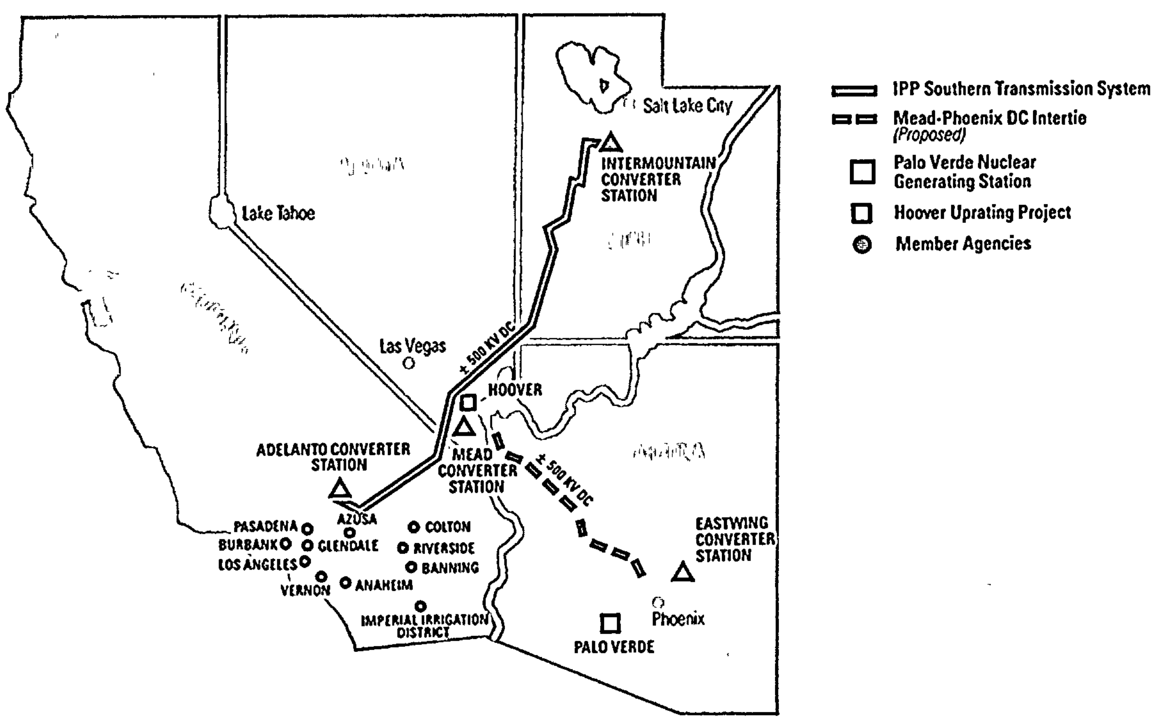
Introduction

The Southern California Public Power Authority (Authority) is comprised of all 11 public power agencies in Southern California. SCPPA has proved to be a reliable and economic source of energy for member communities by financing projects for the generation and transmission of electric energy for its member agencies.

The municipalities of Anaheim, Azusa, Banning, Burbank, Colton, Glendale, Los Angeles, Pasadena, Riverside and Vernon, as well as the Imperial Irrigation District comprise the vast area of the Authority. These member agencies serve more than 1.7 million customers —from the rural areas of Banning and the Imperial Irrigation District to metropolitan Los Angeles—and the growing, sprawling communities in between.

With combined sales of more than 32 million megawatt-hours—which had non-coincidental peak requirements of more than 7,500 megawatts—the member agencies of the Authority have received in excess of $1.9 billion in annual revenue.

Since initially going to market in 1982, the Authority has issued more than $5 billion in bonds and notes including refunding issues. This has been achieved due to the Authority's high level of acceptance in the financial community.



Management


Gale A. Drews,
President


W. E. Cameron,
Vice President


Eldon A. Cotton
Secretary


Horace W. Rupp, Jr.
Assistant Secretary


Arthur T. Devine,
Executive Director

President
Gale A. Drews
Electrical Utility Director
City of Colton

Vice President
W. E. Cameron
Director of Public Services
City of Glendale

Secretary
Eldon A. Cotton
Assistant Chief Engineer – Power
Los Angeles Department of
Water and Power—
City of Los Angeles

Assistant Secretary
Horace W. Rupp, Jr.
Engineer of Power Contracts
Los Angeles Department of
Water and Power—
City of Los Angeles

Executive Director
Arthur T. Devine
Former Assistant City Attorney
City of Los Angeles
Former Electrical Engineer
Los Angeles Department of
Water and Power—
City of Los Angeles

President's Message

Since its formation in November 1981, the Southern California Public Power Authority (Authority) has efficiently served the needs of member agencies. SCPPA received a strong endorsement as one of the most effective joint action agencies in the nation with a financial rating upgrade to AA from an A+ rate in September 1987. This action translates into reduced borrowing costs for Authority funding due to lower interest rates. We are proud that the Authority is one of the few joint action agencies in the U.S. to carry an AA rating.

During the past fiscal year, the Authority completed funding for the Hoover Uprating Project in Nevada and the Palo Verde Nuclear Generating Station in Arizona. The Hoover Uprate, a project of the federal government scheduled for 1992 completion, is designed to increase the output rating of Hoover Power Plant generators and, in exchange, will provide capacity and energy allocations to Authority members, among others.

Unit 3 of the Palo Verde Station is expected to go on-line in early 1988. Ten Authority members are receiving electrical generation from Units 1 and 2 which were placed into commercial operation during 1986.

The Southern Transmission System (STS), placed into commercial operation last year, ahead of schedule, is being utilized to a greater extent with the operation of the second unit of the Intermountain Generating Station in Utah in May 1987. The STS provides six Authority members with transmission for additional energy and capacity, so members rely less on gas- and oil-fired generation in the Los Angeles Basin.

The Authority has borrowed funds for the Mead-Phoenix DC Intertie Project, and the feasibility study continued during the year.

During the past fiscal year, the Authority moved forward on all of its projects, and I have been pleased to be associated with these accomplishments. I want to especially thank the staff, Board of Directors, and all those responsible for the strength of this organization.

Gale A. Drews

Gale A. Drews
President

Anaheim

Located 25 miles southeast of Los Angeles, Anaheim is best known as the home of Disneyland and other popular tourist attractions. The tourism industry, including hundreds of hotels, motels, and restaurants, as well as the 685,000 gross square-foot Anaheim Convention Center, and a strong presence of high-tech defense businesses are the economic base for Anaheim.

The city's power needs are supplied by its ownership interest in San Onofre Nuclear Generating Station Units 2 and 3, non-firm sources, the Intermountain Generating Station and its entitlement in the Hoover Power Plant, in addition to power purchased from Southern California Edison Company (Edison). In fiscal 1987, power purchases and generation of 2,199,100 megawatt-hours met the needs of Anaheim's 94,000 customers, with a record system peak demand of 483 megawatts.

The city's population of 238,000 ranks it as the largest city in Orange County, one of the fastest growing population centers in the United States.

Azusa

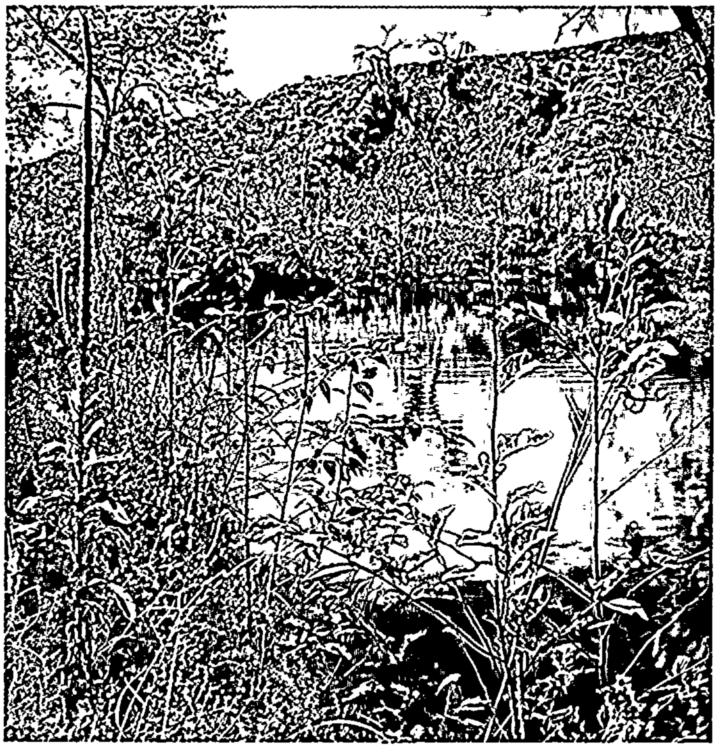
Situated 20 miles east of Los Angeles near the Angeles National Forest, Azusa was incorporated in 1898. From its beginnings as a Shoshone Indian village, Azusa today has a population of 30,000 within its 11 square miles.

The city had been almost exclusively dependent on wholesale power from Edison until receiving its Palo Verde Generating Station and Hoover Power Plant entitlements which helped to displace a portion of the power being purchased from Edison. Last year, the utility sold approximately 167,000 megawatt-hours, with a peak demand of 43 megawatts.

Banning

"Stagecoach Town U.S.A.," as Banning is still known today, reveals the city's early roots. Located 85 miles east of Los Angeles, Banning is bordered north and south by mountain ranges—the San Gorgonio and San Jacinto, respectively. The city was incorporated in 1913 and now has a population of 14,000 living within its 17 square miles. Banning's economic foundation is built on agriculture, light manufacturing and recreation.

Banning is using its entitlements from Palo Verde Generating Station and Hoover Power Plant to offset some of its purchased power. It had relied exclusively on Edison, purchasing power at wholesale rates. Banning had a peak demand of 18.5 megawatts during the year, and sold approximately 70,000 megawatt-hours.



A tranquil setting near Banning typifies the rural flavor of the area 85 miles east of Los Angeles. Banning is using its entitlement from the Palo Verde Nuclear Generating Station to help offset its purchased power.

Burbank

The city of Burbank is at the base of the Verdugo Mountains, slightly northwest of Los Angeles. While the city had a population of 400 when it was incorporated in 1887, today Burbank has 85,000 residents.

This city serves as headquarters for Burbank Studios, Columbia Pictures, Walt Disney Productions, National Broadcasting Company, Warner Bros., and Lockheed Aircraft. Burbank industries employ more than 70,000 people.

Burbank supplies electricity to its customers through a combination of oil- and gas-fired generating facilities in the Los Angeles Basin, entitlements from Hoover Power Plant, Palo Verde Generating Station and the Intermountain Generating Station, and purchases from the Bonneville Power Administration and other utilities in the Pacific Northwest and the Southwest.

The city had a peak demand of 228 megawatts during the year while generating and purchasing 981,000 megawatt-hours of energy.

Colton

Colton quickly became established as the "Hub City" when one square mile of land was deeded to the Southern Pacific Railroad in 1875. Today the San Bernardino County community, 55 miles east of Los Angeles, is on the main line of three major railroads and the intersecting point for three major highways.

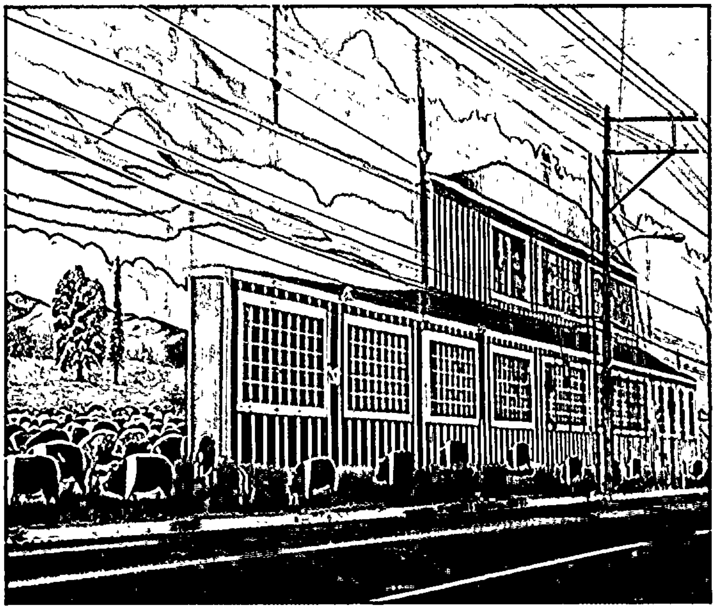
The city of Colton purchases the majority of its energy from Edison and additional energy requirements are met through its entitlements in the Palo Verde Generating Station and Hoover Power Plant. Colton had a peak demand of 39 megawatts and total energy requirements of 159,000 megawatt-hours.

Glendale

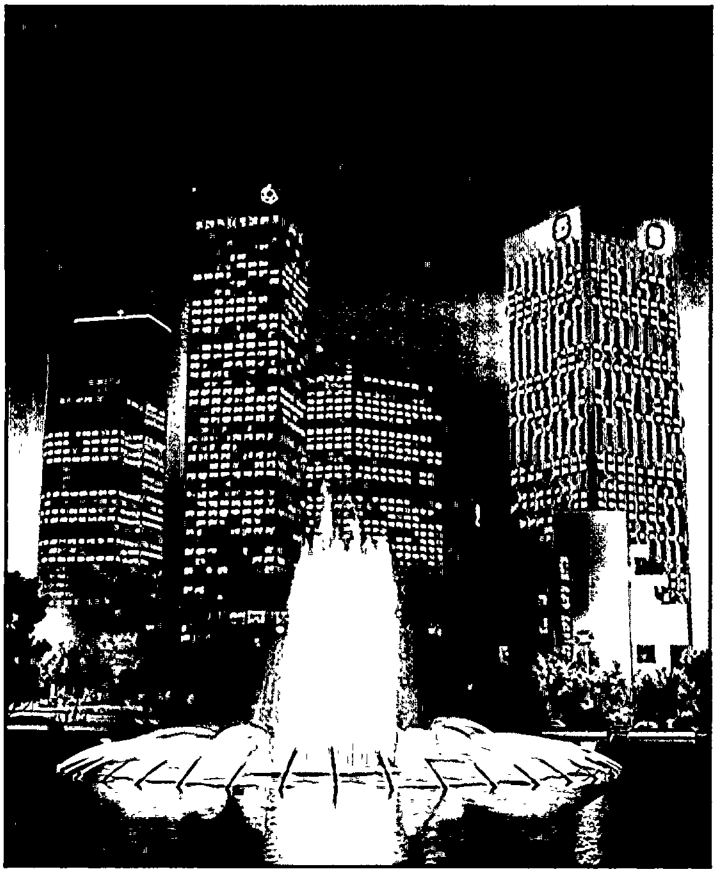
The original 150-acre townsite of Glendale, formed in 1884, had grown almost ten times in size when it was incorporated in 1906. Today, this city just north of Los Angeles has grown to 30 square miles with a population of more than 154,000.

Glendale most recently began receiving its entitlements from the Intermountain Generating Station and the Palo Verde Generating Station. Glendale receives power from several different sources including oil- and gas-fired generation in the Los Angeles Basin, hydroelectric generation from Hoover Power Plant and purchases from the Bonneville Power Administration and other utilities.

Glendale purchased and generated a total of approximately 914,000 megawatt-hours in the fiscal year, serving almost 73,000 customers, and had a peak demand of 232 megawatts.



Industrialized Vernon supports a working population of about 55,000 within its 5 square miles. The city has been serving the needs of industry since 1905.



Los Angeles has established itself as an international city. Through its membership in the Authority, Los Angeles is receiving power from Utah via the Southern Transmission System and from the Palo Verde Nuclear Generating Station to meet its growing needs.

Los Angeles

A pueblo founded in 1781 along the Los Angeles river, the city of Los Angeles has grown to a population of 3.2 million, the nation's second largest city. Water and energy needs are served by the Los Angeles Department of Water and Power (Department), the largest U.S. municipal utility. The Department services about 1.3 million electric customers throughout Los Angeles' vast 465 square miles.

Los Angeles receives power from hydroelectric generating stations; coal, oil- and gas-fired facilities; a nuclear generating station; and purchases power from Pacific Northwest and Southwest utilities. During the fiscal year, Los Angeles experienced a peak demand of 4,713 megawatts while a total of 23 million megawatt-hours were generated. The Department provides a net dependable system capability of 7,254 megawatts.

Los Angeles is benefiting through its association with the Authority from two new power sources—the Intermountain Generating Station in Utah, completed in May 1987, and the Palo Verde Nuclear Generating Station in Arizona. Los Angeles has an entitlement in the Southern Transmission System which enables it to transmit power from the Intermountain Generating Station to its service territory and has an entitlement through the Authority of approximately 145 megawatts from the Palo Verde Nuclear Generating Station.

Pasadena

The home of the annual Tournament of Roses Parade and Rose Bowl college football competition each New Year's Day, Pasadena was founded in 1875 and incorporated the following year. Recognized as a major economic, cultural, residential and recreational center, the city is located northeast of Los Angeles at the base of the San Gabriel Mountains.

Among Pasadena's most prestigious employers are the California Institute of Technology, one of the world's major scientific research centers.

Pasadena supplies electricity through a combination of oil- and gas-fired generation in the Los Angeles Basin, hydroelectric generation from Hoover Power Plant and purchases from the Bonneville Power Administration, as well as receiving an entitlement from the Intermountain Generating Stations and Palo Verde.

Pasadena generated and purchased a total of approximately 1 million megawatt-hours for the year, and its peak demand was 232 megawatts.

Riverside

Riverside is located about 45 miles east of Los Angeles and is 72 square miles in area with a population of more than 175,000. It is the home of the University of California, Riverside.

The city was incorporated in 1883 in order to ensure an adequate water supply by annexing lands owned by an irrigation company. The present municipal utility, the oldest in California, had its beginning when a small hydroelectric plant was opened on a canal in 1888, and in 1896 the city started to distribute electric power from a more modern hydroelectric plant.

Riverside purchases power from Edison at wholesale rates, has ownership in Units 2 and 3 of the San Onofre Nuclear Generating Station, and receives power from an entitlement in the Palo Verde Generating Station, Hoover Power Plant and the Intermountain Generating Station.

Riverside has more than 1,600 circuit miles of subtransmission and distribution lines as well as 18 substations to meet the needs of its more than 75,000 customers. The city had a peak demand of 323 megawatts and total energy requirements of 1.2 million megawatt-hours.

Vernon

Vernon, a planned industrial city, has a small residential population which swells to more than 55,000 people during working hours. Four miles south of Los Angeles, the city, incorporated in 1905, provides a home for all types of industry within its five square miles.

More than 525 manufacturing plants and another 400 establishments engage in the wholesale-retail trade. It is served by four railroads operating 114 miles of line within the city. Every industry or business is on a direct transcontinental railway in Vernon, and 77 trucking lines have terminals in the city.

The Vernon Electrical System, established in 1931, receives most of its energy from Edison. The remainder is supplied from its entitlements in the Palo Verde Generating Station, Hoover Power Plant and a city operated diesel generating plant. During the year, Vernon had a peak demand of 193 megawatts and a total energy requirement of 1.15 million megawatt-hours.

Imperial Irrigation District

The Imperial Irrigation District (IID) provides power to 60,000 customers in Imperial and Riverside counties, one of the most productive agricultural areas in the country.

Formed in 1911, IID originally delivered water to 500,000 acres of farmland in Imperial County from distribution canals. Hydroelectric plants were developed along the waterways, and the properties of a private power company were purchased in 1943. Shortly afterward IID became the distributor of electric energy in Imperial County, and part of the Coachella Valley of Riverside County.

In addition to its hydroelectric plants, IID generates power from oil-fired units, gas turbines and diesel generators. It is receiving power from the Palo Verde Generating Station, has geothermal generation from the Heber Plant and purchases power from other utilities in the Southwest.

IID produced and purchased 1,393,000 megawatt-hours during the year, with a peak demand of 413 megawatts.

Palo Verde Generating Station

Unit 3 of the Palo Verde Nuclear Generating Station (Palo Verde) in Arizona is scheduled to go on-line in early 1988. Units 1 and 2 went into commercial operation during 1986. Each of the three generating units at the site, located 50 miles west of Phoenix, has a nominal capacity of 1,270 megawatts. The Authority has a 5.91 percent interest in Palo Verde and will receive about 216 megawatts (based on the licensed reactor thermal power level per unit of 1221 MW) when the facility is completed.

Ten member agencies have contracted with the Authority for entitlement in Palo Verde. This capacity will be used to meet growth, to replace more expensive purchased power, and to displace oil- or gas-fired generation.

The project is managed and operated by Arizona Public Service Company, with the switchyard portion operated by the Salt River Project. The Authority will use a certain portion of the project transmission system.

Palo Verde Project Participation

Participants	Project Entitlement	Generating Capability (Megawatts)
Los Angeles	67.0%	145.04
Imperial Irrigation District	6.5%	14.07
Riverside	5.4%	11.69
Vernon	4.9%	10.61
Burbank	4.4%	9.53
Glendale	4.4%	9.53
Pasadena	4.4%	9.53
Azusa	1.0%	2.16
Banning	1.0%	2.16
Colton	1.0%	2.16
Total	100.0%	216.48

Palo Verde is expected to have a net annual energy output of more than 22 million megawatt-hours by the early 1990s. The Authority's interest in the generating station is projected to deliver approximately 207 megawatts of capacity after allowing for transmission losses and 1,271,777 megawatt-hours of energy per year at the various points of delivery.

The Authority issued approximately $600 million in refunding bonds in 1985 and the first half of 1986, taking advantage of lower interest rates which resulted in a gross debt savings of $130 million to participating members over the life of the project. Total financing for the project amounted to $1 billion.

Southern Transmission Systems

With the completion of Unit 2 of the Intermountain Generating Station (IGS) during 1987, the ±500 kilovolt direct current Southern Transmission System (STS) has been officially rated at a 1920 megawatt capacity.

Six Authority members are receiving power over the STS, carried 488 miles across mountain and desert from the coal-fired IGS in Utah. Alternating current produced from the generating station is changed into direct current at an adjacent converter station. After transmission over the line, it is changed back to alternating current at the Adelanto Converter Station in Southern California and then delivered to project participants.

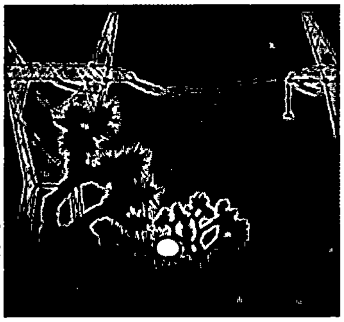
Los Angeles was appointed project manager and operating agent by the Intermountain Power Agency, a political subdivision of the State of Utah. A total of 36 utilities in California, Nevada and Utah are receiving power from the generating station.

Power transmitted by the project will be used by Authority participants to meet load growth, displace Los Angeles basin oil- and gas-fueled generation, and, for some, to reduce purchases from Edison.

Three refunding sales were completed by the Authority in 1985 and 1986 which totalled approximately $1 billion. This action translates into a gross debt service savings of approximately $725 million over the life of the project.

Hoover Uprating Project

The U.S. Bureau of Reclamation's (Bureau) plan to uprate the 17 original generators at the Hoover Power Plant is fully underway. Generator capacity is being increased by installing modern stator windings and upgrading various auxiliary equipment. Other modifications to the power plant to increase its efficiency include the replacement of existing transformer banks, consolidation of control rooms and

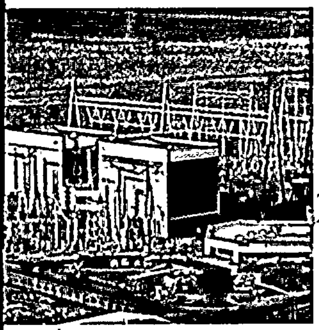


The ±500 kilovolt, direct current Southern Transmission System brings power from the Intermountain Generating Station in Utah to Southern California.

NEVADA

UTAH

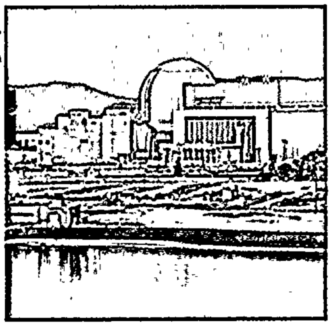
NIA



Adelanto Converter Station on the edge of the Mojave Desert is the terminus of the Southern California Transmission System.

The capacity of the generators at Hoover Power Plant are being increased through an Uprating project which will benefit Authority members.

ARIZONA



Construction has been completed at the Palo Verde Nuclear Generating Station in Arizona.

modernization to provide for automatic and remote control. The Bureau determined that the nameplate capacity of the 50-year-old facility can be uprated to 1,951 megawatts at 498 feet of head, resulting in 503 megawatts of Uprate capacity.

Bonds were issued for approximately $34.5 million to advance the costs to the Bureau of the six Authority members participating in the Authority portion of the project. The members financing through the Authority will be allocated 94 megawatts of the additional output when the project is completed in 1992. The energy and capacity entitlements are now available to participants, and increasingly more amounts will be made available as the project advances until full entitlement is received in 1992.

Hoover Uprating Project Participation

Participants	Contingent Capacity		Associated Firm Energy
	MW	%	MWh
Anaheim	40.0	48.40	52,000
Riverside	30.0	36.30	39,000
Burbank	15.0	5.07	5,442
Azusa	4.0	4.65	5,000
Colton	3.0	3.72	4,000
Banning	2.0	1.86	2,000
Total	94.0	100.00	107,442

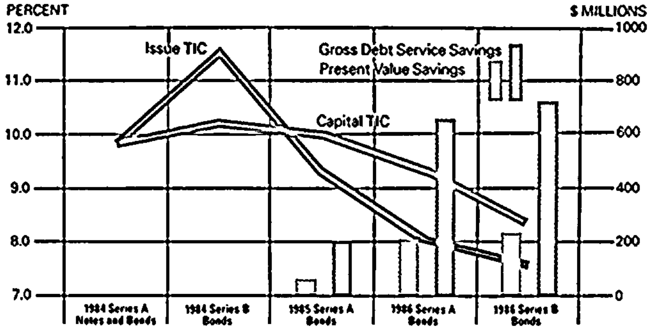
Mead-Phoenix DC Intertie Project

Studies continue by the Authority and other Southwest utilities as to the feasibility of constructing, owning and operating a ±500 kilovolt, direct current transmission line. The intertie between Phoenix, Arizona and Boulder City, Nevada, is a two-terminal 1,600 megawatts project which later could be expanded to 2,200 megawatts.

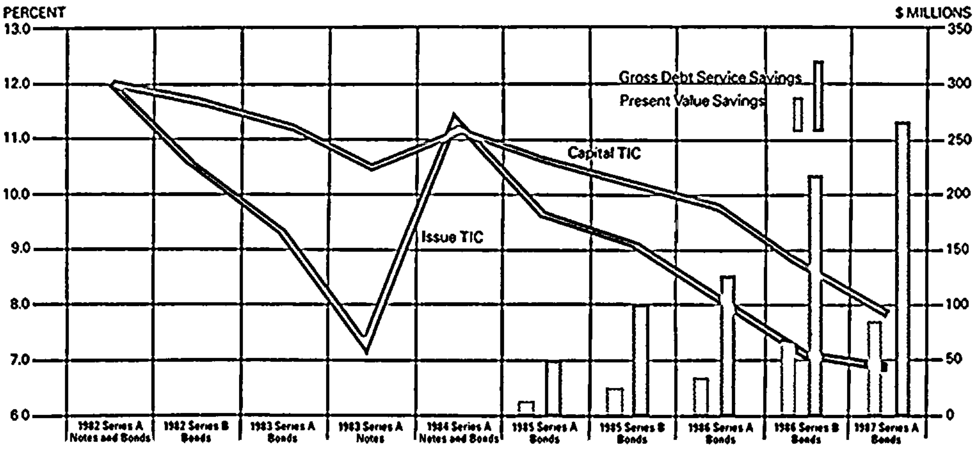
The intertie is currently scheduled for completion in the mid-1990s and would be used to transmit Palo Verde generation entitlements for the Authority participants and facilitate economy energy/capacity transactions with other utilities in the inland-Southwest. The other utilities participating in the studies are Salt River Project, M-S-R and the Western Area Power Administration.

If the participants elect to construct a two-terminal project, the Authority's participation would be 1500 megawatts with a potential increase to 2,062 megawatts if the project is expanded to 2200 megawatts.

Summary of Transmission Project Revenue Bond Program



Summary of Power Project Revenue Bond Program



September 30, 1987

**To the Board of Directors of
Southern California Public
Power Authority**

In our opinion, the accompanying combined balance sheet and the related combined statements of operations and of changes in financial position present fairly the financial position of the Southern California Public Power Authority (Authority) at June 30, 1987 and 1986, and the results of its operations and the changes in its financial position for the years then ended, in conformity with generally accepted accounting principles consistently applied. Our examinations of these statements were made in accordance with generally accepted auditing standards and accordingly included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

In our opinion, the accompanying separate balance sheets and the related separate statements of changes in financial position of the Authority's Palo Verde Project, Southern Transmission Project, Hoover Uprating Project and Mead-Phoenix Project, and the separate statements of operations of the Palo Verde Project, Southern Transmission Project and Hoover Uprating Project present fairly the financial position of each of the Projects at June 30, 1987, and the changes in each of their financial positions and the results of operations of the Palo Verde Project, Southern Transmission Project and Hoover Uprating Project for the year then ended, in conformity with generally accepted accounting principles consistently applied. Our examinations of these statements were made in accordance with generally accepted auditing standards and accordingly included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Our examinations were made for the purpose of forming an opinion on the basic financial statements taken as a whole. The supplemental financial data and schedules, as listed in the accompanying index, are presented for purposes of additional analysis and are not a required part of the basic financial statements. Such supplemental financial data and schedules have been subjected to the auditing procedures applied in the examinations of the basic financial statements and, in our opinion, are fairly stated in all material respects in relation to the basic financial statements taken as a whole.

Price Waterhouse

Price Waterhouse

Southern California Public Power Authority
Combined Balance Sheet

(In thousands)

ASSETS	Palo Verde Project (June 30, 1987)	Southern Transmission Project (June 30, 1987)	Hoover Uprating Project (June 30, 1987)	Mead-Phoenix Project (June 30, 1987)	Total (June 30, 1987)	June 30, 1986 Total
Utility plant						
Production	$ 368,755				$ 368,755	$ 203,247
Transmission	3,512	$ 633,034			636,546	1,864
General	58	18,068			18,126	33
	372,325	651,102			1,023,427	205,144
Less—Accumulated Depreciation	15,983	18,089			34,072	3,340
	356,342	633,013			989,355	201,804
Construction work in progress	224,809		$ 3,064	$11,703	239,576	989,653
Nuclear fuel, at amortized cost	36,415				36,415	37,412
Net utility plant	617,566	633,013	3,064	11,703	1,265,346	1,228,869
Special funds (Notes C, D and E)						
Investments	222,229	156,446	30,962	2,910	412,547	497,788
Advance to Intermountain Power Agency		20,981			20,981	
Interest receivable	1,753	2,968	502		5,223	4,547
Cash	538			8	546	211
	224,520	180,395	31,464	2,918	439,297	502,546
Accounts receivable	2,859	2,662	66		5,587	5,442
Costs recoverable from future billings to participants (Note F)	26,069	58,241			84,310	7,340
Deferred costs						
Unamortized debt expenses, less accumulated amortization of $28,178 and $14,492 in 1987 and 1986	218,503	167,084	1,212	3	386,802	316,099
Other deferred costs	1,542				1,542	1,972
	220,045	167,084	1,212	3	388,344	318,071
	$1,091,059	$1,041,395	$35,806	$14,624	$2,182,884	$2,062,268
LIABILITIES						
Long-term debt (Notes C, D and E)	$1,039,335	$ 999,556	$34,293	$14,148	$2,087,332	$1,878,593
Current liabilities (Notes C and D)						
Bond anticipation notes						75,000
Accrued interest	37,454	38,611	689	426	77,180	91,762
Accounts payable and accrued expenses	14,270	3,228	824	50	18,372	16,913
	51,724	41,839	1,513	476	95,552	183,675
Commitments and contingencies						
	$1,091,059	$1,041,395	$35,806	$14,624	$2,182,884	$2,062,268

The accompanying notes are an integral part of these financial statements.

Southern California Public Power Authority
Combined Statement of Operations

(In thousands)

	Year ended June 30, 1987				
	Palo Verde Project	Southern Trans-mission Project	Hoover Uprating Project	Total	Year ended June 30, 1986
Operating revenues					
Sales of electric energy	$ 51,949		$66	$ 52,015	$ 10,042
Sales of transmission services		$ 40,617		40,617	
Total operating revenues	$ 51,949	$ 40,617	$66	$ 92,632	$ 10,042
Operating expenses					
Nuclear fuel expense	$ 7,259			$ 7,259	$ 2,022
Other operation	10,162	$ 7,036	$66	17,264	3,395
Maintenance	3,192	3,082		6,274	1,440
Depreciation	12,643	18,089		30,732	3,340
Expense charged to projects during construction	(370)			(370)	(1,056)
Total operating expenses	32,886	28,207	66	61,159	9,141
Debt expenses					
Interest on debt, net	78,290	70,651		148,941	84,294
Allowance for borrowed funds used during construction	(40,498)			(40,498)	(76,053)
Net debt expense	37,792	70,651		108,443	8,241
	70,678	98,858	66	169,602	17,382
Costs recoverable from future billings to participants (Note F)	(18,729)	(58,241)		(76,970)	(7,340)
Total expenses	$ 51,949	$ 40,617	$66	$ 92,632	$ 10,042

The accompanying notes are an integral part of these financial statements.

Southern California Public Power Authority
Combined Statement of Changes in Financial Position

(In thousands)

	Year ended June 30, 1987 Palo Verde Project	Southern Transmission Project	Hoover Uprating Project	Mead-Phoenix Project	Total	Year ended June 30, 1986 Total
Funds provided by (used for)						
Operations						
Revenues	$ 51,949	$ 40,617	$ 66		$ 92,632	$ 10,042
Expenses	(70,678)	(98,858)	(66)		(169,602)	(17,382)
Charges not involving funds:						
Depreciation and amortization	19,098	18,089			37,187	5,362
Other, net	9,723	8,052			17,775	7,933
	10,092	(32,100)	0		(22,008)	5,955
Financing						
Sale of revenue bonds			34,293		34,293	
Sale of refunding bonds	679,434				679,434	1,343,525
Defeasance of revenue bonds	(508,703)				(508,703)	(1,130,929)
Defeasance of bond anticipation notes						(200,000)
Reduction in long-term debt						(75,000)
Bond issue costs	(106,289)		(1,260)		(107,549)	(232,270)
	64,442		33,033		97,475	(294,674)
Utility plant	(55,131)	(14,395)	(3,064)	$(1,073)	(73,663)	(191,950)
Other, net		23,157	48	12	23,217	(1,033)
	$ 19,403	$(23,338)	$30,017	$(1,061)	$ 25,021	$ (481,702)
Increase (Decrease in funds)						
Investments	$ (52,336)	$(63,100)	$30,962	$ (766)	$ (85,240)	$ (438,017)
Advance to Intermountain Power Agency		20,981			20,981	
Interest receivable	(515)	690	502		677	(21,910)
Cash	340		66	(5)	401	(56)
Accounts receivable	(2,560)	2,649		(10)	79	(1,233)
Bond anticipation notes	75,000				75,000	(75,000)
Accrued interest payable	4,529	11,107	(689)	(365)	14,582	6,266
Accounts payable and accrued expenses	(5,055)	4,335	(824)	85	(1,459)	48,248
	$ 19,403	$(23,338)	$30,017	$(1,061)	$ 25,021	$ (481,702)

The accompanying notes are an integral part of these financial statements.

NOTE A—Organization and purpose:

Southern California Public Power Authority (Authority), a public entity organized under the laws of the State of California, was formed by a Joint Powers Agreement dated as of November 1, 1980 pursuant to the Joint Exercise of Powers Act of the State of California. The Authority's participant membership consists of ten Southern California cities and one public district of the State of California. The Authority was formed for the purpose of planning, financing, developing, acquiring, constructing, operating and maintaining projects for the generation and transmission of electric energy for sale to its participants. The Joint Powers Agreement has a term of fifty years.

Palo Verde Project—The Authority, pursuant to an assignment agreement dated as of August 14, 1981 with the Salt River Project Agricultural Improvement and Power District (Salt River Project), has purchased a 5.91% interest in the Palo Verde Nuclear Generating Station (PVNGS), a 3,810 megawatt nuclear-fueled generating station being constructed near Phoenix, Arizona, and a 6.55% share of the right to use certain portions of the Arizona Nuclear Power Project Valley Transmission System (collectively, the Palo Verde Project). Units 1 and 2 of the Palo Verde Project began commercial operation in January and September 1986, respectively. Unit 3 is scheduled for commercial operation in January 1988.

Mead-Phoenix Project—The Authority is also studying the feasibility of constructing the proposed Mead-Phoenix DC Intertie Project (Mead-Phoenix Project), a transmission line from Arizona to Nevada. The Authority's present interest in the Mead-Phoenix Project is 93.75%.

Southern Transmission Project—The Authority, pursuant to an agreement dated as of May 1, 1983 with the Intermountain Power Agency (IPA), has agreed to make payments-in-aid of construction to IPA to defray all the costs of acquisition and construction of the Southern Transmission System Project (STS), a transmission line which will provide for the transmission of energy from the Intermountain Power Project in Utah to Southern California. The Authority entered into an agreement also dated as of May 1, 1983 with six of its members pursuant to which each member assigned its entitlement to capacity of the Southern Transmission Project to the Authority in return for the Authority's agreement to make payments-in-aid of construction to IPA. STS commenced commercial operations in July 1986.

Hoover Uprating Project—On August 13, 1986, six participant members of the Authority entered into an agreement with the Bureau of Reclamation of the United States of America (Bureau) to make advance payments toward the cost of uprating the Hoover Dam Facility's generating equipment. Construction is scheduled for completion by September 1992. The Authority will have an 18.68% interest in contingent capacity of the Hoover Uprating Project. Several "uprated" generators of the Hoover Uprating Project commenced commercial operations in June 1987.

NOTE B—Summary of significant accounting policies:

The Authority maintains its records substantially in accordance with accounting principles and methods prescribed by the Federal Energy Regulatory Commission and the California Public Utilities Commission. The Authority is not subject to regulation by such commissions.

Utility plant—All expenditures, including general administrative and other overhead expenses, payments-in-aid of construction, interest net of related investment income, deferred cost amortization and the fair value of test power generated and delivered to the participants are capitalized as utility plant construction work in progress until a facility begins commercial operation.

The Authority's share of costs associated with PVNGS Units 1 and 2 is included as Utility Plant in Service. Depreciation is provided using the straight-line method over the assets estimated useful lives of thirty-five years. Nuclear fuel is amortized and charged to expense on the basis of actual thermal energy produced relative to total thermal energy expected to be produced over the life of the fuel. A contract has been entered into with the United States Department of Energy for disposal of the spent fuel.

The costs associated with the STS project are included as Utility Plant in Service. Depreciation is provided using the straight-line method over the assets estimated useful lives of primarily thirty-five years.

Nuclear decommissioning—Decommissioning of PVNGS is projected to commence sometime after 2022. Estimated future decommissioning costs are provided over the commercial life of PVNGS through annual charges to expense.

Deferred costs—Deferred costs are shown net of accumulated amortization. Unamortized debt issue costs, including the cost of refunding, are amortized over the terms of the respective issues. Other deferred costs are amortized generally over five years.

Investments—Investments include United States Government and governmental agency securities and repurchase agreements which are collateralized by such securities. These investments are stated at amortized cost. As discussed in Notes C and D, all of the investments are restricted as to their use.

Investments, in thousands, were as follows:

	June 30,			
	1987		1986	
Project	Carrying Value	Market	Carrying Value	Market
Palo Verde	$222,229	$232,845	$274,565	$291,969
Southern Transmission	177,427	189,351	219,546	233,641
Hoover Uprating	30,962	30,651		
Mead-Phoenix	2,910	2,910	3,677	3,679
	$433,528	$455,757	$497,788	$529,289

Revenues—Revenues consist of billings to participants for the sales of electric energy and of transmission service in accordance with the participation agreements. Generally, revenues are fixed at a level to recover all operating and debt service costs over the commercial life of the plant. (See Note F).

Debt expenses—Debt expenses include interest on debt, the amortization of bond premiums and discounts, and debt issue and refunding costs. Income from investments is recorded as a reduction of debt expense.

NOTE C—Long-term debt:

Palo Verde Project—To finance the purchase and construction of the Authority's share of the Palo Verde Project, the Authority has issued Power Project Revenue Bonds and Power Project Bond Anticipation Notes pursuant to the Authority's Indenture of Trust dated as of July 1, 1981 (Bond Indenture), as amended and supplemented, and the Authority's Power Project Bond Anticipation Note Resolution (Note Resolution) adopted August 13, 1982, as amended and supplemented. Reference is made to the Combined Supplemental Schedule of Revenue and Refunding Bonds Payable at June 30, 1987 for details related to outstanding bonds.

The Bond Indenture provides that the Revenue Bonds shall be special, limited obligations of the Authority payable solely from and secured solely by (1) proceeds from the sale of bonds, (2) all revenues, incomes, rents and receipts attributable to the Palo Verde Project (see Note E) and interest on all moneys or securities (other than in the Construction Fund)

held pursuant to the Bond Indenture and (3) all funds established by the Bond Indenture (excluding the Decommissioning Account in the Reserve and Contingency Fund); subject to the provisions of the Palo Verde Project Bond Indenture providing for the application thereof. The Note Resolution provides that the Bond Anticipation Notes shall be special, limited obligations of the Authority payable from the proceeds of additional bonds, notes or loans obtained under the Revolving Credit Agreement. During fiscal 1987, the Bond Anticipation Notes were defeased and are considered extinguished for purposes of financial statement presentation.

All outstanding Power Project Revenue Term Bonds, at the option of the Authority, are subject to redemption prior to maturity.

The Bond Indenture requires mandatory sinking fund instalments to be made beginning in fiscal 1998 for the 1982 Series A Bonds, 1999 for the 1982 Series B Bonds and the 1983 Series A Bonds, 2001 for the 1984 Series A Bonds and 1985 Series A Bonds, 2005 for the 1985 Series B Bonds and 2003 for the 1986 Series A Bonds, the 1986 Series B Bonds and the 1987 Series A Bonds. Scheduled principal maturities for the Palo Verde Project during the five fiscal years succeeding June 30, 1987 are $13,095,000 in 1989, $13,870,000 in 1990, $14,745,000 in 1991 and $15,790,000 in 1992. No principal maturities of bonds outstanding at June 30, 1987 are scheduled for fiscal 1988. The effective interest rate on outstanding debt during 1987 was 8.4%.

The funds required by the Bond Indenture contain balances, in thousands, as follows:

	June 30, 1987	June 30, 1986
Construction Fund—Initial Facilities Account	$ 38,454	$ 52,826
Debt Service Fund—		
Debt Service Account	67,711	105,473
Debt Service Reserve Account	90,235	98,299
Bond Anticipation Note Fund	30	6,080
Revenue Fund	1	2,720
Operating Fund	15,739	5,016
Reserve and Contingency Fund	8,169	6,272
General Reserve Fund	4,181	345
Total Special Funds	$224,520	$277,031

Southern Transmission Project—To finance payments-in-aid of construction to IPA for construction of the Southern Transmission Project, the Authority has issued Transmission Project Revenue Bonds pursuant to the Authority's Indenture of Trust dated as of May 1, 1983 (Bond Indenture). Reference is made to the Supplemental Schedule of Revenue and Refunding Bonds Payable at June 30, 1987 for details related to the outstanding bonds.

The Bond Indenture provides that the Revenue Bonds shall be special, limited obligations of the Authority payable solely from and secured solely by (1) proceeds from the sale of bonds, (2) all revenues, incomes, rents and receipts attributable to the Southern Transmission Project (see Note E) and interest on all moneys or securities (other than in the Construction Fund) held pursuant to the Bond Indenture and (3) all funds established by the Bond Indenture; subject to the provisions of the Bond Indenture providing for the application thereof.

All outstanding Transmission Project Revenue Term Bonds, at the option of the Authority, are subject to redemption prior to maturity.

The Bond Indenture requires mandatory sinking fund instalments to be made beginning in fiscal 2000 for the 1984 Series A Bonds, 2001 for the 1984 Series B Bonds and the 1985 Series A Bonds, 2003 for the 1986 Series A Bonds and 2002 for the 1986 Series B Bonds. Scheduled principal maturities for the Southern Transmission Project during the five fiscal years succeeding June 30, 1987 are $2,260,000 in 1989, $3,785,000 in 1990, $7,945,000 in 1991 and $8,485,000 in 1992. No principal maturities of bonds outstanding at June 30, 1987 are scheduled for fiscal 1988. The effective interest rate on outstanding debt during 1987 was 7.7%.

The special funds required by the Bond Indenture contain balances, in thousands, as follows:

	June 30, 1987	June 30, 1986
Construction Fund—Initial Facilities Account	$ 18,638	$ 94,857
Debt Service Fund—		
Debt Service Account	38,623	35,705
Debt Service Reserve Account	91,192	91,262
Revenue Fund	1	
Operating Fund	6,249	
General Reserve Fund	4,711	
Total Special Funds	$159,414	$221,824

In addition, $20,981,000 has been advanced during fiscal year 1987 to IPA for SCPPA's share of the initial working capital for the Southern Transmission Project. The advance will be returned to SCPPA at the end of the project.

Hoover Uprating Project—Pursuant to the Authority's Indenture of Trust dated as of March 1, 1986 (Bond Indenture), the Authority issued $34,435,000 of Hydroelectric Power Project Revenue Bonds 1986 Series A to finance advance payments to the U.S. Bureau of Reclamation for application to the costs of the Hoover Uprating Project. The Bond Indenture provides that the Revenue Bonds shall be special, limited obligations of the Authority payable solely from and secured solely by (1) the proceeds of the sale of the bonds, (2) all revenues from sales of energy to project participants, (3) interest or other receipts derived from any moneys or securities held pursuant to the Bond Indenture, and (4) all funds established by the Indenture of Trust (except for the Interim Advance Payments Account in the Advance Payment Fund); subject to the provisions of the Bond Indenture providing for the application thereof.

All outstanding Hydroelectric Power Project Revenue Term Bonds, at the option of the Authority, are subject to redemption prior to maturity.

The Bond Indenture requires mandatory sinking fund instalments to be made beginning in fiscal 2002 for the 1986 Series A Bonds. No scheduled principal maturities of bonds outstanding at June 30, 1987 are scheduled for fiscal 1988 through fiscal 1992. The effective interest rate on outstanding debt during 1987 was 8.1%.

The funds required by the Bond Indenture contain balances, in thousands, as follows:

	June 30, 1987
Advance Payments Fund	$27,277
Debt Service Fund	
Debt Service Account	932
Debt Service Reserve Account	3,255
Total Special Funds	$31,464

Summary of Special Funds—The Bond Indentures and Note Resolution for each of the three projects require the above listed special funds to be established to account for the Authority's receipts and disbursements. The moneys and investments held in these funds are restricted in

use to the purposes stipulated in the bond indentures and note resolution. A summary of these funds follows:

Fund	Held by	Purpose
Construction	Trustee	To disburse funds for the acquisition and construction of the Project
Debt Service	Trustee	To pay interest and principal related to the Revenue Bonds
Bond Anticipation Note	Trustee	To pay interest related to the Bond Anticipation Note
Revenue	Trustee	To initially receive all revenues and disburse them to other funds
Operating	Trustee	To pay operating expenses
Reserve and Contingency	Trustee	To pay capital improvements and make up deficiencies in other funds and, in the case of the Palo Verde Project, accumulate funds for decommissioning
General Reserve	Trustee	To make up any deficiencies in other funds
Advance Payments	Trustee	To disburse funds for the cost of acquisition capacity of the project

Refunding bonds—During fiscal 1987 the proceeds from the sale of $707,275,000 of Power Project Refunding Bonds were used to advance refund $630,120,000 of previously issued bonds. In connection therewith, the net proceeds of the refunding bonds have been invested in securities of the United States Government, the principal and interest from which will be sufficient to fund the remaining principal, interest and call premium payments on all refunded bonds until the stated first call dates of the respective issues. Accordingly, all amounts related to the refunded bonds have been removed from the balance sheets and the cost of refunding the debt is included in unamortized debt expenses at June 30, 1987. At June 30, 1987 the aggregate amount of debt considered to be extinguished was $1,875,050,000.

NOTE D—Long-term bank loan payable:

At June 30, 1987, the Authority had borrowed $14,148,000 to finance the feasibility study and development costs of the Mead-Phoenix Project. This loan bears interest at approximately 67% of the prime rate; however, the interest rate cannot exceed 12%. The average interest rate on this loan was 5.2% and 6.1% during 1987 and 1986.

The proceeds of the loan were deposited in a Development Fund for which the lender is the trustee and can only be used for payment of Mead-Phoenix Project development costs, costs of issuance of the loan, including general and administrative expenses of the Authority related to the Mead-Phoenix Project, and loan principal and interest. At June 30, 1987 and 1986, the balance in the Development Fund was $2,918,000 and $3,690,000 of which substantially all were invested in securities of the United States Government.

If the Mead-Phoenix Project is terminated for any reason prior to the issuance of long-term bonds to refinance the loan, ten California cities, the Salt River Project and the United States Department of Energy, Western Area Power Administration, have contracted to make payments to the Authority based on their participation percentage sufficient to retire the loan and accrued interest thereon. The loan is secured solely by the restricted assets and the above mentioned contracts.

NOTE E—Power sales and transmission service contracts:

The Authority has sold its entitlement to the output of the Palo Verde Project pursuant to power sales contracts with ten member participants (see Note G). Under the terms of the power sales contracts, the purchasers are entitled to power output from the Palo Verde Nuclear Generating Station and are obligated to make payments on a "take or pay" basis for their proportionate share of operating and maintenance expenses and debt service on Power Project Revenue Bonds and other debt, whether or not the Palo Verde Project or any part thereof has been completed, is operating or operable, or its output is suspended, interfered with, reduced or curtailed or terminated. The contracts expire in 2030 and, as long as any Power Project Revenue Bonds are outstanding, cannot be terminated or amended in any manner which will impair or adversely affect the rights of the bondholders.

The Authority has entered into transmission service contracts with six member participants (see Note G). Under the terms of the transmission service contracts, the project participants are entitled to transmission service utilizing the Southern Transmission Project and are obligated to make payments on a "take or pay" basis for their proportionate share of operating and maintenance expenses and debt service on Transmission Project Revenue Bonds and other debt, whether or not the Southern Transmission Project or any part thereof has been completed, is operating or is operable, or its service is suspended, interfered with, reduced or curtailed or terminated. The contracts expire in 2027 and, as long as any Transmission Project Revenue Bonds are outstanding, cannot be terminated or amended in any manner which will impair or adversely affect the rights of the bondholders.

NOTE F—Costs recoverable from future billings to participants:

Billings to participants are designed to recover "costs" as defined by the power sales and transmission service agreements. The billings are structured to systematically provide for the debt requirements, operating funds and reserves in accordance with these agreements. Those expenses, according to generally accepted accounting principles, which are not included as "costs" are deferred to such periods as they are intended to be recovered through billings.

NOTE G—Related party transactions:

Under the terms of the various contracts, the Authority reimbursed the following entities for work performed on the respective projects. The Department of Water and Power of the City of Los Angeles has performed administrative and other work for the Authority totaling $469,000 and $310,000 for fiscal 1987 and 1986. The Arizona Public Service Company (APS), as project manager of the Palo Verde Project, billed the Authority for various construction, operating and maintenance costs totaling $36,005,000 and $50,101,000 for fiscal 1987 and 1986. The Intermountain Power Authority billed the Authority for payments-in-aid of construction, operating and maintenance costs relating to the Southern Transmission Project amounting to $25,267,000 and $62,561,000 for fiscal 1987 and 1986. The U.S. Bureau of Reclamation as project manager of the Hoover Uprating Project, billed the Authority for various construction costs totaling $2,448,000 for fiscal 1987. The Salt River Project, as development manager of the Mead-Phoenix Project, billed the Authority for various development costs amounting to $470,000 and $1,165,000 for fiscal 1987 and 1986.

Member participants have the following participation percentages in the Authority's interest in the four projects (see Note A):

Project Participation Percentage				
Participant	Palo Verde	Southern Transmission	Hoover Uprating Project	Mead-Phoenix
City of Los Angeles	67.0%	59.5%		61.2%
City of Anaheim		17.6	42.6%	15.0
City of Riverside	5.4	10.2	31.9	6.0
Imperial Irrigation District	6.5			
City of Vernon	4.9			3.0
City of Azusa	1.0		4.2	.6
City of Banning	1.0		2.1	.6
City of Colton	1.0		3.2	.6
City of Burbank	4.4	4.5	16.0	5.0
City of Glendale	4.4	2.3		5.0
City of Pasadena	4.4	5.9		3.0
	100.0%	100.0%	100.0%	100.0%

NOTE H—Commitments and contingencies:

The Authority estimates that the total financing requirements for its interest in the Hoover Uprating Project will approximate $34 million, of which substantially all will be expended for payments for capacity and associated firm energy and the acquisition of entitlements to capability. Construction is scheduled for completion in September 1992.

The Authority is involved in various legal actions. In the opinion of management, the outcome of such litigation or claims will not have a material effect on the financial position of the Authority or the respective separate projects.

Southern California Public Power Authority Index to Supplemental Financial Data and Schedules

Southern California Public Power Authority
Combined Supplemental Schedule of Revenue and Refunding Bonds Payable
At June 30, 1987

(In thousands)

	Series	Date of Sale	Effective Interest Rate	Maturity on July 1	Total
Palo Verde Project Revenue and Refunding Bonds	1982A	8/13/82	10.9%	1988 to 2017	$ 26,325
	1982B	11/12/82	7.7%	1988 to 2017	44,445
	1983A	4/ 8/83	8.8%	1988 to 2017	36,015
	1984A	7/18/84	10.3%	1990 to 2004	24,090
	1985A	5/22/85	8.7%	1988 to 2014	12,515
	1985B	7/ 2/85	9.1%	1988 to 2017	101,815
	1986A	3/13/86	8.2%	1988 to 2015	157,645
	1986B	12/16/86	7.2%	1988 to 2017	354,630
	1987A	2/11/87	6.9%	1988 to 2017	352,645
					1,110,125
Southern Transmission Project Revenue and Refunding Bonds	1984A	2/ 9/84	9.3%	1990 to 2004	65,945
	1984B	10/17/84	10.2%	1990 to 2000	18,770
	1985A	8/15/85	8.9%	1989 to 2021	121,620
	1986A	3/18/86	8.0%	1988 to 2021	371,720
	1986B	4/29/86	7.5%	1988 to 2023	480,010
					1,058,065
Hoover Uprating Project Revenue Bonds	1986A	8/13/86	8.1%	1993 to 2017	34,435
Total Principal Amount					2,202,625
Less: Unamortized Bond Discount—					
Palo Verde Project Revenue and Refunding Bonds					70,790
Southern Transmission Project Revenue and Refunding Bonds					58,509
Hoover Uprating Power Project Revenue Bonds					142
Total Unamortized Bond Discount					129,441
Total Revenue and Refunding Bonds Less Amortized Bond Discount					$2,073,184

Long-term debt representing a bank loan of $14,148,000 for the Mead-Phoenix Project and bonds which have been refunded are excluded from this schedule.

Southern California Public Power Authority
Palo Verde Project
Supplemental Balance Sheet

(In thousands)

	June 30, 1987	June 30, 1986
ASSETS		
Utility plant		
Production	$ 368,755	$203,247
Transmission	3,512	1,864
General	58	33
	372,325	205,144
Less—Accumulated depreciation	15,983	3,340
	356,342	201,804
Construction work in progress	224,809	342,317
Nuclear fuel, at amortized cost	36,415	37,412
Net utility plant	617,566	581,533
Special funds		
Investments	222,229	274,565
Interest receivable	1,753	2,268
Cash	538	198
	224,520	277,031
Accounts receivable	2,859	5,419
Costs recoverable from future billings to participants	26,069	7,340
Deferred costs		
Unamortized debt expenses, less accumulated amortization of $13,698 and $6,949 in 1987 and 1986	218,503	118,963
Other deferred costs	1,542	1,972
	220,045	120,935
	$1,091,059	$992,258
LIABILITIES		
Long-term debt	$1,039,335	$866,060
Current liabilities		
Bond anticipation notes		75,000
Accrued interest payable	37,454	41,983
Accounts payable and accrued expenses	14,270	9,215
	51,724	126,198
Commitments and contingencies		
	$1,091,059	$992,258

The accompanying notes are an integral part of these financial statements.

Southern California Public Power Authority
Palo Verde Project
Supplemental Statement of Operations

(In thousands)

	Year ended June 30, 1987	1986
Operating revenues		
Sales of electric energy	$ 51,949	$ 10,042
Operating expenses		
Nuclear fuel expense	$ 7,259	$ 2,022
Other operation	10,162	3,395
Maintenance	3,192	1,440
Depreciation	12,643	3,340
Expense charged to projects during construction	(370)	(1,056)
Total operating expenses	32,886	9,141
Debt expenses		
Interest on debt, net	78,290	84,294
Allowance for borrowed funds used during construction	(40,498)	(76,053)
Net debt expense	37,792	8,241
	70,678	17,382
Costs recoverable from future billings to participants	(18,729)	(7,340)
Total expenses	$ 51,949	$ 10,042

Southern California Public Power Authority
Palo Verde Project
Supplemental Statement of Changes in Financial Position

(In thousands)

	Year ended June 30, 1987	1986
Funds provided by (used for)		
Operations		
Revenues	$ 51,949	$ 10,042
Expenses	(70,678)	(17,382)
Charges not involving funds:		
Depreciation and amortization	19,098	5,362
Other, net	9,723	7,933
	10,092	5,955
Financing		
Sale of refunding bonds	679,434	333,312
Defeasance of revenue bonds	(508,703)	(289,320)
Reduction of long-term debt		(75,000)
Bond issue costs	(106,289)	(57,653)
	64,442	(88,661)
Utility plant	(55,131)	(87,465)
Other, net		(1,972)
	$ 19,403	$(172,143)
Increase (Decrease) in funds		
Investments	$ (52,336)	$ (94,031)
Interest receivable	(515)	(12,308)
Cash	340	(56)
Accounts receivable	(2,560)	4,741
Bond anticipation notes	75,000	(75,000)
Accrued interest payable	4,529	6,725
Accounts payable and accrued expenses	(5,055)	(2,214)
	$ 19,403	$(172,143)

Southern California Public Power Authority
Palo Verde Project
Supplemental Schedule of Receipts and Disbursements in Funds Required by the Bond Indenture
Year Ended June 30, 1987

(In thousands)	*Construction Fund Initial Facilities Account*	*Debt Service Fund*	*Bond Anticipation Note Fund*	*Revenue Fund*	*Operation Fund*	*Reserve & Contingency Note Fund*	*General Reserve Fund*	*Total*
Balance at June 30, 1986	$53,386	$201,277	$6,041	$ 2,719	$ 4,963	$6,456	$ 342	$275,184
Additions								
Bond and note proceeds	75,312							75,312
Bond and note interest received		4,561						4,561
Investment earnings	3,694	18,753	225	292	405	830	13	24,212
Sales—power	1,350			59,064	606			61,020
Other income	142				160			302
Transfer—bond closing	(7,893)	(22,841)						(30,734)
Transfer—note payment	(73,719)							(73,719)
Transfer—interest payment		67,803	(3,000)					64,803
Transfer—investments	3,600			(195)	1,460		(1,265)	3,600
Transfer—investment earnings	13,313	(21,865)	(237)	9,661	(361)	(459)	(51)	1
Transfer—power sales receipts		44,087		(61,374)	14,613	1,518	1,156	0
Transfer—other	622	304		(10,167)	6,178	132	3,983	1,052
Total	16,421	90,802	(3,012)	(2,719)	23,061	2,021	3,836	130,410
Deductions								
Construction expenditures	19,933							19,933
Operating expenditures	424				11,264			11,688
Fuel costs	6,189							6,189
Interest paid	54	133,658	3,000		61			136,773
Property tax paid	1,686				1,124			2,810
Financing costs	2,346							2,346
Interest paid on investment purchases	774	515						1,289
Premium paid on investment purchases	167							167
Total	31,573	134,173	3,000	0	12,449	0	0	181,195
Balance at June 30, 1987	$38,234	$157,906	$ 29	$ 0	$15,575	$8,477	$ 4,178	$224,399

This schedule summarizes the receipts and disbursements in funds required under the bond indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable of $1,753 and $2,268 at June 30, 1987 and 1986, nor do they include total amortized net investment premiums of ($1,632) and ($421) at June 30, 1987 and 1986.

Southern California Public Power Authority
Southern Transmission Project
Supplemental Balance Sheet

(In thousands)

	June 30, 1987	June 30, 1986
ASSETS		
Utility plant		
Transmission	$ 633,034	
General	18,068	
	651,102	
Less—Accumulated depreciation	18,089	
	633,013	
Construction work in progress		$ 636,706
Net utility plant	633,013	636,706
Special funds		
Investments	156,446	219,546
Advance to Intermountain Power Agency	20,981	
Interest receivable	2,968	2,278
	180,395	221,824
Accounts receivable	2,662	13
Costs recoverable from future billings to participants	58,241	
Deferred costs		
Unamortized debt expenses, less accumulated amortization of $13,999 and $7,121 in 1987 and 1986	167,084	197,122
	$1,041,395	$1,055,665
LIABILITIES		
Long-term debt	$ 999,556	$ 998,385
Current liabilities		
Accrued interest	38,611	49,717
Accounts payable and accrued expenses	3,228	7,563
	41,839	57,280
Commitments and contingencies		
	$1,041,395	$1,055,665

Southern California Public Power Authority
Southern Transmission Project
Supplemental Statement of Operations

(In thousands)

	Year ended June 30, 1987
Operating revenues	
Sales of transmission services	$ 40,617
Operating expenses	
Other operation	7,036
Maintenance	3,082
Depreciation	18,089
Total operating expenses	28,207
Debt expenses	
Interest on debt, net	70,651
	98,858
Costs recoverable from future billings to participants	(58,241)
Total expenses	$ 40,617

Southern California Public Power Authority
Southern Transmission Project
Supplemental Statement of Changes in Financial Position

(In thousands)

	Year ended June 30, 1987	*1986*
Funds provided by (used for)		
Operations		
Revenues	$ 40,617	
Expenses	(98,858)	
Charges not involving funds:		
Depreciation	18,089	
Other, net	8,052	
	(32,100)	
Financing		
Sale of refunding bonds		$ 1,010,213
Defeasance of bond anticipation notes		(200,000)
Defeasance of revenue bonds		(841,609)
Bond issue costs		(174,617)
		(206,013)
Utility plant	(14,395)	(102,530)
Other, net	23,157	903
	$(23,338)	$ (307,640)
Increase (Decrease) in funds		
Investments	$(63,100)	$ (342,128)
Advance to Intermountain Power Agency	20,981	
Interest receivable	690	(9,602)
Accounts receivable	2,649	(5,984)
Accrued interest	11,107	(472)
Accounts payable and accrued expenses	4,335	50,546
	$(23,338)	$ (307,640)

Southern California Public Power Authority
Southern Transmission Project
Supplemental Schedule of Receipts and Disbursements in Funds Required by the Bond Indenture
Year Ended June 30, 1987

(In thousands)

	Construction Fund-Initial Facilities Account	*Debt Service Fund*	*Revenue Fund*	*Operating Fund*	*General Reserve Fund*	*Total*
Balance at June 30, 1986	$ 93,836	$124,314	$ 0	$ 0	$ 0	$218,150
Additions						
Investment earnings	3,905	11,080	90	230	581	15,886
Sales			42,071			42,071
Transfer of interest payment		85,841				85,841
Transfer of funds	(38,534)	48,224	(9,751)	6,000	(5,939)	0
Transfer—transmission sales receipt		14,556	(38,201)	12,958	10,687	0
Other receipts			117			117
Total	(34,629)	159,701	(5,674)	19,188	5,329	143,915
Deductions						
Payments-in-aid of construction and administrative costs paid	19,255					19,255
Advance to Intermountain Power Agency	20,981					20,981
Operating expenditures				12,728		12,728
Interest paid	142	151,369				151,511
Interest paid on investment purchases	139	375			267	781
Financing costs paid	539					539
Transfer of investment earnings	(434)	5,407	(5,674)	223	478	0
Other	105					105
Total	40,727	157,151	(5,674)	12,951	745	205,900
Balance at June 30, 1987	$ 18,480	$126,864	$ 0	$ 6,237	$ 4,584	$156,165

This schedule summarizes the receipts and disbursements in funds required under the bond indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable of $2,968 and $2,278 at June 30, 1987 and 1986, nor do they include total amortized net investment discounts and premiums of $281 and $1,396 at June 30, 1987 and 1986.

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SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

REPORT AND FINANCIAL STATEMENTS

JUNE 30, 1987 AND 1986

400 South Hope Street
Los Angeles, CA 90071-2889
Telephone 213 236 3000

Price Waterhouse

September 30, 1987

To the Board of Directors of
Southern California Public
Power Authority

In our opinion, the accompanying combined balance sheet and the related combined statements of operations and of changes in financial position present fairly the financial position of the Southern California Public Power Authority (Authority) at June 30, 1987 and 1986, and the results of its operations and the changes in its financial position for the years then ended, in conformity with generally accepted accounting principles consistently applied. Our examinations of these statements were made in accordance with generally accepted auditing standards and accordingly included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

In our opinion, the accompanying separate balance sheets and the related separate statements of changes in financial position of the Authority's Palo Verde Project, Southern Transmission Project, Hoover Uprating Project and Mead-Phoenix Project, and the separate statements of operations of the Palo Verde Project, Southern Transmission Project and Hoover Uprating Project present fairly the financial position of each of the Projects at June 30, 1987, and the changes in each of their financial positions and the results of operations of the Palo Verde Project, Southern Transmission Project and Hoover Uprating Project for the year then ended, in conformity with generally accepted accounting principles consistently applied. Our examinations of these statements were made in accordance with generally accepted auditing standards and accordingly included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Our examinations were made for the purpose of forming an opinion on the basic financial statements taken as a whole. The supplemental financial data and schedules, as listed in the accompanying index, are presented for purposes of additional analysis and are not a required part of the basic financial statements. Such supplemental financial data and schedules have been subjected to the auditing procedures applied in the examinations of the basic financial statements and, in our opinion, are fairly stated in all material respects in relation to the basic financial statements taken as a whole.

Price Waterhouse

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

COMBINED BALANCE SHEET

(In thousands)

	June 30, 1987 Palo Verde Project	Southern Transmission Project	Hoover Uprating Project	Mead-Phoenix Project	Total	June 30, 1986 Total
ASSETS						
Utility plant						
Production	$ 368,755				$ 368,755	$ 203,247
Transmission	3,512	$ 633,034			636,546	1,864
General	58	18,068			18,126	33
	372,325	651,102			1,023,427	205,144
Less - Accumulated depreciation	15,983	18,089			34,072	3,340
	356,342	633,013			989,355	201,804
Construction work in progress	224,809		$ 3,064	$11,703	239,576	989,653
Nuclear fuel, at amortized cost	36,415				36,415	37,412
Net utility plant	617,566	633,013	3,064	11,703	1,265,346	1,228,869
Special funds (Notes C, D and E)						
Investments	222,229	156,446	30,962	2,910	412,547	497,788
Advance to Intermountain Power Agency		20,981			20,981	
Interest receivable	1,753	2,968	502		5,223	4,547
Cash	538			8	546	211
	224,520	180,395	31,464	2,918	439,297	502,546
Accounts receivable	2,859	2,662	66		5,587	5,442
Costs recoverable from future billings to participants (Note F)	26,069	58,241			84,310	7,340
Deferred costs						
Unamortized debt expenses, less accumulated amortization of $28,178 and $14,492 in 1987 and 1986	218,503	167,084	1,212	3	386,802	316,099
Other deferred costs	1,542				1,542	1,972
	220,045	167,084	1,212	3	388,344	318,071
	$1,091,059	$1,041,395	$35,806	$14,624	$2,182,884	$2,062,268
LIABILITIES						
Long-term debt (Notes C, D and E)	$1,039,335	$ 999,556	$34,293	$14,148	$2,087,332	$1,878,593
Current liabilities (Notes C and D)						
Bond anticipation notes						75,000
Accrued interest	37,454	38,611	689	426	77,180	91,762
Accounts payable and accrued expenses	14,270	3,228	824	50	18,372	16,913
	51,724	41,839	1,513	476	95,552	183,675
Commitments and contingencies						
	$1,091,059	$1,041,395	$35,806	$14,624	$2,182,884	$2,062,268

The accompanying notes are an integral part of these financial statements.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

COMBINED STATEMENT OF OPERATIONS
(In thousands)

	Year ended June 30, 1987				Year ended June 30, 1986
	Palo Verde Project	Southern Trans-mission Project	Hoover Uprating Project	Total	
Operating revenues					
Sales of electric energy	$ 51,949		$ 66	$ 52,015	$ 10,042
Sales of transmission services		$ 40,617		40,617	
Total operating revenues	$ 51,949	$ 40,617	$ 66	$ 92,632	$ 10,042
Operating expenses					
Nuclear fuel expense	$ 7,259			$ 7,259	$ 2,022
Other operation	10,162	$ 7,036	$ 66	17,264	3,395
Maintenance	3,192	3,082		6,274	1,440
Depreciation	12,643	18,089		30,732	3,340
Expense charged to projects during construction	(370)			(370)	(1,056)
Total operating expenses	32,886	28,207	66	61,159	9,141
Debt expenses					
Interest on debt, net	78,290	70,651		148,941	84,294
Allowance for borrowed funds used during construction	(40,498)			(40,498)	(76,053)
Net debt expense	37,792	70,651		108,443	8,241
	70,678	98,858	66	169,602	17,382
Costs recoverable from future billings to participants (Note F)	(18,729)	(58,241)		(76,970)	(7,340)
Total expenses	$ 51,949	$ 40,617	$ 66	$ 92,632	$ 10,042

The accompanying notes are
an integral part of these financial statements.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

COMBINED STATEMENT OF CHANGES IN FINANCIAL POSITION
(In thousands)

	Year ended June 30, 1987					
	Palo Verde Project	Southern Transmission Project	Hoover Uprating Project	Head-Phoenix Project	Total	Year ended June 30, 1986 Total
Funds provided by (used for)						
Operations						
Revenues	$ 51,949	$ 40,617	$ 66		$ 92,632	$ 10,042
Expenses	(70,678)	(98,858)	(66)		(169,602)	(17,382)
Charges not involving funds:						
Depreciation and amortization	19,098	18,089			37,187	5,362
Other, net	9,723	8,052			17,775	7,933
	10,092	(32,100)	-0-		(22,008)	5,955
Financing						
Sale of revenue bonds			34,293		34,293	
Sale of refunding bonds	679,434				679,434	1,343,525
Defeasance of revenue bonds	(508,703)				(508,703)	(1,130,929)
Defeasance of bond anticipation notes						(200,000)
Reduction in long-term debt						(75,000)
Bond issue costs	(106,289)		(1,260)		(107,549)	(232,270)
	64,442		33,033		97,475	(294,674)
Utility plant	(55,131)	(14,395)	(3,064)	$(1,073)	(73,663)	(191,950)
Other, net		23,157	48	12	23,217	(1,033)
	$ 19,403	$(23,338)	$30,017	$(1,061)	$ 25,021	$ (481,702)
Increase (Decrease) in funds						
Investments	$(52,336)	$(63,100)	$30,962	$ (766)	$(85,240)	$ (438,017)
Advance to Intermountain Power Agency		20,981			20,981	
Interest receivable	(515)	690	502		677	(21,910)
Cash	340		66	(5)	401	(56)
Accounts receivable	(2,560)	2,649		(10)	79	(1,233)
Bond anticipation notes	75,000				75,000	(75,000)
Accrued interest payable	4,529	11,107	(689)	(365)	14,582	6,266
Accounts payable and accrued expenses	(5,055)	4,335	(824)	85	(1,459)	48,248
	$ 19,403	$(23,338)	$30,017	$(1,061)	$ 25,021	$ (481,702)

The accompanying notes are an integral part of these financial statements.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

NOTES TO FINANCIAL STATEMENTS

NOTE A - Organization and purpose:

Southern California Public Power Authority (Authority), a public entity organized under the laws of the State of California, was formed by a Joint Powers Agreement dated as of November 1, 1980 pursuant to the Joint Exercise of Powers Act of the State of California. The Authority's participant membership consists of ten Southern California cities and one public district of the State of California. The Authority was formed for the purpose of planning, financing, developing, acquiring, constructing, operating and maintaining projects for the generation and transmission of electric energy for sale to its participants. The Joint Powers Agreement has a term of fifty years.

Palo Verde Project - The Authority, pursuant to an assignment agreement dated as of August 14, 1981 with the Salt River Project Agricultural Improvement and Power District (Salt River Project), has purchased a 5.91% interest in the Palo Verde Nuclear Generating Station (PVNGS), a 3,810 megawatt nuclear-fueled generating station being constructed near Phoenix, Arizona, and a 6.55% share of the right to use certain portions of the Arizona Nuclear Power Project Valley Transmission System (collectively, the Palo Verde Project). Units 1 and 2 of the Palo Verde Project began commercial operation in January and September 1986, respectively. Unit 3 is scheduled for commercial operation in January 1988.

Mead-Phoenix Project - The Authority is also studying the feasibility of constructing the proposed Mead-Phoenix DC Intertie Project (Mead-Phoenix Project), a transmission line from Arizona to Nevada. The Authority's present interest in the Mead-Phoenix Project is 93.75%.

Note A - Organization and purpose:
(Continued)

Southern Transmission Project - The Authority, pursuant to an agreement dated as of May 1, 1983 with the Intermountain Power Agency (IPA), has agreed to make payments-in-aid of construction to IPA to defray all the costs of acquisition and construction of the Southern Transmission System Project (STS), a transmission line which will provide for the transmission of energy from the Intermountain Power Project in Utah to Southern California. The Authority entered into an agreement also dated as of May 1, 1983 with six of its members pursuant to which each member assigned its entitlement to capacity of the Southern Transmission Project to the Authority in return for the Authority's agreement to make payments-in-aid of construction to IPA. STS commenced commercial operations in July 1986.

Hoover Uprating Project - On August 13, 1986, six participant members of the Authority entered into an agreement with the Bureau of Reclamation of the United States of America (Bureau) to make advance payments toward the cost of uprating the Hoover Dam Facility's generating equipment. Construction is scheduled for completion by September 1992. The Authority will have an 18.68% interest in contingent capacity of the Hoover Uprating Project. Several "uprated" generators of the Hoover Uprating Project commenced commercial operations in June 1987.

NOTE B - Summary of significant accounting policies:

The Authority maintains its records substantially in accordance with accounting principles and methods prescribed by the Federal Energy Regulatory Commission and the California Public Utilities Commission. The Authority is not subject to regulation by such commissions.

Utility plant - All expenditures, including general administrative and other overhead expenses, payments-in-aid of construction, interest net of related investment income, deferred cost

NOTE B - Summary of significant accounting policies:
(Continued)

amortization and the fair value of test power generated and delivered to the participants are capitalized as utility plant construction work in progress until a facility begins commercial operation.

The Authority's share of costs associated with PVNGS Units 1 and 2 is included as Utility Plant in Service. Depreciation is provided using the straight-line method over the assets estimated useful lives of thirty-five years. Nuclear fuel is amortized and charged to expense on the basis of actual thermal energy produced relative to total thermal energy expected to be produced over the life of the fuel. A contract has been entered into with the United States Department of Energy for disposal of the spent fuel.

The costs associated with the STS project are included as Utility Plant in Service. Depreciation is provided using the straight-line method over the assets estimated useful lives of primarily thirty-five years.

Nuclear decommissioning - Decommissioning of PVNGS is projected to commence sometime after 2022. Estimated future decommissioning costs are provided over the commercial life of PVNGS through annual charges to expense.

Deferred costs - Deferred costs are shown net of accumulated amortization. Unamortized debt issue costs, including the cost of refunding, are amortized over the terms of the respective issues. Other deferred costs are amortized generally over five years.

Investments - Investments include United States Government and governmental agency securities and repurchase agreements which are collateralized by such securities. These investments are stated at amortized cost. As discussed in Notes C and D, all of the investments are restricted as to their use.

NOTE B - Summary of significant accounting policies:
(Continued)

Investments, in thousands, were as follows:

	June 30,			
	1987		1986	
Project	Carrying Value	Market	Carrying Value	Market
Palo Verde	$222,229	$232,845	$274,565	$291,969
Southern Transmission	177,427	189,351	219,546	233,641
Hoover Uprating	30,962	30,651		
Mead-Phoenix	2,910	2,910	3,677	3,679
	$433,528	$455,757	$497,788	$529,289

Revenues - Revenues consist of billings to participants for the sales of electric energy and of transmission service in accordance with the participation agreements. Generally, revenues are fixed at a level to recover all operating and debt service costs over the commercial life of the plant. (See Note F).

Debt expenses - Debt expenses include interest on debt, the amortization of bond premiums and discounts, and debt issue and refunding costs. Income from investments is recorded as a reduction of debt expense.

NOTE C - Long-term debt:

Palo Verde Project - To finance the purchase and construction of the Authority's share of the Palo Verde Project, the Authority has issued Power Project Revenue Bonds and Power Project Bond Anticipation Notes pursuant to the Authority's Indenture of Trust dated as of July 1, 1981 (Bond Indenture), as amended and supplemented, and the Authority's Power Project Bond Anticipation Note Resolution (Note Resolution) adopted August 13, 1982, as amended and supplemented. Reference is made to the Combined Supplemental Schedule of Revenue and Refunding Bonds Payable at June 30, 1987 for details related to outstanding bonds.

NOTE C - Long-term debt:
(Continued)

The Bond Indenture provides that the Revenue Bonds shall be special, limited obligations of the Authority payable solely from and secured solely by (1) proceeds from the sale of bonds, (2) all revenues, incomes, rents and receipts attributable to the Palo Verde Project (see Note E) and interest on all moneys or securities (other than in the Construction Fund) held pursuant to the Bond Indenture and (3) all funds established by the Bond Indenture (excluding the Decommissioning Account in the Reserve and Contingency Fund); subject to the provisions of the Palo Verde Project Bond Indenture providing for the application thereof. The Note Resolution provides that the Bond Anticipation Notes shall be special, limited obligations of the Authority payable from the proceeds of additional bonds, notes or loans obtained under the Revolving Credit Agreement. During fiscal 1987, the Bond Anticipation Notes were defeased and are considered extinguished for purposes of financial statement presentation.

All outstanding Power Project Revenue Term Bonds, at the option of the Authority, are subject to redemption prior to maturity.

The Bond Indenture requires mandatory sinking fund instalments to be made beginning in fiscal 1998 for the 1982 Series A Bonds, 1999 for the 1982 Series B Bonds and the 1983 Series A Bonds, 2001 for the 1984 Series A Bonds and 1985 Series A Bonds, 2005 for the 1985 Series B Bonds and 2003 for the 1986 Series A Bonds, the 1986 Series B Bonds and the 1987 Series A Bonds. Scheduled principal maturities for the Palo Verde Project during the five fiscal years succeeding June 30, 1987 are $13,095,000 in 1989, $13,870,000 in 1990, $14,745,000 in 1991 and $15,790,000 in 1992. No principal maturities of bonds outstanding at June 30, 1987 are scheduled for fiscal 1988. The effective interest rate on outstanding debt during 1987 was 8.4%.

The funds required by the Bond Indenture contain balances, in thousands, as follows:

NOTE C - Long-term debt:

(Continued)

	June 30, 1987	June 30, 1986
Construction Fund-Initial Facilities Account	$ 38,454	$ 52,826
Debt Service Fund -		
Debt Service Account	67,711	105,473
Debt Service Reserve Account	90,235	98,299
Bond Anticipation Note Fund	30	6,080
Revenue Fund	1	2,720
Operating Fund	15,739	5,016
Reserve and Contingency Fund	8,169	6,272
General Reserve Fund	4,181	345
Total Special Funds	$224,520	$277,031

Southern Transmission Project - To finance payments-in-aid of construction to IPA for construction of the Southern Transmission Project, the Authority has issued Transmission Project Revenue Bonds pursuant to the Authority's Indenture of Trust dated as of May 1, 1983 (Bond Indenture). Reference is made to the Supplemental Schedule of Revenue and Refunding Bonds Payable at June 30, 1987 for details related to the outstanding bonds.

The Bond Indenture provides that the Revenue Bonds shall be special, limited obligations of the Authority payable solely from and secured solely by (1) proceeds from the sale of bonds, (2) all revenues, incomes, rents and receipts attributable to the Southern Transmission Project (see Note E) and interest on all moneys or securities (other than in the Construction Fund) held pursuant to the Bond Indenture and (3) all funds established by the Bond Indenture; subject to the provisions of the Bond Indenture providing for the application thereof.

All outstanding Transmission Project Revenue Term Bonds, at the option of the Authority, are subject to redemption prior to maturity.

NOTE C - Long-term debt:
(Continued)

The Bond Indenture requires mandatory sinking fund instalments to be made beginning in fiscal 2000 for the 1984 Series A Bonds, 2001 for the 1984 Series B Bonds and the 1985 Series A Bonds, 2003 for the 1986 Series A Bonds and 2002 for the 1986 Series B Bonds. Scheduled principal maturities for the Southern Transmission Project during the five fiscal years succeeding June 30, 1987 are $2,260,000 in 1989, $3,785,000 in 1990, $7,945,000 in 1991 and $8,485,000 in 1992. No principal maturities of bonds outstanding at June 30, 1987 are scheduled for fiscal 1988. The effective interest rate on outstanding debt during 1987 was 7.7%.

The special funds required by the Bond Indenture contain balances, in thousands, as follows:

	June 30, 1987	June 30, 1986
Construction Fund - Initial Facilities Account	$ 18,638	$ 94,857
Debt Service Fund -		
Debt Service Account	38,623	35,705
Debt Service Reserve Account	91,192	91,262
Revenue Fund	1	
Operating Fund	6,249	
General Reserve Fund	4,711	
Total Special Funds	$ 159,414	$ 221,824

In addition, $20,981,000 has been advanced during fiscal year 1987 to IPA for SCPPA's share of the initial working capital for the Southern Transmission Project. The advance will be returned to SCPPA at the end of the project.

Hoover Uprating Project - Pursuant to the Authority's Indenture of Trust dated as of March 1, 1986 (Bond Indenture), the Authority issued $34,435,000 of Hydroelectric Power Project Revenue Bonds 1986 Series A to finance advance payments to the U. S. Bureau of Reclamation for application to the costs of the Hoover Uprating Project. The Bond Indenture provides that the Revenue Bonds shall

NOTE C - Long-term debt:
(Continued)

be special, limited obligations of the Authority payable solely from and secured solely by (1) the proceeds of the sale of the bonds, (2) all revenues from sales of energy to project participants, (3) interest or other receipts derived from any moneys or securities held persuant to the Bond Indenture, and (4) all funds established by the Indenture of Trust (except for the Interim Advance Payments Account in the Advance Payment Fund); subject to the provisions of the Bond Indenture providing for the application thereof.

All outstanding Hydroelectric Power Project Revenue Term Bonds, at the option of the Authority, are subject to redemption prior to maturity.

The Bond Indenture requires mandatory sinking fund instalments to be made beginning in fiscal 2002 for the 1986 Series A Bonds. No scheduled principal maturities of bonds outstanding at June 30, 1987 are scheduled for fiscal 1988 through fiscal 1992. The effective interest rate on outstanding debt during 1987 was 8.1%.

The funds required by the Bond Indenture contain balances, in thousands, as follows:

	June 30, 1987
Advance Payments Fund	$27,277
Debt service Fund	
Debt Service Account	932
Debt Service Reserve Account	3,255
Total Special Funds	$31,464

Summary of Special Funds - The Bond Indentures and Note Resolution for each of the three projects require the above listed special funds to be established to account for the Authority's receipts and disbursements. The moneys and investments held in

NOTE C - Long-term debt:
(Continued)

these funds are restricted in use to the purposes stipulated in the bond indentures and note resolution. A summary of these funds follows:

Fund	Held by	Purpose
Construction	Trustee	To disburse funds for the acquisition and construction of the Project
Debt Service	Trustee	To pay interest and principal related to the Revenue Bonds
Bond Anticipation Note	Trustee	To pay interest related to the Bond Anticipation Note
Revenue	Trustee	To initially receive all revenues and disburse them to other funds
Operating	Trustee	To pay operating expenses
Reserve and Contingency	Trustee	To pay capital improvements and make up deficiencies in other funds and, in the case of the Palo Verde Project, accumulate funds for decommissioning
General Reserve	Trustee	To make up any deficiencies in other funds
Advance Payments	Trustee	To disburse funds for the cost of acquisition capacity of the project

Refunding bonds - During fiscal 1987 the proceeds from the sale of $707,275,000 of Power Project Refunding Bonds were used to advance refund $630,120,000 of previously issued bonds. In connection therewith, the net proceeds of the refunding bonds have been invested in securities of the United States Government, the principal and interest from which will be sufficient to fund the remaining principal, interest and call premium payments on all refunded bonds until the stated first call dates of the respective

Note C - Long-term debt:
(Continued)

issues. Accordingly, all amounts related to the refunded bonds have been removed from the balance sheets and the cost of refunding the debt is included in unamortized debt expenses at June 30, 1987. At June 30, 1987 the aggregate amount of debt considered to be extinguished was $1,875,050,000.

NOTE D - Long-term bank loan payable:

At June 30, 1987, the Authority had borrowed $14,148,000 to finance the feasibility study and development costs of the Mead-Phoenix Project. This loan bears interest at approximately 67% of the prime rate; however, the interest rate cannot exceed 12%. The average interest rate on this loan was 5.2% and 6.1% during 1987 and 1986.

The proceeds of the loan were deposited in a Development Fund for which the lender is the trustee and can only be used for payment of Mead-Phoenix Project development costs, costs of issuance of the loan, including general and administrative expenses of the Authority related to the Mead-Phoenix Project, and loan principal and interest. At June 30, 1987 and 1986, the balance in the Development Fund was $2,918,000 and $3,690,000 of which substantially all were invested in securities of the United States Government.

If the Mead-Phoenix Project is terminated for any reason prior to the issuance of long-term bonds to refinance the loan, ten California cities, the Salt River Project and the United States Department of Energy, Western Area Power Administration, have contracted to make payments to the Authority based on their participation percentage sufficient to retire the loan and accrued interest thereon. The loan is secured solely by the restricted assets and the above mentioned contracts.

NOTE E - Power sales and transmission service contracts:

The Authority has sold its entitlement to the output of the Palo Verde Project pursuant to power sales contracts with ten member participants (see Note G). Under the terms of the power sales contracts, the purchasers are entitled to power output from the Palo Verde Nuclear Generating Station and are obligated to make payments on a "take or pay" basis for their proportionate share of operating and maintenance expenses and debt service on Power Project Revenue Bonds and other debt, whether or not the Palo Verde Project or any part thereof has been completed, is operating or operable, or its output is suspended, interfered with, reduced or curtailed or terminated. The contracts expire in 2030 and, as long as any Power Project Revenue Bonds are outstanding, cannot be terminated or amended in any manner which will impair or adversely affect the rights of the bondholders.

The Authority has entered into transmission service contracts with six member participants (see Note G). Under the terms of the transmission service contracts, the project participants are entitled to transmission service utilizing the Southern Transmission Project and are obligated to make payments on a "take or pay" basis for their proportionate share of operating and maintenance expenses and debt service on Transmission Project Revenue Bonds and other debt, whether or not the Southern Transmission Project or any part thereof has been completed, is operating or is operable, or its service is suspended, interfered with, reduced or curtailed or terminated. The contracts expire in 2027 and, as long as any Transmission Project Revenue Bonds are outstanding, cannot be terminated or amended in any manner which will impair or adversely affect the rights of the bondholders.

NOTE F - Costs recoverable from future billings to participants:

Billings to participants are designed to recover "costs" as defined by the power sales and transmission service agreements. The billings are structured to systematically provide for the debt

NOTE F - Costs recoverable from future billings to participants: (Continued)

requirements, operating funds and reserves in accordance with these agreements. Those expenses, according to generally accepted accounting principles, which are not included as "costs" are deferred to such periods as they are intended to be recovered through billings.

NOTE G - Related party transactions:

Under the terms of the various contracts, the Authority reimbursed the following entities for work performed on the respective projects. The Department of Water and Power of the City of Los Angeles has performed administrative and other work for the Authority totaling $469,000 and $310,000 for fiscal 1987 and 1986. The Arizona Public Service Company (APS), as project manager of the Palo Verde Project, billed the Authority for various construction, operating and maintenance costs totaling $36,005,000 and $50,101,000 for fiscal 1987 and 1986. The Intermountain Power Authority billed the Authority for payments-in-aid of construction, operating and maintenance costs relating to the Southern Transmission Project amounting to $25,267,000 and $62,561,000 for fiscal 1987 and 1986. The U.S. Bureau of Reclamation as project manager of the Hoover Uprating Project, billed the Authority for various construction costs totaling $2,448,000 for fiscal 1987. The Salt River Project, as development manager of the Mead-Phoenix Project, billed the Authority for various development costs amounting to $470,000 and $1,165,000 for fiscal 1987 and 1986.

NOTE G - Related party transactions:
(Continued)

Member participants have the following participation percentages in the Authority's interest in the four projects (see Note A):

Project Participation Percentage

Participant	Palo Verde	Southern Transmission	Hoover Uprating Project	Mead-Phoenix
City of Los Angeles	67.0%	59.5%		61.2%
City of Anaheim		17.6	42.6%	15.0
City of Riverside	5.4	10.2	31.9	6.0
Imperial Irrigation District	6.5			
City of Vernon	4.9			3.0
City of Azusa	1.0		4.2	.6
City of Banning	1.0		2.1	.6
City of Colton	1.0		3.2	.6
City of Burbank	4.4	4.5	16.0	5.0
City of Glendale	4.4	2.3		5.0
City of Pasadena	4.4	5.9		3.0
	100.0%	100.0%	100.0%	100.0%

NOTE H - Commitments and contingencies:

The Authority estimates that the total financing requirements for its interest in the Hoover Uprating Project will approximate $34 million, of which substantially all will be expended for payments for capacity and associated firm energy and the acquisition of entitlements to capability. Construction is scheduled for completion in September 1992.

NOTE H - Commitments and contingencies:
(Continued)

The Authority is involved in various legal actions. In the opinion of management, the outcome of such litigation or claims will not have a material effect on the financial position of the Authority or the respective separate projects.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

INDEX TO SUPPLEMENTAL FINANCIAL DATA AND SCHEDULES

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

COMBINED SUPPLEMENTAL SCHEDULE OF REVENUE AND REFUNDING BONDS PAYABLE AT JUNE 30, 1987 (In thousands)

	Series	Date of Sale	Effective Interest Rate	Maturity on July 1	Total
Palo Verde Project Revenue and Refunding Bonds	1982A	8/13/82	10.9%	1988 to 2017	$ 26,325
	1982B	11/12/82	7.7%	1988 to 2017	44,445
	1983A	4/ 8/83	8.8%	1988 to 2017	36,015
	1984A	7/18/84	10.3%	1990 to 2004	24,090
	1985A	5/22/85	8.7%	1988 to 2014	12,515
	1985B	7/ 2/85	9.1%	1988 to 2017	101,815
	1986A	3/13/86	8.2%	1988 to 2015	157,645
	1986B	12/16/86	7.2%	1988 to 2017	354,630
	1987A	2/11/87	6.9%	1988 to 2017	352,645
					1,110,125
Southern Transmission Project Revenue and Refunding Bonds	1984A	2/ 9/84	9.3%	1990 to 2004	65,945
	1984B	10/17/84	10.2%	1990 to 2000	18,770
	1985A	8/15/85	8.9%	1989 to 2021	121,620
	1986A	3/18/86	8.0%	1988 to 2021	371,720
	1986B	4/29/86	7.5%	1988 to 2023	480,010
					1,058,065
Hoover Uprating Project Revenue Bonds	1986A	8/13/86	8.1%	1993 to 2017	34,435
Total Principal Amount					2,202,625
Less: Unamortized Bond Discount -					
Palo Verde Project Revenue and Refunding Bonds					70,790
Southern Transmission Project Revenue and Refunding Bonds					58,509
Hoover Uprating Power Project Revenue Bonds					142
Total Unamortized Bond Discount					129,441
Total Revenue and Refunding Bonds Less Unamortized Bond Discount					$2,073,184

Long-term debt representing a bank loan of $14,148,000 for the Mead-Phoenix Project and bonds which have been refunded are excluded from this schedule.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

PALO VERDE PROJECT

SUPPLEMENTAL BALANCE SHEET
(In thousands)

	June 30, 1987	June 30, 1986
ASSETS		
Utility plant		
Production	$ 368,755	$203,247
Transmission	3,512	1,864
General	58	33
	372,325	205,144
Less - Accumulated depreciation	15,983	3,340
	356,342	201,804
Construction work in progress	224,809	342,317
Nuclear fuel, at amortized cost	36,415	37,412
Net utility plant	617,566	581,533
Special funds		
Investments	222,229	274,565
Interest receivable	1,753	2,268
Cash	538	198
	224,520	277,031
Accounts receivable	2,859	5,419
Costs recoverable from future billings to participants	26,069	7,340
Deferred costs		
Unamortized debt expenses, less accumulated amortization of $13,698 and $6,949 in 1987 and 1986	218,503	118,963
Other deferred costs	1,542	1,972
	220,045	120,935
	$1,091,059	$992,258
LIABILITIES		
Long-term debt	$1,039,335	$866,060
Current liabilities		
Bond anticipation notes		75,000
Accrued interest payable	37,454	41,983
Accounts payable and accrued expenses	14,270	9,215
	51,724	126,198
Commitments and contingencies		
	$1,091,059	$992,258

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

PALO VERDE PROJECT

SUPPLEMENTAL STATEMENT OF OPERATIONS
(In thousands)

	June 30, 1987	June 30, 1986
Operating revenues		
Sales of electric energy	$ 51,949	$ 10,042
Operating expenses		
Nuclear fuel expense	$ 7,259	$ 2,022
Other operation	10,162	3,395
Maintenance	3,192	1,440
Depreciation	12,643	3,340
Expense charged to projects during construction	(370)	(1,056)
Total operating expenses	32,886	9,141
Debt expenses		
Interest on debt, net	78,290	84,294
Allowance for borrowed funds used during construction	(40,498)	(76,053)
Net debt expense	37,792	8,241
	70,678	17,382
Costs recoverable from future billings to participants	(18,729)	(7,340)
Total expenses	$ 51,949	$ 10,042

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

PALO VERDE PROJECT

SUPPLEMENTAL STATEMENT OF CHANGES IN FINANCIAL POSITION
(In thousands)

	Year ended June 30, 1987	1986
Funds provided by (used for)		
Operations		
Revenues	$ 51,949	$ 10,042
Expenses	(70,678)	(17,382)
Charges not involving funds:		
Depreciation and amortization	19,098	5,362
Other, net	9,723	7,933
	10,092	5,955
Financing		
Sale of refunding bonds	679,434	333,312
Defeasance of revenue bonds	(508,703)	(289,320)
Reduction of long-term debt		(75,000)
Bond issue costs	(106,289)	(57,653)
	64,442	(88,661)
Utility plant	(55,131)	(87,465)
Other, net		(1,972)
	$ 19,403	$(172,143)
Increase (Decrease) in funds		
Investments	$(52,336)	$ (94,031)
Interest receivable	(515)	(12,308)
Cash	340	(56)
Accounts receivable	(2,560)	4,741
Bond anticipation notes	75,000	(75,000)
Accrued interest payable	4,529	6,725
Accounts payable and accrued expenses	(5,055)	(2,214)
	$ 19,403	$(172,143)

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

PALO VERDE PROJECT

SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS REQUIRED BY THE BOND INDENTURE

YEAR ENDED JUNE 30, 1987
(In thousands)

	Construction Fund Initial Facilities Account	Debt Service Fund	Bond Anticipation Note Fund	Revenue Fund	Operation Fund	Reserve & Contingency Note Fund	General Reserve Fund	Total
Balance at June 30, 1986	$53,386	$201,277	$ 6,041	$ 2,719	$ 4,963	$6,456	$ 342	$275,184
Additions								
Bond and note proceeds	75,312							75,312
Bond and note interest received		4,561						4,561
Investment earnings	3,694	18,753	225	292	405	830	13	24,212
Sales - power	1,350			59,064	606			61,020
Other income	142				160			302
Transfer - bond closing	(7,893)	(22,841)						(30,734)
Transfer - note payment	(73,719)							(73,719)
Transfer - interest payment		67,803	(3,000)					64,803
Transfer - investments	3,600			(195)	1,460		(1,265)	3,600
Transfer - investment earnings	13,313	(21,865)	(237)	9,661	(361)	(459)	(51)	1
Transfer - power sales receipts		44,087		(61,374)	14,613	1,518	1,156	0
Transfer - other	622	304		(10,167)	6,178	132	3,983	1,052
Total	16,421	90,802	(3,012)	(2,719)	23,061	2,021	3,836	130,410
Deductions								
Construction expenditures	19,933							19,933
Operating expenditures	424				11,264			11,688
Fuel costs	6,189							6,189
Interest paid	54	133,658	3,000		61			136,773
Property tax paid	1,686				1,124			2,810
Financing costs	2,346							2,346
Interest paid on investment purchases	774	515						1,289
Premium paid on investment purchases	167							167
Total	31,573	134,173	3,000	0	12,449	0	0	181,195
Balance at June 30, 1987	$38,234	$157,906	$ 29	$ 0	$15,575	$8,477	$4,178	$224,399

This schedule summarizes the receipts and disbursements in funds required under the bond indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable of $1,753 and $2,268 at June 30, 1987 and 1986, nor do they include total amortized net investment premiums of ($1,632) and ($421) at June 30, 1987 and 1986.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

SOUTHERN TRANSMISSION PROJECT

SUPPLEMENTAL BALANCE SHEET
(In thousands)

	June 30, 1987	June 30, 1986
ASSETS		
Utility plant		
Transmission	$ 633,034	
General	18,068	
	651,102	
Less - Accumulated depreciation	18,089	
	633,013	
Contruction work in progress		$ 636,706
Net utility plant	633,013	636,706
Special funds		
Investments	156,446	219,546
Advance to Intermountain Power Agency	20,981	
Interest receivable	2,968	2,278
	180,395	221,824
Accounts receivable	2,662	13
Costs recoverable from future billings to participants	58,241	
Deferred costs		
Unamortized debt expenses, less accumulated amortization of $13,999 and $7,121 in 1987 and 1986	167,084	197,122
	$1,041,395	$1,055,665
LIABILITIES		
Long-term debt	$ 999,556	$ 998,385
Current liabilities		
Accrued interest	38,611	49,717
Accounts payable and accrued expenses	3,228	7,563
	41,839	57,280
Commitments and contingences		
	$1,041,395	$1,055,665

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

SOUTHERN TRANSMISSION PROJECT

SUPPLEMENTAL STATEMENT OF OPERATIONS
(In thousands)

	Year ended June 30, 1987
Operating revenues	
Sales of transmission services	$ 40,617
Operating expenses	
Other operation	7,036
Maintenance	3,082
Depreciation	18,089
Total operating expenses	28,207
Debt expenses	
Interest on debt, net	70,651
	98,858
Costs recoverable from future billings to participants	(58,241)
Total expenses	$ 40,617

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

SOUTHERN TRANSMISSION PROJECT

SUPPLEMENTAL STATEMENT OF CHANGES
IN FINANCIAL POSITION
(In thousands)

	Year ended June 30, 1987	1986
Funds provided by (used for)		
Operations		
Revenues	$ 40,617	
Expenses	(98,858)	
Charges not involving funds:		
Depreciation	18,089	
Other, net	8,052	
	(32,100)	
Financing		
Sale of refunding bonds		$1,010,213
Defeasance of bond anticipation notes		(200,000)
Defeasance of revenue bonds		(841,609)
Bond issue costs		(174,617)
		(206,013)
Utility plant	(14,395)	(102,530)
Other, net	23,157	903
	$(23,338)	$ (307,640)
Increase (Decrease) in funds		
Investments	$(63,100)	$ (342,128)
Advance to Intermountain Power Agency	20,981	
Interest receivable	690	(9,602)
Accounts receivable	2,649	(5,984)
Accrued interest	11,107	(472)
Accounts payable and accrued expenses	4,335	50,546
	$(23,338)	$ (307,640)

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

SOUTHERN TRANSMISSION PROJECT

SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS
IN FUNDS REQUIRED BY THE BOND INDENTURE

YEAR ENDED JUNE 30, 1987
(In thousands)

	Construction Fund-Initial Facilities Account	Debt Service Fund	Revenue Fund	Operating Fund	General Reserve Fund	Total
Balance at June 30, 1986	$ 93,836	$124,314	$ -0-	$ -0-	$ -0-	$218,150
Additions						
Investment earnings	3,905	11,080	90	230	581	15,886
Sales			42,071			42,071
Transfer of interest payment		85,841				85,841
Transfer of funds	(38,534)	48,224	(9,751)	6,000	(5,939)	0
Transfer - transmission sales receipt		14,556	(38,201)	12,958	10,687	0
Other receipts			117			117
Total	(34,629)	159,701	(5,674)	19,188	5,329	143,915
Deductions						
Payments-in-aid of construction and administrative costs paid	19,255					19,255
Advance to Intermountain Power Agency	20,981					20,981
Operating expenditures				12,728		12,728
Interest paid	142	151,369				151,511
Interest paid on investment purchases	139	375			267	781
Financing costs paid	539					539
Transfer of investment earnings	(434)	5,407	(5,674)	223	478	0
Other	105					105
Total	40,727	157,151	(5,674)	12,951	745	205,900
Balance at June 30, 1987	$ 18,480	$126,864	$ -0-	$ 6,237	$ 4,584	$156,165

This schedule summarizes the receipts and disbursements in funds required under the bond indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable of $2,968 and $2,278 at June 30, 1987 and 1986, nor do they include total amortized net investment discounts and premiums of $281 and $1,396 at June 30, 1987 and 1986.

NEW ISSUE

In the opinion of Bond Counsel, assuming compliance with the tax covenant described herein, under existing statutes, regulations, rulings and court decisions, interest on the 1987 Bonds is excluded from gross income for Federal income tax purposes. See, however, "Federal and State Income Taxes" herein for a description of certain other taxes on corporations. Bond Counsel is further of the opinion that, under the Act, interest on the 1987 Bonds is exempt from personal income taxes of the State of California.

$352,645,000

Southern California Public Power Authority

(a public entity organized under the laws of the State of California)

Power Project Revenue Bonds, 1987 Refunding Series A

(Palo Verde Project)

Dated January 1, 1987 — *Due July 1, as shown below*

Semiannual interest on the 1987 Bonds (interest payable each January 1 and July 1, commencing July 1, 1987) is payable by check or draft mailed to the registered owner. Principal of the 1987 Bonds is payable at the principal corporate trust offices of First Interstate Bank of California, Los Angeles, California, Trustee. The 1987 Bonds will be issued as fully registered bonds in the denomination of $5,000 or any integral multiple thereof.

The 1987 Bonds are redeemable prior to maturity as set forth herein.

The 1987 Bonds are being issued (i) to advance refund $233,210,000 aggregate principal amount of the Authority's Power Project Revenue Bonds issued to finance costs of acquisition and construction of the Authority's interest and rights in the Palo Verde Nuclear Generating Station located near Phoenix, Arizona and certain associated facilities, and (ii) to finance costs of acquisition and construction of the Authority's interest and rights in the Palo Verde Nuclear Generating Station and certain associated facilities, including the payment at maturity of the Authority's $75,000,000 aggregate principal amount of Power Project Bond Anticipation Notes, 1984 Series A, maturing June 1, 1987.

The principal of, premium, if any, and interest on the 1987 Bonds are payable solely from and secured solely by a pledge and assignment of Revenues and certain other moneys as described herein. Such Revenues include all payments attributable to the Project to be made to the Authority by the Project Participants pursuant to the Power Sales Contracts. Such payments, together with other available Revenues, are to equal the Authority's costs relating to the Project. Each Project Participant has agreed to make its share of such payments solely from its electric system revenues. The payment obligations of the Project Participants under the Power Sales Contracts are not contingent upon the operation of the Project or the performance or nonperformance by any party under any agreement for any cause whatever.

The 1987 Bonds are not obligations of the State of California, any public agency thereof (other than the Authority), any member of the Authority or any Project Participant and neither the faith and credit nor the taxing power of any of the foregoing (including the Authority) is pledged for the payment of the 1987 Bonds. The Authority has no taxing power.

$69,405,000 Serial Bonds

Due July 1	Principal Amount	Rate	Price	Due July 1	Principal Amount	Rate	Price
1988	$3,690,000	3.90%	100%	1996	$ 3,580,000	6 %	100%
1989	3,830,000	4.40	100	1997	3,790,000	6⅛	100
1990	2,655,000	4.80	100	1998	4,030,000	6¼	100
1991	2,775,000	5⅛	100	1999	4,280,000	6⅜	100
1992	2,910,000	5⅜	100	2000	4,545,000	6½	100
1993	3,055,000	5½	100	2001	6,505,000	6.60	100
1994	3,210,000	5¾	100	2002	6,930,000	6.70	100
1995	3,385,000	5.90	100	2003	10,235,000	6¾	100

$ 60,000,000 6⅞% Term Bonds Due July 1, 2006 Price 99½%

$ 50,000,000 6.60% Term Bonds Due July 1, 2008 Price 99¾% †

$133,100,000 6⅞% Term Bonds Due July 1, 2015 to Yield 7.00%

$ 40,140,000 5 % Term Bonds Due July 1, 2017 to Yield 6.80%

(Accrued interest from January 1, 1987 to be added)

The 1987 Bonds are offered when, as and if issued and received by the Underwriters, and subject to the approval of legality by Mudge Rose Guthrie Alexander & Ferdon, Los Angeles, California, Bond Counsel, and certain other conditions. Certain legal matters will be passed upon for the Underwriters by their counsel, O'Melveny & Myers. It is expected that the 1987 Bonds in definitive form will be available for delivery in New York, New York on or about February 11, 1987.

Salomon Brothers Inc

Bear, Stearns & Co. Inc.

The First Boston Corporation

E. F. Hutton & Company Inc.

Merrill Lynch Capital Markets

Smith Barney, Harris Upham & Co.
Incorporated

Daniels & Bell, Inc.

January 29, 1987

† AMBAC Insured.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

BOARD OF DIRECTORS

W. E. Cameron (Glendale)
Bill D. Carnahan (Riverside)
Gale A. Drews (Colton)
Gordon W. Hoyt (Anaheim)
Joseph F. Hsu (Azusa)
Henry C. Lee (Pasadena)
Bruce V. Malkenhorst (Vernon)
Thomas H. McCauley (Burbank)
Norman E. Nichols (Los Angeles)
Kenneth S. Noller (Imperial)
Eldridge Sinclair (Banning)

MANAGEMENT

Gale A. Drews	— President
W. E. Cameron	— Vice President
Eldon A. Cotton	— Secretary
Arthur T. Devine	— Executive Director, Treasurer/Auditor
Frank Salas	— Assistant Secretary

PROJECT PARTICIPANTS

Department of Water and Power of The City of Los Angeles
Imperial Irrigation District
City of Riverside
City of Vernon
City of Burbank
City of Glendale
City of Pasadena
City of Azusa
City of Banning
City of Colton

TRUSTEE, REGISTRAR AND PAYING AGENT

First Interstate Bank of California
Los Angeles, California

CONSULTING ENGINEER

R. W. Beck and Associates
Seattle, Washington

BOND COUNSEL

Mudge Rose Guthrie Alexander & Ferdon
Los Angeles, California

LEGAL COUNSEL

Rourke & Woodruff, a Professional Corporation
Orange, California

FINANCIAL ADVISOR

James J. Lowrey & Co., Incorporated
New York, New York

No dealer, broker, salesman or other person has been authorized by Southern California Public Power Authority or by the Underwriters to give any information or to make any representations, other than as contained in this Official Statement, and if given or made such other information or representations must not be relied upon as having been authorized by the Authority or the Underwriters. This Official Statement does not constitute an offer to sell or the solicitation of an offer to buy, nor shall there be any sale of the 1987 Bonds by any person in any jurisdiction in which it is unlawful for such persons to make such offer, solicitation or sale.

The information set forth herein has been furnished by the Authority and the Project Participants, and includes information obtained from other sources which are believed to be reliable, but no representation as to the accuracy or completeness of such information is made by the Underwriters. The information and expressions of opinion contained herein are subject to change without notice and neither the delivery of this Official Statement nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in the affairs of the Authority or any Project Participant since the date hereof.

IN CONNECTION WITH THE OFFERING OF THE 1987 BONDS, THE UNDERWRITERS MAY OVERALLOT OR EFFECT TRANSACTIONS WHICH STABILIZE OR MAINTAIN THE MARKET PRICE OF SUCH BONDS AT LEVELS ABOVE THAT WHICH MIGHT OTHERWISE PREVAIL IN THE OPEN MARKET. SUCH STABILIZING, IF COMMENCED, MAY BE DISCONTINUED AT ANY TIME.

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Official Statement
relating to
$352,645,000

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

Power Project Revenue Bonds, 1987 Refunding Series A

INTRODUCTION

This Official Statement (which includes the cover page, the table of contents and the Appendices attached hereto) is furnished by Southern California Public Power Authority (the "Authority"), a joint powers agency and a public entity organized under the laws of the State of California, to provide information concerning the Project described herein, and the $352,645,000 aggregate principal amount of Power Project Revenue Bonds, 1987 Refunding Series A (the "1987 Bonds") to be issued by the Authority.

The 1987 Bonds are being issued pursuant to the provisions relating to the joint exercise of powers found in Chapter 5 of Division 7 of Title 1 of the Government Code of California, as amended (the "Act"), and the Authority's Indenture of Trust (the "Original Indenture"), dated as of July 1, 1981, by and between the Authority and First Interstate Bank of California, as trustee (the "Trustee"), as amended and supplemented by the First Supplemental Indenture of Trust, dated as of August 1, 1982, by and between the Authority and the Trustee, and as supplemented by the Ninth Supplemental Indenture of Trust, dated as of January 1, 1987, by and between the Authority and the Trustee. The Original Indenture and indentures supplemental thereto and amendatory thereof, including the First Supplemental Indenture of Trust and the Ninth Supplemental Indenture of Trust, are herein collectively referred to as the "Bond Indenture". The 1987 Bonds and other bonds heretofore or hereafter issued by the Authority pursuant to the Act and the Bond Indenture, to the extent Outstanding (as defined in the Bond Indenture) are herein referred to as the "Bonds".

The Authority currently has Outstanding $990,690,000 aggregate principal amount of Bonds, including the Bonds being refunded by the 1987 Bonds (together, the "Prior Series Bonds"), issued to finance costs of acquisition and construction of the Authority Interest (hereinafter defined). Upon issuance of the 1987 Bonds, $1,110,125,000 aggregate principal amount of Bonds will be Outstanding.

The 1987 Bonds are being issued by the Authority (i) to advance refund $120,820,000 aggregate principal amount of the Authority's Power Project Revenue Bonds, 1985 Refunding Series A, maturing July 1, 2012; $62,390,000 aggregate principal amount of the Authority's Power Project Revenue Bonds, 1985 Series B Refunding, maturing July 1, 2011; and $50,000,000 aggregate principal amount of the Authority's Power Project Revenue Bonds, 1985 Refunding Series B, maturing July 1, 2017; (together, the "Refunded Bonds") and (ii) to finance costs of acquisition and construction of the Authority Interest, including the payment at maturity of $75,000,000 aggregate principal amount of Power Project Bond Anticipation Notes, 1984 Series A, maturing June 1, 1987 (the "Prior Series Notes") which were issued pursuant to the Act and the Authority's Power Project Bond Anticipation Note Resolution, adopted June 7, 1984 (the "Note Resolution"). See "The Authority's Refunding Plan and Payment of Prior Series Notes".

The Authority

The Authority, the membership of which is comprised of ten cities and one irrigation district of the State of California, was formed pursuant to the Act, and the Joint Powers Agreement, dated as of November 1, 1980 (said Joint Powers Agreement as amended to the date hereof being hereinafter

referred to as the "Joint Powers Agreement"). See "Southern California Public Power Authority — Formation and Membership". Certain duties and responsibilities of the Authority arising in connection with the Project are performed by the Department of Water and Power of The City of Los Angeles (the "Agent" or "Department") pursuant to the Agency Agreement, dated as of July 1, 1981 (the "Agency Agreement"). See "Southern California Public Power Authority — Organization and Management".

The Project and the ANPP Transmission System

The Prior Series Notes and the Prior Series Bonds were issued by the Authority for the purpose of financing the purchase from Salt River Project Agricultural Improvement and Power District ("Salt River Project"), pursuant to the Salt River Project-Authority Palo Verde Nuclear Generating Station Assignment Agreement, dated as of August 14, 1981, as amended (the "Assignment Agreement"), and financing costs of acquisition, construction and placing into operation, of (a)(i) a 5.91% undivided ownership interest in the Palo Verde Nuclear Generating Station, Units 1, 2 and 3 ("PVNGS"), certain associated facilities and contractual rights relating thereto, and (ii) a 5.56% undivided ownership interest in the ANPP High Voltage Switchyard and contractual rights relating thereto; and (b) a 6.55% share of the right to use the Arizona Nuclear Power Project Valley Transmission System. PVNGS, including certain associated facilities and contractual rights and the ANPP High Voltage Switchyard and associated contractual rights are collectively referred to herein as the "Project". Additionally, the Arizona Nuclear Power Project Valley Transmission System is referred to herein as the "ANPP Transmission System". The Authority's ownership interest in and rights to use the Project and the ANPP Transmission System are collectively referred to herein as the "Authority Interest". The transfer of the Authority Interest from Salt River Project to the Authority took place on September 10, 1982 at a cost to the Authority of $265,005,281. The Project and the ANPP Transmission System are presently owned as tenants in common by Salt River Project, Arizona Public Service Company ("APS"), Public Service Company of New Mexico ("PNM") and El Paso Electric Company ("El Paso") pursuant to the Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, as amended (the "Participation Agreement"). The Authority, Southern California Edison Company ("Edison") and the Department are also owners as tenants in common of the Project pursuant to the Participation Agreement, but they have no ownership interest in the ANPP Transmission System. In connection with financing of the Project, APS, PNM and El Paso have transferred portions of their ownership interests in PVNGS and related facilities in various sale and leaseback transactions. See "Availability of Construction Funds and Available Information Concerning Other Owners of Palo Verde Nuclear Generating Station". Pursuant to the Participation Agreement, APS is constructing and will operate and maintain the Project on its behalf and on behalf of the other owners, with the exception of the switchyard portions of the Project which were constructed and are being managed by Salt River Project.

Construction of the Project began on June 10, 1976. The construction of large electric generating facilities such as the Project includes two basic phases. The first phase, identified and reported by APS as "construction," includes erection of the various buildings and installation of equipment and systems. The second phase, identified and reported by APS as "startup," includes certain operational activities such as cleaning systems, starting and testing equipment and systems and measuring performance. The start-up phase is completed upon the loading of nuclear fuel into the reactor pressure vessel. Following fuel loading, the operation of each unit is tested, in a power ascension program, at various power levels up to 100 percent power. The power ascension program is completed upon declaration that the unit has achieved firm power operation at full power.

Units 1 and 2 were declared to have achieved firm power operation on January 27, 1986 and September 18, 1986, respectively. Unit 1 is presently experiencing an unplanned outage, which began on January 18, 1987. This outage is due to a steam generator tube leak in the nuclear steam supply system. While, preliminarily, APS has estimated that the outage will last approximately one month, the

cause of the leakage, the required corrective action and the impact on Project schedule and operations cannot now be determined.

As of December 31, 1986, APS reported that construction of Unit 3 was approximately 99.9% complete. APS also reported that startup of Unit 3 was approximately 96.9% complete. APS has scheduled the loading of nuclear fuel for Unit 3 for the first quarter of 1987. In January 1986, APS estimated that firm power operation at full power for Unit 3 would occur during the third quarter of 1987. This schedule assumes no delay in construction of Unit 3 resulting from such matters as starting up and testing of Unit 3, shortages or delays in receipt of equipment or materials, shortages of labor, strikes or other similar matters. Such delays are common in the construction of facilities such as the Project. To the extent that delays do occur, the estimated completion dates of components of the Project may be delayed. In addition, the participants in the Project, in certain circumstances, might elect to approve a planned schedule delay. Any schedule delays may result in increased Project costs.

APS's current schedule anticipates that the operating license will be received from the Nuclear Regulatory Commission (the "NRC") for Unit 3 in sufficient time to meet the projected power ascension schedule for this unit as set forth above.

Based on, among other things, cost estimates provided by APS and certain assumptions provided by the Agent, the estimated construction costs of the Authority Interest are $465,170,000. The assumptions provided by the Agent include an Authority contingency allowance for uncertainties not included in APS's estimate of the total construction costs for the Project. This contingency allowance could be expended for additional direct labor costs, contractor overheads and escalation associated with the commercial operation schedule for the Project or for such costs should a delay occur in Project completion. The scheduled commercial operation date for Unit 3, as used in the Project Participants' (defined below) power supply planning, is March 1, 1988. This schedule for Unit 3 is approximately three months later than the schedule now estimated by APS.

Power Sales and Transmission

The Authority has sold the entire capability of the Authority Interest in the Project pursuant to power sales contracts (the "Power Sales Contracts") with nine California municipalities and a California irrigation district (collectively, the "Project Participants"). For selected information with respect the the Project Participants, see "The Project Participants" and Appendix B hereto.

The existing power supplies for the Project Participants consist of owned generation and purchases from other utilities. Although the Authority Interest will provide a source of firm capacity and energy to assist in meeting load growth, it is more important to the Project Participants as a source of energy which can be produced from fuel sources other than oil and natural gas.

Under the Power Sales Contracts, the Project Participants are entitled to Project generation capabilities based on their respective Project Entitlement Shares and the Project Participants are obligated to make payments therefor on a "take or pay" basis, that is, whether or not the Authority Interest or any part thereof is operating or is operable (or has been completed), or its output is suspended, interfered with, reduced or curtailed or terminated in whole or in part. The payment obligations under the Power Sales Contracts constitute operating expenses of the respective Project Participants, payable solely from their electric system revenues. See "Security and Sources of Payment for the Bonds — Power Sales Contracts" and "Summary of Certain Provisions of the Power Sales Contracts" in Appendix C hereto.

Pursuant to the Transmission Agreement, dated as of August 14, 1981, as amended, between the Authority and Salt River Project (the "Transmission Agreement"), the Authority has purchased the right to use 6.55% of the capability of the ANPP Transmission System which will be utilized by Salt River Project for delivery of power and energy associated with the Authority Interest, excluding the Project Entitlement of the Imperial Irrigation District (the "District"). The output of the Authority Interest, with the exception of the District's Project Entitlement, will be received by Salt River Project at the transmission side of the high voltage bus of the ANPP High Voltage Switchyard. Salt River Project will make available to the Authority an equivalent amount of power and energy at a

combination of the Navajo Switchyard, the Eldorado Substation or the Mead Substation (the "Project Interconnection Point"). The Navajo Switchyard is located at the Navajo Generating Station in northern Arizona. The Eldorado and Mead substations are located at the southern tip of Nevada, south of Lake Mead, near the Mohave Generating Station. The District has acquired an ownership interest in the Palo Verde to Imperial Valley portion of the APS/San Diego Gas & Electric Company 525 kV Interconnection Project (the "Southwest Powerlink") as a permanent means of transmitting its Project Entitlement. This project was completed in June 1984. The District completed the new 230 kV interconnection between the Southwest Powerlink and the District system in December 1984.

Cost and Entitlement Shares

The following table sets forth the Cost and Entitlement Shares of each of the Project Participants with respect to the Authority Interest.

Project Participants	Cost Share and Entitlement Share
Department of Water and Power of The City of Los Angeles	67.0%
Imperial Irrigation District	6.5
City of Riverside	5.4
City of Vernon	4.9
City of Burbank	4.4
City of Glendale	4.4
City of Pasadena	4.4
City of Azusa	1.0
City of Banning	1.0
City of Colton	1.0
Total	100.0%

Financing Requirement for the Authority Interest

R. W. Beck and Associates (the "Consulting Engineer") estimates that, based upon the principal considerations and assumptions set forth in its report attached hereto as Appendix A (the "Consulting Engineer's Report"), the permanent financing requirement for the costs of acquisition and construction of the Authority Interest will total approximately $1,110,125,000. This total estimated financing requirement for the Authority Interest has increased from the estimate of $779,000,000 included in the Consulting Engineer's report dated August 13, 1982, which was issued in connection with the Authority's initial issuance of Bonds.

Escalation of costs to levels in excess of present estimates, construction delays, testing and startup delays, changes in tax laws, design changes, unavailability of financing and other factors outside the control of the Authority could result in increased costs of the Authority Interest. Many nuclear power plants in the United States have experienced significant cost increases and delays during construction. In addition, to the extent actual interest rates exceed those assumed herein, the financing requirement for the Authority Interest will increase. See "The Project and the ANPP Transmission System — Estimated Construction Costs", "The Project and the ANPP Transmission System — Estimated Financing Requirement", "Availability of Construction Funds and Available Information Concerning Other Owners of Palo Verde Nuclear Generating Station" and "Certain Factors Affecting the Utility Industry and Take or Pay Power Supply Agreements".

For a discussion of other proposed projects of the Authority, see "Southern California Public Power Authority — Other Activities of the Authority".

In preparing this Official Statement, the Authority has relied upon (i) the studies, considerations, assumptions and opinions set forth in the Consulting Engineer's Report, (ii) a letter of the Department, a copy of which is attached hereto as Appendix F, (iii) certain information relating to the Project provided to the Authority by Salt River Project, APS and the Agent, and (iv) certain information relating to the Project Participants furnished to the Authority by the respective Project Participants. This Official Statement also includes summaries of the terms of the Bonds, the Bond Indenture and certain contracts and other arrangements for the supply of power and energy. The summaries of and references to all documents, statutes, reports and other instruments referred to herein do not purport to be complete, comprehensive or definitive, and each such summary and reference is qualified in its entirety by reference to each such document, statute, report or instrument. Capitalized terms not defined herein shall have the meanings as set forth in the respective documents.

THE AUTHORITY'S REFUNDING PLAN AND PAYMENT OF THE PRIOR SERIES NOTES

The 1987 Bonds are being issued for the purpose of advance refunding the Refunded Bonds and to pay at maturity the Prior Series Notes. See "Estimated Sources and Uses of Funds". Pursuant to the terms of the Bond Indenture, the advance refunding of the Refunded Bonds will be effected by depositing a portion of the proceeds of the 1987 Bonds and transferring certain other available moneys to the 1987 Refunding Series A Bonds Escrow Fund created and established pursuant to the Bond Indenture (the "Escrow Fund"). Such proceeds and moneys will be used to purchase certain non-callable State and Local Government Series direct obligations of the United States of America issued by the Bureau of Public Debt and certain direct obligations of the United States of America purchased on the open market (the "Government Obligations"). The Government Obligations will bear interest at such rates and will be scheduled to mature at such times and in such amounts so that, when paid in accordance with their respective terms, sufficient moneys will be available to pay (i) on July 1, 1995, the Redemption Price of the Refunded Bonds; and (ii) interest to become due on and prior to July 1, 1995 on the Refunded Bonds. The Escrow Fund shall be held by the Trustee in irrevocable trust and used solely for the payment of the Redemption Price of and interest on the Refunded Bonds, subject only to the payment to the Authority in accordance with the Bond Indenture of any cash not required for such purpose.

The refunding of the Refunded Bonds will discharge the pledge and assignment of any Revenues and other moneys and securities securing the Refunded Bonds under the Bond Indenture, except for the rights of the holders of the Refunded Bonds to payments from the Escrow Fund.

Simultaneously with the delivery of the 1987 Bonds, moneys consisting of a portion of the 1987 Bonds proceeds and of moneys on deposit in the Note Fund will be deposited in the Notes Escrow Fund created and established pursuant to the Note Resolution and used to purchase certain non-callable State and Local Government Series direct obligations of the United States of America issued by the Bureau of Public Debt (the "Notes Escrow Obligations"). The Notes Escrow Obligations will provide funds sufficient to pay the principal amount of, and interest on, the Prior Series Notes on June 1, 1987. The Notes Escrow Fund will be held by Security Pacific National Bank, as Fiscal Agent under the Note Resolution, in trust for the payment of the principal of and interest on the Prior Series Notes.

The mathematical accuracy of certain computations relating to the adequacy of (i) the Government Obligations and the interest thereon to pay the Redemption Price and interest due on the Refunded Bonds on and prior to the redemption date thereof, and (ii) the Notes Escrow Obligations and interest thereon to pay the principal of and interest on the Prior Series Notes on June 1, 1987, will be verified at the time of delivery of the 1987 Bonds by Ernst & Whinney, independent certified public accountants. See "Verification of Mathematical Computations".

ESTIMATED SOURCES AND USES OF FUNDS

The estimated sources and uses of funds (including accrued interest) to accomplish the refunding of the Refunded Bonds and the payment of the Prior Series Notes is shown below:

Sources:	
Principal Amount of 1987 Bonds	$352,645,000
Accrued Interest	2,525,000
Less: Original Issue Discount	(11,714,500)
Less: Underwriters' Discount	(4,055,400)
Subtotal	$339,400,100
Transfer from Construction Fund	8,000,000
Transfer from Debt Service Account	9,474,200
Transfer from Debt Service Reserve Account	1,004,600
Transfer from Note Fund	3,000,000
Total Sources	$360,878,900
Uses:	
Deposit to Escrow Fund	$272,467,200
Deposit to Notes Escrow Fund	76,719,300
AMBAC Insurance Premium	690,900
Other Costs of Issuance	901,500
Deposit to Debt Service Account	10,100,000
Total Uses	$360,878,900

DESCRIPTION OF THE 1987 BONDS

General

The 1987 Bonds are to be issued in the aggregate principal amount of $352,645,000, will be dated January 1, 1987, will bear interest at the rates per annum set forth on the cover page of this Official Statement and will mature on July 1 in the years and in the principal amounts set forth on the cover page of this Official Statement. Interest on the 1987 Bonds will be payable semiannually on January 1 and July 1 of each year, commencing July 1, 1987.

The 1987 Bonds will be issued as fully registered bonds in the denomination of $5,000 or any integral multiple thereof.

The principal of and premium, if any, on the 1987 Bonds are payable at the principal corporate trust office of First Interstate Bank of California, Los Angeles, California, Trustee and Paying Agent. Semiannual interest on the 1987 Bonds will be payable by check or draft mailed to the registered owner thereof as of the applicable record date at such owner's address as shown on the registration books of the Authority kept for that purpose at the corporate trust office of the Trustee, acting as Bond Registrar. The record date for the 1987 Bonds is the close of business on the 15th day of the calendar month immediately preceding the interest payment date.

The 1987 Bonds will rank on a parity with all other Bonds to be Outstanding immediately after the advance refunding of the Refunded Bonds. See "The Authority's Refunding Plan" and Appendix D hereto.

Optional Redemption

The 1987 Bonds maturing on or after July 1, 1997 (except the 1987 Bonds maturing July 1, 2017) are subject to redemption prior to maturity at the option of the Authority on and after July 1, 1996, in

whole or in part at any time, at the following redemption prices, plus accrued interest to the date of redemption:

Period During Which Redeemed (both dates inclusive)	Redemption Prices
July 1, 1996 to June 30, 1997	102%
July 1, 1997 to June 30, 1998	101
July 1, 1998 to thereafter	100

The 1987 Bonds maturing July 1, 2017 shall also be subject to redemption prior to maturity at the option of the Authority as a whole or in part, at any time on or after July 1, 1996, at par plus accrued interest to the redemption date.

If less than all of the 1987 Bonds are to be so redeemed, the Authority may select the maturity or maturities to be redeemed. If less than all of the 1987 Bonds of any maturity are to be redeemed, the particular 1987 Bonds or portion of 1987 Bonds of such maturity to be redeemed shall be selected at random by the Trustee in such manner as the Trustee in its discretion may deem fair and appropriate. The portion of any registered 1987 Bond of a denomination of more than $5,000 to be redeemed will be in the principal amount of $5,000 or an integral multiple thereof, and in selecting portions of such Bonds for redemption the Trustee will treat each such Bond as representing that number of Bonds of $5,000 denomination which is obtained by dividing the principal amount of such Bond by $5,000.

Mandatory Redemption

The 1987 Bonds maturing July 1, 2006, July 1, 2008, July 1, 2015 and July 1, 2017 will be subject to mandatory redemption prior to maturity at a redemption price of 100% of the principal amount thereof plus interest accrued to the redemption date on July 1, 2003, July 1, 2006, July 1, 2007 and July 1, 2016, respectively, and on each July 1 thereafter to maturity, in the following principal amounts in the years specified:

1987 Bonds Maturing July 1, 2006

Year	Principal Amount	Year	Principal Amount
2003	$ 5,110,000	2005	$24,775,000
2004	16,390,000	2006 (final maturity)	13,725,000

1987 Bonds Maturing July 1, 2008

Year	Principal Amount	Year	Principal Amount
2006	$12,750,000	2008 (final maturity)	$19,220,000
2007	18,030,000		

1987 Bonds Maturing July 1, 2015

Year	Principal Amount	Year	Principal Amount
2007	$10,230,000	2012	$13,505,000
2008	10,935,000	2013	4,530,000
2009	32,170,000	2014	9,695,000
2010	23,345,000	2015 (final maturity)	8,070,000
2011	20,620,000		

1987 Bonds Maturing July 1, 2017

Year	Principal Amount	Year	Principal Amount
2016	$19,580,000	2017 (final maturity)	$20,560,000

Giving effect to the mandatory redemption schedule set forth above, the average lives of the 1987 Bonds maturing July 1, 2006, July 1, 2008, July 1, 2015 and July 1, 2017 would be approximately 18 years and 3 months, 20 years and 7 months, 23 years and 11 months, and 30 years, respectively, calculated from the date of such 1987 Bonds.

Notice of Redemption

The Bond Indenture requires the Trustee to give notice of any redemption of the 1987 Bonds by publication and, in the case of registered 1987 Bonds, by mail. Failure to mail notice, or any defect in such mailed notice, however, will not affect the validity of the proceedings for redemption of any 1987 Bond. See "Summary of Certain Provisions of the Bond Indenture — Notice of Redemption" in Appendix C hereto.

Interchangeability

The 1987 Bonds may be exchanged and transferred as provided in the Bond Indenture. See "Summary of Certain Provisions of the Bond Indenture — Interchangeability" in Appendix C hereto.

AMBAC Insurance

AMBAC Indemnity Corporation ("AMBAC Indemnity"), has made a commitment to issue a municipal bond insurance policy (the "Municipal Bond Insurance Policy") relating to the 1987 Bonds maturing July 1, 2008 (the "Insured Bonds"), effective as of the date of issuance of the 1987 Bonds. A form of the Municipal Bond Insurance Policy is attached hereto as Appendix G. The information relating to AMBAC Indemnity contained below has been furnished by AMBAC Indemnity. No representation is made herein as to the accuracy or adequacy of such information or as to the absence of material adverse changes in such information subsequent to the date hereof.

Under the terms of the Municipal Bond Insurance Policy, AMBAC Indemnity will guarantee the payment of the principal of and interest on the Insured Bonds which shall become Due for Payment but shall be unpaid by reason of Nonpayment by the Issuer (as such terms are defined in the Municipal Bond Insurance Policy). The insurance will extend for the term of the Insured Bonds and, once issued, cannot be cancelled by AMBAC Indemnity.

The Municipal Bond Insurance Policy will insure payment only on stated maturity dates and sinking fund installment dates, in the case of principal, and on stated dates for payment, in the case of interest. It will not insure payment on acceleration, as a result of a call for redemption (other than sinking fund redemption) or as a result of any other advancement of maturity, nor will it insure the payment of any redemption, prepayment or acceleration premium. The Municipal Bond Insurance Policy will not insure against nonpayment of principal or interest caused by the insolvency or negligence of any Trustee or Paying Agent or United States Trust Company of New York (the "Insurance Trustee"). If the Insured Bonds become subject to mandatory redemption and insufficient funds are available for redemption of all Outstanding Insured Bonds, AMBAC Indemnity will remain obligated to pay principal of and interest on Outstanding Insured Bonds on the originally scheduled interest and principal payment dates.

If it becomes necessary to call upon the Municipal Bond Insurance Policy guarantee, payment of interest and principal may require surrender of Bonds or an assignment of the Bondholders' rights to payment to the Insurance Trustee or AMBAC Indemnity. Transfers of Insured Bonds may be required for timely payment.

Upon payment of the insurance benefits, AMBAC Indemnity will become the owner of the surrendered Insured Bonds and will be fully subrogated to the surrendering Bondholders' rights to payment.

AMBAC Indemnity has obtained a ruling from the Internal Revenue Service to the effect that the insuring of an obligation by AMBAC Indemnity will not affect the treatment for federal income tax purposes of interest on such obligation and that insurance proceeds representing maturing interest paid by AMBAC Indemnity under policy provisions substantially identical to those contained in the municipal bond insurance policy shall be treated for federal income tax purposes in the same manner as if such payments were made by the issuer of the bonds.

AMBAC Indemnity Corporation is a Wisconsin-domiciled stock insurance company, regulated by the Insurance Department of the State of Wisconsin, and licensed to do business in various states, with admitted assets (unaudited) of approximately $811,000,000 and qualified capital (unaudited) of approximately $245,000,000 as of September 30, 1986. Qualified capital consists of AMBAC Indemnity's statutory contingency reserve and policyholders' surplus. AMBAC Indemnity is a wholly-owned subsidiary of AMBAC Inc., a financial holding company which is owned by Citibank, N.A., the employees of AMBAC Indemnity, Xerox Financial Services, Inc. and Stephens Inc. Standard & Poor's Corporation has assigned its rating of "AAA" to the claims paying ability of AMBAC Indemnity. Copies of AMBAC Indemnity's financial statements prepared in accordance with statutory accounting standards are available from AMBAC Indemnity. The address of AMBAC Indemnity's administrative offices and its telephone number are One State Street Plaza, 17th Floor, New York, New York, 10004 and (212) 668-0340.

AMBAC Indemnity has entered into stop-loss reinsurance agreements with a number of unaffiliated reinsurers designed to supplement its resources. The stop-loss reinsurance agreements cover all AMBAC Indemnity's existing insured mutual funds, unit trusts, portfolios and new issues insured by AMBAC Indemnity. In addition, AMBAC Indemnity has entered into quota share reinsurance agreements under which a percentage of the insurance or reinsurance underwritten pursuant to certain municipal bond insurance programs of AMBAC Indemnity has been and will be assumed by such reinsurers.

SECURITY AND SOURCES OF PAYMENT FOR THE BONDS

Pledge Effected by the Bond Indenture

The Bond Indenture provides that the Bonds shall be special, limited obligations of the Authority payable solely from and secured solely by (i) the proceeds of the sale of Bonds, (ii) all revenues, income, rents and receipts derived or to be derived by the Authority from or attributable to the ownership and operation of the Authority Interest, the proceeds of any insurance covering business interruption loss relating to the Authority Interest and interest on all moneys or securities (other than in the Construction Fund) held pursuant to the Bond Indenture and required to be paid into the Revenue Fund ("Revenues"), and (iii) all funds established by the Bond Indenture (excluding the Decommissioning Account in the Reserve and Contingency Fund); subject only to the provisions of the Bond Indenture permitting the application thereof for the purposes and on the terms and conditions set forth in the Bond Indenture (including application of the moneys on deposit in the Escrow Fund).

The Bonds are not obligations of the State of California, any public agency thereof (other than the Authority), any member of the Authority or any Project Participant and neither the faith and credit nor the taxing power of any of the foregoing (including the Authority) is pledged for the payment of the Bonds. The Bonds shall never constitute the debt or indebtedness of the Authority within the meaning of any provision or limitation of the Constitution or statutes of the State of California, and shall not constitute nor give rise to a pecuniary liability of the Authority or a charge against its general credit. The Authority has no taxing power.

See "Summary of Certain Provisions of the Bond Indenture" in Appendix C hereto for further discussion of certain of the terms and provisions of the Bond Indenture.

Power Sales Contracts

Each Power Sales Contract between the Authority and a Project Participant constitutes an obligation of the parties until the terms of all of the Power Sales Contracts expire on October 31, 2030 or such later date as all Bonds and the interest thereon shall have been paid in full or adequate provision for such payment shall have been made. As long as any Bonds issued under the Bond Indenture are Outstanding or until provision has been made for the payment of any Bonds Outstanding in accordance with the Bond Indenture, the Power Sales Contracts may not be terminated or amended in any manner which will reduce the amount of, or extend the time for, the payments which are pledged as security for the Bonds or which will impair or adversely affect the rights of the holders of the Bonds.

The payment obligations under the Power Sales Contracts constitute operating expenses of the respective Project Participants, payable solely from their electric system revenues.

Each Project Participant has covenanted in its Power Sales Contract to establish, maintain and collect rates and charges for the electric service it furnishes sufficient to provide revenues which, together with its available electric system reserves, are adequate to enable it to pay the Authority all amounts payable under its Power Sales Contract and to pay all other amounts payable from, and all liens on and lawful charges against, its electric system revenues.

Payments are to be made by the Project Participants on a "take or pay" basis, that is, whether or not the Authority Interest or any part thereof, is operating or operable (or has been completed), or its output is suspended, interfered with, reduced or curtailed or terminated in whole or in part, and such payments shall not be subject to reduction whether by offset or otherwise and shall not be conditional upon the performance or nonperformance by any party of any agreement for any cause whatever.

A failure of a Project Participant to make payments when due under its Power Sales Contract may result in larger payments being made by the other Project Participants in subsequent periods for the purpose of enabling the Authority to pay operating expenses, debt service and other costs of the Authority Interest and to maintain required reserves therefor. To the extent the amount to be paid by the nonpaying Project Participant is not offset by revenues from sales of power derived by the Authority in respect of such non-paying Project Participant's Project Entitlement Share, such non-payment may result in deficits in funds under the Bond Indenture. In such event, the Authority would be required to amend, in accordance with the Power Sales Contracts and the Bond Indenture, the Annual Budget to provide increases in subsequent billings to all Project Participants, including the non-paying Project Participant, equal to the amount of such deficiency. Such increased billings are not conditioned upon any transfer of the non-paying Project Participant's Project Entitlement Share to the other Project Participants. Amounts thereafter collected from such non-paying Project Participant shall be credited against the next billing of such other Project Participants as shall be appropriate. In the event, however, of a termination of the Project and a resultant default by the Authority under the Bond Indenture, each Project Participant would, under its Power Sales Contract, be severally obligated to pay only its respective Project Entitlement Share of the debt service on the Bonds and interest on the Prior Series Notes (including fees and expenses of the Trustee and Paying Agents) and other fixed costs.

The Power Sales Contracts provide that the obligations of the Project Participants under the respective Power Sales Contracts are several and not joint. During each Power Supply Year, each Project Participant is obligated to pay its share of Monthly Power Costs, which consist of all of the Authority's costs resulting from the ownership, operation and maintenance of, and renewals and replacements to, the Authority Interest, to the extent not paid from the proceeds of Bonds or from Notes or other evidences of indebtedness issued in anticipation of the issuance of Bonds. Such

Monthly Power Costs, which consist of a minimum cost component and a variable cost component, are to be billed monthly.

The minimum cost component will be billed each month for the then current month based on the estimates contained in the Annual Budget prepared by the Authority prior to the beginning of each Power Supply Year, as such Annual Budget may be amended during such year. For each month, the minimum cost component includes:

(1) The amounts which the Bond Indenture requires the Authority to pay or deposit during such month into funds or accounts for: debt service on the Bonds or reserve requirements for the Bonds; and the payment of interest on Notes or other evidences of indebtedness issued in anticipation of the issuance of Bonds; and

(2) One-twelfth of: the amount which the Authority is required under the Bond Indenture to pay or deposit during the then current Power Supply Year into any other fund or account established by the Bond Indenture, including any amount needed to eliminate a deficiency in any such other fund whether or not resulting from a default in payments by any Project Participant of amounts due under any Power Sales Contract; the costs of producing and delivering capacity and energy from the Authority Interest during the then current Power Supply Year, including ordinary operation and maintenance costs, costs of water, overhead and certain fixed costs of fuel for the Authority Interest; and the amount necessary during the then current Power Supply Year to pay or provide reserves for all taxes which the Authority is required to pay with respect to the Authority Interest.

The variable cost component will be billed each month for the immediately preceding month. The variable cost component of Monthly Power Costs consists of: (i) all costs of fuel not included in the minimum cost component and (ii) the Authority's cost of transmission under the Transmission Agreement.

The Bond Indenture requires the Authority, quarterly, to review its estimates set forth in the then current Annual Budget and in the event such estimates do not substantially correspond with actual Revenues, Authority Operating Expenses or other requirements, to adopt an amended Annual Budget for the remainder of the Power Supply Year. The Authority is also required to adopt such an amended Annual Budget if there are at any time during the year extraordinary receipts or payments of unusual costs.

The amount of Monthly Power Costs to be paid by each Project Participant for any month shall be the sum of (i) its Project Entitlement Share times the minimum cost component for such month and (ii) the percentage of the energy delivered from the Authority Interest to it during such month times the variable cost component.

Within 120 days after the end of each Power Supply Year, the Authority will submit to each Project Participant a statement of the actual amounts payable under the Power Sales Contracts for such year and any adjustments to such amounts for any prior year, based on the annual audit required by the Power Sales Contracts. If for any Power Supply Year the actual amounts payable under the Power Sales Contract exceed the amount which the Project Participants have been billed, the Project Participants shall promptly pay the amount of such excess to the Authority; if such amounts are less than the amounts billed, the Authority will credit the excess against the Project Participants' next monthly payment.

In the event of a default or inability to perform by a Project Participant under its Power Sales Contract, the Authority shall proceed to enforce the Project Participant's covenants or obligations thereunder, or seek damages for the breach thereof, by action at law or equity. The Power Sales Contracts also provide that if a payment due under the Power Sales Contract remains unpaid when due, the Authority shall, upon 120 days' written notice to the Project Participant, discontinue the delivery of capacity and energy to, and the use of the Authority Interest facilities by, such Project Participant while the default continues. Except as a result of a transfer of the defaulting Project Participant's rights to delivery of capacity and energy and the use of the Authority Interest facilities, the discontinuance of delivery of capacity and energy to and the use of the Authority Interest facilities

by a defaulting Project Participant by the Authority will not reduce the obligation of such Project Participant to make payments under its Power Sales Contract. See "Summary of Certain Provisions of the Power Sales Contracts" in Appendix C hereto for a discussion of certain additional provisions of the Power Sales Contracts.

Authority Rate Covenant

Pursuant to the Bond Indenture, the Authority has covenanted to at all times establish and collect rates and charges with respect to the Authority Interest to provide Revenues at least sufficient, together with other available funds, for the payment each Fiscal Year of the sum of: (i) Authority Operating Expenses, (ii) Aggregate Debt Service, (iii) all other required deposits to any funds under the Bond Indenture and (iv) all other charges or liens payable out of Revenues.

Budgeting

The Power Sales Contracts require the Authority to adopt an Annual Budget not less than 30 days prior to the beginning of each Power Supply Year. Each such Annual Budget will set forth a detailed estimate of the Monthly Power Costs and all Revenues, income or other funds to be applied to such costs, for and applicable to such Power Supply Year. See "Security and Sources of Payment for the Bonds — Power Sales Contracts". The Bond Indenture requires the Authority, following the end of each quarter of each Power Supply Year, to review its estimates set forth in the Annual Budget for such Power Supply Year and in the event such estimates do not substantially correspond with actual Revenues, Authority Operating Expenses or other requirements, adopt an amended Annual Budget. The Authority shall also adopt an amended Annual Budget, in accordance with the Power Sales Contracts, if there are at any time during the year extraordinary receipts or payment of unusual costs. The Authority may also at any time, in accordance with the provisions of the Power Sales Contracts, adopt an amended Annual Budget for the remainder of the then current Power Supply Year.

Flow of Funds

The Bond Indenture establishes the following funds and accounts (each of which is held by the Trustee): Construction Fund, Revenue Fund, Operating Fund, Debt Service Fund (including the Debt Service Account and Debt Service Reserve Account), Bond Anticipation Note Fund, Reserve and Contingency Fund (including the Renewal and Replacement Account, Decommissioning Account and Reserve Account), General Reserve Fund, 1985 Refunding Series A Bonds Escrow Fund, 1985 Refunding Series B Bonds Escrow Fund, 1986 Refunding Series A Bonds Escrow Fund, 1986 Refunding Series B Bonds Escrow Fund and the Escrow Fund.

Pursuant to the Bond Indenture, all Revenues received are to be deposited promptly in the Revenue Fund. Amounts in the Revenue Fund are to be paid monthly to the following funds in the following order of priority:

(1) To the Operating Fund, a sum which, together with any amount in the Operating Fund not set aside as reserves, equals the total moneys appropriated for Authority Operating Expenses in the Annual Budget for the then current month.

(2) To the Debt Service Account and the Debt Service Reserve Account in the Debt Service Fund, the respective amounts required so that the balances in such accounts (excluding, in the case of the Debt Service Account, the amount set aside therein from the proceeds of Bonds or otherwise for payment of interest on Bonds in excess of the amount to be applied to pay interest accrued and unpaid and to accrue on Bonds to the last day of the then current calendar month) equal the Accrued Aggregate Debt Service and the Debt Service Reserve Requirement, respectively, as of the end of the then current month. The Trustee will apply amounts in the Debt Service Account to the payment of principal of, redemption premium, if any, and interest on the Bonds.

(3) To the Bond Anticipation Note Fund, the amount, if any, required so that the balance in said Fund (excluding the amount, if any, set aside in such Fund from the proceeds of Bond Anticipation Notes (including the Prior Series Notes) in excess of the amount thereof to be

applied to pay interest accrued and unpaid and to accrue on Bond Anticipation Notes to the last day of the then current calendar month) shall equal all interest accrued and unpaid and to accrue on outstanding Bond Anticipation Notes to the end of the then current calendar month. The Trustee will apply amounts in the Bond Anticipation Note Fund to the payment of interest on Bond Anticipation Notes in accordance with the provisions of the resolution, agreement or contract relating to the issuance of such Bond Anticipation Notes.

(4) To the Reserve and Contingency Fund, for credit to the Renewal and Replacement Account, the Decommissioning Account and the Reserve Account, the respective amounts provided for such purposes for the then current month in the current Annual Budget.

(5) To the General Reserve Fund, the balance, if any, in the Revenue Fund.

For a more detailed discussion of the application of moneys deposited in the various funds and accounts, see "Summary of Certain Provisions of the Bond Indenture — Application of Revenues" in Appendix C hereto.

Debt Service Reserve Account

Moneys already on deposit in the Debt Service Reserve Account will be sufficient to satisfy the Debt Service Reserve Requirement at the time of issuance of the 1987 Bonds. For the definition of Debt Service Reserve Requirement, see "Summary of Certain Provisions of the Bond Indenture — Debt Service Reserve Requirement and Certain Other Definitions Pertaining to the Issuance of Bonds" in Appendix C hereto. Should the amount on deposit in the Debt Service Reserve Account fall below the Debt Service Reserve Requirement, such deficit is to be cured by application of funds from amounts in the General Reserve Fund, the Reserve Account in the Reserve and Contingency Fund, the Renewal and Replacement Account in the Reserve and Contingency Fund, and the Bond Anticipation Note Fund, and from the first available Revenues (after payments to the Operating Fund and Debt Service Account required by the Bond Indenture), in that order.

Capitalized Interest

At the time of issuance of the 1987 Bonds, moneys on deposit in the Debt Service Account will at least equal 100% of the interest on the Outstanding Bonds from January 1, 1987 to January 31, 1987 and 33⅓% of such interest from February 1, 1987 to March 1, 1988.

Additional and Refunding Bonds

The Authority may issue additional Bonds for the purpose of financing the costs of acquisition and construction of the Authority Interest on the terms and conditions specified in the Bond Indenture. Any additional Bonds, including the Lender Bonds (as defined in the Bond Indenture), will rank equally as to security and payment with the Prior Series Bonds and the 1987 Bonds except that certain Lender Bonds will not have any interest in, lien on or pledge of moneys on deposit in the Debt Service Reserve Account. The Bond Indenture also provides for the issuance of refunding Bonds to refund Outstanding Bonds, in certain circumstances. The Project Participants have authorized the issuance of refunding Bonds by the Authority at such times as the Board of Directors determines. See "Summary of Certain Provisions of the Bond Indenture — Certain Requirements of and Conditions to Issuance of Bonds", "Summary of Certain Provisions of the Bond Indenture — Additional Bonds" and "Summary of Certain Provisions of the Bond Indenture — Refunding Bonds" in Appendix C hereto.

Additional Provisions Relating to the 1987 Bonds

With respect to the Internal Revenue Code of 1986, as amended (the "Code"), as signed into law by President Reagan on October 22, 1986, the Authority has covenanted in the Bond Indenture as follows:

In order to maintain the exclusion from Federal gross income of interest on the 1987 Refunding Series A Bonds, and for no other purpose, the Authority covenants to comply, as of the date of issuance of the Bonds, with each applicable requirement of the Internal Revenue Code of 1986 except any such requirement with respect to which the Authority receives an Opinion of Bond Counsel to the effect that continuing compliance by the Authority with such requirement of the Code is not required in order to maintain the exclusion from Federal gross income of interest on the 1987 Bonds. The provisions of this covenant shall no longer be of any force or effect upon receipt of an Opinion of Bond Counsel to the effect that noncompliance with the applicable requirements of the Code will not change the then current Federal income tax status of the interest on the 1987 Bonds.

Notwithstanding any other provision of the Indenture to the contrary, upon the Authority's failure to observe, or refusal to comply with, the above covenant the Holders of any Bonds other than the 1987 Bonds, shall not be entitled to exercise any right or remedy provided to Holders under the Indenture or otherwise based upon the Authority's failure to observe, or refusal to comply with, the above covenant.

The Bond Indenture also contains provisions and restrictions with respect to defeasance which are related to the Code.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

Formation and Membership

The Authority, a joint powers agency and a public entity organized under the laws of the State of California, was created pursuant to the Act and the Joint Powers Agreement, for the purpose of the planning, financing, development, acquisition, construction, operation and maintenance of projects for the generation or transmission of electric energy. The Joint Powers Agreement has a term expiring in 2030.

Organization and Management

The Authority is governed by a Board of Directors which consists of one representative for each of the members. The current representatives are listed on the inside cover of this Official Statement. The management of the Authority is under the direction of its Executive Director, Arthur T. Devine, who serves at the pleasure of the Board of Directors. Prior to his appointment as Executive Director, Mr. Devine served the Department for over 25 years as an electrical engineer and, more recently, as an Assistant City Attorney.

The other officers of the Authority also serve at the pleasure of the Board of Directors. The President of the Authority is Gale A. Drews, who has been the Electrical Utility Director for the City of Colton since 1978. W. E. Cameron, the Vice President of the Authority, has been the Director of Public Services for the City of Glendale since 1984. Eldon A. Cotton, the Secretary of the Authority, has been employed by the Department since 1965 and has served as the Assistant Chief Engineer — Power of the Department since 1985. Frank Salas, the Assistant Secretary of the Authority, has been employed by the Department as an engineer since 1963. Mr. Salas has held the title of Engineer of Power Contracts since 1985.

With respect to any matter involving the Authority Interest to be decided by the Board of Directors, each Director is entitled to cast votes weighted according to the size of the entitlement to the Authority Interest of the Project Participant represented by such Director in addition to the vote

each Director is entitled to cast as a member of the Authority. See "Introduction — Cost and Entitlement Shares". All such matters involving the Authority Interest must be decided by at least 80% of the votes cast, and no such vote may be taken unless there shall be present at the meeting Directors entitled to cast more than 50% of the votes relative to such matter.

The Authority has entered into the Agency Agreement pursuant to which the Department, as agent, represents, and undertakes certain activities on behalf of, the Authority in connection with the Authority's acquisition, construction, operation and maintenance of the Authority Interest. The Agency Agreement gives the Agent the responsibility of (a) undertaking those activities necessary (i) to secure regulatory approvals to allow the Authority to acquire the Authority Interest, (ii) to determine the cost of acquisition, construction, operation and maintenance of the Authority Interest, (iii) to formulate arrangements for the transmission of Authority Interest output to the Project Participants, (iv) to formulate the financing program and develop financing documents and (v) to construct, operate and maintain the Authority Interest, and (b) representing the Authority with respect to matters arising under or in connection with the Project Agreements or the construction, operation and maintenance of the Authority Interest.

Further information concerning the Authority may be obtained from the Executive Director, Southern California Public Power Authority, 613 East Broadway, Glendale, California 91205.

Other Activities of the Authority

Southern Transmission System. The Authority has entered in agreements providing for (i) the making of payments-in-aid of construction by the Authority to Intermountain Power Agency with respect to a ± 500 kV DC transmission line from the coal-fired steam-electric generating plant and switchyard located near Lynndyl, in Millard County, Utah, to Adelanto, California, approximately 490 miles in length, together with an AC/DC converter station at each end (the "Southern Transmission System"), (ii) the acquisition of the entitlements to the capability of such System previously held by the Department and the California cities of Anaheim, Riverside, Burbank, Glendale and Pasadena (the "Southern Transmission System Participants") and (iii) the sale by the Authority of transmission service on the Southern Transmission System to the Southern Transmission System Participants. The Authority has issued and has outstanding $1,058,065,000 principal amount of its bonds, including refunding bonds, to finance the making of payments-in-aid of construction with respect to the Southern Transmission System. Such bonds are payable from payments to be made by the Southern Transmission System Participants under transmission service contracts (on the basis of transmission service shares). The Consulting Engineer estimates that the permanent financing necessary to provide for all such payments-in-aid of construction and the acquisition of such entitlements will total $1,058,065,000. For a discussion of the Intermountain Power Project of which the Southern Transmission System is a part, see "The Project Participants — Other Projects of the Project Participants".

Mead-Phoenix DC Intertie Project. In 1982, the Authority executed agreements pursuant to which the Authority, Salt River Project, M-S-R Public Power Agency, and the Western Area Power Administration ("Western") are studying the feasibility of constructing, owning and operating the Mead-Phoenix DC Intertie Project. The Mead-Phoenix DC Intertie Project is a proposed 240 mile ± 500 kV DC transmission line (with AC/DC converter stations at each end) to be constructed between Mead Substation near Boulder City, Nevada and the Phoenix, Arizona area. The Authority has issued notes in the aggregate principal amount of approximately $14.1 million to finance the costs of such study. Such notes mature on December 1, 1987 and will be payable from the proceeds of long-term bonds to be issued by the Authority for the Mead-Phoenix DC Intertie Project or from payments by the participants, under project development agreements, on the basis of project entitlement shares. It is currently planned that the transmission line would have a capacity of 2,200 megawatts electric ("MWe"), and that the converter stations would be built with an initial capacity of 1,600 MWe. The initial converter station capacity could be upgraded to the transmision line capacity should this become desirable. If the Mead-Phoenix DC Intertie Project is undertaken, the Authority would finance its interest from the proceeds of long-term bonds secured by payments to be made by the

participants on a "take or pay" basis under transmission service contracts. The Authority's present interest is 93.75%. It is estimated that this facility, if built, would be in service in the early 1990's. For a further discussion of the Mead-Phoenix DC Intertie Project, see the caption "The Department of Water and Power of The City of Los Angeles — The Power System — Transmission and Distribution" in Appendix B hereto.

In connection with the Mead-Phoenix DC Intertie Project, certain members of the Authority, Salt River Project, M-S-R Public Power Agency, and Western have initiated a study to determine the feasibility and estimated costs of the construction and operation of related transmission facilities connecting the Boulder City, Nevada area to the Adelanto, California area, a distance of approximately 180 miles. The proposed participants anticipate that, if constructed, the transmission line could be put into service within the same time frame as the Mead-Phoenix DC Intertie Project. It has not been determined what, if any, role the Authority will have in this transmission line project.

Hoover Power Plant On August 17, 1984, the Hoover Power Plant Act of 1984 was signed into law. The Hoover Power Plant Act, among other things, authorizes the Secretary of Energy to offer to purchasers in California eligible to enter into contracts under Section 5 of the Boulder Canyon Project Act, contracts for delivery of capacity and associated energy from the Hoover uprating project, commencing (with respect to capacity) on June 1, 1987, or as soon thereafter as it becomes available, in the amount of 127 MWe. All of the associated firm energy will be available beginning June 1, 1987. Allocations to the cities of Anaheim, Azusa, Banning, Burbank, Colton, Glendale, Pasadena, Riverside and Vernon totaling 127 MWe of capacity and approximately 143 megawatt-hours ("MWh") of associated energy annually from the Hoover uprating project were announced by Western on November 20, 1985. These cities have entered or will enter into contracts with the United States, acting through the United States Bureau of Reclamation ("the Bureau"), which provide for the manner in which funds will be advanced by these cities to the Bureau. The cities also have entered or will enter into contracts with Western for the purchase of power from the Hoover uprating project. The cities of Anaheim, Riverside, Burbank, Asuza, Colton and Banning (the "Hoover Participants") and the Authority have entered into assignment agreements, dated as of March 1, 1986, pursuant to which each Hoover Participant will assign its entitlement to the Hoover uprating project capacity and associated energy to the Authority in return for the Authority's agreement to provide funds to the Bureau for the Hoover uprating project. Based on Western's allocations and the assignment agreements, the Authority's proportionate share of the total capacity of the Hoover uprating project will be approximately 94 MWe (Contingent Capacity) and associated firm energy. The Hoover Participants and the Authority have executed power sales contracts, dated as of March 1, 1986, under which the Hoover Participants will be entitled to their shares of the Authority's proportionate share of Hoover capacity and associated energy (the "Hoover Entitlements") and will agree to make monthly payments on a "take or pay" basis. Western has stated that the Hoover Entitlements will be made available by Western at the Mead Substation. The Hoover Participants each expect to obtain the necessary transmission service from the Mead Substation to their respective electric systems. On August 13, 1986, the Authority issued an aggregate of $34,435,000 principal amount of its bonds to finance the advance payments for the Hoover uprating project contingent capacity and associated firm energy. The Consulting Engineer estimated at that time that the proceeds from such bonds, together with the investment earnings thereon, would be sufficient to finance the advance payments for contingent capacity and associated firm energy to be made by the Authority to the Bureau for application by the Bureau to the costs of the Hoover uprating project.

THE PROJECT AND THE ANPP TRANSMISSION SYSTEM

General Description

PVNGS consists of three nominal 1,270 MWe nuclear generating units two of which have commenced commercial operation and one of which is currently under construction. In May 1986, APS reported to the NRC an adjustment to the design electrical rating of each of Units 1 and 2 from 1,270 MWe net to 1,221 MWe net to reflect the licensed reactor thermal power level. The actual, as-

built, performance ratings of the Project including the maximum dependable capacity for each unit are presently being evaluated by APS. For purposes of its analysis, the Consulting Engineer based the Authority interest output on an assumed production capacity of 1,221 MWe net from each of the three units. It is estimated that by 1988 the Project will have a net generating capacity of approximately 3,663 MWe. Additionally, it is estimated that by 1992 each unit will have achieved a mature plant factor and the Project will have an annual energy output of approximately 22,500,000 MWh. It is estimated that the Authority Interest will be capable of delivering approximately 207.4 MWe of capacity and, on average, 1,271,777 MWh of energy annually at the various points of delivery, after adjustment for transmission losses. The Project is located on a site of approximately 4,000 acres about 50 miles west of downtown Phoenix, Arizona. The three units are essentially identical in design and share certain common facilities, including a water reclamation plant, make-up water storage reservoir, two on-site wells, domestic water system, demineralized water system, sanitary waste treatment facility, evaporation ponds, laundry and decontamination facility, administration building, guardhouse, service warehouse building, switchyard and miscellaneous buildings. Each unit is designed for a forty year life.

The nuclear steam supply system for each unit of the Project, supplied by Combustion Engineering, Inc., is a closed-cycle pressurized water reactor system licensed at 3,817 megawatts of thermal capacity with two reactor coolant loops containing two reactor coolant pumps in each loop. The turbine generators are tandem compound units supplied by the General Electric Company. The main condensers are being supplied by the Westinghouse Electric Company and are cooled by circulating water through mechanical draft cooling towers. Make-up water for the dissipated circulating water is obtained primarily from the 91st Avenue Sewage Treatment Plant operated by the City of Phoenix. This processed effluent is piped to the on-site water reclamation plant where it undergoes additional treatment and is then stored in the on-site reservoir as make-up water. Blow-down from the circulating water system, demineralized water wastes, domestic water wastes, nonradioactive demineralizer regenerants and miscellaneous nonradioactive wastes are directed to the on-site evaporation ponds where they are completely evaporated. Thus, no off-site liquid discharges are required.

At design steam flow and condenser back pressure, the output from the main turbine-generators is 1,304 MWe. The main transformers will step up the output voltage of each generator to 525 kV for interconnection into the ANPP Transmission System.

The Project is being designed and constructed by the Bechtel Power Corporation, Norwalk, California. APS is the Project Manager and also operates the three units. The switchyard portions of the Project were constructed and are being managed by Salt River Project.

Pursuant to the Participation Agreement and the Assignment Agreement, the utilities listed in the following table currently have the indicated interests in the Project. See "Availability of Construction Funds and Available Information Concerning Other Owners of Palo Verde Nuclear Generating Station".

	Current Interests
Arizona Public Service Company	29.10%
Salt River Project Agricultural Improvement and Power District	17.49
Southern California Edison Company	15.80
Public Service Company of New Mexico	10.20
El Paso Electric Company	15.80
Southern California Public Power Authority	5.91
Department of Water and Power of The City of Los Angeles	5.70
Total	100.00%

In connection with financing of the Project, APS, PNM and El Paso have recently entered into several sale and leaseback transactions involving certain portions of their respective ownership interests in the Project.

The ANPP High Voltage Switchyard consists of a breaker-and-a-half scheme which comprises the termination facilities for the transmission lines, generator step-up transformers and auxiliaries, including, but not limited to, the high voltage busses, structures, power circuit breakers, disconnect switches, control building, switchyard auxiliary, protection systems and fencing.

The ANPP Transmission System consists of the facilities listed below, along with associated rights-of-way:

Palo Verde — Westwing 525 kV Transmission Lines Nos. 1 and 2
Palo Verde — Kyrene 525 kV Transmission Line
Westwing 525 kV Switchyard expansion
Kyrene 230 kV Switchyard expansion
Second Kyrene 230 kV Switchyard
Kyrene 525/230 kV Switchyard
Microwave Communication System

The design and construction of the ANPP Transmission System, with the exception of the Westwing 525 kV Switchyard expansion, was managed by Salt River Project. The design and construction of the Westwing 525 kV Switchyard expansion was managed by APS. Salt River Project is also operating the ANPP Transmission System, with the exception of the Westwing 525 kV Switchyard, which is being operated by APS. Construction of the major components of the ANPP Transmission System, with the exception of the second Kyrene 230 kV Switchyard and the second Palo Verde-Westwing 525 kV transmission line, was completed in August 1982. Salt River Project has reported that as of October 30, 1986, the second Kyrene 230 kV Switchyard was operational, having been completed ahead of schedule and under budget. Additionally, Salt River Project reported that, as of June 13, 1986, the second Palo Verde — Westwing 525 kV transmission line was operational.

Status and Schedule

For a discussion of the current status and schedule, see "Introduction — The Project and the ANPP Transmission System".

Estimated Construction Costs

The most recent estimate of the construction costs for the Project by APS is dated October 7, 1986. APS has also estimated the cash flow requirements for nuclear fuel associated with the Project. Salt River Project's most recent estimate of the construction costs for the ANPP Transmission System is dated June 30, 1986. The following table shows the total estimated costs for the Project and the ANPP Transmission System and the total estimated cost for the Authority Interest, including an additional Authority contingency to allow for uncertainties in addition to those provided for by APS. During the power ascension program, each unit generates non-firm energy. The Consulting Engineer has not included such energy or the Authority's related revenues in its analysis.

Estimated Construction Costs
($000)

	Total Project and ANPP Transmission System	Authority Interest
Plant(1)	$4,556,000	$ 269,260
Preoperations and Startup Costs(2)	1,344,000	79,430
Sewage Effluent Prepayment and Startup Power Costs(3)	77,771	4,594
Transmission Facilities Rights and Ownership Interest(4)	115,776	7,358
Other(5)	71,438	4,222
Direct Construction Costs	$6,164,985	$ 364,864
Project and Transmission Facilities Rights and Ownership Interest Purchase Costs(6)		52,784
Nuclear Fuel(7)		28,982
Ad Valorem Taxes(8)		8,540
Authority's Contingency(9)		10,000
Total Construction Costs		$ 465,170

(1) Estimated by APS. Includes land, structures, nuclear steam supply system, turbine generator, other improvements and nuclear information communications costs.

(2) Estimated by APS.

(3) Sewage effluent prepayment costs estimated by APS. Startup power costs based on actual Authority expenditures subsequent to purchase of the Authority Interest on September 10, 1982 and such power requirements provided by APS and purchased from Salt River Project at rates prescribed in the Salt River Project/Authority — ANPP Testing and Startup Power and Energy Agreement dated July 13, 1982, as revised. Such rates were escalated at 7% per year.

(4) Estimated by Salt River Project. Includes ANPP High Voltage Switchyard, Kyrene and Westwing switchyards, associated transmission lines and rights-of-way, microwave facilities and capitalized operation and maintenance expenses during the construction period.

(5) Includes expenditures prior to purchase of the Authority Interest under the Assignment Agreement for the following: startup power costs, ad valorem taxes, Green Mountain Uranium Venture, research and development and Salt River Project direct costs. Also reflects an adjustment for differences between APS's estimate of cash flow requirements dated October 7, 1986 and actual cash flow requirements as well as the Authority's portion of the costs incurred for a prudency audit.

(6) Based on actual closing costs in connection with purchase of the Authority Interest. With the exception of an additional ownership interest in the ANPP High Voltage Switchyard, includes Salt River Project AFUDC, carrying costs from Project inception to September 10, 1982 and an administrative charge. Includes such applicable costs from Project inception to May 2, 1983 for the additional ownership interest in the ANPP High Voltage Switchyard.

(7) Based on actual nuclear fuel expenditures and estimates prepared by APS.

(8) Estimated ad valorem taxes to be paid by the Authority during construction on the Authority Interest.

(9) Estimated by the Authority to allow for additional uncertainties not included in APS's estimated costs. The Authority's contingency could provide for additional construction costs which have not been specifically identified. The scheduled commercial operation date for Unit 3, as used in the Project Participants' power supply planning, is March 1, 1988.

Estimated Financing Requirement

Based on the APS Project construction cost estimate, the Salt River Project estimate of ANPP Transmission System construction costs and consultation with the Authority's Financial Advisor, the Consulting Engineer has estimated the financing requirement for the Authority Interest to be as shown in the following table:

Estimated Financing Requirement
($000)

	Prior Series Notes	Prior Series Bonds	1987 A Bonds Adjustments To Prior Series Bonds (1)	1987 A Bonds	Total Requirements
Total Construction Costs	$ 217,700	$246,726	$ —	$ 744	$ 465,170
Bond Reserve Fund(2)	—	89,251	(1,619)	614	88,246
Interest During Construction(3)	107,691	259,396	(9,474)	10,100	367,713
Working Capital, Reserve and Contingency Fund and Authority Expenses(4)	—	14,700	—	—	14,700
Financing Costs(5)	4,116	167,108	—	17,362	188,586
Gross Requirements	$ 329,507	$777,181	$ (11,093)	$ 28,820	$1,124,415
Less: Reinvestment Earnings(6)	(21,816)	(100,575)	—	(23,642)	(146,033)
Repayment of Prior Series Notes	(307,691)	232,691	—	75,000(7)	—
Defeasance of Prior Series Bonds	—	(774,714)	(222,117)	—	(996,831)
Net Deposits to Escrow Funds(8)	—	856,107	—	272,467	1,128,574
Total Requirement(9)	$ 0	$990,690	$(233,210)	$352,645	$1,110,125

(1) Net adjustments to Prior Series Bonds resulting from the advance refunding of the Refunded Bonds by the 1987 Bonds.

(2) Actual and estimated maximum annual debt service deposited in the Debt Service Reserve Account in the Debt Service Fund for the Prior Series Bonds and the additional Bonds, respectively.

(3) Based on the actual annual interest rates for the Prior Series Notes with 100% of the interest capitalized. Based on the actual annual interest rates for the Prior Series Bonds and the 1987 Bonds. Based on 100% of the interest capitalized until May 1, 1986, 66⅔% of the interest capitalized from May 1, 1986 to January 1, 1987 and 33⅓% of the interest capitalized from January 1, 1987 to March 1, 1988.

(4) Working Capital requirements are based on providing 90 days of estimated annual costs, excluding debt service. Reserve and Contingency Fund requirements are based on 1.5% of the net utility plant component of the Authority Interest in the Project and are deposited in the Reserve Account in the Reserve and Contingency Fund. Authority expenses are estimated by the Authority. The Consulting Engineer has assumed that the Authority will appropriate $700,000 for the Reserve and Contingency Fund from available funds.

(5) For the Prior Series Notes and Prior Series Bonds, includes actual underwriters' discount and original issue discount of approximately $157,506,970 and other costs of issuance, including costs of the revolving credit agreements, estimated at approximately $13,717,039. For the 1987 Bonds, includes actual underwriters' discount and original issue discount of $15,769,963.10 and other costs of issuance estimated at $1,592,321.24.

(Footnotes continued on following page)

(6) For the purpose of calculating the Estimated Financing Requirement, the estimated amounts earned on invested funds, through October 30, 1986, have been included. The estimated rates of interest on the investment of undisbursed proceeds of Prior Series Bonds and Prior Series Notes are based upon the remaining, weighted average yield to maturity of instruments in the various funds on October 30, 1986. The estimated rates of interest on the investment of undisbursed proceeds of a portion of the Prior Series Bonds and the 1987 Bonds are as follows:

	Debt Service Account	Debt Service Reserve Account	Reserve and Contingency Fund
Prior Series Bonds	5.7%	6.9%	5.8%
1987 Bonds	5.5%	7.0%	5.5%

The investment income is all deposited in the Construction Fund until July 27, 1986. From July 27, 1986 to March 18, 1987, 66⅔% of the investment income is deposited in the Construction Fund. From March 18, 1987 to May 1, 1988, 33⅓% of the investment income is deposited in the Construction Fund. The investment income not deposited in the Construction Fund is deposited in the Revenue Fund.

(7) Includes income from temporary investment of the amounts to be deposited in the Note Escrow Fund.

(8) For the Prior Series Bonds, deposit into the 1985 Refunding Series A Bonds Escrow Fund, net of the funds released from the Debt Service Account in the Debt Service Fund pursuant to the Fifth Supplemental Indenture of Trust, dated as of April 1, 1985 and deposit into the 1985 Refunding Series B Bonds Escrow Fund, net of the funds released from the Debt Service Account in the Debt Service Fund and the Debt Service Reserve Account in the Debt Service Fund pursuant to the Sixth Supplemental Indenture of Trust, dated as of May 1, 1985 deposit into the 1986 Refunding Series A Bonds Escrow Fund, net of funds released from the Debt Service Account in the Debt Service Fund pursuant to the Seventh Supplemental Indenture of Trust, dated as of February 1, 1986 and deposit into the 1986 Refunding Series B Bonds Escrow Fund, net of funds released from the Debt Service Account in the Debt Service Fund pursuant to the Eighth Supplemental Indenture of Trust, dated as of November 1, 1986. For the 1987 Bonds, deposit required into the 1987 Refunding Series A Bonds Escrow Fund, net of funds released from the Debt Service Account and Debt Serice Reserve Account in the Debt Service Fund pursuant to the Ninth Supplemental Indenture of Trust, dated as of January 1, 1987.

(9) Changes in interest or reinvestment rate assumptions may result in changes to the Estimated Financing Requirement.

Authority Interest Annual Costs of Power

The following table shows the estimated annual costs of power from the Authority Interest at the high voltage bus of the ANPP High Voltage Switchyard for fiscal years 1987 through 1994.

The projections set forth in the Consulting Engineer's Report are based on preliminary discussions with APS and are subject to adjustment by APS. For purposes of this analysis, the plant factor for each unit is assumed by the Consulting Engineer to vary from an initial level of approximately 60% for the first cycle of commercial operation to approximately 65% for the second cycle and to approximately 70% for the third cycle and thereafter. The variance in Total Average Unit Costs results from the periodic overlap of refueling outages of two or more of the three units in the same year, as scheduled by APS, combined with the lower plant factors typically experienced during the initial years of the operation of a new plant resulting from required equipment adjustments.

Estimated Annual Cost of Power from the Authority Interest(1) ($000)

	Fiscal Year Ending June 30							
	1987	1988	1989	1990	1991	1992	1993	1994
Interest and Amortization:								
Prior Series Bonds(2)(3)	$ 29,784	$ 49,400	$ 60,876	$ 62,195	$ 62,204	$ 62,210	$ 62,219	$ 62,236
1987 Bonds(2)	7,458	21,198	26,234	24,861	24,853	24,846	24,835	24,822
Operation and Maintenance(4)	9,465	11,899	14,596	15,794	16,593	17,409	18,278	19,192
Administrative and General(5)	1,657	2,230	2,405	2,600	2,748	2,916	3,091	3,276
Insurance(6)	726	953	1,029	1,122	1,178	1,236	1,296	1,362
Nuclear Fuel(7)	6,586	7,144	11,215	11,824	13,301	15,063	13,915	15,510
Renewals and Replacements(4)	2,164	3,353	2,918	2,238	2,367	2,508	2,662	2,822
Taxes(8)	2,034	2,335	4,376	5,846	5,846	5,846	5,846	5,846
Subtotal Project	$ 59,874	$ 98,512	$123,649	$126,480	$129,090	$132,034	$132,142	$135,066
Less: Interest Earnings(9)	3,408	4,056	5,709	5,709	6,580	7,013	7,013	7,013
Total Project	$ 56,466	$ 94,456	$117,940	$120,771	$122,510	$125,021	$12 5,129	$128,053
Total Project Unit Cost (Mills/kWh)	69.54	111.91	91.36	100.31	93.81	88.73	99.9 4	95.14
Total ANPP Transmission System Rights	$ 721	$ 1,121	$ 1,359	$ 1,399	$ 1,393	$ 1,391	$ 1,395	$ 1,400
Total ANPP Transmission System Rights Unit Cost (Mills/kWh)	0.89	1.33	1.05	1.16	1.07	0.99	1.11	1.04
TOTAL COST OF POWER TO AUTHORITY(10)	$ 57,187	$ 95,577	$119,299	$122,170	$123,903	$126,412	$126,524	$129,453
Energy Delivered (000 MWh)(11)	812	844	1,291	1,204	1,306	1,409	1,252	1,346
TOTAL AVERAGE UNIT COST (Mills/kWh)(12)	70.43	113.24	92.41	101.47	94.87	89.72	101.06	96.18

(1) Based on cost estimate which includes Authority financing and schedule contingencies as previously discussed and shown in the tables entitled "Estimated Construction Costs" and "Estimated Financing Requirement."

(2) Based on 100% of interest capitalized until May 1, 1986, 66⅔% of the interest capitalized from May 1, 1986 to January 1, 1987 and 33⅓% of the interest capitalized from January 1, 1987 to March 1, 1988. Remaining interest to be paid from revenues. Principal payments begin July 1, 1988. Interest is accrued during the six months prior to each semi-annual payment on July 1 and January 1. Principal is accrued during the twelve months prior to each annual payment on July 1.

(3) Reflects interest and amortization of the Prior Series Bonds, net of the interest and amortization on the Refunded Bonds.

(4) Based on estimates provided by APS.

(5) Based on estimates provided by APS. Also includes estimated Authority expenses.

(6) Based on estimates provided by APS. Includes nuclear insurance.

(7) Based on APS's estimate of nuclear fuel costs. An additional sinking fund allowance, which was based, in part, on APS's estimate for decommissioning each unit, has been added by the Consulting Engineer to the annual nuclear fuel cost. The NRC, in its proposed rule entitled "Decommissioning Criteria For Nuclear Facilities", is proposing amendments to its regulations that would set forth technical and financial criteria for decommissioning licensed facilities. The proposed amendments address decommissioning planning needs, timing, funding mechanisms, and environmental review requirements. Changes in the present NRC regulations with respect to decommissioning of nuclear facilities may result in changes to the Estimated Annual Cost of Power.

(8) Based on the Authority ad valorem taxes at rates estimated by APS and Salt River Project.

(9) Based on transferring 33⅓% of the investment income to the Revenue Fund from the Debt Service and Debt Service Reserve Accounts in the Debt Service Fund, the Reserve Account in the Reserve and Contingency Fund and the Operating Fund from July 27, 1986 to March 18, 1987. From March 18, 1987 to May 1, 1988, includes 66⅔% of such investment and includes 100% thereafter.

(10) Sum of Total Project and Total ANPP Transmission System Rights costs.

(11) At the high voltage bus of the ANPP High Voltage Switchyard. Computed as the Authority's share of estimated total generation at the Project site.

(12) The variance in annual unit costs between 1987 and subsequent years results from the timing of interest to be paid from revenues and assumed annual plant capacity factors during the initial years of operation.

In the table above, the weighted average of the estimated annual Total Average Unit Cost of power for the period of fiscal years ending June 30, 1988 through June 30, 1993 is 97.71 Mills/kWh. If adjusted to reflect the commercial operation dates and debt service and interest earnings capitalization dates used in the Consulting Engineer's Report, the weighted average of the estimated annual Total Average Unit Cost of power presented in the Consulting Engineer's report to the Authority, dated August 13, 1982, with respect to the Authority's initial issuance of Bonds for the Authority Interest, would have been 92.68 Mills/kWh for a comparable period.

Project Participants' Costs for Power

Each Project Participant will incur additional costs to deliver its power to its electric system, pursuant to the transmission and other arrangements discussed in the Consulting Engineer's Report. The estimates of the Consulting Engineer of costs of the Project Participants for power from the Authority Interest assume, among other things, that the cities of Riverside, Azusa, Banning and Colton will enter into transmission service agreements, and into supplemental agreements to their respective existing Integrated Operations Agreements, with Edison. Such agreements have been entered into by each of the above-named cities and Edison.

Transmission Arrangements

Pursuant to the Transmission Agreement, the Authority has purchased the right to use 6.55% of the capability of the ANPP Transmission System which will be utilized by Salt River Project for delivery of power and energy associated with the Authority Interest, excluding the Project Entitlement of the District. The Authority has purchased from Salt River Project an undivided ownership interest in the entire ANPP High Voltage Switchyard. The output of the Authority Interest, with the exception of the District's Project Entitlement, will be received by Salt River Project at the transmission side of the high voltage bus of the ANPP High Voltage Switchyard. Salt River Project will make available to the Authority an equivalent amount of power and energy at a combination of the Navajo Switchyard, the Eldorado Substation or the Mead Substation (the "Project Interconnection Point"). The Navajo Switchyard is located at the Navajo Generating Station in northern Arizona. The Eldorado and Mead substations are located at the southern tip of Nevada, south of Lake Mead, near the Mohave Generating Station.

The Department will transmit its Project Entitlement from the Project Interconnection Point utilizing its own transmission system.

Pursuant to the terms and conditions of the Palo Verde Nuclear Generating Station Transmission Service Agreements between the Department and the other Project Participants, with the exception of the District (the "Transmission Service Agreements"), the Department will provide transmission service for each such Project Participant's Project Entitlement between the Project Interconnection Point and the Project Participant's Points of Interconnection.

The District has acquired an ownership interest in the Southwest Powerlink as a permanent means of transmitting its Project Entitlement. This project was completed in June 1984. The District completed the new 230 kV interconnection between the Southwest Powerlink and the District system in December 1984.

The proposed Mead-Phoenix DC Intertie Project, although not required for transmission of the Authority Interest, would allow the Authority members to operate more efficiently. In the event that the Mead-Phoenix DC Intertie is constructed, pursuant to the Transmission Agreement, Salt River Project will transmit, as necessary, the Authority Interest power and energy, with the exception of the District's Project Entitlement, to the Authority at the Project Interconnection Point. The effects of these proposed facilities have not been included in the Consulting Engineer's analysis.

Fuel Supply

The nuclear fuel cycle consists of four basic activities necessary for the manufacture of fuel assemblies. These activities are acquisition of uranium concentrates, conversion of the uranium concentrates to uranium hexafluoride, enrichment of the uranium hexafluoride and fabrication of the enriched uranium into fuel assemblies. After the fuel has been used in the reactor, it is removed for reprocessing or disposal.

The following tabulation shows the approximate percentages of the required amounts of materials and services APS presently has under contract, including options, for the Project:

	Uranium	Conversion	Enrichment	Fabrication
1987-1989	100%	100%	100%	100%
1990-2000	100%	15%	100%	100%

APS expects to contract for the required conversion services from 1990-2000, and all additional services required beyond 2000, well in advance of its needs. APS has been notified that, as of September 18, 1985, the U.S. District Court of Colorado has ruled that the form of the utilities services enrichment contracts used by the United States Department of Energy ("DOE") in its negotiations with utilities, including APS, are null and void. APS has a utilities services enrichment contract which is subject to this ruling. DOE has indicated that it will appeal the ruling and will continue to honor the contracts through the appeal process. APS does not anticipate any difficulty in procuring enrichment services for the Project even if this ruling is upheld.

At the present time, no operating facilities for the reprocessing of spent fuel are available. On October 8, 1981, the President of the United States released a policy statement lifting the ban previously placed on the commercial reprocessing of spent nuclear fuel. The policy statement also called for the elimination of unnecessary governmental barriers and regulatory impediments to the licensing of nuclear power plants, the development of commercial interest in spent fuel reprocessing technology and the development of radioactive waste disposal programs. The effects of these policies cannot be predicted at this time. On-site spent fuel storage capacity for the Project is estimated by APS to be sufficient to accommodate storage of all spent fuel into the 1990's and, by adding special materials to the spent fuel pool storage racks, is estimated by APS to be sufficient to accommodate storage of all spent fuel, including maintaining full core discharge capability, during approximately 17 years of normal operation. This spent fuel storage capability could allow operation until 2002, 2003 and 2004 for Units 1, 2 and 3, respectively. On January 7, 1983, the President of the United States signed the Nuclear Waste Policy Act of 1982. This Act establishes a national program for spent fuel disposal which is to be further defined and implemented over the next several years. DOE is responsible for the national program for spent fuel disposal. With respect to this program, DOE currently faces multiple law suits over its selection of three potential repository sites in Nevada, Texas and Washington for detailed characterization work, its decision in May 1986, to postpone indefinitely any site-specific work related to a second geologic repository, its selection of sites in Tennessee for a monitored retrievable storage facility and its repository siting guidelines. The Consulting Engineer cannot predict what, if any, impact this litigation will have on the national program for spent fuel disposal, the extent to which the program will be implemented, and the extent to which either reprocessing or off-site storage services may be required or available.

Permits, Licenses and Approvals

Construction permits for the Project were issued on May 25, 1976. On April 28, 1982, the NRC approved amendments to the construction permits for each unit of the Project which allowed the transfer to the Authority of a 5.91% ownership interest in the Project.

Application has been made to the NRC for operating licenses for each unit. Hearings have been completed on an intervenor's petition which raised, primarily, an issue relating to the adequacy of cooling water supply for the Project. The Atomic Safety and Licensing Board ("ASLB") issued a favorable initial decision rejecting the intervenor's contentions. On February 15, 1983, the Atomic Safety and Licensing Appeal Board affirmed this initial decision which decision became final on April 27, 1983. Subsequent to the conclusion of the ASLB hearings, an entity representing operators of farms in the vicinity of the Project (the "Intervenor") petitioned the ASLB to reopen the hearings to consider an environmental issue related to salt emissions associated with the Project's cooling system. By its order issued on July 22, 1985, the ASLB granted the Intervenor's request to withdraw its petition

to intervene, in connection with the settlement agreement dated May 20, 1985. Further, since the ASLB noted that the Project's operating license proceeding is now uncontested, it authorized the NRC, upon making certain findings not embraced by the ASLB order, in accordance with NRC regulations, to issue operating licenses for Units 2 and 3 of the Project. See "Litigation — Project-Related Litigation".

On December 31, 1984, Unit 1 received a 40-year Full-Power Operating License with a 5-percent power level restriction. On May 30, 1985, the NRC lifted this power level restriction. On December 9, 1985, Unit 2 received a 40-year Full-Power Operating License with a 5-percent power level restriction. On April 23, 1986, the NRC lifted this power level restriction. Except for the receipt of the operating license for Unit 3, APS has stated that there are no remaining major approvals required to complete or operate the Project.

On or about November 28, 1986, Plains Electric Generation and Transmission Cooperative, Inc. ("Plains"), a generation and transmission cooperative serving loads in New Mexico and eastern Arizona, filed comments with the NRC alleging that El Paso, a participant in the Project, has taken anti-competitive actions to prevent Plains from transmitting power from northern New Mexico to southern New Mexico. Plains requests that an antitrust hearing be held before the NRC to review El Paso's alleged actions and recommends that the operating license for Unit 3 include certain conditions applicable solely to El Paso, to assure Plains that it will have long term transmission access to southern New Mexico. The requested conditions do not purport to limit or restrict operation of Unit 3, or to regulate transmission of power from Unit 3. It is not known what effect, if any, the Plains request will have on the operating license for Unit 3, or the timing of the receipt thereof.

THE PROJECT PARTICIPANTS

General

The Project Participants, each of which has executed a Power Sales Contract with the Authority, are the Department, the District, the City of Riverside, the City of Vernon, the City of Burbank, the City of Glendale, the City of Pasadena, the City of Azusa, the City of Banning and the City of Colton. Although a member of the Authority, the City of Anaheim is not a Project Participant. Each of the Project Participants owns and operates an electric system for the distribution of electric energy to its retail customers. This section briefly describes the Project Participants. For additional information about the Project Participants and their respective electric systems, see "The Project Participants" in the Consulting Engineer's Report and Appendix B hereto.

Historical Operations

The following tables summarize certain historical operating statistics of the Department and the other Project Participants' electric systems, respectively. See "The Project Participants" in the Consulting Engineer's Report and Appendix B hereto for more detailed information.

Historical Number of Customers, Load Requirements and Operating Revenues for the Department

Fiscal Year Ending June 30	Average Number of Customers	% Increase (*)	Energy Requirements (MWh)	% Increase (*)	Peak Demand (MWe)	% Increase (*)	Operating Revenues ($000)	% Increase (*)	Operating Revenues per kWh (Mills)	% Increase (*)
1982	1,221,867	—	20,691,869	—	4,364	—	1,193,913	—	57.70	—
1983	1,231,929	0.82	21,019,326	1.58	4,456	2.11	1,106,408	−7.33	52.64	−8.77
1984	1,243,092	0.91	21,848,064	3.94	4,444	−0.27	1,177,469	6.42	53.89	2.37
1985	1,251,206	0.65	22,529,539	3.12	4,882	9.86	1,287,967	9.38	57.17	6.09
1986	1,261,972	0.86	22,262,629	−1.18	4,713	−3.46	1,358,134	5.45	61.01	6.72
Compound Annual Growth Rate 1982-1986		0.81%		1.85%		1.94%		3.27%		1.40%

* Over previous year.

Historical Number of Customers, Load Requirements and Operating Revenues for All Project Participants Excluding the Department

Fiscal Year Ending June 30	Average Number of Customers (1)	% Increase (2)	Energy Requirements (MWh) (1) (3)	% Increase (2)	Peak Demand (MWe) (4)	% Increase (2)	Operating Revenues ($000) (1)	% Increase (2)	Operating Revenues per kWh (Mills) (1)	% Increase (2)
1982	317,000	—	6,632,596	—	1,673	—	$ 397,519	—	59.93	—
1983	320,762	1.19	6,372,664	−3.92	1,610	−3.77	407,404	2.49	63.93	6.67
1984	324,031	1.02	6,767,039	6.18	1,587	−1.43	430,663	5.71	63.64	−0.45
1985	327,988	1.22	7,108,863	5.05	1,730	9.01	434,294	12.45	68.13	7.06
1986	337,513	2.90	7,208,997	1.41	1,722	−0.46	481,007	−0.68	66.72	−2.07
Compound Annual Growth Rate 1982-1986		1.58%		2.11%		0.72%		4.88%		2.72%

(1) District data have been adjusted, on an average annual basis, from calendar year to fiscal year.

(2) Over previous year.

(3) Excludes Bonneville Power Administration ("BPA") exchange obligation.

(4) Non-Coincidental.

The Department

The Department, the largest municipal utility in the United States, is a separate proprietary agency of The City of Los Angeles, controlling its own funds and with full responsibility for meeting the water and electric requirements of The City of Los Angeles. It provides water and electricity services almost entirely within the boundaries of The City of Los Angeles, which encompasses some 465 square miles, to a population of approximately 3.2 million.

Administration of the Department is under the direction of a five-member Board of Water and Power Commissioners. The Board of Water and Power Commissioners fixes the Department's electric rates, subject to the approval of the City Council, by ordinance. The Department's rates are not regulated by any California state agency and are not subject to approval by any Federal agency, but the Department is subject to certain ratemaking provisions of the Federal Public Utility Regulatory Policies Act of 1978.

The Department's maximum net hourly peak demand, 4,882 MWe, occurred in September 1984. The power supply of the Department consists primarily of its own generating resources, part of which are located within the Los Angeles Basin, and its 500 MWe entitlement currently available from the Hoover Power Plant. On August 17, 1984, the Hoover Power Plant Act of 1984 was signed into law. Among other things, as discussed in "Southern California Public Power Authority — Other Activities of the Authority — Hoover Power Plant", such Act authorizes the Secretary of Energy to offer, and he has offered, the Department a renewal contract for delivery, commencing June 1, 1987, of capacity in the amount of approximately 491 MWe from the Hoover Power Plant. The Department currently has a net dependable system capability of over 7,200 MWe, which is owned or operated generation. Steam electric generating capability was equal to 65% of the system's total net capability and owned or operated hydroelectric generating capacity accounted for 27% of such capability. Purchases are made on a day to day or week to week basis that will alter these percentages. The Department estimates that its capital expenditures for power generating and distribution facilities for the five-year period which began July 1, 1986 will total approximately $1.8 billion.

Imperial Irrigation District

The District is a publicly-owned water and power utility located in southern California. The gross area served by the District is approximately 6,400 square miles in Imperial County and the Coachella Valley of Riverside County. The power supply of the District consists of hydroelectric units on the All-American Canal and oil- and gas-fired generating facilities, as well as purchases of capacity and energy from other sources. In the twelve months ended December 31, 1985, the District experienced a peak demand of approximately 404 MWe, generated 777,076 MWh and purchased 770,003 MWh.

Administration of the District is under the direction of a five-member Board of Directors. Electric rates are set by the Board of Directors after a series of public hearings and presentations to the city councils of the cities located within the District's service area. The District's electric rates are not subject to regulation by any California state agency and are not subject to approval by any Federal agency, but the District is subject to certain rate making provisions of the Public Utility Regulatory Policies Act of 1978.

Cities of Riverside, Vernon, Azusa, Banning and Colton

The cities of Riverside, Vernon, Azusa, Banning and Colton each are municipal corporations existing under the laws of the State of California, each owning and operating electric public utilities for their respective citizens, providing electric service to virtually all of the electric customers within the respective city limits, which encompass approximately 77, 5, 11, 19 and 16 square miles, respectively. The principal facilities of the cities' electric systems are sub-transmission and distribution lines aggregating approximately 1,514 circuit miles of transmission lines, and for the City of Riverside, 711 circuit miles of street lighting distribution lines, as of June 30, 1986.

Electric rates for the City of Riverside are established by the Riverside Board of Public Utilities, subject to approval of the Riverside City Council. Electric rates for the other cities are established by the respective city councils. None of these electric rates are subject to regulation by any California state agency. The cities of Riverside and Vernon (because of the magnitude of their energy sales) are subject to certain rate making provisions of the Public Utility Regulatory Policies Act of 1978.

The five cities operate their respective electric systems and obtain their bulk power supply in accordance with provisions of their respective Integrated Operations Agreements, as amended ("IOA"), which each city has executed with Edison. Each IOA provides, among other things, that the requirements of each city's electric system will be met by generating resources in which each such city has a contractual ownership interest and, to the extent required, by wholesale purchases from Edison.

The City of Riverside has a 1.79% ownership interest in the San Onofre Nuclear Generating Station, Units 2 and 3 ("San Onofre"). This percentage ownership interest is equivalent to 38.49 MWe of capability with associated energy, after unit capacities were rerated in January 1985 based on actual performance. San Onofre Unit 2 commenced commercial operation in October 1983 and Unit 3 commenced commercial operation in April 1984.

At this time the cities of Riverside, Vernon, Azusa, Banning and Colton receive power and energy from their respective Project Entitlements in Unit 1 and Unit 2 and purchase interruptible energy from other utilities and governmental agencies when it is available at an economically attractive price and transmission is available. In addition, the City of Riverside has a 1.79% ownership interest in San Onofre. This percentage ownership interest is equivalent to 38.49 MWe of capability with associated energy, after unit capacities were rerated in January 1985 based on actual performance. San Onofre Unit 2 commenced commercial operation in October 1983 and Unit 3 commenced commercial operation in April 1984. The City of Riverside also has a 7.61% generation entitlement share in IPP (118.90 MWe), of which 60.94 MWe is currently available from Unit 1, which was declared commercially available in June 1986. The City of Vernon receives power and energy from its diesel units. All remaining power and energy requirements for each of the five cities are purchased from Edison at wholesale rates. The capacity and energy expected to be received from Unit 3 of the Project will be used to displace a portion of the power currently purchased from Edison.

During the period from fiscal years 1987 through 1994, the cities' power supply plans include the capability available from the Hoover uprating project and, for the City of Riverside, IPP Unit 2 and capacity and energy available from the Deseret Generation & Transmission Co-operative ("Deseret"). The City of Banning has recently issued $2,570,000 of Certificates of Participation to fund a hydroelectric generating project which is anticipated to generate approximately 829 kWe and 5,280 MWh annually. The project is presently in the design and engineering phase and is anticipated by the City to be in full commercial operation in December 1987. Additionally, the City of Vernon has recently issued $125,000,000 of Electric System Revenue Bonds to fund such City's Bear Butte hydroelectric, pumped storage project which is anticipated by the City to generate approximately 120 MWe of peaking capacity and 205,500 MWh and 161,100 MWh annually during high and low water years, respectively. The City further anticipates utilizing approximately 42 MWe to meet a portion of its electric load with the balance of the project power sold to one or more publicly owned utilities. The project is presently in the design and engineering phase and is anticipated by the City to be in commercial operation during the fourth quarter of 1992. Due to the preliminary nature of design, licensing and contract status, the Consulting Engineer has not included the power and energy from this project in its analysis.

Cities of Burbank, Glendale and Pasadena

The cities of Burbank, Glendale and Pasadena are each municipal corporations existing under the laws of the State of California, owning and operating electric public utilities providing electric service to virtually all of the electric customers within their respective city limits.

Electric rates for each city are fixed by its City Council and are not subject to regulation by any California state agency. Each city is subject to certain ratemaking provisions of the Public Utility Regulatory Policies Act of 1978.

Burbank, Glendale and Pasadena supply electricity to their respective electric systems through a combination of oil- and gas-fired generating facilities located in the Los Angeles Basin, 34 MWe of hydroelectric generation at the Hoover Power Plant and purchases from the Bonneville Power Administration and other utilities in the Northwest and Southwest. On August 17, 1984, the Hoover Power Plant Act of 1984 was signed into law. Among other things, as discussed in "Southern California Public Power Authority — Other Activities of the Authority — Hoover Power Plant", such Act authorizes the Secretary of Energy to offer, and he has offered, the cities of Burbank, Glendale and Pasadena renewal contracts for delivery commencing June 1, 1987 of capacity in the total amount of approximately 34 MWe from the Hoover Power Plant. The City of Pasadena also purchases electric energy from the Azusa Hydroelectric Plant. In the twelve months ended June 30, 1986, the three cities generated an aggregate of 659,753 MWh of energy and purchased an aggregate of 2,223,764 MWh.

Other Projects of the Project Participants

Intermountain Power Project. In 1977, several Utah municipalities organized the Intermountain Power Agency ("IPA"), a political subdivision of the State of Utah. The purpose of IPA is to provide for the financing, constructing and operating of the Intermountain Power Project ("IPP").

In 1980, the Department and the cities of Anaheim, Burbank, Glendale, Pasadena and Riverside (the "California IPP Purchasers") each entered into a power sales contract with IPA which obligates each such Purchaser to purchase, on a "take or pay" basis, a percentage share of IPP capacity and energy. The Department and the cities of Burbank, Glendale and Pasadena also entered into an Excess Power Sales Agreement, also on a "take or pay" basis, with the Utah municipal and cooperative IPP purchasers, pursuant to which IPP generation entitlement which is surplus to such Utah purchasers' needs will be made available to the Department and the cities of Burbank, Glendale and Pasadena.

In early 1983, each IPP Purchaser entered into an amendment to its power sales contract, the primary purpose of which was to reduce the size of IPP from four to two generating units. The parties thereto also entered into an amendment to the Excess Power Sales Agreement. All California IPP Purchasers except Glendale also entered into Lay-off Power Purchase Contracts (the "Lay-off Contracts") with IPA and Utah Power & Light Company ("UP&L") through which UP&L assigned portions of its entitlement to IPP capacity and energy to such Purchasers.

The IPP generation entitlement of each of the California IPP Purchasers resulting from the power sales contracts, as amended, and the Lay-off Contracts is shown in the following table:

	Percentage Share	Generating Capability (kW)
Los Angeles Department of Water and Power	44.617%	696,471
City of Anaheim	13.225	206,442
City of Riverside	7.617	118,901
City of Pasadena	4.409	68,825
City of Burbank	3.371	52,621
City of Glendale	1.704	26,600
Total	74.943%	1,169,860

Based on the uprated capacity of 800 MWe net for IPP Unit No. 1 and the original design rating of 761 MWe net for IPP Unit No. 2, and subsequent to both IPP generating units achieving an assumed 70% plant factor, the California IPP Purchasers will receive, pursuant to the power sales contracts, as amended, and the Lay-off Contracts, approximately 1,141 MWe of capacity and 6,995,678 MWh of energy annually, after losses, at the Adelanto point of delivery. The amounts of generating capability that will be available pursuant to the Excess Power Sales Agreement, as amended, will vary in

accordance with the provisions of that Agreement. Quantities of capacity and energy that will be available at the Adelanto point of delivery as a result of the Excess Power Sales Agreement, as amended, will vary between approximately 164 and 321 MWe and 863,447 and 1,965,600 MWh annually, based on amounts presently established. These values will be subject to annual adjustment.

IPP will consist of the following: (a) a two unit, 1,561 MWe (reflecting the recent rating increase of Unit No. 1 to 800 MWe) coal-fired, steam-electric generation station located near Lynndyl, Utah; (b) the Southern Transmission System; and (c) two 345 kV AC transmission lines from the generation station to a switchyard near Mona, Utah and a 230 kV AC transmission line from the generation station to a switchyard near Ely, Nevada. The first IPP generating unit was declared commercially available effective June 10, 1986. The second unit is scheduled for commercial operation on July 1, 1987.

In June 1986, the Department submitted to the IPA Board and the IPP Coordinating Committee a construction cost estimate for IPP of approximately $3.243 billion which was approved by the IPP Coordinating Committee. Changes that have been made between the June 1985 construction cost estimate and the June 1986 construction cost estimate have generally been minor, with the exception of additional amounts for purchasing coal reserves and establishing a self-insurance fund. Reductions have included a decrease in test energy revenues previously expected to affect construction costs and the reduction of the IPP contingency previously associated with the Southern Transmission System. A portion of the funds required for construction is being provided by IPA with the remainder being provided by the Authority as payments-in-aid of construction with respect to the Southern Transmission System. By October 1984, IPA had issued an aggregate of $4.1 billion principal amount of bonds and $300 million of commercial paper which together with the payments-in-aid of construction with respect to the Southern Transmission System to be provided by the Authority are intended to be sufficient to allow IPA to construct and place IPP in service. In 1985 and 1986, IPA issued a total of approximately $6,674,443,000 principal amount of revenue, refunding and special obligation bonds to defease $3,942,480,000 of bonds, to refinance $300 million of commercial paper previously outstanding and to provide funds to redeem, on July 1, 1995, $1,532,100,000 of bonds currently outstanding. The total IPA outstanding debt, excluding the special obligation bonds, is now approximately $5,216,885,000 including accrued but unpaid interest on Growth and Income Securities and Capital Appreciation Bonds as of January 1, 1987. Additionally, IPA has recently contracted to sell approximately $192,270,000 principal amount of refunding bonds to defease $155,095,000 of bonds currently outstanding. IPA will continue to review the options that are available to it to reduce its annual debt service and may undertake additional refundings. For a discussion of the Southern Transmission System, including the total financing requirements for the Authority's payments-in-aid of construction, see the caption "Future Power Supply Resources — Southern Transmission System" in the Consulting Engineer's Report.

Procurement of all major equipment for the IPP generation station has been completed. The Department has reported that, as of December 20, 1986, construction of Unit 2 was on schedule and approximately 99.0% complete. Construction for the IPP transmission systems, including the HVDC transmission line, the AC/DC converter stations and related microwave communications facilities is essentially complete.

All permits, licenses and approvals required to be obtained for IPP to date have been obtained.

The Authority has been informed that litigation seeking to apply southern California air quality requirements to the IPP generation station has been threatened by a company whose efforts to construct a 35 MWe power plant in southern California have been adversely impacted by the more stringent southern California air quality requirements. The Authority has been advised by the Department that all air quality permits necessary to operate the IPP generation station have been obtained.

The Department has executed agreements to provide transmission service from the Adelanto Converter Station as necessary to enable the other five California IPP Purchasers to accept delivery of their shares of IPP generation.

Southern Transmission System. Certain of the Project Participants have entitlements in the Southern Transmission System totalling approximately 82.4%. See "Southern California Public Power Authority — Other Activities of the Authority" for a discussion of this project.

White Pine Power Project. Certain of the Project Participants, apart from the Authority and together with other public and private utilities in California and Nevada, have undertaken studies to explore the feasibility of constructing a coal-fired generating station near Ely, Nevada. This generating station would have a capability of approximately 1,500 MWe. It is contemplated that White Pine County would own all, or a major portion of, and finance this project through bonds issued by White Pine County which would be secured by power sales contracts entered into with the various purchasers of power from the project. The Project Participants' combined entitlement percentage share for feasibility studies is approximately 47.36%. The participants in the White Pine Power Project entered into power supply development agreements with White Pine County in the fall of 1980 for the purpose of conducting a study to determine the feasibility of constructing and operating the project. In November 1980 and October 1984, White Pine County issued notes in the principal amounts of $14,994,000 and $2,000,000, respectively, for such purposes. In August 1985, White Pine County issued an additional note in the principal amount of $2,935,000 and extended the maturity date of the notes to December 31, 1987. Such notes will be payable from the proceeds of long-term bonds to be issued by the County or from payments by the participants under such agreements on the basis of entitlement shares. The estimated commercial operation date for the two 750 MWe generating units, if built, is in the early 1990's. For a further discussion of the White Pine Power Project, see the caption "The Department of Water and Power of The City of Los Angeles — Power System Generation Resource Additions — White Pine Power Project" in Appendix B hereto.

Mead-Phoenix DC Intertie Project. Certain of the Project Participants have entitlements in the Authority's interest in the Mead-Phoenix DC Intertie Project totalling approximately 56.7%. See "Southern California Public Power Authority — Other Activities of the Authority" for a discussion of this proposed project.

Devers-Palo Verde #2 Transmission Line. The Department, the District, M-S-R Public Power Agency, and the cities of Riverside, Vernon, Burbank, Glendale, Pasadena, Azusa, Banning and Colton along with Edison, as project manager, and M-S-R Public Power Agency have undertaken studies to explore the feasibility of constructing a 500 kV AC transmission line. This proposed Devers-Palo Verde #2 transmission line, if built, will parallel the existing Devers-Palo Verde #1 transmission line from the Project to Edison's Devers Substation, which is located west of Desert Hot Springs, California. The Project Participants' participation rights in the proposed Devers-Palo Verde #2 transmission line total 36.8%. Edison has scheduled this project for completion in 1990, at an estimated cost of $247,000,000.

California-Oregon Transmission Project. The cities of Riverside, Vernon, Azusa, Banning and Colton executed a Memorandum of Understanding, dated as of December 19, 1984, which authorizes these cities, along with other non Project Participant utilities and governmental agencies located in California, to study the construction of the California-Oregon Transmission Project. Such Project relates to possible alternative methods of developing additional 500 kV AC transmission facilities between California and the Pacific Northwest. The participants have executed a Project Development Agreement pursuant to which they will study the feasibility of constructing and operating the California-Oregon Transmission Project.

Sylmar Expansion Project. The Department and the cities of Burbank, Glendale and Pasadena are participants in the Sylmar Expansion Project ("SEP") which provides an 1,100 MWe expansion of the terminal capacity at the AC/DC converter station which is located at Sylmar, California. This Project will increase the capacity of the Pacific Northwest-Southwest DC Intertie ("Intertie") from 2,000 MWe to 3,100 MWe. The Department is the project manager for the southern terminal of the Intertie and is responsible for the construction of the SEP. The Bonneville Power Administration is the project manager for the northern terminal and is responsible for a similar expansion at the northern converter station of the Intertie in Oregon. The Department estimates that the cost of the SEP will be $171,000,000 and that the SEP will be completed in February 1989.

For a discussion of other projects under consideration by the Department, see "The Department of Water and Power of The City of Los Angeles — Power System Generation Resource Additions" in Appendix B hereto.

AVAILABILITY OF CONSTRUCTION FUNDS AND AVAILABLE INFORMATION CONCERNING OTHER OWNERS OF PALO VERDE NUCLEAR GENERATING STATION

In major construction projects such as the Project, completion of construction on time and within cost estimates is dependent upon, among other things, the owners providing on a timely basis the funds necessary to construct and place such projects in operation. The capability of owners to provide such funds is dependent upon their continued ability to generate capital from internal or external sources. Certain other major construction projects in the United States, including nuclear power projects, have been adversely affected by, among other things, the failure of owners to provide their shares of the necessary funds in a timely manner.

Information concerning other owners of the Project is available from a number of sources.

APS, Edison, El Paso Electric Company and Public Service Company of New Mexico, respectively, are subject to the informational requirements of the Securities Exchange Act of 1934 and in accordance therewith file reports and other information with the SEC, which can be inspected and copied at the offices of the Commission at Room 1024, 450 Fifth Street, N.W., Washington, D.C.; Room 1204, Everett McKinley Dirksen Building, 219 South Dearborn Street, Chicago, Illinois; Room 1102, Jacob K. Javits, Federal Building, 26 Federal Plaza, New York, New York; and Suite 500 East, 5757 Wilshire Boulevard, Los Angeles, California. Copies of such material can also be obtained at prescribed rates from the Public Reference Section of the SEC at its principal office at 450 Fifth Street, N.W., Washington, D.C. 20549. Certain securities of APS and Edison, respectively, are listed on the New York and Pacific Stock Exchanges. Reports, proxy material and other information concerning APS and Edison can be inspected at the respective offices of these exchanges located on the 7th Floor, 20 Broad Street, New York, New York, and at 115 Sansome Street, San Francisco, California. Information regarding Edison, which is also listed on the American Exchange, may also be obtained at the offices of the American Exchange at 86 Trinity Place, New York, New York. Information regarding Public Service Company of New Mexico, which is listed on the New York Stock Exchange, may be obtained at said Exchange's offices listed above.

Copies of the most recent official statement and annual report of the Department may be obtained from B C Monk, Room 466, Department of Water and Power, P.O. Box 111, Terminal Annex, Los Angeles, California 90051.

Copies of the most recent official statement and annual report of Salt River Project may be obtained from Mark B. Bonsall, Corporate Treasurer, Box 52025, Phoenix, Arizona 85072-2025.

CONSIDERATIONS, ASSUMPTIONS AND OPINIONS OF THE CONSULTING ENGINEER

Principal Considerations and Assumptions

The estimates and projections contained herein are based, in part, on the following information which was provided by the identified sources. While the Consulting Engineer believes these sources to be reliable and has no reason to believe such information is unreasonable, the Consulting Engineer has not independently verified such information.

1. Forecasts of the Department's power and energy requirements, resources and power supply costs, excluding costs of its Project Entitlement and IPP generation entitlements, were provided by the Department.

2. Forecasts of power and energy requirements for the cities of Riverside, Burbank, Glendale, Pasadena, Vernon, Azusa, Banning and Colton and the District were provided by those Project Participants.

3. Excluding their Project Entitlements, IPP generation entitlements and the Hoover uprating project, forecasts of resources for the cities of Burbank, Glendale and Pasadena were provided by those Project Participants.

4. Forecasts of capital expenditures and operation and maintenance expenses for the Department, the District, and the cities of Riverside, Burbank, Glendale and Pasadena were provided by those Project Participants.
5. The City of Vernon provided a forecast of its capital expenditures.
6. The Financial Advisor has provided the Consulting Engineer with assumed reinvestment and investment rates, respectively, of 7.0% for the proceeds of the Prior Series Bonds and the 1987 Bonds deposited in the Debt Service Reserve Account in the Debt Service Fund, and 5.5% for such proceeds deposited in the Debt Service Account in the Debt Service Fund, the Initial Facilities Account in the Construction Fund, the Operating Fund and the Reserve and Contingency Fund.

In the Consulting Engineer's report to the Authority dated July 27, 1983, the Consulting Engineer expressed the opinion that the estimated direct construction costs of the Project as then prepared by APS and Salt River Project were comparable with the direct construction costs reported for similar projects being developed in the same time frame. While the Consulting Engineer continues to believe that opinion was appropriate at the time, changes in the nuclear industry have adversely affected the reliability of the construction schedules and cost estimates for nuclear generating facilities. The effects of these changes on other individual nuclear generating facilities' costs and schedules, which would be used for comparison, are not necessarily a matter of public record or disclosure. Further, when they do become a matter of public record, the cost and schedule estimates, including the parameters and methods upon which they are based, are not necessarily consistent among projects. As a result, a comparison of the estimated direct construction costs of the Project with such costs for other nuclear generating facilities similar to the Project is currently of questionable validity. Additionally, in the preparation of its report, the Consulting Engineer has not undertaken an independent review of the estimated direct construction costs or schedules for the Project, as prepared by APS. However, at this time, the Consulting Engineer has no reason to believe that the currently estimated direct construction costs for the Project, as prepared by APS and Salt River Project, together with the Authority's contingency, are not reasonable for use by the Authority in preparing its plan for financing the Authority Interest.

In the preparation of its report and the numbered opinions that follow, the Consulting Engineer has made certain assumptions with respect to conditions which may occur in the future. While the Consulting Engineer believes these assumptions are reasonable for the purpose of its report, they are dependent upon future events, and actual conditions may differ from those assumed. In making such assumptions, the Consulting Engineer has used and relied upon certain information provided to the Consulting Engineer by the Department, acting as the Authority's agent, the Project Participants, Edison and others. While the Consulting Engineer believes the sources to be reliable, the Consulting Engineer has not independently verified the information and offers no assurances with respect thereto. To the extent that actual future conditions differ from those assumed in the Consulting Engineer's Report or from the information provided to the Consulting Engineer by others, the actual results will vary from those forecast. The principal assumptions made by the Consulting Engineer and the principal information related to such assumptions provided to the Consulting Engineer by others are as follows:

1. Based on APS's current schedule for the Project, Salt River Project's schedule for the ANPP Transmission System and information relating to construction, preoperations and startup supplied by the Department acting as the Authority's agent, the Consulting Engineer has assumed that, for the Project Participants' power supply and financial planning purposes, commercial operation for Unit 3 of the Project will commence on March 1, 1988.
2. Based on APS's estimate of direct construction costs of the Project, Salt River Project's estimate of direct construction costs of the ANPP Transmission System, and the Authority contingency allowance for uncertainties not included in APS's estimate of the total construction costs for the Project provided by the Department, as the Authority's Agent, the cost of acquisition of the Authority Interest will be $465,170,000.

3. Operating costs of the Project were estimated by APS with the exception of taxes.

4. Based on APS's estimate, as adjusted by the Consulting Engineer, each unit will have a plant factor of approximately 60% during the first cycle of operation, 65% during the second cycle of operation and 70% thereafter.

5. By such time as the on-site fuel storage facilities reach capacity, a national program for spent fuel disposal will have been implemented.

6. Existing environmental laws and regulations will not be modified to adversely affect the construction cost or scheduled completion date of the Project or the Project operation.

7. Based on information provided by the Department, acting as the Authority's agent, permits, licenses and approvals as necessary to complete and operate the Project will, to the extent not already received, be received on a timely basis.

8. The cities of Riverside, Vernon, Azusa, Banning and Colton will be able to integrate their respective Project Entitlements as a City Capacity Resource under their respective Integrated Operations Agreements with Edison on the commercial operation dates assumed for the Project Participants' power supply and financial planning purposes.

9. Power and energy requirements of the cities of Vernon, Azusa, Banning and Colton, beyond that provided by their respective Project Entitlements and their respective Hoover uprating project entitlements, including Western energy credits, and the City of Vernon's diesel generators and the City of Banning's hydroelectric generating project, will be purchased from Edison in accordance with the terms of their respective Integrated Operations Agreements.

10. Power and energy requirements of the City of Riverside, beyond those provided by its Project Entitlement, San Onofre Nuclear Generating Station Units 2 and 3, IPP, Deseret and its Hoover uprating project entitlement including Western Energy credits, will be purchased from Edison in accordance with the terms of its Integrated Operations Agreement.

11. With the exception of the Department and the cities of Burbank, Glendale and Pasadena, the Project Participants' participation in other potential resources or economy purchases which are not under contract but which may become available to such Project Participants during the forecast period have not been included in the forecast power costs or the Consulting Engineer's forecast of resources of the Project Participants.

12. Based on information provided by the respective Project Participants, such Project Participants, other than the Department, Burbank, Pasadena, Riverside, Vernon and Banning, will finance the estimated costs of normal capital replacements and improvements, if any, to their electric systems from current revenues.

13. Transmission for each Project Participant's Project Entitlement will be provided in accordance with the agreements as discussed in the Consulting Engineer's Report.

14. Based on prior yields and maturities of investments, the future yield on investments from the proceeds of the Prior Series Notes and Prior Series Bonds are based on the remaining, weighted average yield to maturity of instruments in the various funds on October 30, 1986.

15. Projected wholesale power and energy rates for Edison are based on historical results of Edison operations, Edison's November 8, 1983 rate filing, which became effective, subject to refund, on June 8, 1984, the wholesale rate filing of Edison made on January, 1986, and Edison's electric system resource plans and load forecasts. Further, in projecting Edison rates, the Consulting Engineer has supplemented recent Edision filings with the following assumptions: (1) FERC will allow Edison a 13.25% rate of return on common equity in 1987 through 1990 and 12.75% in 1991 and thereafter; (2) the basic rate of inflation will be approximately 4.5% per year; (3) annual escalation for coal will be 5.1% per year; (4) operating expenses will escalate at 5.8% per year; and (5) the cost of construction will generally escalate at 5.8% per year. The resulting average wholesale power rates paid by the cities of Azusa, Banning, Colton, Riverside, and Vernon to Edison would increase at 3.5%, 4.3%, and 5.2% per year, respectively, for the low, medium and high fuel price cases during the period of fiscal years

1987-1991. These average increases in average wholesale rates do not reflect prospective refunds that may be received by wholesale customers through final order of the FERC 1982 and 1984 rate cases.

16. The 1986 average revenue per unit of energy sales, based on 1986 revenues from the sales of electricity and total energy sales, as provided by all Project Participants other than the Department, will continue at the same level for the projected energy sales over the period of fiscal years ending June 30, 1987 through 1991.

17. The existing ratemaking authority of the cities of Riverside, Vernon, Burbank, Glendale, Pasadena, Azusa, Banning and Colton and the District to establish rates for the purpose of providing necessary revenues for their respective electric utility systems will not be adversely modified.

18. The capital expenditures and operation and maintenance expenses for the cities of Azusa, Banning and Colton will follow historical trends.

19. The operation and maintenance expenses for the City of Vernon will follow historical trends.

Opinions

Based upon the Consulting Engineer's studies and analyses, the considerations and assumptions set forth above and the information supplied by the Project Participants, the Department, acting as the Authority's Agent, and Edison with respect to the Authority's acquisition, construction and placing into operation of the Authority Interest, the Consulting Engineer is of the opinion that:

1. The estimated cost of power from the Authority Interest is reasonable when compared with the cost of power expected from other long-term power supply resources which may be available to the Project Participants in the same time frame as the Project.

2. The output from the Authority Interest will provide long-term economic power supply benefits to the Project Participants in meeting increasing requirements, displacing base load oil- and gas-fired generation, or displacing wholesale purchases of power generated using a substantial amount of oil- and gas-fired generating resources.

3. The forecast revenue requirements from the sale of electricity for the cities of Riverside, Vernon, Burbank, Glendale, Pasadena, Azusa, Banning and Colton and the District during fiscal years ending June 30, 1987 through 1991 can reasonably be met.

4. The Department's use of its Project Entitlement to displace base load oil- and gas-fired generation will provide long-term economic power supply benefits to the Department as compared with the Department's projected cost of oil- and gas-fired generation.

LETTER OF THE DEPARTMENT

As stated in the letter of the Department attached hereto as Appendix F, based upon, among other things, the Department's studies and analyses which have included projections with respect to, among other things, the estimated cost of power from the Authority Interest as contained in the Consulting Engineer's Report, the estimated cost and availability of oil and natural gas, future load growth in The City of Los Angeles, and the estimated future electric system revenue requirements, as estimated by the Department, the Department is of the opinion that:

1. The Department's share of the output from the Authority Interest will, over time, be economically beneficial to the Department in displacing base load oil- and natural gas-fired generation in the Los Angeles basin;

2. The projected cost of power to the Department from the Authority Interest makes such power economically attractive in the long term to the Department when compared with the projected price levels of oil and natural gas and with the projected cost of power from other alternative resources which may be available to the Department; and

3. For the period through June 30, 1991, the Department's electric system revenues will be sufficient to enable it to pay the Authority all amounts payable under the Department's Power Sales Contract and to pay all other amounts payable from, and all liens on and lawful charges against, the Department's power system revenues.

CERTAIN FACTORS AFFECTING THE UTILITY INDUSTRY AND TAKE OR PAY POWER SUPPLY AGREEMENTS

The electric utility industry has experienced and is experiencing various problems, including the effect of inflation on the cost of construction and operation of utility facilities, the fluctuating costs and uncertain availability of fuel, particularly fossil fuels, compliance with new legislation, the uncertain availability and increased cost of capital, cancellation of projects and related contractual litigation, and environmental regulations, licensing procedures, litigation and other factors which may delay the construction and increase the cost of new facilities, the cost of power or limit use of, or necessitate costly modifications to, existing facilities.

Federal energy legislation enacted in 1978 authorizes the President to allocate coal supplies in the event of an energy supply interruption or fuel supply shortage, authorizes the Federal Energy Regulatory Commission to order mandatory interconnection and wheeling and to review automatic rate adjustment clauses and directs state regulatory authorities and nonregulated utilities to consider certain standards for rate design and other utility procedures. The Authority is unable to determine the effect such legislation may have on its operations and those of the Project Participants.

In June 1983, the Supreme Court of the State of Washington held invalid the "take or pay" participation agreements between the Washington Public Power Supply System (the "Supply System"), a joint action power agency, and certain State of Washington public entities relating to two terminated nuclear generating projects of the Supply System. The Court held that those public entities lacked statutory authority under Washington law to enter into such participation agreements. Following the Court's decisions, the Superior Court of King County, Washington held unenforceable the "take or pay" participation agreements entered into between the Supply System and the 88 participants in the two terminated nuclear generating projects. The Superior Court's decision was affirmed by the Supreme Court of the State of Washington. A petition seeking review of that decision was denied by the United States Supreme Court. In March 1984, the Supreme Court of the State of Oregon unanimously reversed a lower court decision and upheld the authority of Oregon public entities to enter into the "take or pay" participation agreements. Additionally, the Supreme Court of the State of Idaho in September 1983 held that the "take or pay" participation agreements entered into between the five Idaho cities and the Supply System are void because the Idaho cities failed to comply with a constitutional provision requiring voter approval before incurring indebtedness or liability exceeding a certain amount.

Notwithstanding the foregoing litigation and decisions, the Authority believes that the Power Sales Contracts are valid, binding and enforceable obligations of the Project Participants. Mudge Rose Guthrie Alexander & Ferdon, Bond Counsel, are of the opinion that none of these decisions affect the validity of the Power Sales Contracts. See the proposed form of the opinion of Bond Counsel attached hereto as Appendix E.

LITIGATION

At the time of delivery of the 1987 Bonds, an appropriate officer of the Authority will certify that, except for the action and threatened proceedings described below under "Thurston Litigation", there is no litigation or other proceeding pending or, to the knowledge of the Authority, threatened in any court, agency or other administrative body (either state or Federal) restraining or enjoining the issuance, sale or delivery of the 1987 Bonds or the collection of Revenues, or in any way questioning or affecting (i) the proceedings under which the 1987 Bonds are to be issued, (ii) the validity of any provision of the 1987 Bonds or the Bond Indenture, (iii) the pledge by the Authority under the Bond

Indenture, (iv) the validity or enforceability of the Power Sales Contracts, (v) the legal existence of the Authority or the title to office of the present officials of the Authority, or (vi) the authority of the Authority to own and operate the Authority Interest.

Thurston Litigation

On July 27, 1982, three individual plaintiffs filed an action entitled *Thurston et al. v. Southern California Public Power Authority et al.* in the Superior Court for the County of Los Angeles against the Authority, the Department and other unnamed defendants, seeking, among other relief, a temporary restraining order, a preliminary injunction and a permanent injunction to, among other things, prevent the Authority from selling or issuing revenue bonds to finance the Authority Interest and to prevent the expenditure of public moneys by the defendants with respect to the Authority Interest. The plaintiffs allege, among other things, that (i) the undertaking by the Department of its obligations under, and the performance by the Department of, its Power Sales Contract violates certain provisions of the Constitution and statutes of the State of California and the Los Angeles City Charter, (ii) the terms of the revenue bonds proposed to be issued by the Authority would violate, and the authorization of such issuance by the Project Participants without a vote of the electorate violates, certain provisions of the statutes of the State of California, and (iii) the proposed transactions and certain acts of the defendants in connection therewith are unsound or unlawful business practices, an unsound business venture, or are otherwise illegal. On July 27, 1982, the plaintiffs' motion for a temporary restraining order was denied.

A hearing on plaintiffs' motion for a preliminary injunction in the action was held on August 10, 1982; plaintiffs' motion was denied at that hearing. On August 16, 1982, the plaintiffs appealed to the California Court of Appeal for the Second Appellate District from the denial of their motion for a preliminary injunction. The plaintiffs also filed with that court a petition for writ of supersedeas to stay enforcement of the order denying the preliminary injunction and to enjoin the Authority from issuing indebtedness, and from delivering any proceeds of indebtedness pursuant to the assignment agreement. On August 20, 1982, the Court of Appeal denied plaintiffs' petition. On July 12, 1984, the Court of Appeal entered its decision affirming the decision of the trial court and rejecting all issues raised by the plaintiffs.

The plaintiffs did not seek appellate review by the California Supreme Court of the July 12, 1984 Court of Appeal decision. The action has now been returned to the Superior Court, as the trial court, and is awaiting further action, if any, by the plaintiffs. The Authority and its Legal Counsel, Rourke & Woodruff, and the Department and the Los Angeles City Attorney have reviewed the complaint and the other court documents filed in the action (including those relating to the Court of Appeal proceedings) and have researched the legal issues raised by the plaintiffs therein. Based upon such review and research, the Authority and its Legal Counsel are of the opinion that insofar as the action relates to the Authority, and the Department and the Los Angeles City Attorney are of the opinion that insofar as the action relates to the Department, the issues raised by the plaintiffs are without merit and the defendants have sound legal defenses to the causes of action contained in the complaint.

Project-Related Litigation

In January 1982, the Salt River Pima-Maricopa Indian Community filed an action entitled *Salt River Pima-Maricopa Indian Community v. United States et al.* against the United States, the Secretary of the Interior, Salt River Project, Salt River Valley Water Users Association, a number of water conservation and irrigation districts, the City of Phoenix, and other cities in the Greater Phoenix Metropolitan area, and the participants in PVNGS.

The action was originally brought only against the United States and the Secretary of the Interior in the United States District Court for the District of Columbia. The United States moved for transfer of the action to the United States District Court for Arizona and the motion was granted. Upon transfer, the Indian Community filed an amended complaint adding the additional parties, including the Authority and the Department.

The gist of the Complaint is that the Indian Community is entitled to certain water rights in and to the waters of the Salt River, including underground waters, under the Winters doctrine, contracts, court decisions and other federal law, and that the United States is not requiring Salt River Project to make water available to the Indian Community in accordance with those rights. Among the claims is the claim that Salt River Project delivers water to certain cities, including the City of Phoenix; that these cities pump water from the ground water basin; that the waters delivered to and pumped by the cities are subject to the claims made by the Indian Community; that the City of Phoenix and the other cities have agreed to sell effluent from the sewage treatment plant of the City to the Project for cooling purposes, and such effluent is subject to the claims of the Indian Community, and therefore the contract for sale of a portion of the effluent to the Project is invalid. The participants in the Project joined with other defendants in a motion to dismiss. The Court's judgment, as amended on June 13, 1983, dismissed the entire action as to the Authority, the Department and APS, among others, but not as to Salt River Project. The Court held that the plaintiff had no standing to challenge the Salt River Project — APS effluent contract. On June 13, 1983, the plaintiff appealed from the Court's judgment. On September 4, 1984, the United States Court of Appeals for the Ninth Circuit reversed the District Court's judgment. The Ninth Circuit held that the plaintiffs had standing to challenge the effluent contract and remanded the case to the United States District Court for Arizona. The Authority and other participants in the Project filed a petition for a writ of certiorari seeking review of the United States Court of Appeals for the Ninth Circuit's decision by the United States Supreme Court. This petition was denied. On February 25, 1985, the District Court stayed discovery on the claim challenging the effluent contract, pending resolution of the claims against the Secretary of the Interior and Salt River Project relating to the administration of the reclamation project. Since that date, there have been no further material developments in this case. Salt River Project has reported that in the event of a successful challenge to the validity of the contracts for the sale of effluent, it believes that alternate sources of cooling water could be obtained.

On November 3, 1982, a lawsuit entitled *A Tumbling T Ranches, et al. v. City of Phoenix, et al.* was filed in the Arizona Superior Court by certain Arizona farm operators against, among others, the Department, the City of Phoenix and the Project participants, including the Authority. The lawsuit seeks, among other relief, declarations that the plaintiffs have previously established rights to some of the sewage effluent water contracted for by the Project participants for use at the Project and that the sale of that effluent by the City of Phoenix and other cities violates Arizona statutory and common law, and a permanent injunction enjoining the sale and delivery of the sewage effluent to the Project. The Project participants, including the Authority, have answered the complaint denying the substantive allegations thereof and discovery has commenced.

On January 23, 1983, APS and Salt River Project, as contracting parties to the effluent contract, and others filed a declaratory relief action in the Arizona Superior Court against the plaintiffs in the *A Tumbling T Ranches* action and the plaintiffs in the federal action entitled *Long, et al. v. Salt River Project, et al.* (described below). This state suit, which is entitled *Arizona Public Service Co., et al. v. Long, et al.*, seeks a declaration that, under Arizona law, effluent is neither surface water nor groundwater, but rather is the property of, and can be disposed of, by the entity that produces it. This state action has been consolidated with the *A Tumbling T Ranches* action (hereinafter, "consolidated state cases").

On October 2, 1985, the Judge in the consolidated state cases ruled on cross-motions for summary judgment, denying the motions filed by the plaintiffs in the *A Tumbling T Ranches* action and the defendants in *Arizona Public Service Co., et al. v. Long, et al.* and granting APS', Salt River Project's and others' motions for summary judgment to the extent said motions were consistent with his declaration that "[t]he effluent which is the subject of the sales contracts between the Cities and the utilities in this case is not subject to regulation under the surface water or ground water laws of the State of Arizona." The plaintiffs in the *A Tumbling T Ranches* action filed a motion for new trial which was denied on February 4, 1986. The defendants in *Arizona Public Service Co., et al. v. Long, et al.* filed a Notice of Appeal on January 14, 1986. The Authority and the other participants in the Project except

for Salt River Project filed a notice of cross-appeal in order to preserve an issue in the event of a remand. On December 17, 1986, the appeals were ordered transferred from the Arizona Court of Appeals to the Arizona Supreme Court. Oral argument before the Arizona Supreme Court is scheduled for February 20, 1987. The impact, if any, on the Project and the Authority cannot be predicted at this time.

A federal lawsuit was filed on December 12, 1983 in the United States District Court for the District of Arizona entitled *Long, et al. v. Salt River Project, et al.*, by an owner of land within the Salt River Project district and others, naming the Authority, the Department, Salt River Project and others as defendants. The lawsuit challenges on several grounds the validity of the primary contract for the sale of effluent for cooling purposes at the Project. The federal action also asserted on behalf of an alleged class a claim against the Project participants, including the Authority, for $50,000,000 based upon alleged inverse condemnation of water rights. On November 22, 1985, the District Court entered judgment dismissing the federal action. On December 19, 1985 the plaintiffs in the federal action filed a notice of appeal of this judgment to the United States Court of Appeals for the Ninth Circuit. Oral argument was held December 12, 1986, and the matter was taken under submission. Salt River Project has reported that in the event of a successful challenge to the validity of the contracts for the sale of effluent, it believes that alternate sources of cooling water could be obtained.

On November 22, 1985, certain cities who are parties to the effluent contract (the "Cities") filed a declaratory relief action in the Arizona Superior Court against the plaintiffs in the above-described federal action seeking a judgment that the primary effluent contract is valid. The defendants filed a Special Action counterclaim against the Cities. The court subsequently added APS and Salt River Project to the counterclaim as real parties in interest. The counterclaim sought a judgment declaring, among other things, that in approving the effluent contract the Cities exceeded their legal authority and that the Cities should be directed to cease performance under the effluent contract. APS and Salt River Project denied the allegations of the counterclaim and asserted as affirmative defenses that the defendants lacked standing to assert the counterclaim and that the counterclaim was barred by the statute of limitations and by laches. The defendants sought leave to file an amended answer and counterclaims and to join additional parties, including the Authority. By Order dated May 29, 1986, the court permitted the defendants to file their amended answer and counterclaims only to the extent that counterclaims 1 through 4 restated the substance of the original counterclaims concerning the legal authority of the Cities to approve the effluent contract. The defendants were denied leave to file their remaining proposed counterclaims and to add the parties named therein. By Order dated June 2, 1986, the court ruled on cross-motions for summary judgment, denying the defendants' motion and granting judgment in favor of the Cities, APS and Salt River Project. The court rejected each of the defendants' challenges to the effluent contract and declared that it "is a valid and enforceable contract." The defendants filed a Notice of Appeal on August 27, 1986, and APS filed a Notice of Cross-Appeal on September 15, 1986, concerning the issue of whether the defendants' claims are barred by laches, estoppel, the statute of limitations and lack of standing. The appeal is in its preliminary stage.

FEDERAL AND STATE INCOME TAXES

The Internal Revenue Code of 1986, as amended, establishes certain requirements which must be met subsequent to the issuance and delivery of the 1987 Bonds for interest thereon to be and remain excluded from Federal gross income. Noncompliance with such requirements could cause the interest on the 1987 Bonds to be included in Federal gross income retroactive to the date of issue of the 1987 Bonds. These requirements include, but are not limited to, provisions which prescribe yield and other limits within which the proceeds of the 1987 Bonds and other amounts are to be invested and require that certain investment earnings on the foregoing must be rebated on a periodic basis to the Treasury Department of the United States. Pursuant to the Resolution, the Authority has covenanted to maintain the exclusion from Federal gross income of the interest on the 1987 Bonds.

In the opinion of Bond Counsel, assuming compliance with the aforementioned covenant, under existing statutes, regulations, rulings and court decisions, interest on the 1987 Bonds is excluded from gross income for Federal income tax purposes.

Bond Counsel is further of the opinion that under existing statutes, regulations, rulings and court decisions, the 1987 Bonds are not "specified private activity bonds" within the meaning of Section 57(a)(5) of the Code and, therefore, the interest on the 1987 Bonds will not be treated as a preference item for purposes of computing the alternative minimum tax imposed on individuals by Section 55 of the Code. For taxable years beginning after December 31, 1986, however, the alternative minimum tax on corporations will be computed by taking into account one-half (75 percent after 1989) of the excess of adjusted net book income (adjusted current earnings after 1989) over pre-book alternative minimum taxable income. Thus, a portion of the interest on the Bonds may be subject to an alternative minimum tax for taxable years beginning after December 31, 1986, when such 1987 Bonds are held by corporations. The Superfund Amendments and Reauthorization Act of 1986 imposes an environmental tax on corporations based upon modified alternative minimum taxable income. The environmental tax is not an alternative tax, and the amount of the tax is equal to 0.12 percent of the amount of a corporation's modified alternative minimum taxable income in excess of a specified amount (generally $2,000,000). Modified alternative minimum taxable income is generally determined for purposes of this environmental tax in the same manner as under the corporate alternative minimum tax described herein but without regard to net operating losses and the deduction for the environmental tax itself. Thus, the interest on the Bonds may be subject to this environmental tax when such 1987 Bonds are held by corporations for taxable years beginning after December 31, 1986, and before January 1, 1992. The interest on the 1987 Bonds may also be subject to the branch profits tax imposed by Section 884 of the Code when such 1987 Bonds are owned by, and interest thereon is effectively connected with the trade or business of, United States branches of foreign corporations for taxable years beginning after December 31, 1986.

Bond Counsel is further of the opinion that the difference between the principal amount of the 1987 Bonds maturing on July 1, 2006, 2008, 2015 and 2017, respectively, and the initial offering price to the public (excluding bond houses and brokers) at which price a substantial amount of such 1987 Bonds of the same maturity was sold represents interest which is excluded from Federal gross income. Further, such interest accrues on an actuarial basis (*i.e.*, on the basis of a geometric progression over the term of such 1987 Bonds) and the basis in such 1987 Bonds of an owner who acquires the Bonds at such price in this offering will be increased by the amount of such accrued discount. Such discount may also be taken into account in determining the amount of the alternative minimum tax, the environmental tax and the branch profits tax described above. Owners of the 1987 Bonds maturing on July 1, 2006, 2008, 2015 and 2017, respectively, should consult their own advisors with respect to the state and local tax consequences of owning such 1987 Bonds. Interest may be deemed to be received in the year of accrual even though there will not be a corresponding cash payment.

Bond Counsel is further of the opinion that, under the Act, interest on the 1987 Bonds is exempt from personal income taxation of the State of California.

UNDERWRITING

The Underwriters have jointly and severally agreed, subject to certain conditions, to purchase the 1987 Bonds from the Authority at an aggregate Underwriters' discount of $4,055,417.50 and to make a bona fide public offering of the 1987 Bonds at not in excess of public offering prices, plus accrued interest, agreed to by the Underwriters and the Authority. The Underwriters will be obligated to purchase all such 1987 Bonds if any such 1987 Bonds are purchased.

The 1987 Bonds may be offered and sold to certain dealers (including Underwriters and other dealers depositing such Bonds into investment trusts) at prices lower than such public offering prices, and such public offering prices may be changed, from time to time, by the Underwriters.

CERTAIN LEGAL MATTERS

Certain legal matters in connection with the authorization and issuance of the 1987 Bonds are subject to the approval of Mudge Rose Guthrie Alexander & Ferdon, Los Angeles, California, Bond Counsel. The form of opinion Bond Counsel proposes to render with respect to the 1987 Bonds is attached as Appendix E hereto. Copies of such opinion will be provided to the original purchasers without charge. Certain legal matters with respect to the Authority will be passed upon by its legal counsel, Rourke & Woodruff, a Professional Corporation, Orange, California. Certain legal matters will be passed upon for the Underwriters by O'Melveny & Myers, Counsel to the Underwriters.

VERIFICATION OF MATHEMATICAL COMPUTATIONS

Upon delivery of the 1987 Bonds, Ernst & Whinney, independent certified public accountants, will deliver a report stating that the firm has reviewed (a) the mathematical accuracy of certain computations relating to the adequacy of the Government Obligations and the interest thereon to pay the Redemption Price of and interest on the Refunded Bonds on and prior to the redemption dates thereof, (b) the mathematical accuracy of certain computations relating to the adequacy of the Notes Escrow Obligations and interest thereon to pay the principal and interest due on the Prior Series Notes on the maturity date thereof, and (c) the computations of actuarial yield of the 1987 Bonds and Government Obligations which support Bond Counsel's conclusion that interest on the 1987 Bonds is excluded from Federal gross income.

MISCELLANEOUS

During the initial offering period for the 1987 Bonds, copies of the Authority's audited financial statements for the year ended June 30, 1985 may be obtained upon written request from the Executive Director of the Authority, 613 East Broadway, Glendale, California 91205, and copies of the forms of the Power Sales Contracts, the Bond Indenture, the Participation Agreement, the Agency Agreement, and the Transmission Agreement may be obtained upon written request from Salomon Brothers Inc, One New York Plaza, New York, N.Y. 10004, Attention: Municipal Finance Department.

SOUTHERN CALIFORNIA PUBLIC
POWER AUTHORITY

By: /s/ GALE A. DREWS
President

APPENDIX A

R. W. BECK AND ASSOCIATES

ENGINEERS AND CONSULTANTS

PLANNING
DESIGN
RATES
ENVIRONMENTAL
ECONOMICS
MANAGEMENT

FOURTH & BLANCHARD BUILDING
2121 FOURTH AVENUE
SEATTLE, WASHINGTON 98121
TEL: 206-441-7500

GENERAL OFFICE
SEATTLE, WASHINGTON
Telephone: 206-441-7500
Telex: 4990402 BECKSEA
Seattle, WA Telecopier:
206-441-4962

January 29, 1987

Board of Directors
SOUTHERN CALIFORNIA PUBLIC
POWER AUTHORITY
613 East Broadway
Glendale, California 91205

Gentlemen:

Consulting Engineer's Report
Southern California Public Power Authority
Palo Verde Project

INTRODUCTION

Presented herewith is a summary of our analyses and studies with respect to the proposal by the Southern California Public Power Authority (the "Authority") to issue $352,645,000 of its Power Project Revenue Bonds, 1987 Refunding Series A (the "1987 A Bonds"), (a) to provide for advance refunding of outstanding Power Project Revenue Bonds of the Authority in the aggregate amount of $233,210,000 (the "Refunded Bonds"); (b) to complete financing of the estimated construction costs of the Authority's interest and rights in the Palo Verde Nuclear Generating Station and certain associated facilities; (c) to provide for the payment at maturity of the Authority's outstanding Power Project Bond Anticipation Notes, 1984 Series A (the "1984 Notes"); and (d) to meet interest during construction and financing cost requirements. The 1984 Notes and Refunded Bonds were issued to finance (a) (i) a portion of the costs of acquisition, construction and placing into operation of the Authority's 5.91% ownership interest in the Palo Verde Nuclear Generating Station, Units 1, 2 and 3, including certain associated facilities and contractual rights, and (ii) the Authority's 5.56% ownership interest in the ANPP High Voltage Switchyard and contractual rights; and (b) the Authority's 6.55% share of the rights to use the Arizona Nuclear Power Project Valley Transmission System. The Palo Verde Nuclear Generating Station, Units 1, 2 and 3, including certain associated facilities and contractual rights and the ANPP High Voltage Switchyard and contractual rights are collectively referred to herein as the "Project." Additionally, the Arizona Nuclear Power Project Valley Transmission System is referred to herein as the "ANPP Transmission System." The Authority's ownership interests in and rights to the Project and the ANPP Transmission System are referred to herein as the "Authority Interest."

Including the 1987 A Bonds, the Authority will have issued a total of $1,110,125,000 of its Power Project Revenue Bonds. Such Bonds complete financing of the estimated construction costs of the Authority Interest contemplated by the Authority's present financing program and include $990,690,000 of Power Project Revenue Bonds, 1982 Series A and B, 1983 Series A, 1984 Series A, 1985

Seattle, WA • Denver, CO • Phoenix, AZ • Orlando, FL • Columbus, NE • Boston, MA • Indianapolis, IN • Minneapolis, MN • Sacramento, CA • Austin, TX • Nashville, TN • Washington, D.C.

Refunding Series A and B, and 1986 Refunding Series A and B (the "Prior Series Bonds"). The Authority has also issued a total of $407,875,000 Power Project Bond Anticipation Notes (the "Prior Series Notes"), none of which will remain outstanding after issuance of the 1987 A Bonds. (See "The Authority Interest — Estimated Financing Requirement".)

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY

The Authority is organized pursuant to the provisions relating to the joint exercise of powers found in the Government Code of California, as amended, and the Joint Powers Agreement, dated as of November 1, 1980, as amended. Its membership consists of 10 cities and one irrigation district which supply electric energy in southern California. The Authority is governed by its Board of Directors which consists of a representative of each of its members. The management of the Authority is under the direction of the Executive Director, who serves at the pleasure of the Board of Directors.

THE PROJECT AND ANPP TRANSMISSION SYSTEM

The Project

The Palo Verde Nuclear Generating Station consists of three nominal 1,270 megawatt electric ("MWe") nuclear generating units, two of which have commenced commercial operation and one of which is nearing completion of construction. In May, 1986, Arizona Public Service Company ("APS") reported to the Nuclear Regulatory Commission (the "NRC"), an adjustment to the design electrical rating of each of Units 1 and 2 from 1,270 MWe net to 1,221 MWe net to reflect the licensed reactor thermal power level. The actual, as-built, performance ratings of the Project (including the maximum dependable capacity for each unit) are presently being evaluated by APS. For purposes of this analysis, we have based the Authority Interest output on an assumed production capacity of 1,221 MWe net from each of the three units. It is estimated that by 1988 the Project will have a net generating capacity of approximately 3,663 MWe. Additionally, it is estimated that by 1992 each unit will have achieved a mature plant factor and the Project will have an annual energy output of approximately 22,500,000 megawatt-hours ("MWh"). It is estimated that the Authority Interest will be capable of delivering approximately 207.4 MWe of capacity and, on average, 1,271,777 MWh of energy annually at the various points of delivery, after adjustment for transmission losses. The Project is located on a site of approximately 4,000 acres about 50 miles west of downtown Phoenix, Arizona. The three units are essentially identical in design and share certain common facilities, including a water reclamation plant, make-up water storage reservoir, two on-site wells, domestic water system, demineralized water system, sanitary waste treatment facility, evaporation ponds, laundry and decontamination facility, administration building, guardhouse, service warehouse building, switchyard and miscellaneous buildings. Each unit is designed for a forty year life.

The nuclear steam supply system for each unit of the Project, supplied by Combustion Engineering, Inc., is a closed-cycle pressurized water reactor system licensed at 3,817 megawatts of thermal capacity, with two reactor coolant loops, containing two reactor coolant pumps in each loop. The turbine generators are tandem compound units supplied by the General Electric Company. The main condensers are being supplied by the Westinghouse Electric Company and are cooled by circulating water through mechanical draft cooling towers. Make-up water for the dissipated circulating water is obtained primarily from the 91st Avenue Sewage Treatment Plant operated by the City of Phoenix. This processed effluent is piped to the on-site water reclamation plant where it undergoes additional treatment and is then stored in the on-site reservoir as make-up water. Blow-down from the circulating water system, demineralized water wastes, domestic water wastes, nonradioactive demineralizer regenerants and miscellaneous nonradioactive wastes are directed to the on-site evaporation ponds where they are completely evaporated. Thus, no off-site liquid discharges are required.

At design steam flow and condenser back pressure, the output from the main turbine-generators is 1,304 MWe. The main transformers will step up the output voltage of each generator to 525 kV for interconnection into the ANPP Transmission System.

The Project is being designed and constructed by the Bechtel Power Corporation, Norwalk, California. APS is the Project Manager and also operates the three units. The switchyard portions of the Project were constructed and are being managed by the Salt River Project Agricultural Improvement and Power District ("Salt River Project").

Pursuant to the Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, as amended (the "Participation Agreement"), and the Salt River-Authority Palo Verde Nuclear Generating Station Assignment Agreement, dated as of August 14, 1981, as amended (the "Assignment Agreement"), the utilities listed in the table below are participants in the Project in the following percentages.

	Current Interests
Arizona Public Service Company	29.10%
Salt River Project Agricultural Improvement and Power District	17.49
Southern California Edison Company	15.80
Public Service Company of New Mexico	10.20
El Paso Electric Company	15.80
Southern California Public Power Authority	5.91
Department of Water and Power of The City of Los Angeles	5.70
Total	100.00%

In connection with financing of the Project, APS, Public Service Company of New Mexico ("PNM") and El Paso Electric Company ("EPE"), have entered into sale and leaseback transactions involving certain portions of their respective ownership interests in the Project.

The Authority has sold the entire capability of the Authority Interest pursuant to power sales contracts (the "Power Sales Contracts") with nine California municipalities and a California irrigation district (the "Project Participants"). The following is a list of the Project Participants, their percentage shares of the Authority Interest (the "Project Entitlement") and the estimated maximum Project generating capability available to each at the high voltage bus of the ANPP High Voltage Switchyard:

	Project Entitlement	Generating Capability* (MWe)
Department of Water and Power of The City of Los Angeles	67.0%	145.04
Imperial Irrigation District	6.5	14.07
City of Riverside	5.4	11.69
City of Vernon	4.9	10.61
City of Burbank	4.4	9.53
City of Glendale	4.4	9.53
City of Pasadena	4.4	9.53
City of Azusa	1.0	2.16
City of Banning	1.0	2.16
City of Colton	1.0	2.16
Total	100.0%	216.48

* Based on the assumed per unit production capacity level of 1,221 MWe net.

Under the Power Sales Contracts, the Project Participants are entitled to the generating capability of the Authority Interest based on their respective Project Entitlements, and the Project Participants are obligated to make payments therefor on a "take or pay" basis. For a further discussion by the Authority of the Power Sales Contracts, see the Official Statement to which this report is attached (the "Official Statement") and "Summary of Certain Provisions of the Power Sales Contracts" in Appendix C thereto.

Status and Schedule

Construction of the Project began on June 10, 1976. The construction of large electric generating facilities such as the Project includes two basic phases. The first phase, identified and reported by APS as "construction," includes erection of the various buildings and installation of equipment and systems. The second phase, identified and reported by APS as "startup," includes certain operational activities such as cleaning systems, starting and testing equipment and systems and measuring performance. The startup phase is completed upon loading of nuclear fuel into the reactor pressure vessel. Following fuel loading, the operation of each unit is tested, in a power ascension program, at various power levels up to 100 percent power. The power ascension program is completed upon declaration that the unit has achieved firm power operation at full power.

Units 1 and 2 were declared to have achieved firm power operation on January 27, 1986 and September 18, 1986, respectively. Unit 1 is presently experiencing an unplanned outage, which began on January 18, 1987. This outage was due to a steam generator tube leak in the nuclear steam supply system. While, preliminarily, APS has estimated that the outage will last approximately one month, the cause of the leakage and required corrective action and impact on Project schedule and operations cannot now be determined.

As of December 31, 1986, APS reported that construction of Unit 3 was approximately 99.9% complete. APS also reported that startup of Unit 3 was approximately 96.9% complete. APS has scheduled the loading of nuclear fuel for Unit 3 for the first quarter of 1987. In January 1986, APS estimated that firm power operation at full power for Unit 3 would occur during the third quarter of 1987. This schedule assumes no delay in construction of the Project resulting from such matters as starting up and testing of Unit 3, shortages or delays in receipt of equipment or materials, shortages of labor, strikes or other similar matters. Such delays are common in the construction of facilities such as the Project. To the extent that delays do occur, the estimated completion dates of components of the Project may be delayed. In addition, the participants in the Project, in certain circumstances, might elect to approve a planned schedule delay. Any schedule delays may result in increased Project costs.

APS's current schedule anticipates that the operating license will be received from the NRC for Unit 3 in sufficient time to meet the projected power ascension schedule for this unit, as set forth above.

Based on, among other things, cost estimates provided by APS and certain assumptions provided by the Department of Water and Power of The City of Los Angeles (the "Department"), as the Authority's agent, the estimated construction costs of the Authority Interest are $465,170,000. The assumptions provided by the Department include an Authority contingency allowance for uncertainties not included in APS's estimate of the total construction costs for the Project. This contingency allowance could be expended for additional direct labor costs, contractor overheads and escalation associated with the commercial operation schedule for the Project or for such costs should a delay occur in Project completion. The scheduled commercial operation date for Unit 3, as used in the Project Participants' power supply planning, is March 1, 1988. This schedule for Unit 3 is approximately three months later than the schedule now estimated by APS.

Permits, Licenses and Approvals

Construction permits for the Project were issued on May 25, 1976. On April 28, 1982, the NRC approved amendments to the construction permits for each unit of the Project which allowed the transfer to the Authority of a 5.91% ownership interest in the Project.

Application has been made to the NRC for operating licenses for each unit. Hearings have been completed on an intervenor's petition which raised, primarily, an issue relating to the adequacy of cooling water supply for the Project. The Atomic Safety and Licensing Board (the "ASLB") issued a favorable initial decision rejecting the intervenor's contentions. On February 15, 1983, the Atomic Safety and Licensing Appeal Board (the "Appeal Board") affirmed this initial decision, which decision became final on April 27, 1983. Subsequent to the conclusion of the ASLB hearings, an entity representing operators of farms in the vicinity of the Project (the "Intervenor") petitioned the ASLB to reopen the hearings to consider an environmental issue related to salt emissions associated with the Project's cooling system. By its order issued on July 22, 1985, the ASLB granted the Intervenor's request to withdraw its petition to intervene, in connection with the settlement agreement dated May 20, 1985. Further, since the ASLB noted that the Project's operating license proceeding is now uncontested, it authorized the NRC, upon making certain findings not embraced by the ASLB order, in accordance with NRC regulations, to issue operating licenses for Units 2 and 3 of the Project. For additional information provided by others on the NRC operating license proceeding, see "Litigation — Project-Related Litigation" and "The Project and the ANPP Transmission System — Permits, Licenses and Approvals" in the Official Statement.

On December 31, 1984, Unit 1 received a 40-year Full-Power Operating License with a 5-percent power level restriction. On May 30, 1985, the NRC lifted this power level restriction. On December 9, 1985, Unit 2 received a 40-year Full-Power Operating License with a 5-percent power level restriction. On April 23, 1986, the NRC lifted this power level restriction. Except for the receipt of the operating license for Unit 3, APS has stated that there are no remaining major approvals required to complete or operate the Project.

On or about November 28, 1986, Plains Electric Generation and Transmission Cooperative, Inc. ("Plains") filed a request with the NRC for an antitrust hearing and for the imposition of conditions on the operating license for Unit 3. Plains, a generation and transmission cooperative serving loads in New Mexico and eastern Arizona, alleges that EPE, a participant in the Project, has taken anti-competitive actions to prevent Plains from transmitting power from northern New Mexico to southern New Mexico. Plains requests an antitrust hearing with the NRC to review EPE's alleged actions and recommends that the operating license for Unit 3 include certain conditions to assure Plains that it will have long term transmission access to southern New Mexico. Each of Plains' recommended conditions concerns action to be taken by EPE to provide such assurances to Plains. The recommended conditions do not purport to limit or restrict operation of Unit 3, or to regulate transmission of power from Unit 3. It is not known what effect, if any, the Plains request will have on the operating license for Unit 3, or the timing of the receipt thereof.

Nuclear Fuel

The nuclear fuel cycle consists of four basic activities necessary for the manufacture of fuel assemblies. These activities are acquisition of uranium concentrates, conversion of the uranium concentrates to uranium hexafluoride, enrichment of the uranium hexafluoride and fabrication of the enriched uranium into fuel assemblies. After the fuel has been used in the reactor, it is removed for reprocessing or disposal.

The following tabulation shows the approximate percentages of the required amounts of materials and services APS presently has under contract, including options, for the Project:

	Uranium	Conversion	Enrichment	Fabrication
1987-1989	100%	100%	100%	100%
1990-2000	100%	15%	100%	100%

APS expects to contract for the required conversion services from 1990-2000, and all additional services required beyond 2000, well in advance of its needs. APS has been notified that, as of September 18, 1985, the U.S. District Court of Colorado ruled that the form of the utilities services enrichment contract used by the United States Department of Energy ("DOE") in its negotiations with utilities, including APS, is null and void. APS has a utilities services enrichment contract which is subject to this ruling. DOE has appealed the decision and has announced that it will continue to honor the contracts through the appeal process. APS does not anticipate any difficulty in procuring enrichment services for the Project even if this ruling is upheld.

At the present time, no operating facilities for the reprocessing of spent fuel are available. On October 8, 1981, the President of the United States released a policy statement lifting the ban previously placed on the commercial reprocessing of spent nuclear fuel. The policy statement also called for the elimination of unnecessary governmental barriers and regulatory impediments to the licensing of nuclear power plants, the development of commercial interest in spent fuel reprocessing technology and the development of radioactive waste disposal programs. The effects of these policies cannot be predicted at this time. On-site spent fuel storage capacity for the Project is estimated by APS to be sufficient to accommodate storage of all spent fuel into the 1990's and, by adding special materials to the spent fuel pool storage racks, is estimated by APS to be sufficient to accommodate storage of all spent fuel, including maintaining full core discharge capability, during approximately 17 years of normal operation. This spent fuel storage capability could allow operation until 2002, 2003 and 2004 for Units 1, 2 and 3, respectively. On January 7, 1983, the President of the United States signed the Nuclear Waste Policy Act of 1982. This Act establishes a national program for spent fuel disposal which is to be further defined and implemented over the next several years. DOE is responsible for the national program for spent fuel disposal. With respect to this program, DOE currently faces multiple law suits over its selection of three potential repository sites in Nevada, Texas and Washington for detailed characterization work, its decision in May 1986 to postpone indefinitely any site-specific work related to a second geologic repository, its selection of sites in Tennessee for a monitored retrievable storage facility and its repository siting guidelines. We are unable to predict the outcome of this litigation or what, if any, impact this litigation will have on the national program for spent fuel disposal, the extent to which the program will be implemented, and the extent to which either reprocessing or off-site storage services may be required or available.

ANPP High Voltage Switchyard and ANPP Transmission System

The ANPP High Voltage Switchyard consists of a breaker-and-a-half scheme which comprises the termination facilities for the transmission lines, generator step-up transformers and auxiliaries, including, but not limited to, the high voltage busses, structures, power circuit breakers, disconnect switches, control building, switchyard auxiliary, protection systems and fencing.

The ANPP Transmission System consists of the facilities listed below, along with associated rights-of-way:

Palo Verde — Westwing 525 kV Transmission Lines Nos. 1 and 2
Palo Verde — Kyrene 525 kV Transmission Line
Westwing 525 kV Switchyard expansion
Kyrene 230 kV Switchyard expansion
Second Kyrene 230 kV Switchyard
Kyrene 525/230 kV Switchyard
Microwave Communication System

The design and construction of the ANPP Transmission System, with the exception of the Westwing 525 kV Switchyard expansion, was managed by Salt River Project. The design and construction of the Westwing 525 kV Switchyard expansion was managed by APS. Salt River Project is also operating the ANPP Transmission System, with the exception of the Westwing 525 kV Switchyard, which is being operated by APS. Construction of the major components of the ANPP Transmission System, with the exception of the second Kyrene 230 kV Switchyard and the second Palo Verde — Westwing 525 kV transmission line, was completed in August 1982. Salt River Project has reported that, as of October 30, 1986, the second Kyrene 230 kV Switchyard was operational, having been completed ahead of schedule and under budget. Additionally, Salt River Project reported that, as of June 13, 1986, the second Palo Verde — Westwing 525 kV transmission line was operational.

THE AUTHORITY INTEREST

Estimated Construction Costs

The most recent estimate of the construction costs for the Project by APS is dated October 7, 1986. APS has also estimated the cash flow requirements for nuclear fuel associated with the Project. Salt River Project's most recent estimate of the construction costs for the ANPP Transmission System is dated June 30, 1986. The following table shows the total estimated costs for the Project and the ANPP Transmission System and the total estimated cost for the Authority Interest, including an additional Authority contingency to allow for uncertainties in addition to those provided for by APS. During the power ascension program, each unit generates non-firm energy. We have not included such energy or the Authority's related revenues in our analysis herein.

Estimated Construction Costs
($000)

	Total Project and ANPP Transmission System	Authority Interest
Plant(1)	$4,556,000	$ 269,260
Preoperations and Startup Costs(2)	1,344,000	79,430
Sewage Effluent Prepayment and Startup Power Costs(3)	77,771	4,594
Transmission Facilities Rights and Ownership Interest(4)	115,776	7,358
Other(5)	71,438	4,222
Direct Construction Costs	$6,164,985	$ 364,864
Project and Transmission Facilities Rights and Ownership Interest Purchase Costs(6)		52,784
Nuclear Fuel(7)		28,982
Ad Valorem Taxes(8)		8,540
Authority's Contingency(9)		10,000
Total Construction Costs		$ 465,170

(1) Estimated by APS. Includes land, structures, nuclear steam supply system, turbine generator, other improvements and nuclear information communications costs.

(Footnotes continued on following page)

(2) Estimated by APS.

(3) Sewage effluent prepayment costs estimated by APS. Startup power costs based on actual Authority expenditures subsequent to purchase of the Authority Interest on September 10, 1982 and such power requirements provided by APS and purchased from Salt River Project at rates prescribed in the Salt River Project/Authority — ANPP Testing and Startup Power and Energy Agreement dated July 13, 1982, as revised. Such rates were escalated at 7% per year.

(4) Estimated by Salt River Project. Includes ANPP High Voltage Switchyard, Kyrene and Westwing switchyards, associated transmission lines and rights-of-way, microwave facilities and capitalized operation and maintenance expenses during the construction period.

(5) Includes expenditures prior to purchase of the Authority Interest under the Assignment Agreement for the following: startup power costs, ad valorem taxes, Green Mountain Uranium Venture, research and development and Salt River Project direct costs. Also reflects an adjustment for differences between APS's estimate of cash flow requirements dated October 7, 1986 and actual cash flow requirements as well as costs incurred for a prudency audit.

(6) Based on actual closing costs in connection with purchase of the Authority Interest. With the exception of an additional ownership interest in the ANPP High Voltage Switchyard, includes Salt River Project AFUDC, carrying costs from Project inception to September 10, 1982 and an administrative charge. Includes such applicable costs from Project inception to May 2, 1983 for the additional ownership interest in the ANPP High Voltage Switchyard.

(7) Based on actual nuclear fuel expenditures and estimates prepared by APS.

(8) Estimated ad valorem taxes to be paid by the Authority during construction on the Authority Interest.

(9) Estimated by the Authority to allow for additional uncertainties not included in APS's estimated costs. The Authority's contingency could provide for additional construction costs which have not been specifically identified. The scheduled commercial operation date for Unit 3, as used in the Project Participants' power supply planning, is March 1, 1988.

Estimated Financing Requirement

Based on the APS Project construction cost estimate, the Salt River Project estimate of ANPP Transmission System construction costs and consultation with the Authority's Financial Advisor, we have estimated the financing requirement for the Authority Interest to be as shown in the following table:

Estimated Financing Requirement
($000)

	Prior Series Notes	Prior Series Bonds	1987 A Bonds Adjustments To Prior Series Bonds (1)	1987 A Bonds	Total Requirements
Total Construction Costs	$ 217,700	$246,726	$ —	$ 744	$ 465,170
Bond Reserve Fund(2)	—	89,251	(1,619)	614	88,246
Interest During Construction(3)	107,691	259,396	(9,474)	10,100	367,713
Working Capital, Reserve and Contingency Fund and Authority Expenses(4)	—	14,700	—	—	14,700
Financing Costs(5)	4,116	167,108	—	17,362	188,586
Gross Requirements	$ 329,507	$777,181	$ (11,093)	$ 28,820	$1,124,415
Less: Reinvestment Earnings(6)	(21,816)	(100,575)	—	(23,642)	(146,033)
Repayment of Prior Series Notes	(307,691)	232,691	—	75,000(7)	—
Defeasance of Prior Series Bonds	—	(774,714)	(222,117)	—	(996,831)
Net Deposits to Escrow Funds(8)	—	856,107	—	272,467	1,128,574
Total Requirement(9)	$ 0	$990,690	$(233,210)	$352,645	$1,110,125

(1) Net adjustments to Prior Series Bonds resulting from the advance refunding of the Refunded Bonds by the 1987 A Bonds.

(2) Actual and estimated maximum annual debt service deposited in the Debt Service Reserve Account in the Debt Service Fund for the Prior Series Bonds and the additional Bonds, respectively.

(3) Based on the actual annual interest rates for the Prior Series Notes with 100% of the interest capitalized. Based on the actual annual interest rates for the Prior Series Bonds and the 1987 A Bonds. Based on 100% of the interest capitalized until May 1, 1986, 66⅔% of the interest capitalized from May 1, 1986 to January 1, 1987 and 33⅓% of the interest capitalized from January 1, 1987 to March 1, 1988.

(Footnotes continued on following page)

(4) Working Capital requirements are based on providing 90 days of estimated annual costs, excluding debt service. Reserve and Contingency Fund requirements are based on 1.5% of the net utility plant component of the Authority Interest in the Project and are deposited in the Reserve Account in the Reserve and Contingency Fund. Authority expenses are estimated by the Authority. We have assumed that the Authority will appropriate $700,000 for the Reserve and Contingency Fund from available funds.

(5) For the Prior Series Notes and Prior Series Bonds, includes actual underwriters' discount and original issue discount of approximately $157,506,970 and other costs of issuance, including costs of the revolving credit agreements, estimated at approximately $13,717,039. For the 1987 A Bonds, includes actual underwriters' discount and original issue discount of $15,769,963.10 and other costs of issuance estimated at $1,592,321.24.

(6) For the purpose of calculating the Estimated Financing Requirement, the estimated amounts earned on invested funds, through October 30, 1986, have been included. The estimated rates of interest on the investment of undisbursed proceeds of Prior Series Bonds and Prior Series Notes are based upon the remaining, weighted average yield to maturity of instruments in the various funds on October 30, 1986. The estimated rates of interest on the investment of undisbursed proceeds of a portion of the Prior Series Bonds and the 1987 A Bonds are as follows:

	Debt Service Account	Debt Service Reserve Account	Reserve and Contingency Fund
Prior Series Bonds	5.7%	6.9%	5.8%
1987 A Bonds	5.5%	7.0%	5.5%

The investment income is all deposited in the Construction Fund until July 27, 1986. From July 27, 1986 to March 18, 1987, 66⅔% of the investment income is deposited in the Construction Fund. From March 18, 1987 to May 1, 1988, 33⅓% of the investment income is deposited in the Construction Fund. The investment income not deposited in the Construction Fund will be deposited in the Revenue Fund.

(7) Includes income from temporary investment of the amounts to be deposited in the Note Escrow Fund.

(8) For the Prior Series Bonds, deposit into the 1985 Refunding Series A Bonds Escrow Fund, net of the funds released from the Debt Service Account in the Debt Service Fund pursuant to the Fifth Supplemental Indenture of Trust, dated as of April 1, 1985, deposit into the 1985 Refunding Series B Bonds Escrow Fund, net of the funds released from the Debt Service Account in the Debt Service Fund and the Debt Service Reserve Account in the Debt Service Fund pursuant to the Sixth Supplemental Indenture of Trust, dated as of May 1, 1985 deposit into the 1986 Refunding Series A Bonds Escrow Fund, net of funds released from the Debt Service Account in the Debt Service Fund pursuant to the Seventh Supplemental Indenture of Trust, dated as of February 1, 1986 and deposit into the 1986 Refunding Series B Bonds Escrow Fund, net of funds released from the Debt Service Account and the Debt Service Reserve Account in the Debt Service Fund pursuant to the Eighth Supplemental Indenture of Trust, dated as of November 1, 1986. For the 1987 A Bonds, deposit required into the 1987 Refunding Series A Bonds Escrow Fund, net of funds released from the Debt Service Account and Debt Service Reserve Account in the Debt Service Fund pursuant to the Ninth Supplemental Indenture of Trust, dated as of January 1, 1987.

(9) Changes in interest or reinvestment rate assumptions may result in changes to the Estimated Financing Requirement.

Authority Interest Annual Costs of Power

The following table shows the estimated annual costs of power from the Authority Interest at the high voltage bus of the ANPP High Voltage Switchyard for fiscal years 1987 through 1994. The projections set forth herein are based on preliminary discussions with APS and are subject to adjustment by APS. For purposes of this analysis, the plant factor for each unit is assumed by us to vary from an initial level of approximately 60% for the first cycle of commercial operation to approximately 65% for the second cycle and to approximately 70% for the third cycle and thereafter. The variance in Total Average Unit Costs results from the periodic overlap of refueling outages of two or more of the three units in the same year, as scheduled by APS, combined with the lower plant factors typically experienced during the initial years of the operation of a new plant resulting from required equipment adjustments.

Estimated Annual Cost of Power from the Authority Interest(1) ($000)

	Fiscal Year Ending June 30							
	1987	1988	1989	1990	1991	1992	1993	1994
Interest and Amortization:								
Prior Series Bonds(2)(3)	$29,784	$49,400	$ 60,876	$ 62,195	$ 62,204	$ 62,210	$ 62,219	$ 62,236
1987 A Bonds(2)	7,458	21,198	26,234	24,861	24,853	24,846	24,835	24,822
Operation and Maintenance(4)	9,465	11,899	14,596	15,794	16,593	17,409	18,278	19,192
Administrative and General(5)	1,657	2,230	2,405	2,600	2,748	2,916	3,091	3,276
Insurance(6)	726	953	1,029	1,122	1,178	1,236	1,296	1,362
Nuclear Fuel(7)	6,586	7,144	11,215	11,824	13,301	15,063	13,915	15,510
Renewals and Replacements(4)	2,164	3,353	2,918	2,238	2,367	2,508	2,662	2,822
Taxes(8)	2,034	2,335	4,376	5,846	5,846	5,846	5,846	5,846
Subtotal Project	$59,874	$98,512	$123,649	$126,480	$129,090	$132,034	$132,142	$135,066
Less: Interest Earnings(9)	3,408	4,056	5,709	5,709	6,580	7,013	7,013	7,013
Total Project	$56,466	$94,456	$117,940	$120,771	$122,510	$125,021	$125,129	$128,053
Total Project Unit Cost (Mills/kWh)	69.54	111.91	91.36	100.31	93.81	88.73	99.94	95.14
Total ANPP Transmission System Rights	$ 721	$ 1,121	$ 1,359	$ 1,399	$ 1,393	$ 1,391	$ 1,395	$ 1,400
Total ANPP Transmission System Rights Unit Cost (Mills/kWh)	0.89	1.33	1.05	1.16	1.07	0.99	1.11	1.04
TOTAL COST OF POWER TO AUTHORITY(10)	$57,187	$95,577	$119,299	$122,170	$123,903	$126,412	$126,524	$129,453
Energy Delivered (000 MWh)(11)	812	844	1,291	1,204	1,306	1,409	1,252	1,346
TOTAL AVERAGE UNIT COST (Mills/kWh)(12)	70.43	113.24	92.41	101.47	94.87	89.72	101.06	96.18

(1) Based on cost estimate which includes Authority financing and schedule contingencies as previously discussed and shown in the tables entitled "Estimated Construction Costs" and "Estimated Financing Requirement."

(2) Based on 100% of interest capitalized until May 1, 1986, 66⅔% of the interest capitalized from May 1, 1986 to January 1, 1987 and 33⅓% of the interest capitalized from January 1, 1987 to March 1, 1988. Remaining interest to be paid from revenues. Principal payments begin July 1, 1988. Interest is accrued during the six months prior to each semi-annual payment on July 1 and January 1. Principal is accrued during the twelve months prior to each annual payment on July 1.

(3) Reflects interest and amortization of the Prior Series Bonds, net of the interest and amortization on the aggregate amount of $233,210,000 Power Project Revenue Bonds, consisting of the following series of Power Project Revenue Bonds: 1985 Refunding Series A, due July 1, 2012 in the principal amount of $120,820,000; 1985 Refunding Series B, due July 1, 2011 in the principal amount of $62,390,000; and 1985 Refunding Series B, due July 1, 2017 in the principal amount of $ 50,000,000.

(4) Based on estimates provided by APS.

(5) Based on estimates provided by APS. Also includes estimated Authority expenses.

(6) Based on estimates provided by APS. Includes nuclear insurance.

(7) Based on APS's estimate of nuclear fuel costs. An additional sinking fund allowance, which was based on APS's estimate for decommissioning each unit, has been added by us to the annual nuclear fuel cost. The NRC, in its proposed rule entitled "Decommissioning Criteria for Nuclear Facilities", is proposing amendments to its regulations that would set forth technical and financial criteria for decommissioning licensed facilities. The proposed amendments address decommissioning planning needs, timing, funding mechanisms, and environmental review requirements. Changes in the present NRC regulations with respect to decommissioning of nuclear facilities may result in changes to the Estimated Annual Cost of Power.

(8) Based on the Authority ad valorem taxes at rates estimated by APS and Salt River Project.

(9) Based on transferring 33⅓% of the investment income to the Revenue Fund from the Debt Service and Debt Service Reserve Accounts in the Debt Service Fund, the Reserve Account in the Reserve and Contingency Fund and the Operating Fund from July 27, 1986 to March 18, 1987. From March 18, 1987 to May 1, 1988, includes 66⅔% of such investment income and 100% thereafter.

(10) Sum of Total Project and Total ANPP Transmission System Rights costs.

(11) At the high voltage bus of the ANPP High Voltage Switchyard. Computed as the Authority's share of estimated total generation at the Project site.

(12) The variance in annual unit costs between 1987 and subsequent years results from the timing of interest to be paid from revenues and assumed annual plant capacity factors during the initial years of operation.

In the table above, the weighted average of our estimated annual Total Average Unit Cost of power for the period of fiscal years ending June 30, 1988 through June 30, 1993 is 97.71 Mills/kWh. If adjusted to reflect the commercial operation dates and debt service and interest earnings capitalization dates used in this report, the weighted average of our estimated annual Total Average Unit Cost of

power presented in our report to the Authority, dated August 13, 1982, with respect to the Authority's initial issuance of Bonds for the Authority Interest, would have been 92.68 Mills/kWh for a comparable period.

Transmission of the Authority Interest

Pursuant to the Transmission Agreement, dated as of August 14, 1981, as amended, between the Authority and Salt River Project (the "Transmission Agreement"), the Authority has purchased the right to use 6.55% of the capability of the ANPP Transmission System which will be utilized by Salt River Project for delivery of power and energy associated with the Authority Interest, excluding the Project Entitlement of Imperial Irrigation District (the "District"). The Authority has purchased from Salt River Project an undivided ownership interest in the entire ANPP High Voltage Switchyard. The output of the Authority Interest, with the exception of the District's Project Entitlement, will be received by Salt River Project at the transmission side of the high voltage bus of the ANPP High Voltage Switchyard. Salt River Project will make available to the Authority an equivalent amount of power and energy at a combination of the Navajo Switchyard, the Eldorado Substation or the Mead Substation (the "Project Interconnection Point"). The Navajo Switchyard is located at the Navajo Generating Station in northern Arizona. The Eldorado and Mead substations are located at the southern tip of Nevada, south of Lake Mead, near the Mohave Generating Station.

The Department will transmit its Project Entitlement from the Project Interconnection Point utilizing its own transmission system.

Pursuant to the terms and conditions of the Palo Verde Nuclear Generating Station Transmission Service Agreements between the Department and the other Project Participants, with the exception of the District (the "Transmission Service Agreements"), the Department will provide transmission service for each such Project Participant's Project Entitlement between the Project Interconnection Point and the Project Participant's Points of Interconnection. These Transmission Service Agreements extend for an indefinite period, subject to termination by the Department on ten years prior notice upon a finding by the Department that surplus capacity for such transmission will not be available. The Point of Interconnection for the cities of Burbank, Glendale and Pasadena is the point where the Department's Victorville-McCullough transmission line connects to the 525 kV bus at the McCullough Switching Station ("Point of Interconnection A"). The Point of Interconnection for the cities of Riverside, Vernon, Azusa, Banning and Colton is either the point where the Department's McCullough-Eldorado transmission line connects to the 525 kV bus at the Eldorado Substation ("Point of Interconnection B") or the midpoint of the Victorville-Lugo transmission line where the Department's and Southern California Edison Company's ("Edison") electric systems interconnect ("Point of Interconnection C"). For purposes of this analysis, we have assumed that the cities of Riverside, Vernon, Azusa, Banning and Colton each designate Point of Interconnection C as its point of delivery.

Pursuant to the terms and conditions of the McCullough-Victorville Line 2 Transmission Agreement between the Department and the cities of Burbank, Glendale and Pasadena (the "McCullough-Victorville Line 2 Transmission Agreement"), the Victorville to Receiving Station E — Transmission Service Agreements between the Department and the cities of Burbank and Glendale and the Victorville to Sylmar Switching Station Transmission Service Agreement between the Department and the City of Pasadena, the Department will provide transmission service to the points of interconnection with the cities' electric systems for the cities of Burbank and Glendale, or to an interconnection point with Edison's electric system for the City of Pasadena. Pursuant to the 230 kV Interconnection and Transmission Agreement between the City of Pasadena and Edison, as amended, Edison will provide transmission service from the Sylmar Switching Station to the City of Pasadena's electric system. The City of Pasadena's agreement with Edison extends to 1990 with an option by Pasadena to renew for an additional 20 years.

The cities of Riverside, Vernon, Azusa, Banning and Colton have each signed an Integrated Operations Agreement and a Supplemental Agreement for the integration of their separate Project

Entitlements of the Authority Interest (the "Supplemental Agreements") with Edison which provide, among other things, that Edison will continue to supply the cities' power and energy requirements, over and above the capability of the cities' Project Entitlements and any other city-owned resource and credit the cities on their monthly billing statements for the power and energy generated by such resources that are integrated with Edison's resources. The Supplemental Agreements provide that these cities' Project Entitlements are included as an integrated resource pursuant to each City's respective Integrated Operations Agreement.

The cities of Riverside, Vernon, Azusa, Banning and Colton have signed Transmission Service Agreements with Edison. Pursuant to these Transmission Service Agreements, Edison will provide transmission service for these cities from Point of Interconnection C to the respective cities' electric systems.

The District has acquired an ownership interest in the Palo Verde to Imperial Valley portion of the APS/San Diego Gas & Electric Company ("SDG&E") 525 kV Interconnection Project (the "Southwest Powerlink"). The District will transmit its Project Entitlement from the high voltage bus of the ANPP High Voltage Switchyard to the District system at the Imperial Valley Substation over its ownership entitlement in the Southwest Powerlink. This project was completed in June 1984. The District completed the new 230 kV interconnection between the Southwest Powerlink and the District system in December 1984.

The Authority, Salt River Project, M-S-R Public Power Agency and the Western Area Power Administration ("Western") are studying the feasibility of constructing, owning and operating new electrical transmission facilities connecting the Phoenix, Arizona area with southern Nevada and southern California. For a discussion of this topic, see the paragraph entitled "Mead-Phoenix DC Intertie Project" under the caption "Future Power Supply Resources — Mead-Phoenix DC Intertie Project." These proposed facilities are not required for transmission of the Authority Interest, but would allow Authority members to operate more efficiently. In the event that the Mead-Phoenix DC Intertie is constructed, pursuant to the Transmission Agreement, Salt River Project will transmit, as necessary, the Authority Interest power and energy, with the exception of the District's Project Entitlement, to the Authority at the Project Interconnection Point. The effects of these proposed facilities have not been included in our analysis.

The Department, the District and the cities of Riverside, Vernon, Burbank, Glendale, Pasadena, Azusa, Banning and Colton along with Edison, as project manager, and M-S-R Public Power Agency have undertaken studies to explore the feasibility of constructing a 500 kV AC transmission line. This proposed Devers-Palo Verde #2 transmission line, if built, will parallel the existing Devers-Palo Verde #1 transmission line from the Project to Edison's Devers Substation, which is located west of Desert Hot Springs, California. The Project Participants' participation rights in the proposed Devers-Palo Verde #2 transmission line total 36.8%. Edison has scheduled this project for completion in 1990, at an estimated cost of $247,000,000.

FUTURE POWER SUPPLY RESOURCES

The Authority and the Project Participants have ongoing programs to investigate other potential power supply resources and transmission capability. In addition to the Authority Interest and other potential resources mentioned in the following paragraphs, certain of the Project Participants are interested in varying degrees in certain hydroelectric and geothermal projects in California and other generating facilities which may be available to them.

Intermountain Power Project

In 1977, several Utah municipalities organized the Intermountain Power Agency ("IPA"), a political subdivision of the State of Utah. The purpose of IPA is to provide for the financing, constructing and operating of the Intermountain Power Project ("IPP").

In 1980, the Department and the cities of Anaheim, Burbank, Glendale, Pasadena and Riverside (the "California IPP Purchasers") each entered into a power sales contract with IPA which obligates each such Purchaser to purchase, on a "take or pay" basis, a percentage share of IPP capacity and energy. The Department and the cities of Burbank, Glendale and Pasadena also entered into an Excess Power Sales Agreement, also on a "take or pay" basis, with the Utah municipal and cooperative IPP purchasers, pursuant to which IPP generation entitlement which is surplus to such Utah purchasers' needs will be made available to the Department and the cities of Burbank, Glendale and Pasadena.

In early 1983, each IPP Purchaser entered into an amendment to its power sales contract, the primary purpose of which was to reduce the size of IPP from four to two generating units. The parties thereto also entered into an amendment to the Excess Power Sales Agreement. All California IPP Purchasers except Glendale also entered into Lay-off Power Purchase Contracts (the "Lay-off Contracts") with IPA and Utah Power & Light Company ("UP&L") through which UP&L assigned portions of its entitlement to IPP capacity and energy to such Purchasers.

The IPP generation entitlement of each of the California IPP Purchasers resulting from the power sales contracts, as amended, and the Layoff Contracts is shown in the following table:

	Percentage Share	Generating Capability (kW)
Los Angeles Department of Water and Power	44.617%	696,471
City of Anaheim	13.225	206,442
City of Riverside	7.617	118,901
City of Pasadena	4.409	68,825
City of Burbank	3.371	52,621
City of Glendale	1.704	26,600
Total	74.943%	1,169,860

Based on the uprated capacity of 800 MWe net for IPP Unit 1 and the original design rating of 761 MWe net for IPP Unit 2, and subsequent to both IPP generating units achieving an assumed 70% plant factor, the California IPP Purchasers will receive, pursuant to the power sales contracts, as amended, and the Lay-off Contracts, approximately 1,141 MWe of capacity and 6,995,678 MWh of energy annually, after losses, at the Adelanto point of delivery. The amounts of generating capability that will be available pursuant to the Excess Power Sales Agreement, as amended, will vary in accordance with the provisions of that Agreement. Quantities of capacity and energy that will be available at the Adelanto point of delivery as a result of the Excess Power Sales Agreement, as amended, will vary between approximately 164 and 321 MWe and 863,447 and 1,965,600 MWh annually, based on amounts presently established. These values may be adjusted annually.

IPP will consist of the following: (a) a two unit, 1,561 MWe (reflecting the rating increase of Unit 1 to 800 MWe) coal-fired, steam-electric generation station located near Lynndyl, Utah; (b) a ±500 kV DC transmission line ("HVDC transmission line") from the generation station to Adelanto, California with an AC/DC converter station at each end (the "Southern Transmission System"); and (c) two 345 kV AC transmission lines from the generation station to a switchyard near Mona, Utah and a 230 kV AC transmission line from the generation station to a switchyard near Ely, Nevada. Unit 1 was declared commercially available effective June 10, 1986. Unit 2 is scheduled for commercial operation on July 1, 1987. However, the Department has recently indicated that it may be possible to advance this date by approximately 30 to 60 days. This schedule assumes no delays in construction of IPP resulting from such matters as strikes, shortages or delays in receipt of equipment or materials, shortages of labor, defaults by contractors, design changes, delays in the receipt of permits, delays in obtaining financing or other material matters. Such delays are common in the construction of facilities such as IPP. To the extent that such delays do occur, the estimated completion dates of IPP or its components may be delayed. Any such delay may be expected to result in increased IPP costs.

In June 1986, the Department submitted to the IPA Board and the IPP Coordinating Committee a construction cost estimate for IPP of approximately $3.243 billion which was approved by the IPP Coordinating Committee. Changes that have been made between the June 1985 construction cost estimate and the June 1986 construction cost estimate have generally been minor, with the exception of additional amounts for purchasing coal reserves and establishing a self-insurance fund. Reductions have included a decrease in test energy revenues previously expected to affect construction costs and the reduction of the IPP contingency previously associated with the Southern Transmission System. A portion of the funds required for construction is being provided by IPA with the remainder being provided by the Authority as payments-in-aid of construction with respect to the Southern Transmission System. By October 1984, IPA had issued an aggregate of $4.1 billion principal amount of bonds and $300 million of commercial paper which together with the payments-in-aid of construction with respect to the Southern Transmission System to be provided by the Authority are intended to be sufficient to allow IPA to construct and place IPP in service. In 1985 and 1986, IPA issued a total of approximately $6,674,443,000 principal amount of revenue, refunding and special obligation bonds to defease $3,942,480,000 of bonds, to refinance $300 million of commercial paper previously outstanding and to provide funds to redeem, on July 1, 1995, $1,532,110,000 of bonds currently outstanding. The total IPA outstanding debt, excluding the special obligation bonds, is now approximately $5,216,885,000, including accrued but unpaid interest on Growth and Income Securities and Capital Appreciation Bonds as of January 1, 1987. Additionally, IPA has recently contracted to sell approximately $192,270,000 principal amount of refunding bonds to defease $155,095,000 of bonds currently outstanding. IPA will continue to review the options that are available to it to reduce its annual debt service and may undertake additional refundings. For a discussion of the Southern Transmission System, including the total financing requirements for the Authority's payments-in-aid of construction, see the caption "Future Power Supply Resources — Southern Transmission System".

Procurement of all major equipment for the IPP generation station has been completed. The Department has reported that, as of December 20, 1986, construction of Unit 2 was on schedule and approximately 99.0% complete. Construction of the IPP transmission systems, including the HVDC transmission line, the AC/DC converter stations and related microwave communications facilities, is essentially complete.

Southern Transmission System

The Southern Transmission System consists of the AC/DC Intermountain Converter Station adjacent to the IPP AC switchyard, the HVDC transmission line, approximately 490 miles in length, from the Intermountain Converter Station to the City of Adelanto, California, and the AC/DC Adelanto Converter Station at that point where it connects to the Department's transmission system. The HVDC transmission line is designed to have the capability of transmitting capacity in excess of the capacity of IPP anticipated to be delivered to the California IPP Purchasers. The AC/DC converter stations are designed to have a capacity of 1,600 MWe and are physically arranged to provide for future expansion should transmission of additional capacity become desirable. These facilities are in service.

The Southern Transmission System is presently energized and being used to transmit power and has been successfully tested up to 1,250 MWe. Full power system tests of the Southern Transmission System are scheduled for completion in October 1987, shortly after scheduled commercial operation of the second IPP generating unit.

While the IPP generating units have been estimated to have a rating of 761 MWe net per unit, load tests of Unit 1 have resulted in a current rating of Unit 1 of 800 MWe net. At the higher rating for Unit 1, the rated capacity of the Southern Transmission System will be slightly insufficient to meet the respective IPP generation entitlements' capability to which certain participants are contractually entitled, including Excess Power Sales Agreement capability, to be delivered at the Adelanto Converter Station. For purposes of this report, we have assumed that the necessary arrangements to correct the slight contractual deficiency in the Southern Transmission System entitlement will be made.

IPA and the Authority have entered into the Southern Transmission System Agreement, dated as of May 1, 1983. The Southern Transmission System Agreement provides for, among other things, the financing and making payments-in-aid of construction by the Authority with respect to the Southern Transmission System. Pursuant to the Southern Transmission System Agreement, the Authority will make such payments to IPA, and IPA will apply these payments to pay costs of the Southern Transmission System. We have estimated the Authority's long-term financing requirement for the Southern Transmission System to be $1,058,065,000. The Authority has issued and has outstanding $1,058,065,000 principal amount of its bonds, including refunding bonds, to finance the making of payments-in-aid of construction with respect to the Southern Transmission System.

Hoover Power Plant

On August 17, 1984, the Hoover Power Plant Act of 1984 was signed into law. The Hoover Power Plant Act, among other things, authorizes the Secretary of Energy to offer to purchasers in California eligible to enter into contracts under Section 5 of the Boulder Canyon Project Act, contracts for delivery of capacity from the Hoover uprating project, commencing on June 1, 1987, or as soon thereafter as it becomes available, in the amount of 127 MWe. All of the associated firm energy will be available beginning June 1, 1987. Allocations to the cities of Anaheim, Azusa, Banning, Burbank, Colton, Glendale, Pasadena, Riverside and Vernon totaling 127 MWe of capacity and approximately 143 MWh of associated energy annually from the Hoover uprating project were announced by Western on November 20, 1985. These cities have entered into, or will enter into, contracts with the United States, acting through the United States Bureau of Reclamation ("Bureau"), which provide for the manner in which funds will be advanced by these cities to the Bureau. The cities have also entered into, or will enter into, contracts with Western for the purchase of power from the Hoover uprating project. The cities of Anaheim, Riverside, Burbank, Azusa, Colton and Banning (the "Hoover Participants") and the Authority have entered into assignment agreements dated as of March 1, 1986, pursuant to which each Hoover Participant has assigned its entitlement to the Hoover uprating project capacity and associated firm energy to the Authority in return for the Authority's agreement to make advance payments to the Bureau for the Hoover uprating project. Based on Western's allocations and the assignment agreements, the Authority's proportionate share of the total capacity of the Hoover uprating project will be approximately 94 MWe (Contingent Capacity), and associated firm energy. The Hoover Participants and the Authority have executed power sales contracts, dated as of March 1, 1986, under which the Hoover Participants will be entitled to their shares of the Authority's proportionate share of Hoover capacity and associated energy (the "Hoover Entitlements") and agree to make monthly payments on a "take or pay" basis. Western has stated that the Hoover Entitlements will be made available by Western at the Mead Substation. The Hoover Participants each expect to obtain the necessary transmission service from the Mead Substation to their respective electric systems. On August 13, 1986, the Authority issued an aggregate of $34,435,000 principal amount of its bonds to finance the advance payments for the Hoover uprating project capacity and associated firm energy. At that time we estimated that the proceeds from such bonds, together with the investment earnings thereon, would be sufficient to finance the advance payments for Contingent Capacity and associated firm energy to be made by the Authority to the Bureau for application by the Bureau to the costs of the Hoover uprating project.

White Pine Power Project

Certain of the Project Participants, apart from the Authority and together with other public and private utilities in California and Nevada, have undertaken studies to explore the feasibility of constructing a coal-fired generating station near Ely, Nevada. This generating station would have a capability of approximately 1,500 MWe. It is contemplated that White Pine County would own all, or a major portion, of and finance this project through bonds issued by White Pine County which would be secured by power sales contracts entered into with the various purchasers of power from the project. The Project Participants' combined entitlement percentage share for feasibility studies is approximately 47.36%. The participants in the White Pine Power Project entered into power supply development agreements with White Pine County in the fall of 1980 for the purpose of conducting a

study to determine the feasibility of constructing and operating the project. In November 1980 and October 1984, White Pine County issued notes in the principal amounts of $14,994,000 and $2,000,000, respectively, for such purposes. In August 1985, White Pine County issued an additional note in the principal amount of $2,935,000 for such purposes and extended the maturity date of the notes to December 31, 1987. Such notes will be payable from the proceeds of long-term bonds to be issued by the County or from payments by the participants under such agreements on the basis of entitlement shares. The estimated commercial operation date for the two 750 MWe generating units, if built, is in the mid 1990's. For a further discussion by the Department of the White Pine Power Project, see the caption "The Department of Water and Power of The City of Los Angeles — Power System Generation Resource Additions — White Pine Power Project" in Appendix B to the Official Statement.

Mead-Phoenix DC Intertie Project

The Authority has executed agreements pursuant to which the Authority, Salt River Project, M-S-R Public Power Agency, and Western are studying the feasibility of constructing, owning and operating the Mead-Phoenix DC Intertie Project. The Mead-Phoenix DC Intertie Project is a proposed ±500 kV DC transmission line, with AC/DC converter stations at each end, to be constructed between Mead Substation near Boulder City, Nevada and the Phoenix, Arizona area. The Authority has issued notes in the aggregate principal amount of approximately $14.1 million to finance the costs of such study. Such notes mature on December 1, 1987 and will be payable from the proceeds of long-term bonds to be issued by the Authority for the Mead-Phoenix DC Intertie Project or from payments by the participants under project development agreements, on the basis of project entitlement shares. It is currently planned that the transmission line would have a capacity of 2,200 MWe and that the converter stations would be built with an initial capacity of 1,600 MWe. The initial converter station capacity could be upgraded to the transmission line capacity should this become desirable. If the Mead-Phoenix DC Intertie Project is undertaken, the Authority would finance its 93.75% interest from the proceeds of long-term bonds secured by payments to be made by the participants under transmission service contracts. The Project Participants' entitlement shares in the Mead-Phoenix DC Intertie Project total approximately 53.1%. It is estimated that this facility, if built, would be in service in the early 1990's. For a further discussion by the Authority of the Mead-Phoenix DC Intertie Project, see "Southern California Public Power Authority — Other Activities of the Authority" in the Official Statement.

In connection with the Mead-Phoenix DC Intertie Project, certain members of the Authority, Salt River Project, M-S-R Public Power Agency, and Western have initiated a study to determine the feasibility and estimated costs of the construction and operation of related transmission facilities connecting the Boulder City, Nevada area to the Adelanto, California area, a distance of approximately 180 miles. The proposed participants anticipate that, if constructed, the transmission line could be put into service within the same time frame as the Mead-Phoenix DC Intertie Project. It has not been determined what, if any, role the Authority will have in this transmission line project.

California-Oregon Transmission Project

The cities of Riverside, Vernon, Azusa, Banning and Colton executed a Memorandum of Understanding, dated as of December 19, 1984, which authorizes these cities, along with other non-Project Participant utilities and governmental agencies located in California, to study the construction of the California-Oregon Transmission Project. Such Project relates to possible alternative methods of developing additional 500 kV AC transmission facilities between California and the Pacific Northwest. The participants have executed a Project Development Agreement pursuant to which they will study the feasibility of constructing and operating the California-Oregon Transmission Project.

The Sylmar Expansion Project

The Department and the cities of Burbank, Glendale and Pasadena are participants in the Sylmar Expansion Project ("SEP") which is an 1100 MWe expansion of the terminal capacity at the existing

AC/DC converter station which is located at Sylmar, California. This project will increase the capacity of the Pacific Northwest-Southwest DC Intertie ("Intertie") from 2000 MWe to 3100 MWe. The Department is the project manager for the southern terminal of the Intertie and is responsible for the construction of the SEP. The Bonneville Power Administration ("BPA") is the project manager for the northern terminal and is responsible for a similar expansion at the northern converter station of the Intertie in Oregon. The Department estimates that the cost of the SEP will be $171,000,000 and that the SEP will be completed in February 1989.

THE PROJECT PARTICIPANTS

Historical Operations of Project Participants

During the fiscal year period 1982 through 1986, average number of customers and operating revenues for the Project Participants have increased. Over the same period, increases in peak demand and energy requirements have occurred for all Project Participants, with the exception of the City of Vernon. For a discussion of historical and projected peak demand and energy requirements, see "Power Requirements". The following tables summarize this historical data for the Project Participants.

Historical Number of Customers, Load Requirements and Operating Revenues for the Department

Fiscal Year Ending June 30	Average Number of Customers	% Increase *	Energy Requirements (MWh)	% Increase *	Peak Demand (MWe)	% Increase *	Operating Revenues ($000)	% Increase *	Operating Revenues per kWh (Mills)	% Increase *
1982	1,221,867	—	20,691,869	—	4,364	—	$1,193,913	—	57.70	—
1983	1,231,929	0.82	21,019,326	1.58	4,456	2.11	1,106,408	-7.33	52.64	-8.77
1984	1,243,092	0.91	21,848,064	3.94	4,444	-0.27	1,177,469	6.42	53.89	2.37
1985	1,251,206	0.65	22,529,539	3.12	4,882	9.86	1,287,967	9.38	57.17	6.09
1986	1,261,972	0.86	22,262,629	-1.18	4,713	-3.46	1,358,134	5.45	61.01	6.72
Compound Annual Growth Rate 1982-1986		0.81%		1.85%		1.94%		3.27%		1.40%

* Over previous year.

Historical Number of Customers, Load Requirements and Operating Revenues for All Project Participants Excluding the Department

Fiscal Year Ending June 30	Average Number of Customers (1)	% Increase (2)	Energy Requirements (MWh) (1) (3)	% Increase (2)	Peak Demand (MWe) (4)	% Increase (2)	Operating Revenues ($000) (1)	% Increase (2)	Operating Revenues per kWh (Mills) (1)	% Increase (2)
1982	317,000	—	6,632,596	—	1,673	—	$ 397,519	—	59.93	—
1983	320,762	1.19	6,372,664	-3.92	1,610	-3.77	407,404	2.49	63.93	6.67
1984	324,031	1.02	6,767,039	6.18	1,587	-1.43	430,663	5.71	63.64	-0.45
1985	327,988	1.22	7,108,863	5.05	1,730	9.01	434,294	12.45	68.13	7.06
1986	337,513	2.90	7,208,997	1.41	1,722	-0.46	481,007	-0.68	66.72	-2.07
Compound Annual Growth Rate 1982-1986		1.58%		2.11%		0.72%		4.88%		2.72%

(1) District data have been adjusted, on an average annual basis, from calendar year to fiscal year.

(2) Over previous year.

(3) Excludes BPA exchange obligation.

(4) Non-Coincidental.

Power Requirements

The Project Participants' load growth during recent years has been lower than that experienced in prior years with some recent minor growth in energy requirements for all of the Project Participants. The Project Participants, with the exception of the City of Vernon, believe that these changes can primarily be attributed to moderate temperatures, ongoing conservation efforts coupled with sluggish economic conditions, and higher electric rates. As a group, such Project Participants' peak load forecasts for the period 1987 through 1994 show a higher rate of growth than that experienced during the 1982 to 1986 period, but lower than that experienced during the period 1977 to 1982, while the rate of growth for their combined energy forecasts is only slightly lower than that experienced during the 1977 to 1982 period. Individually, all Project Participants except the City of Glendale project rates of peak load growth which are slightly higher than the rate of growth in the last five year period, while all Project Participants except the cities of Burbank, Glendale, Pasadena and Azusa project rates of energy growth which are slightly higher than the rates in the same period. Abnormally high temperatures in September 1984 resulted in record peak demand for most of the Project Participants. The load forecasts, as developed by these Project Participants, were prepared considering, among other things, continuing economic recovery of the region which began in 1984, price elasticity, normal temperatures and ongoing conservation efforts. Each such Project Participant anticipates growth in loads over the next twenty years. One of the City of Vernon's major industrial customers significantly reduced its level of operations in Vernon in 1982. This reduction resulted initially in a decrease in Vernon's energy requirements and peak demand, due specifically to this one customer. Recent historical data and estimated future loads indicate that Vernon's total energy requirements have essentially recovered to the 1982 level while peak demand remains at a reduced level with a small amount of forecast growth.

A summary of the fiscal year historical and estimated future peak power and energy requirements, as estimated by the Project Participants are shown on the following table.

PROJECT PARTICIPANTS' POWER REQUIREMENTS

Peak Requirements (MWe)*

	Historical					Estimated			
	Fiscal Year Ending June 30								
	1982	1983	1984	1985	1986	1988	1990	1992	1994
The Department	4,364	4,456	4,444	4,882	4,713	5,018	5,236	5,464	5,676
The District	382	363	376	404	413	431	457	485	514
City of Riverside	319	299	293	332	328	316	337	347	365
City of Vernon	238	236	191	192	193	198	200	200	200
City of Burbank	220	210	217	234	228	245	256	266	278
City of Glendale	211	207	208	232	232	242	253	264	273
City of Pasadena	212	208	214	238	231	246	259	271	284
City of Azusa	42	40	40	45	43	49	53	55	57
City of Banning	18	17	18	18	19	19	20	21	22
City of Colton	31	30	30	35	35	41	47	54	62
Total	6,037	6,066	6,031	6,612	6,435	6,805	7,118	7,427	7,733

* Non-coincidental.

Total Energy Requirements (000 MWh)

	Historical					Estimated			
	Fiscal Year Ending June 30								
	1982	1983	1984	1985	1986	1988	1990	1992	1994
The Department	20,692	21,019	21,848	22,530	22,263	23,690	24,645	25,760	26,676
The District	1,481	1,369	1,474	1,556	1,575	1,687	1,788	1,897	2,012
City of Riverside	1,095	1,063	1,194	1,205	1,208	1,292	1,399	1,497	1,572
City of Vernon	1,173	1,066	1,061	1,107	1,151	1,234	1,265	1,272	1,302
City of Burbank*	868	859	931	973	982	1,032	1,075	1,120	1,168
City of Glendale*	791	798	862	892	895	928	972	1,019	1,068
City of Pasadena*	882	878	936	993	1,007	1,039	1,087	1,134	1,181
City of Azusa	155	153	164	170	178	199	220	229	238
City of Banning	67	66	69	74	71	75	78	81	84
City of Colton	120	121	136	139	143	153	168	184	203
Total	27,324	27,392	28,615	29,639	29,473	31,329	32,697	34,193	35,504

* Excludes BPA peaking exchange obligation.

Utilization of Project Entitlement

The existing power supplies for the Project Participants consist of owned generation and firm and non-firm purchases from other utilities. Although the Authority Interest will provide a source of firm capacity and energy to assist in meeting load growth, it is more important to the Project Participants as a source of energy which can be produced from fuel sources other than oil and natural gas.

The Department desires to substantially reduce its dependence on oil and gas. The Department's long-term projections indicate that oil and natural gas prices will return to an increasing trend. Based on the Department's current price of approximately $20 per barrel of oil and the current efficiency of the Department's plants, which produce about 625 kWh per barrel of oil, the present unit fuel oil cost is approximately 30 mills per kWh.

The Department's Project Entitlement and other currently planned resources will assist in reducing its dependence on oil- and gas-fired generation by at least 50% from the 1974 through 1978 levels. Similarly, their respective Project Entitlements will allow the cities of Burbank, Glendale and Pasadena to reduce their dependence upon oil and gas for generation. Based on the projected price levels of oil and natural gas, it is economically attractive, in the long term, for these Project Participants to replace the energy from those sources with energy from the Authority Interest.

The present power supply configuration for each of the cities of Riverside, Vernon, Azusa, Banning and Colton consists of their respective Project Entitlements in Unit 1 and Unit 2 and purchases of interruptible energy from other public and private utilities and governmental agencies when it is available at an economically attractive price. In addition to these sources of supply, the City of Riverside receives power and energy from an ownership interest in the San Onofre Nuclear Generating Station, Units 2 and 3 ("San Onofre") and a project entitlement in IPP Unit 1. The City of Vernon also utilizes its diesel generators to meet a portion of its total power and energy requirements. All remaining power and energy requirements for the five cities are purchased from Edison at wholesale rates. The additional capacity and energy expected to be received from Unit 3 of the Authority Interest will be used to displace a portion of the power and energy currently being purchased from Edison, which is substantially dependent upon gas and oil as fuels for its generating resources. Thus, any comparison of Edison's wholesale power costs with the Project Participants' costs of power from the Authority Interest depends heavily on projected oil and gas prices. Due to the present uncertainty of oil prices, we are unable to predict the future price of oil. However, as discussed more fully later, we have used three different oil price levels in our projections of such Edison wholesale power costs. Based on these projected wholesale power and energy rates for Edison, we believe that it will be economically attractive, over the long term, for these Project Participants to replace wholesale purchases of energy from Edison with energy from the Authority Interest.

In calendar year 1985, the District produced or purchased approximately 27% of its energy requirements from oil- and gas-fired generation and produced or purchased approximately 45% from hydroelectric sources. The remaining energy requirements are obtained from the Authority and purchases from the system resources of EPE. It is estimated that the District's Project Entitlement, together with other purchases, will allow it to meet its projected electric power and energy requirements through fiscal year 1994. Future power purchases include continuing the contracts with EPE and other utilities to purchase firm capacity and energy.

The Department of Water and Power of The City of Los Angeles

The Department, the largest municipal utility in the United States, is a separate proprietary agency of The City of Los Angeles, controlling its own funds and with full responsibility for meeting the water and electric requirements of The City of Los Angeles. It provides water and electricity services almost entirely within the boundaries of The City of Los Angeles, which encompasses some 465 square miles, to a population of approximately 3.2 million.

Administration of the Department is under the direction of a five-member Board of Water and Power Commissioners. The Board of Water and Power Commissioners fixes the Department's electric rates, subject to the approval of the City Council, by ordinance. The Department's rates are not regulated by any California state agency and are not subject to approval by any Federal agency, but the Department is subject to certain ratemaking provisions of the Federal Public Utility Regulatory Policies Act of 1978.

The Department's maximum net hourly peak demand, 4,882 MWe, occurred in September 1984. The power supply of the Department consists primarily of its own generating resources, part of which are located within the Los Angeles Basin, and its 501 MWe entitlement currently available from the Hoover Power Plant. On August 17, 1984, the Hoover Power Plant Act of 1984 was signed into law. Among other things, as discussed previously, such Act authorizes the Secretary of Energy to offer, and he has offered, the Department a renewal contract for delivery, commencing June 1, 1987, of capacity in the amount of approximately 491 MWe from the Hoover Power Plant. The Department currently has a net dependable system capability of over 7,200 MWe, which is owned or operated generation. Steam electric generating capability was equal to 65% of the system's total net capability, and owned or operated hydroelectric generating capacity accounted for 27% of such capability. Purchases are made on a day to day or week to week basis that will alter these percentages. The Department estimates that its capital expenditures for power generating and distribution facilities for the five-year period which began July 1, 1986 will total approximately $1.8 billion.

The Department had an ownership interest in the Coronado coal-fired project in the amount of 210 MWe. This ownership interest was exchanged for a 5.7% ownership interest in the Project on January 29, 1986. The Department has entered into contracts to purchase 44.617% of IPP capacity and energy. The Department has contracted to purchase 59.534% of the transmission capacity of the Southern Transmission System. The Department has a 39.117% feasibility study participation percentage in the White Pine Power Project. The Department has a 40% ownership interest in the SEP.

The following table summarizes the Department's fiscal year historical peak loads and resources and its estimate of future peak loads and resources through 1994:

The Department
Peak Loads and Resources (MWe)

	Historical					Estimated			
	Fiscal Year Ending June 30								
	1982	1983	1984	1985	1986	1988	1990	1992	1994
Loads	4,364	4,456	4,444	4,882	4,713	5,018	5,236	5,464	5,676
Resources(1):									
Basin Thermal (Oil & Gas)	3,217	3,207	3,178	3,252	3,252	3,252	2,879	2,879	2,879
Hydroelectric(2)	1,951	1,951	1,924	1,933	1,948	1,462	1,463	1,467	1,468
Joint Facilities(3)	1,076	1,076	1,076	1,076	1,508	1,867	1,797	1,797	1,797
Project Entitlement(4)	0	0	0	0	48	145	145	145	145
Additional Project Interest(4)(5)	0	0	0	0	70	209	209	209	209
Other(6)	598	598	598	0	589	114	424	434	634
Total	6,842	6,832	6,776	6,261	7,415	7,049	6,917	6,931	7,132
Balance Available for Reserves	2,478	2,376	2,332	1,379	2,702	2,031	1,681	1,467	1,456

(1) In the years for which historical loads and resources are presented, some of the Department's resources were not available at the time of system peak. These figures do not include losses.

(2) Actual water conditions for historical years 1982 through 1986. Assumes adverse water conditions for the years 1988 through 1994.

(3) Includes ownership shares of Mohave, Navajo and Coronado coal-fired plants through 1985. The Department's ownership interest in Coronado was exchanged for an equivalent ownership interest in the Project on January 29, 1986. Also includes purchased power from the Intermountain Power Project.

(Footnotes continued on following page)

(4) Project capacity shown is based on the assumed per unit production capacity level of 1221 MWe net at the date of commercial operation, which may not coincide with the Department's peak load.

(5) Department's separate 5.7% ownership interest in the Project.

(6) Includes purchase of peaking capacity from the Pacific Northwest through 1984, co-generation, geothermal, generic and, until April 1984, 73 MWe purchased from Tucson Electric Power Company.

The following table summarizes the estimated cost of power to the Department of its Project Entitlement at the Project Interconnection Point which also is the point of interconnection with the Department's electric system.

Estimated Annual Cost to the Department of Power from the Authority Interest

($000)

	Fiscal Year Ending June 30							
	1987	1988	1989	1990	1991	1992	1993	1994
Project Entitlement Costs(1)	$38,351	$64,087	$79,995	$81,918	$83,080	$84,763	$84,839	$86,798
Transmission Cost to the Project Interconnection Point(2)	213	250	319	329	340	350	359	371
Total Estimated Annual Costs	$38,564	$64,337	$80,314	$82,247	$83,420	$85,113	$85,198	$87,169
Energy Delivered (000 MWh)(3)	521.0	541.5	828.2	772.1	837.9	903.6	803.3	863.7
Unit Cost (Mills/kWh)	74.0	118.8	97.0	106.5	99.6	94.2	106.1	100.9
Capacity Delivered (MWe)(3)(4)	92.6	138.9	138.9	138.9	138.9	138.9	138.9	138.9

(1) At the high voltage bus of the ANPP High Voltage Switchyard.

(2) Based on the Transmission Agreement.

(3) To the Department's distribution network after losses. Loss rates provided by the Department.

(4) Project capacity shown at the date of commercial operation, which may not coincide with the Department's peak load.

The following table summarizes the estimated system power costs to the Department. This estimate is based on the costs of the Department's Project Entitlement, as estimated herein, together with estimates of the costs of power, as provided by the Department, from the other power supply resources scheduled to be used to meet the Department's loads.

Estimated Power Supply Costs to the Department

($000)

	Fiscal Year Ending June 30							
	1987	1988	1989	1990	1991	1992	1993	1994
Power Costs:								
Fuel(1)	$ 812,419	$ 818,185	$ 851,227	$ 921,243	$1,021,734	$1,035,718	$1,079,934	$1,156,490
Project Entitlement	38,564	64,337	80,314	82,247	83,420	85,113	85,198	87,169
Intermountain Power Project(2)	139,248	291,838	312,065	337,680	344,305	357,387	368,115	378,772
Other Purchased Power(3)	287,130	343,859	341,298	397,038	490,183	726,231	941,129	987,762
Total Annual Power Supply Costs	$1,277,361	$1,518,219	$1,584,904	$1,738,208	$1,939,642	$2,204,449	$2,474,376	$2,610,193
Total Energy Requirements (000 MWh)	23,211	23,690	24,108	24,645	25,182	25,760	26,190	26,676
Unit Power Supply Costs (Mills/kWh)	55.0	64.1	65.7	70.5	77.0	85.6	94.5	97.8

(1) Includes the Department's estimated annual cost for operation and maintenance, taxes and depreciation, and is based on the Department's estimate of fuel prices and energy production.

(2) Includes Southern Transmission Project costs.

(Footnotes continued on following page)

(3) Includes the Department's estimated annual costs of power supply from purchases of power and energy from other resources. A portion of these purchases is currently under contract, while the remaining balance is assumed by the Department to be available in sufficient quantities and at rates which would economically displace the Department's basin thermal generation. Also includes IPP purchases pursuant to the Excess Power Sales Agreement which reflect the current load forecasts of the IPP Utah Municipal and Cooperative Purchasers.

Imperial Irrigation District

The District is a publicly-owned water and power utility located in southern California. The gross area served by the District is approximately 6,400 square miles in Imperial County and the Coachella Valley of Riverside County. The power supply of the District consists of hydroelectric units on the All-American Canal and oil- and gas-fired generating facilities, as well as purchases of capacity and energy from other sources. In the twelve months ended December 31, 1985, the District experienced a peak demand of approximately 404 MWe, generated 777,076 MWh and purchased 770,003 MWh.

Administration of the District is under the direction of a five-member Board of Directors. Electric rates are set by the Board of Directors after a series of public hearings and presentations to the city councils of the cities located within the District's service area. The District's electric rates are not subject to regulation by any California state agency and are not subject to approval by any Federal agency, but the District is subject to certain rate making provisions of the Public Utility Regulatory Policies Act of 1978.

The following table summarizes the District's annual historical peak loads and resources for the twelve-month periods ended June 30, 1982 through 1986 and its estimate of future peak loads and resources for the twelve-month periods ending June 30, 1988, 1990, 1992 and 1994:

The District
Peak Loads and Resources (MWe)

	Historical					Estimated			
	Twelve Months Ending June 30								
	1982	1983	1984	1985	1986	1988	1990	1992	1994
Loads(1)	382.2	362.7	375.5	403.8	412.8	431.1	457.2	484.8	514.2
Resources(2):									
Thermal (Oil & Gas)	340.0	340.0	340.0	340.0	340.0	340.0	340.0	340.0	340.0
Geothermal	0	0	0	0	0	0	4.7	4.7	4.7
Hydroelectric	40.0	43.0	43.0	48.3	48.3	48.3	48.3	48.3	48.3
Project Entitlement	0	0	0	0	0	9.4	14.1	14.1	14.1
Other Purchases(3)	104.6	104.6	104.6	147.5	147.5	157.5	157.5	157.5	207.5
Subtotal	484.6	487.6	487.6	535.8	535.8	555.2	564.6	564.6	614.6
Less: Reserves(4)	45.4	42.5	44.4	42.2	43.5	44.8	48.7	52.8	57.3
Net Resources	439.2	445.1	443.2	493.6	492.3	510.4	515.9	511.8	557.3
Balance Available	57.0	82.4	67.7	89.8	79.5	79.3	58.7	27.0	43.1

(1) Estimated annual peak loads are assumed to occur in July.

(2) Capacity available at time of annual system peak.

(3) Includes purchases from Western Area Power Administration, EPE and participation in the Axis Steam Plant.

(4) Projected reserve requirements assumed to be 15% of load less firm purchases.

The following table summarizes the estimated costs of power to the District of its Project Entitlement at the ANPP Switchyard:

Estimated Annual Cost to the District of Power from the Authority Interest

($000)

	Twelve Months Ending June 30							
	1987	1988	1989	1990	1991	1992	1993	1994
Project Entitlement Costs(1)	$3,670	$6,140	$7,666	$7,850	$7,963	$8,126	$8,133	$8,323
Energy Delivered (000 MWh)(2)	51.7	53.8	82.2	76.7	83.2	89.7	79.8	85.8
Unit Cost (Mills/kWh)	71.0	114.1	93.3	102.3	95.7	90.6	101.9	97.0
Capacity Delivered (MWe)(2)(3)	9.2	13.8	13.8	13.8	13.8	13.8	13.8	13.8

(1) At the high voltage bus of the ANPP High Voltage Switchyard excluding the District's transmission cost. The District's Project Entitlement will be delivered over the Southwest Powerlink in which the District has acquired an ownership interest, as discussed in "The Authority Interest — Transmission of the Authority Interest."

(2) Amount available at the District's interconnection at the Imperial Valley Substation.

(3) Project capacity shown at the date of commercial operation, which may not coincide with the District's peak load.

We have estimated power supply costs for the District. This estimate is based on the cost of the District's Project Entitlement, as estimated herein, together with estimates of the costs of power from other power supply resources scheduled to be used to meet the District's loads.

Estimated Power Supply Costs to the District

($000)

	Twelve Months Ending June 30							
	1987	1988	1989	1990	1991	1992	1993	1994
Power Costs:								
Project Entitlement(1)	$ 3,670	$ 6,140	$ 7,666	$ 7,850	$ 7,963	$ 8,126	$ 8,133	$ 8,323
Thermal (Gas and Oil)(2)	14,483	14,914	15,942	17,627	19,467	22,211	22,170	19,610
Hydroelectric Generation(3)	1,154	1,200	1,248	1,298	1,350	1,405	1,463	1,523
Other Purchased Power(4)	41,312	43,809	44,493	44,603	45,259	49,267	63,058	66,589
Total Annual Power Supply Costs	$60,619	$66,063	$69,349	$71,378	$74,039	$81,009	$94,824	$96,045
Total Energy Requirements (000 MWh)	1,637	1,687	1,737	1,788	1,842	1,897	1,953	2,012
Unit Power Supply Costs (Mills/kWh)	37.03	39.16	39.92	39.92	40.19	42.70	48.55	47.74

(1) Excludes transmission costs.

(2) Costs include fuel and other operation and maintenance costs at District plants.

(3) Operation and maintenance costs only.

(4) Excludes the District's Project Entitlement.

Based on the forecast of power costs from the District's Project Entitlement and on certain data supplied by the District and others, we have prepared a projection of operating results of the District's electric system for the twelve-month periods ending June 30, 1987 through 1991. In these projections, we show additional revenues to be obtained beyond those generated by the District's average charges for the calendar year 1985. We estimate an additional average annual increase in revenue requirements for the period 1987 through 1991 of approximately 5.0%. These additional revenues are estimated to be obtained from the energy cost adjustment features of the existing rate structure associated with increases in the cost of purchased and generated energy.

The District presently plans to construct certain major additions and improvements to its transmission system. Such additions and improvements would be used to transmit power to District loads, and to transmit power for others which is expected to be available from existing and proposed

geothermal generating plants in the District's service area. These geothermal generating plants, and the power output thereof, are to be owned by others, except for the Heber Binary Geothermal Plant in which the District has a 10.0% ownership interest. The District presently plans to finance, from its system revenues, the portion of the transmission additions and improvements required to meet its load. The method of financing the expected major transmission additions required for transmitting the output of the geothermal plants owned by others has not yet been determined. It is expected that the revenues from providing additional wheeling service to others will offset the costs of these transmission additions.

The District
Projected Operating Results

($000)

	Twelve Months Ending June 30				
	1987	1988	1989	1990	1991
Gross Revenues:					
Revenues from Sales of Electricity:					
At 1986 Average Charges(1)	$ 89,151	$ 91,853	$ 94,607	$ 97,434	$100,345
Additional Revenue Required(2)	6,855	11,908	14,751	15,428	16,811
Subtotal	$ 96,006	$103,761	$109,358	$112,862	$117,156
Miscellaneous Operating Revenues(3)	2,815	4,024	3,171	1,923	1,965
Other Income(4)	3,167	2,846	2,718	2,594	2,447
Total Estimated Gross Revenues	$101,988	$110,631	$115,247	$117,379	$121,568
Operating Expenses:					
Power Production:					
Project Entitlement	$ 3,670	$ 6,140	$ 7,666	$ 7,850	$ 7,963
Thermal	14,483	14,914	15,942	17,627	19,467
Hydroelectric	1,154	1,200	1,248	1,298	1,350
Other Purchased Power(5)	41,312	43,809	44,493	44,603	45,259
Other Operation and Maintenance Expense	15,552	15,888	16,715	17,505	18,321
Total Estimated Operating Expenses	$ 76,171	$ 81,951	$ 86,064	$ 88,883	$ 92,360
Total Estimated Net Revenues Excluding Depreciation and Amortization	$ 25,817	$ 28,680	$ 29,183	$ 28,496	$ 29,208
Debt Service	7,608	7,609	7,609	7,610	7,610
Balance for Other Purposes	$ 18,209	$ 21,071	$ 21,574	$ 20,886	$ 21,598

(1) Based on average revenues for all power sold in calendar year 1985, including energy cost adjustments.

(2) Estimated additional revenue resulting from the District's Energy Cost Adjustment.

(3) Includes revenues for transmission of output of geothermal generating plants owned by others. These revenues are estimated based upon transmission planning studies completed in November 1986, which identify existing system constraints to transmission of the geothermal power. It is expected that greater amounts of power from additional geothermal plants owned by others will be transmitted subsequent to January 1989 and that the additional revenues (not shown here) from such additional transmission service will offset increased costs, including costs of expected major transmission additions. Changes which may occur in the construction schedule and output of geothermal plants of others would result in changes in transmission revenues.

(4) Based on investment of funds at an 8% interest rate in 1987 and 7.5% thereafter.

(5) Other Purchased Power includes purchases from EPE, Western, and participation in the Axis Steam Plant. The rates to be paid to EPE have been recently agreed upon by the District and EPE and are subject to approval by the Federal Energy Regulatory Commission. The amounts shown include a refund of $2,284,144 in January 1987 from EPE and a Demand Charge Adjustment in which EPE will pay the District by crediting (as a reduction in rates) the District's bill $141,000 each month during the first 60 months of service under the agreement.

Cities of Riverside, Vernon, Azusa, Banning and Colton

The cities of Riverside, Vernon, Azusa, Banning and Colton are each municipal corporations existing under the laws of the State of California, each owning and operating an electric public utility for its citizens, providing electric service to virtually all of the electric customers within its city limits, which encompass a total of approximately 128 square miles for all of these cities. The principal facilities of the cities' electric systems are sub-transmission and distribution lines aggregating approximately 1,514 circuit miles of transmission and, for the City of Riverside, 711 circuit miles of street lighting distribution as of June 30, 1986.

Electric rates for the City of Riverside are established by the Riverside Board of Public Utilities, subject to the approval of the Riverside City Council. Electric rates for the other cities are established by the respective city councils. These electric rates are not subject to regulation by any California State agency. The cities of Riverside and Vernon, due to the magnitude of their energy sales, are subject to certain rate making provisions of the Federal Public Utility Regulatory Policies Act of 1978.

The five cities operate their respective electric systems and obtain their bulk power supply in accordance with provisions of their respective Integrated Operations Agreements, as amended ("IOA"), which each city has executed with Edison. Each IOA provides, among other things, that the requirements of each city's electric system will be met by generating resources in which each such city has a contractual ownership interest and, to the extent required, by wholesale purchases from Edison.

At this time the cities of Riverside, Vernon, Azusa, Banning and Colton receive power and energy from their respective Project Entitlements in Unit 1 and Unit 2 and purchase interruptible energy from other utilities and governmental agencies when it is available at an economically attractive price and transmission is available. In addition, the City of Riverside has a 1.79% ownership interest in San Onofre. This percentage ownership interest is equivalent to 38.49 MWe of capability with associated energy, after unit capacities were rerated in January 1985 based on actual performance. San Onofre Unit 2 commenced commercial operation in October 1983 and Unit 3 commenced commercial operation in April 1984. The City of Riverside also has a 7.617% generation entitlement share in IPP (118.90 MWe), of which 60.94 MWe is currently available from Unit 1, which was declared commercially available in June 1986. The City of Vernon receives power and energy from its diesel units. All remaining power and energy requirements for each of the five cities are purchased from Edison at wholesale rates. The capacity and energy expected to be received from Unit 3 of the Project will be used to displace a portion of the power currently purchased from Edison.

During the period from fiscal years 1987 through 1994, the cities' power supply plans include the capability available from the Hoover uprating project and, for the City of Riverside, IPP Unit 2 and capacity and energy available from the Deseret Generation & Transmission Co-operative ("Deseret"). The City of Banning has recently issued $2,570,000 of Certificates of Participation to fund a hydroelectric generating project which is anticipated to generate approximately 829 kWe and 5,280 MWh annually. The project is presently in the design and engineering phase and is anticipated by the City to be in full commercial operation in December 1987. Additionally, the City of Vernon has recently issued $125,000,000 of Electric System Revenue Bonds to fund such City's Bear Butte hydroelectric, pumped storage project which is anticipated by the City to generate approximately 120 MWe of peaking capacity and 205,500 MWh and 161,100 MWh annually during the high and low water years, respectively. The City further anticipates utilizing approximately 42 MWe to meet a portion of its electric load with the balance of the project power sold to one or more publicly owned utilities. The project is presently in the design and engineering phase and is anticipated by the City to be in commercial operation during the fourth quarter of 1992. Due to the preliminary nature of design, licensing and contract status, we have not included the power and energy from this project in our analysis.

Projected wholesale power and energy rates for Edison are based on historical results of Edison operations, recent rate filings, and Edison's electric system resource plans and load forecasts. Oil and gas prices have a direct impact on Edison rates. Due to the uncertainty of oil and natural gas prices, we

are unable to predict the future prices of either fuel. However, we have used three different levels of oil and natural gas prices in our projections of Edison rates to demonstrate the sensitivity to a range of possible oil and natural gas price levels. The three oil price levels are based on the following world average costs per barrel in 1986 and annual escalation rates thereafter: (1) a low case with oil prices at $15.00 per barrel in 1986 and remaining constant through 1994; (2) a medium case with oil prices at $20.00 per barrel from 1986 through 1990 and escalating at 4.45% per year thereafter; and (3) a high case with oil prices at $20.00 per barrel in 1986, escalating at 4.45% per year from 1987 through 1990, and escalating at 6.1% per year thereafter. The three natural gas price levels are based on the following base costs per million BTU in 1986 and annual escalation rates thereafter: (1) a low case with natural gas prices at $3.22 per million BTU in 1986 and increasing at an average rate of 2.0% per year thereafter; (2) a medium case with natural gas prices at $3.91 per million BTU in 1986 and increasing at an average rate of 3.6% per year thereafter; and (3) a high case with natural gas prices at $3.91 per million BTU in 1986 and increasing at an average rate of 5.5% per year thereafter. Additionally, we cannot presently determine to what extent Edison will be allowed to include Construction Work in Progress ("CWIP") in its wholesale electric rates. Edison has included CWIP in its most recent rate filing. We have included in our projections of Edison's wholesale electric rates the results of our analysis which follows the same allowance for CWIP in its rate base as contained in such Edison rate filing.

Further, in projecting Edison rates, we have supplemented recent Edison filings with the following assumptions: (1) the Federal Energy Regulatory Commission ("FERC") will allow Edison a 13.25% rate of return on common equity in 1987 through 1990 and 12.75% in 1991 and thereafter; (2) the basic rate of annual inflation will be approximately 4.5% per year; (3) annual escalation for coal will be 5.1% per year; (4) operating expenses will escalate at 5.8% per year; and (5) the costs of construction will generally escalate at 5.8% per year. The resulting average Edison base power rates during the study period from fiscal year 1987 through 1991 for the wholesale customer class increase at average annual rates of 3.5%, 4.3% and 5.2% per year for the low, medium and high fuel price level cases, respectively. Such base power rate increase projections include an adjustment to reflect equivalent oil and natural gas prices in fiscal year 1987 for comparison of annual percentage increases and the effect of the declining load factor of the purchases to be made from Edison for the cities of Riverside, Vernon, Azusa, Banning and Colton resulting from the addition of owned resources. Edison resource plans which we have used in forecasting its wholesale rates include participation by some of its wholesale customers in the California-Oregon Transmission Project, as previously discussed under "Future Power Supply Resources". Inclusion of this potential participation by Edison's wholesale customers does not have a substantial impact on the projection of Edison's power and energy rates.

As a result of corrections to calculations and costs allowed by FERC in Edison rate filings, approximately $47.0 million has been refunded to the cities of Riverside, Vernon, Azusa, Banning and Colton by Edison in the last several years. To the extent the cities have determined the disposition and allocation of these refunds, we have included them in our analysis. A decision by an administrative law judge in a pending rate case may result in additional refunds by Edison to the cities. Such decision is subject to FERC review and we have not included any potential refunds in our analysis.

The City of Riverside and Deseret have entered into a power sales agreement pursuant to which the City of Riverside has agreed to purchase 46.69 MWe, plus losses which are to be determined between IPP and the Mona 345-kV bus, of firm capacity and associated energy. Such purchase was originally scheduled to begin January 1, 1987 or the inservice date of the Southern Transmission System, whichever was later. The City has indicated that it expects to initiate firm service from Deseret in March 1987. However, if prior to the commercial operation of IPP Unit 2, the transfer capability of the Southern Transmission System is less than its planned transfer capability of 1600 MWe, the City of Riverside will not be obligated to purchase capacity and energy from Deseret in an amount proportionate to the reduced transmission capability. As discussed under "Future Power Supply Resources — Southern Transmission System," for purposes of this report, we have assumed that the necessary arrangements to correct the slight contractual deficiency in the Southern Transmis-

sion System entitlement will be made. Riverside's contract also provides Deseret with first rights to supply the City of Riverside with certain economy and replacement energy. Certain factors with respect to this power sales agreement must be resolved to establish such capacity and energy as a reliable resource for the City of Riverside. The City of Riverside and Edison must reach agreement with respect to firm transmission arrangements for such capacity and energy to the City of Riverside's point of delivery. Such arrangements are currently being discussed with Edison. There has been no operating experience with Edison for resources such as Deseret, the capacity and energy from which will be used to reduce capacity and energy purchases from Edison and will not be subject to IOA provisions. Although the manner in which Edison will treat such a resource is uncertain, we believe that it is reasonable to assume that transmission will be available for the Deseret power purchase and that the City of Riverside will be able to displace purchases of power from Edison with the Deseret purchases.

As discussed previously, the City of Riverside has a 1.79% ownership interest in San Onofre. The cities of Riverside, Azusa, Banning and Colton have contracted to purchase from the Authority 3.0%, 4.0%, 2.0%, and 3.0%, respectively, of the Contingent Capacity and associated firm energy from the Authority Interest in the Hoover uprating project. The City of Riverside has contracted to purchase 7.617% of IPP capacity and energy. Riverside has a feasibility study participation percentage in White Pine Power Project. We have assumed herein that the City of Riverside's power and energy requirements above those produced by its Project Entitlement, its ownership interest in San Onofre Nuclear Generating Station Units 2 and 3, IPP purchases, its Hoover uprating project entitlement, and Deseret power purchases will be met by purchases from Edison through the IOA. We have further assumed herein that Vernon's, Azusa's, Colton's and Banning's power and energy requirements, above those produced by their respective Project Entitlements and Hoover uprating project entitlements, the City of Vernon's diesel generators and the City of Banning's hydroelectric generating project, will be met by purchases from Edison through their respective IOAs.

The following table summarizes the fiscal year historical peak loads and resources for the cities of Riverside, Vernon, Azusa, Banning and Colton and the estimated future peak loads and resources through 1994. The estimated future peak loads and resources were provided by each of the respective cities. One of the City of Vernon's major industrial customers significantly reduced its level of operations in Vernon in 1982. This reduction results in a decrease in Vernon's fiscal year 1987 forecast peak demand requirement, due specifically to this one customer, of approximately 8% from the fiscal year 1982 level.

Cities of Riverside, Vernon, Azusa, Banning and Colton
Peak Loads and Resources (MWe)

	Historical					Estimated			
	Fiscal Year Ending June 30								
	1982	1983	1984	1985	1986	1988	1990	1992	1994
Loads(1)	647.1	622.3	573.2	621.1	616.8	622.9	656.8	676.6	705.5
Resources:									
San Onofre Nuclear Generating Station(2)	0	0	39.4	39.4	38.5	38.5	38.5	38.5	38.5
Project Entitlement(3)	0	0	0	0	9.6	28.8	28.8	28.8	28.8
Intermountain Power Project(2)	0	0	0	0	0	118.9	118.9	118.9	118.9
Hoover Uprating Project	0	0	0	0	0	35.7	52.7	49.1	61.0
Deseret Power Purchase(2)	0	0	0	0	0	46.7	46.7	46.7	46.7
Purchases(4)	647.1	622.3	543.6	591.0	581.5	407.6	428.5	451.1	470.8
Subtotal	647.1	622.3	583.0	630.4	629.6	676.2	714.1	733.1	764.7
Less: Reserves and Losses(5)	0	0	9.8	9.3	12.8	53.3	57.3	56.5	59.2
Net Resources	647.1	622.3	573.2	621.1	616.8	622.9	656.8	676.6	705.5
Balance Available	0	0	0	0	0	0	0	0	0

(1) Non-coincidental.

(2) City of Riverside resource only.

(3) Project capacity shown at the date of commercial operation, which may not coincide wih the cities' peak loads.

(Footnotes continued on the following page)

requirements are purchased from Edison, with the exception of the Western energy credits related to the Hoover uprating project which may be scheduled to supply a portion of these requirements.

During the study period from 1987 through 1991, Contract Energy is estimated to average approximately 5.1% of all energy purchased from Edison by these cities. The Contract Energy cost is determined by multiplying Edison's cost of fuel for conventional oil-fired combustion turbine and combined-cycle generating resources measured in dollars per million BTU by the weighted heat rate of these generating resources measured in BTU's per kilowatt-hour. This rate, plus a charge for certain other costs associated with fuel, is then adjusted for transmission losses to the cities' points of delivery.

Based upon the foregoing assumptions, our forecast of Edison's wholesale power rates, using the medium oil and gas price level cases, and the forecast costs of the cities' respective Project Entitlements, the following tables show the estimated power supply costs for the cities for a period from 1987 through 1994. Use of the low and high oil and gas price level cases would result in a variation of approximately − 0.6% to + 0.9% in the total annual power costs, respectively, in 1994 for the City of Riverside. For the cities of Vernon, Azusa, Banning and Colton, this variation would be approximately − 4.6% to + 4.6% in 1994.

Estimated Power Supply Costs to the City of Riverside

($000)

	Fiscal Year Ending June 30							
	1987	1988	1989	1990	1991	1992	1993	1994
Power Costs:								
Project Entitlement ...	$ 3,289	$ 5,399	$ 6,747	$ 6,911	$ 7,016	$ 7,161	$ 7,178	$ 7,347
San Onofre	18,405	18,329	18,482	18,628	18,584	19,168	20,036	20,614
Intermountain Power Project(1)	23,220	48,644	52,075	56,351	57,494	59,739	61,582	63,413
Hoover Uprating Project	51	561	633	693	710	730	755	762
Deseret Power Purchase(2)	6,451	15,729	15,966	16,336	16,645	16,838	17,414	17,377
Credit from Surplus Sales(3)	(11)	(890)	(866)	(875)	(857)	(819)	(497)	(645)
Other Purchased Power(4)	46,475	18,221	17,741	19,628	20,994	23,220	26,530	27,073
Total Annual Power Supply Costs	$ 97,880	$105,993	$110,778	$117,672	$120,586	$126,037	$132,998	$135,941
Total Energy Requirements (000 MWh)	1,255	1,292	1,365	1,399	1,433	1,497	1,537	1,572
Unit Power Supply Costs (Mills/kWh)	78.0	82.0	81.2	84.1	84.1	84.2	86.5	86.5

(1) Includes the estimated annual cost of the Southern Transmission System transfer capability associated with the City of Riverside's IPP entitlement.

(2) Includes the estimated annual cost of the excess transfer capability of the Southern Transmission System.

(3) Income derived from the sale of surplus energy generated by City Integrated Resources sold to Edison under the provisions of the IOA.

(4) Based on projected Edison energy and capacity rates and projected Edison contract energy costs using the medium oil and gas price level case.

(4) Includes the City of Vernon's diesel generators, the City of Banning's hydroelectric generating project and purchases as necessary to meet loads to be obtained from Edison or other sources.

(5) Reserves and losses associated with the San Onofre Nuclear Generating Station, IPP, Hoover uprating project and the respective Project Entitlements. Capacity credit for these resources, under the respective Integrated Operations Agreements, is based on an assumed reserve requirement by Edison of 20% of the resource rated capability. The cities purchase capacity reserves from Edison. The Deseret Power Purchase is not expected to be an integrated resource under Riverside's Integrated Operations Agreement and is not subject to Edison's reserve requirements.

The following table summarizes the estimated average cost of power to the cities of Riverside, Vernon, Azusa, Banning and Colton of their Project Entitlements.

Estimated Average Annual Cost to Cities of Riverside, Vernon, Azusa, Banning and Colton of Power from the Authority Interest

($000)

	Fiscal Year Ending June 30							
	1987	1988	1989	1990	1991	1992	1993	1994
Project Entitlement Costs(1)	$7,612	$12,723	$15,879	$16,262	$16,492	$16,825	$16,839	$17,232
Transmission Costs to Eldorado(2)	109	120	138	143	150	156	162	168
Transmission Costs to Point of Interconnection C(3)	216	262	345	356	368	376	388	399
Transmission Costs to the Cities' Points of Delivery(4)	258	300	373	388	402	415	431	445
Total Estimated Annual Costs	$8,195	$13,405	$16,735	$17,149	$17,412	$17,772	$17,820	$18,244
Energy Delivered (000 MWh)	102.4	106.4	162.9	151.9	164.7	177.7	157.9	169.9
Average Unit Cost (Mills/kWh)	80.0	126.0	102.7	112.9	105.7	100.0	112.9	107.4
Capacity Delivered (MWe)(5)	18.2	27.3	27.3	27.3	27.3	27.3	27.3	27.3

(1) At the high voltage bus of the ANPP High Voltage Switchyard.

(2) Based on the Transmission Agreement.

(3) Based on the Transmission Service Agreements. Transmission costs escalated at 3.0% per year.

(4) Estimated transmission costs charged by Edison including scheduling and dispatching for the respective cities' Project Entitlements under provisions of their Integrated Operations Agreements.

(5) Project capacity shown at the date of commercial operation, which may not coincide with cities' peak loads.

We have projected the costs of power to the cities of Riverside, Vernon, Azusa, Banning and Colton for the period 1987 through 1994 assuming that these cities would purchase from Edison all power requirements not supplied from their respective Project Entitlements and Hoover uprating project entitlements, with the exception of the cities of Riverside, Vernon and Banning. For the City of Riverside, we have included its ownership share of San Onofre, its entitlement from IPP and the capability of the Deseret Power Purchase. For the cities of Vernon and Banning we have included the respective production of Vernon's diesel generators and Banning's hydroelectric generating project. In accordance with their Integrated Operations Agreements, these cities will purchase power from Edison at Edison's partial requirements rates. In addition, with the exception of the Hoover uprating project entitlements, when a City Capacity Resource, such as its Project Entitlement, is not available, the cities shall purchase energy from some other source or purchase Contract Energy from Edison in the amount of energy capability associated with the capacity credit, less energy received from City Integrated Resources. For purposes of this report, we have assumed that all Contract Energy

Estimated Average Power Supply Costs to the Cities of Vernon, Azusa, Banning and Colton

($000)

	Fiscal Year Ending June 30							
	1987	1988	1989	1990	1991	1992	1993	1994
Power Costs:								
Project Entitlement	$ 4,906	$ 8,006	$ 9,988	$ 10,238	$ 10,396	$ 10,611	$ 10,642	$ 10,897
Hoover Uprating Project	55	602	675	739	758	777	802	807
Other Purchased Power*	93,081	101,872	107,296	110,892	112,330	115,602	119,991	126,495
Total Annual Power Supply Costs	$98,042	$110,480	$117,959	$121,869	$123,484	$126,990	$131,435	$138,199
Total Energy Requirements (000 MWh)*	1,611	1,661	1,698	1,731	1,752	1,766	1,782	1,827
Unit Power Supply Costs (Mills/kWh)	60.9	66.5	69.5	70.4	70.5	71.9	73.8	75.6

* Includes the City of Vernon's diesel generator production costs, the City of Banning's hydroelectric generating project production costs and Edison purchases based on projected Edison energy and capacity rates and projected Edison contract energy costs using the medium oil and gas price level case.

Based on the forecast of power costs from their respective Project Entitlements and on certain data supplied by the cities of Riverside, Vernon, Azusa, Banning and Colton, we have prepared projections of operating results of their electric systems for the fiscal years ending June 30, 1987 through 1991. In these projections, we show increases in revenue requirements beyond the revenues generated at the cities' existing rates and estimate an average annual increase in revenue requirements over the five-year period of approximately 4.4%, 1.2%, 0.9%, 2.8%, and 6.2% for Riverside, Vernon, Azusa, Banning and Colton, respectively. Revenue requirements are based on covering projected operating expenses, including the cost of power from each city's Project Entitlement, debt service on bonds previously issued, where applicable, and on meeting the respective electric system's projected capital improvement program and other non-operating financial commitments.

City of Riverside
Projected Operating Results

($000)

	Fiscal Year Ending June 30				
	1987	1988	1989	1990	1991
Gross Revenues:					
Revenues from Sales of Electricity:					
At 1986 Average Charges	$107,271	$110,434	$116,673	$119,579	$122,485
Revenue Adjustments(1)	6,834	22,040	5,807	0	0
Additional Revenue Required(2)	7,376	1,208	18,593	27,435	29,092
Subtotal	$121,481	$133,682	$141,073	$147,014	$151,577
Other Operating Revenues(3)	498	513	528	544	561
Surplus Sales Revenue(4)	11	890	866	875	857
Other Income(3)	3,195	2,187	2,172	2,156	2,139
Developers' Contributions(3)	1,642	1,870	1,445	1,587	1,587
Total Estimated Gross Revenues	$126,827	$139,142	$146,084	$152,176	$156,721
Operating Expenses:					
Power Production:					
Project Entitlement(5)	$ 3,289	$ 5,399	$ 6,747	$ 6,911	$ 7,016
San Onofre Nuclear Generating Station	8,793	8,561	8,715	8,872	8,826
Intermountain Power Project(6)	23,220	48,644	52,075	56,351	57,494
Hoover Uprating Project	51	561	633	693	710
Deseret Power Purchase(7)	6,451	15,729	15,966	16,336	16,645
Other Purchased Power(8)	46,475	18,221	17,741	19,628	20,994
Other Operating Expenses(9)	13,869	14,285	14,714	15,155	15,610
Total Estimated Operating Expenses	$102,148	$111,400	$116,591	$123,946	$127,295
Total Estimated Net Revenues Excluding Depreciation and Amortization	$ 24,679	$ 27,742	$ 29,493	$ 28,230	$ 29,426
Debt Service(10)	13,194	13,296	13,256	13,201	13,156
Balance for Other Purposes(11)	$ 11,485	$ 14,446	$ 16,237	$ 15,029	$ 16,270

(1) Additional revenue estimated by the City to be available from the Power Cost Adjustment account and the Rate Stabilization account.

(2) Additional revenues required primarily to pay the costs of future capital improvements to the City of Riverside's electric system and escalating purchased power costs from Edison.

(3) Includes interest income and miscellaneous income as estimated by the City of Riverside.

(4) Revenue from the sale of surplus energy under the provisions of its Integrated Operations Agreement.

(5) The City's share of estimated annual costs of the Project including transmission to the Point of Interconnection C and estimated costs of transmission, scheduling and dispatching to the City over Edison transmission facilities.

(6) Includes payments for the Southern Transmission System associated with the transfer capability required for the City of Riverside's IPP entitlement.

(7) Includes payments for the excess transfer capability of the Southern Transmission System.

(8) Based on projected Edison rates under the provisions of its Integrated Operations Agreement. Such Edison rates were projected using the medium oil and gas price level case.

(9) Estimated by the City of Riverside. Includes other operating expenses and equipment purchases.

(10) Net of capitalized interest.

(11) Includes transfer to the general fund and funds for transmission and distribution projects.

City of Vernon
Projected Operating Results

($000)

	Fiscal Year Ending June 30				
	1987	1988	1989	1990	1991
Gross Revenues:					
Revenues from Sales of Electricity:					
At 1986 Average Charges	$ 81,852	$ 84,312	$ 85,610	$ 86,430	$ 86,908
Additional Revenue Required(1)	(1,832)	3,974	5,046	5,240	5,401
Subtotal	$ 80,020	$ 88,286	$ 90,656	$ 91,670	$ 92,309
Other Operating Revenues	70	70	70	70	70
Other Income	4,000	4,000	4,000	5,000	5,000
Total Estimated Gross Revenues	$ 84,090	$ 92,356	$ 94,726	$ 96,740	$ 97,379
Operating Expenses:					
Project Entitlement(2)	$ 3,000	$ 4,918	$ 6,146	$ 6,297	$ 6,392
Hoover Uprating Project	37	403	455	499	511
Other Purchased Power(3)	66,560	72,378	75,582	77,147	77,456
Other Operating Expenses(4)	8,670	8,756	8,844	8,932	9,022
Total Estimated Operating Expenses	$ 78,267	$ 86,455	$ 91,027	$ 92,875	$ 93,381
Total Estimated Net Revenues Excluding Depreciation and Amortization	$ 5,823	$ 5,901	$ 3,699	$ 3,865	$ 3,998
Debt Service	0	0	0	0	0
Balance for Other Purposes(5)	$ 5,823	$ 5,901	$ 3,699	$ 3,865	$ 3,998

(1) Estimated revenue increases required to cover all operating expenses, capital improvements and taxes.

(2) The City's share of estimated annual costs of the Project including transmission to Point of Interconnection C and estimated costs of transmission, scheduling and dispatching to the City over Edison transmission facilities.

(3) Includes the City's diesel generator production costs and purchases from Edison based on projected Edison rates under the provisions of its Integrated Operations Agreement. Such Edison rates were projected using the medium oil and gas price level case.

(4) Includes estimated expenditures for transmission and distribution, customer accounts and administrative and general. Based on historical expenses and an assumed escalation rate of 1.0% per year.

(5) Includes estimated payments in lieu of taxes and capital additions to be funded from revenues.

City of Azusa
Projected Operating Results

($000)

	Fiscal Year Ending June 30				
	1987	1988	1989	1990	1991
Gross Revenues:					
Revenues from Sales of Electricity:					
At 1986 Average Charges	$ 16,786	$ 17,581	$ 18,465	$ 19,437	$ 19,879
Revenue Adjustment(1)	(364)	(382)	(401)	(199)	0
Additional Revenue Required(2)	(647)	555	1,207	1,094	902
Subtotal	$ 15,775	$ 17,754	$ 19,271	$ 20,332	$ 20,781
Other Operating Revenues	72	76	80	84	88
Other Income	0	0	0	0	0
Total Estimated Gross Revenues	$ 15,847	$ 17,830	$ 19,351	$ 20,416	$ 20,869
Operating Expenses:					
Power Project Entitlement(3)	$ 634	$ 1,027	$ 1,278	$ 1,311	$ 1,332
Hoover Uprating Project	7	85	94	103	106
Other Purchased Power(4)	12,180	13,575	14,711	15,603	15,893
Other Operating Expenses(5)	1,308	1,373	1,442	1,514	1,589
Total Estimated Operating Expenses	$ 14,129	$ 16,060	$ 17,525	$ 18,531	$ 18,920
Total Estimated Net Revenues Excluding Depreciation and Amortization	$ 1,718	$ 1,770	$ 1,826	$ 1,885	$ 1,949
Debt Service	0	0	0	0	0
Balance for Other Purposes(6)	$ 1,718	$ 1,770	$ 1,826	$ 1,885	$ 1,949

(1) The City has received refunds from Edison for the fiscal year 1984 through 1986 period which total approximately $4,088,000. A portion of these funds was used to establish an Edison Refund Trust Fund from which refunds to customers are made at a rate of 2.17% of current year revenues from sales of electricity until all funds are refunded. Revenues in the Edison Refund Trust Fund are assumed to accrue interest at an annual rate of 6%.

(2) Estimated revenue increases required to cover all operating expenses, capital improvements and taxes.

(3) The City's share of estimated annual costs of the Project including transmission to Point of Interconnection C and estimated costs of transmission, scheduling and dispatching to the City over Edison transmission facilities.

(4) Based on projected Edison rates under the provisions of its Integrated Operations Agreement. Such Edison rates were projected using the medium oil and gas price level case.

(5) Includes estimated expenditures for transmission and distribution, customer accounts and administrative and general. Based on historical expenses and an assumed escalation rate of 5.0% per year.

(6) Includes estimated payments to the General Fund, payments in lieu of taxes and capital additions to be funded from revenues.

City of Banning
Projected Operating Results

($000)

	Fiscal Year Ending June 30				
	1987	1988	1989	1990	1991
Gross Revenues:					
Revenues from Sales of Electricity:					
At 1986 Average Charges	$ 7,134	$ 7,300	$ 7,436	$ 7,592	$ 7,729
Additional Revenue Required(1)	243	765	1,009	1,132	1,137
Subtotal	$ 7,377	$ 8,065	$ 8,445	$ 8,724	$ 8,866
Other Operating Revenues	14	16	18	19	20
Other Income	47	31	31	31	31
Total Estimated Gross Revenues	$ 7,438	$ 8,112	$ 8,494	$ 8,774	$ 8,917
Operating Expenses:					
Project Entitlement(2)	$ 641	$ 1,036	$ 1,290	$ 1,323	$ 1,344
Hoover Uprating Project	5	44	50	54	56
Other Purchased Power(3)	4,609	4,787	4,799	4,961	5,007
Other Operating Expenses(4)	775	791	807	823	839
Total Estimated Operating Expenses	$ 6,030	$ 6,658	$ 6,946	$ 7,161	$ 7,246
Total Estimated Net Revenues Excluding Depreciation and Amortization	$ 1,408	$ 1,454	$ 1,548	$ 1,613	$ 1,671
Debt Service	154	204	206	207	209
Balance for Other Purposes(5)	$ 1,254	$ 1,250	$ 1,342	$ 1,406	$ 1,462

(1) Estimated revenue increases required to cover all operating expenses, capital improvements and taxes.

(2) The City's share of estimated annual costs of the Project including transmission to Point of Interconnection C and estimated costs of transmission, scheduling and dispatching to the City over Edison transmission facilities.

(3) Includes the production costs of the City's hydroelectric generating project and purchases from Edison based on projected Edison rates under the provisions of its Integrated Operations Agreement. Such Edison rates were projected using the medium oil and gas price level case.

(4) Includes estimated expenditures for transmission and distribution, customer accounts and administrative and general. Based on historical expenses and an assumed escalation rate of 2.0% per year.

(5) Includes estimated payments in lieu of taxes and capital additions to be funded from revenues.

City of Colton
Projected Operating Results

($000)

	Fiscal Year Ending June 30				
	1987	1988	1989	1990	1991
Gross Revenues:					
Revenues from Sales of Electricity:					
At 1986 Average Charges	$ 12,153	$ 12,744	$ 13,352	$ 13,977	$ 14,652
Additional Revenue Required(1)	1,808	3,283	4,211	4,815	5,167
Subtotal	$ 13,961	$ 16,027	$ 17,563	$ 18,792	$ 19,819
Other Operating Revenues	47	49	51	54	57
Other Income	0	0	0	0	0
Total Estimated Gross Revenues	$ 14,008	$ 16,076	$ 17,614	$ 18,846	$ 19,876
Operating Expenses:					
Project Entitlement(2)	$ 631	$ 1,025	$ 1,274	$ 1,307	$ 1,328
Hoover Uprating Project	6	70	76	83	85
Other Purchased Power(3)	9,732	11,132	12,204	13,181	13,974
Other Operating Expenses(4)	1,681	1,765	1,853	1,946	2,043
Total Estimated Operating Expenses	$ 12,050	$ 13,992	$ 15,407	$ 16,517	$ 17,430
Total Estimated Net Revenues Excluding Depreciation and Amortization	$ 1,958	$ 2,084	$ 2,207	$ 2,329	$ 2,446
Debt Service	97	95	98	100	97
Balance for Other Purposes(5)	$ 1,861	$ 1,989	$ 2,109	$ 2,229	$ 2,349

(1) Estimated revenue increases required to cover all operating expenses, capital improvements, taxes and debt service.

(2) The City's share of estimated annual cost of the Project including transmission to Point of Interconnection C and estimated costs of transmission, scheduling and dispatching to the City over Edison transmission facilities.

(3) Based on projected Edison rates under the provisions of its Integrated Operations Agreement. Such Edison rates were projected using the medium oil and gas price level case.

(4) Includes estimated expenditures for transmission and distribution, customer accounts and administrative and general. Based on historical expenses and an assumed escalation rate of 5.0% per year.

(5) Includes payments in lieu of taxes and estimated capital additions to be funded from revenues.

Cities of Burbank, Glendale and Pasadena

The cities of Burbank, Glendale and Pasadena are each municipal corporations existing under the laws of the State of California, owning and operating electric public utilities providing electric service to virtually all of the electric customers within their respective city limits.

Electric rates for each city are fixed by its City Council and are not subject to regulation by any California state agency. Each city is subject to certain ratemaking provisions of the Public Utility Regulatory Policies Act of 1978.

Burbank, Glendale and Pasadena supply electricity to their respective electric systems through a combination of oil- and gas-fired generating facilities located in the Los Angeles Basin, 34 MWe of hydroelectric generation at the Hoover Power Plant and purchases from BPA and other utilities in the Northwest and Southwest. On August 17, 1984, the Hoover Power Plant Act of 1984 was signed into law. Among other things, as discussed previously, such Act authorizes the Secretary of Energy to offer, and he has offered, the cities of Burbank, Glendale and Pasadena renewal contracts for delivery commencing June 1, 1987 of capacity in the total amount of approximately 34 MWe from the Hoover Power Plant. The City of Pasadena also purchases electric energy from the Azusa Hydroelectric Plant. In the twelve months ended June 30, 1986, the three cities generated an aggregate of 659,753 MWh of energy and purchased an aggregate of 2,223,764 MWh.

The 2.4% estimated combined average annual peak load growth over the period 1987 to 1994 for the cities of Burbank, Glendale and Pasadena reflects their view of the population increase of the area and the effect on consumption of conservation measures already implemented and those proposed, including the introduction, in some instances, of alternative energy resources.

The cities of Burbank, Glendale and Pasadena have entered into contracts to purchase a total of 9.484% (148.046 MWe) of IPP base capacity and energy and 13.719% of the capacity and energy available under the Excess Power Sales Agreement which is presently estimated to be approximately 45.094 MWe. The cities of Burbank, Glendale and Pasadena have a feasibility study participation percentage totaling 5.61% in the White Pine Power Project. The cities of Burbank and Glendale each have a 3.85% ownership interest in the SEP. The City of Pasadena has a 2.3% ownership interest in the SEP. The following table summarizes the fiscal year historical peak loads and resources and estimated future peak loads and resources through 1994 for the cities of Burbank, Glendale and Pasadena. The estimated future peak loads and resources were provided by the cities of Burbank, Glendale and Pasadena.

Cities of Burbank, Glendale and Pasadena
Peak Loads and Resources (MWe)

	Historical					Estimated			
	Fiscal Year Ending June 30								
	1982	1983	1984	1985	1986	1988	1990	1992	1994
Loads(1)	643	625	639	704	691	733	768	801	837
Resources(2):									
Basin Thermal (Oil and Gas)(3)	655	638	656	667	667	502	518	541	494
Hydroelectric	51	51	51	51	51	65	72	71	76
Project Entitlement(4)	0	0	0	0	10	29	29	29	29
Intermountain Power Project(5)	0	0	0	0	0	148	148	148	148
Other(6)	121	124	126	126	156	191	203	214	292
Total	827	813	833	844	884	935	970	1,003	1,039
Balance Available for Reserves and Losses	184	188	194	140	193	202	202	202	202

(1) Non-coincidental.

(2) Resources assumed available to meet peak loads.

(3) Includes those resources required to meet peak loads and planning reserve margin as provided by the cities of Burbank, Glendale and Pasadena.

(4) Project capacity shown at the date of commercial operation, which may not coincide with the cities' peak loads.

(5) Excludes purchases under the Excess Power Sales Agreement.

(6) Includes BPA peaking exchange through 1987 and additional requirements.

The following table summarizes the estimated average Project Entitlement cost of power to the cities of Burbank, Glendale and Pasadena.

Estimated Average Annual Cost to the Cities of Burbank, Glendale and Pasadena of Power from the Authority Interest

($000)

	Fiscal Year Ending June 30							
	1987	1988	1989	1990	1991	1992	1993	1994
Project Entitlement Costs(1)	$7,554	$12,627	$15,759	$16,140	$16,368	$16,698	$16,713	$17,100
Transmission Costs of Power to Eldorado(2)	81	90	105	111	114	120	123	129
Transmission Costs to Point of Interconnection A(3)	78	93	123	126	132	135	138	144
Transmission Costs to the Cities	147	171	212	221	229	238	245	254
Total	$7,860	$12,981	$16,199	$16,598	$16,843	$17,191	$17,219	$17,627
Energy Delivered (000 MWh)(4)	102.6	106.8	163.2	152.1	165.0	177.9	158.4	170.1
Average Unit Cost (Mills/kWh)	76.6	121.5	99.3	109.1	102.1	96.6	108.7	103.6
Capacity Delivered (MWe)(5)	18.2	27.4	27.4	27.4	27.4	27.4	27.4	27.4

(1) At the high voltage bus of the ANPP High Voltage Switchyard.

(2) Based on the Transmission Agreement.

(3) Based on the Transmission Service Agreements. Transmission costs escalated at 3.0% per year.

(4) Not reduced to reflect transmission losses to the cities' points of delivery. Based on the McCullough-Victorville Line 2 Transmission Agreements between the cities of Burbank and Glendale and the Department, the Victorville to Sylmar Switching Station Transmission Service Agreement between the City of Pasadena and the Department, and the 230 kV Interconnection and Transmission Agreement between the City of Pasadena and Edison.

(5) Project capacity shown at the date of commercial operation, which may not coincide with the cities' peak loads.

We have estimated power costs for the cities of Burbank, Glendale and Pasadena. These estimates are based on the costs of the cities' Project Entitlements, as estimated herein, together with estimates of the costs of power from the other power supply resources scheduled to be used to supply power to meet the cities' loads. For the purpose of this analysis, the costs of the resources required, but as yet unidentified, and the costs of operation of power plants owned by the cities of Burbank, Glendale and Pasadena, were provided by these Project Participants. The foregoing estimates are based on power supply plans provided by these Project Participants. The cities of Burbank, Glendale and Pasadena are currently evaluating their power supply plans. In many cases, actual energy costs may differ when final plans, schedules and definitive pooling arrangements are developed.

Estimated Average Power Supply Costs to the Cities of Burbank, Glendale and Pasadena

($000)

	Fiscal Year Ending June 30							
	1987	1988	1989	1990	1991	1992	1993	1994
Power Costs:								
Project Entitlement...	$ 7,860	$ 12,981	$ 16,199	$ 16,598	$ 16,843	$ 17,191	$ 17,219	$ 17,627
Thermal (Gas and Oil)	32,388	32,152	33,138	36,292	41,649	49,920	53,871	58,842
Intermountain Power Project	30,014	62,884	67,222	72,711	74,164	76,993	79,323	81,640
Hoover Uprating Project	24	288	348	399	415	431	452	456
Other Purchased Power*	47,395	45,179	47,187	51,123	53,477	55,171	60,199	64,016
Total Annual Power Supply Costs	$117,681	$153,484	$164,094	$177,123	$186,548	$199,706	$211,064	$222,581
Total Energy Requirements (000 MWh)	2,943	2,999	3,066	3,134	3,202	3,273	3,345	3,417
Unit Power Supply Costs (Mills/kWh)	40.0	51.2	53.5	56.5	58.3	61.0	63.1	65.1

* Includes each city's estimated annual cost of power supply from other resources purchased to serve such city's annual requirements.

Based on the forecast of power costs from their respective Project Entitlements and on certain data supplied by the cities of Burbank, Glendale and Pasadena, we have prepared projections of operating results of their electric systems for the fiscal years ending June 30, 1987 through 1991. In these projections, we show increases in revenue requirements beyond those generated by the cities' current rates and estimate an average annual increase in revenue requirements of 4.3%, 2.3%, and 10.3% for the cities of Burbank, Glendale and Pasadena, respectively. Required revenues are based on covering projected operating costs, including cost of power from each city's respective Project Entitlements, debt service on bonds previously issued and on meeting the respective city's projected improvement program and other non-operating financial commitments.

The City of Burbank
Projected Operating Results

($000)

	Fiscal Year Ending June 30				
	1987	1988	1989	1990	1991
Gross Revenues:					
Revenues from Sale of Electricity:					
At 1986 Average Charges(1)	$ 63,056	$ 64,369	$ 65,683	$ 67,062	$ 68,442
Additional Revenue Required(2)	(4,297)	7,300	8,887	12,344	15,877
Subtotal	$ 58,759	$ 71,669	$ 74,570	$ 79,406	$ 84,319
Other Operating Revenues	0	0	0	0	0
Other Income	1,158	780	301	300	250
Total Estimated Gross Revenues	$ 59,917	$ 72,449	$ 74,871	$ 79,706	$ 84,569
Operating Expenses:					
Power Production:					
Project Entitlement(3)	$ 2,621	$ 4,328	$ 5,401	$ 5,534	$ 5,616
Basin Thermal(4)	12,690	11,057	10,170	10,418	12,425
Intermountain Power Project(5)	10,673	22,361	23,904	25,855	26,372
Hoover Uprating Project	11	142	177	207	216
Other Purchased Power(4)(6)	14,800	14,197	15,129	16,579	17,166
Other Operating Expenses(7)	9,710	10,385	11,115	11,890	12,722
Total Estimated Operating Expenses	$ 50,505	$ 62,470	$ 65,896	$ 70,483	$ 74,517
Total Estimated Net Revenues Excluding Depreciation and Amortization	$ 9,412	$ 9,979	$ 8,975	$ 9,223	$ 10,052
Debt Service	3,213	3,192	3,180	3,090	3,150
Balance for Other Purposes(8)	$ 6,199	$ 6,787	$ 5,795	$ 6,133	$ 6,902

(1) Based on average charge for all power sold in fiscal year ending June 30, 1986, including fuel cost adjustments.

(2) Estimated additional revenue requirements to cover all operating expenses, capital additions, taxes and debt service. Based on historical experience, significant portions of these amounts should be recovered through energy cost adjustments.

(3) Includes the City of Burbank's costs of its Project Entitlement, transmission costs to Point of Interconnection A and transmission and scheduling costs.

(4) Reflects availability of economical outside purchases.

(5) Costs are estimated at the load center. Excludes Excess Power Sales Agreement amounts.

(6) Includes purchases from Hoover Power Plant, payment for capacity from BPA through 1987, payment for purchases from the Northwest and payment for energy and capacity from IPP pursuant to the Excess Power Sales Agreement.

(7) Includes transmission and distribution, customer accounts and administrative and general expenses.

(8) Includes estimated payments in lieu of taxes and capital additions to be funded from revenues.

City of Glendale
Projected Operating Results

($000)

	Fiscal Year Ending June 30				
	1987	1988	1989	1990	1991
Gross Revenues:					
Revenues from Sales of Electricity:					
At 1986 Average Charges(1)	$ 61,515	$ 62,793	$ 64,178	$ 65,607	$ 67,072
Additional Revenue Required(2)	(8,675)	(205)	2,926	5,871	7,935
Subtotal	$ 52,840	$ 62,588	$ 67,104	$ 71,478	$ 75,007
Other Operating Revenues	500	500	500	500	500
Other Income	2,485	2,400	2,400	2,400	2,400
Total Estimated Gross Revenues	$ 55,825	$ 65,488	$ 70,004	$ 74,378	$ 77,907
Operating Expenses:					
Power Production:					
Project Entitlement(3)	$ 2,621	$ 4,328	$ 5,401	$ 5,534	$ 5,616
Basin Thermal(4)	8,005	8,672	9,458	10,235	11,072
Intermountain Power Project(5)	5,399	11,308	12,088	13,075	13,336
Hoover Uprating Project	6	60	65	68	71
Other Purchased Power(4)(6)	15,124	15,483	16,161	17,563	18,856
Other Operating Expenses(7)	10,063	10,667	11,307	11,985	12,704
Total Estimated Operating Expenses	$ 41,218	$ 50,518	$ 54,480	$ 58,460	$ 61,655
Total Estimated Net Revenues Excluding Depreciation and Amortization	$ 14,607	$ 14,970	$ 15,524	$ 15,918	$ 16,252
Debt Service	4,155	4,160	4,162	4,162	4,168
Balance for Other Purposes(8)	$ 10,452	$ 10,810	$ 11,362	$ 11,756	$ 12,084

(1) Based on average charge for all power sold in the fiscal year ending June 30, 1986, including fuel cost adjustments.

(2) Estimated additional revenue requirements to cover all operating expenses, capital additions, taxes and debt service. Based on historical experience, significant portions of these amounts should be recovered through energy cost adjustments.

(3) Includes the City of Glendale's costs of its Project Entitlement, transmission costs to Point of Interconnection A and transmission and scheduling costs.

(4) Reflects availability of economical outside purchases.

(5) Costs are estimated at the load center. Excludes Excess Power Sales Agreement amounts.

(6) Includes purchases from Hoover Power Plant, payment for capacity from BPA through 1987, firm capacity and energy purchases from BPA beginning in 1987 and payment for energy and capacity from IPP pursuant to the Excess Power Sales Agreement.

(7) Includes transmission and distribution, customer accounts and administrative and general expenses.

(8) Includes estimated payments to general fund and capital additions to be funded from revenues.

City of Pasadena
Projected Operating Results
($000)

	Fiscal Year Ending June 30				
	1987	1988	1989	1990	1991
Gross Revenues:					
Revenues from Sales of Electricity:					
At 1986 Average Charges(1)	$ 58,176	$ 59,013	$ 60,388	$ 61,763	$ 63,019
Additional Revenue Required(2)	5,725	25,016	29,867	37,003	39,930
Subtotal	$ 63,901	$ 84,029	$ 90,255	$ 98,766	$102,949
Other Operating Revenues	0	0	0	0	0
Other Income	4,304	2,835	2,303	4,092	3,797
Total Estimated Gross Revenues	$ 68,205	$ 86,864	$ 92,558	$102,858	$106,746
Operating Expenses:					
Power Production:					
Project Entitlement(3)	$ 2,618	$ 4,325	$ 5,397	$ 5,530	$ 5,611
Basin Thermal(4)	11,693	12,424	13,510	15,639	18,152
Intermountain Power Project(5)	13,942	29,215	31,230	33,781	34,456
Hoover Uprating Project	7	86	106	124	128
Other Purchased Power(4)(6)	17,471	15,499	15,897	16,981	17,455
Other Operating Expenses(7)	9,901	12,257	13,040	14,218	14,879
Total Estimated Operating Expenses	$ 55,632	$ 73,806	$ 79,180	$ 86,273	$ 90,681
Total Estimated Net Revenues Excluding Depreciation and Amortization	$ 12,573	$ 13,058	$ 13,378	$ 16,585	$ 16,065
Debt Service	4,274	4,657	4,571	6,242	5,922
Balance for Other Purposes(8)	$ 8,299	$ 8,401	$ 8,807	$ 10,343	$ 10,143

(1) Based on average charge for all power sold in the fiscal year ending June 30, 1986 including fuel cost adjustments.

(2) Estimated additional revenue requirements to cover all operating expenses, taxes and debt service. Based on historical experience, significant portions of these amounts should be recovered through energy cost adjustments.

(3) Includes the City of Pasadena's costs of its Project Entitlement, transmission costs to Point of Interconnection A and transmission and scheduling costs.

(4) Reflects availability of economical outside purchases.

(5) Costs are estimated at the load center. Excludes Excess Power Sales Agreement amounts.

(6) Includes hydroelectric purchases, payment for capacity from BPA through 1987, payments for purchases from the Northwest and payment for energy and capacity from IPP pursuant to the Excess Power Sales Agreement.

(7) Includes transmission and distribution, customer accounts and administrative and general expenses.

(8) Includes estimated payments to general fund and capital additions to be funded from revenues.

PRINCIPAL CONSIDERATIONS AND ASSUMPTIONS

The estimates and projections contained herein are based, in part, on the following information which was provided by the identified sources. While we believe these sources to be reliable and have no reason to believe such information is unreasonable, we have not independently verified such information.

1. Forecasts of the Department's power and energy requirements, resources and power supply costs, excluding costs of its Project Entitlement and IPP generation entitlements, were provided by the Department.
2. Forecasts of power and energy requirements for the cities of Riverside, Burbank, Glendale, Pasadena, Vernon, Azusa, Banning and Colton and the District were provided by those Project Participants.
3. Excluding their Project Entitlements, IPP generation entitlements and the Hoover uprating project, forecasts of resources for the cities of Burbank, Glendale and Pasadena were provided by those Project Participants.
4. Forecasts of capital expenditures and operation and maintenance expenses for the Department, the District, and the cities of Riverside, Burbank, Glendale and Pasadena were provided by those Project Participants.
5. The City of Vernon provided a forecast of its capital expenditures.
6. The Financial Advisor has provided us with assumed reinvestment and investment rates, respectively, of 7.0% for the proceeds of the Prior Series Bonds and the 1987 A Bonds deposited in the Debt Service Reserve Account in the Debt Service Fund, and 5.5% for such proceeds deposited in the Debt Service Account in the Debt Service Fund, the Initial Facilities Account in the Construction Fund, the Operating Fund and the Reserve and Contingency Fund.

In our report to the Authority dated July 27, 1983, we expressed the opinion that the estimated direct construction costs of the Project, as then prepared by APS and Salt River Project, were comparable with the direct construction costs reported for similar projects being developed in the same time frame. While we continue to believe that opinion was appropriate at the time, changes in the nuclear industry have adversely affected the reliability of the construction schedules and cost estimates for nuclear generating facilities. The effects of these changes on other individual nuclear generating facilities' costs and schedules, which would be used for comparison, are not necessarily a matter of public record or disclosure. Further, when they do become a matter of public record, the cost and schedule estimates, including the parameters and methods upon which they are based, are not necessarily consistent among projects. As a result, a comparison of the estimated direct construction costs of the Project with such costs for other nuclear generating facilities similar to the Project is currently of questionable validity. Additionally, in the preparation of this report, we have not undertaken an independent review of the estimated direct construction costs or schedules for the Project, as prepared by APS. However, at this time, we have no reason to believe that the currently estimated direct construction costs for the Project, as prepared by APS and Salt River Project, together with the Authority's contingency, are not reasonable for use by the Authority in preparing its plan for financing the Authority Interest.

In the preparation of this report and the numbered opinions that follow, we have made certain assumptions with respect to conditions which may occur in the future. While we believe these assumptions are reasonable for the purpose of this report, they are dependent upon future events, and actual conditions may differ from those assumed. In making such assumptions, we have used and relied upon certain information provided to us by the Department, acting as the Authority's agent, the Project Participants, Edison and others. While we believe the sources to be reliable, we have not independently verified the information and offer no assurances with respect thereto. To the extent that

actual future conditions differ from those assumed herein or from the information provided to us by others, the actual results will vary from those forecast. The principal assumptions made by us and the principal information related to such assumptions provided to us by others are as follows:

1. Based on APS's current schedule for the Project, Salt River Project's schedule for the ANPP Transmission System and information relating to construction, preoperations and startup supplied by the Department acting as the Authority's agent, we have assumed that, for the Project Participants' power supply and financial planning purposes, commercial operation of Unit 3 of the Project will commence on March 1, 1988.

2. Based on APS's estimate of direct construction costs of the Project, Salt River Project's estimate of direct construction costs of the ANPP Transmission System, and the Authority contingency allowance for uncertainties not included in APS's estimate of the total construction costs for the Project provided by the Department, as the Authority's Agent, the cost of acquisition of the Authority Interest will be $465,170,000.

3. Operating costs of the Project were estimated by APS with the exception of taxes.

4. Based on APS's estimate, as adjusted by us, each unit will have a plant factor of approximately 60% during the first cycle of operation, 65% during the second cycle of operation and 70% thereafter.

5. By such time as the on-site fuel storage facilities reach capacity, a national program for spent fuel disposal will have been implemented.

6. Existing environmental laws and regulations will not be modified to adversely affect the construction cost or scheduled completion date of the Project or the Project operation.

7. Based on information provided by the Department, acting as the Authority's agent, permits, licenses and approvals as necessary to complete and operate the Project will, to the extent not already received, be received on a timely basis.

8. The cities of Riverside, Vernon, Azusa, Banning and Colton will be able to integrate their respective Project Entitlements as a City Capacity Resource under their respective Integrated Operations Agreements with Edison on the commercial operation dates assumed for the Project Participants' power supply and financial planning purposes.

9. Power and energy requirements of the cities of Vernon, Azusa, Banning and Colton, beyond that provided by their respective Project Entitlements and their respective Hoover uprating project entitlements, including Western energy credits, and the City of Vernon's diesel generators and the City of Banning's hydroelectric generating project, will be purchased from Edison in accordance with the terms of their respective Integrated Operations Agreements.

10. Power and energy requirements of the City of Riverside, beyond those provided by its Project Entitlement, San Onofre Nuclear Generating Station Units 2 and 3, IPP, Deseret and its Hoover uprating project entitlement, including Western energy credits, will be purchased from Edison in accordance with the terms of its Integrated Operations Agreement.

11. With the exception of the Department and the cities of Burbank, Glendale and Pasadena, the Project Participants' participation in other potential resources or economy purchases which are not under contract but which may become available to such Project Participants during the forecast period have not been included in the forecast power costs or our forecast of resources of the Project Participants.

12. Based on information provided by the respective Project Participants, such Project Participants, other than the Department, Burbank, Pasadena, Riverside, Vernon and Banning, will finance the estimated costs of normal capital replacements and improvements, if any, to their electric systems from current revenues.

13. Transmission for each Project Participant's Project Entitlement will be provided in accordance with the agreements as discussed herein.

14. Based on prior yields and maturities of investments, the future yield on investments from the proceeds of the Prior Series Notes and Prior Series Bonds are based on the remaining, weighted average yield to maturity of instruments in the various funds on October 30, 1986.

15. Projected wholesale power and energy rates for Edison are based on historical results of Edison operations, recent rate filings, and Edison's electric system resource plans and load forecasts. Further, in projecting Edison rates, we have supplemented recent Edison filings with the following assumptions: (1) FERC will allow Edison a 13.25% rate of return on common equity in 1987 through 1990 and 12.75% in 1991 and thereafter; (2) the basic rate of annual inflation will be approximately 4.5% per year; (3) annual escalation for coal will be 5.1% per year; (4) operating expenses will escalate at 5.8% per year; and (5) the costs of construction will generally escalate at 5.8% per year. The resulting average wholesale power rates paid by the cities Azusa, Banning, Colton, Riverside, and Vernon to Edison would increase at 3.5%, 4.3%, and 5.2% per year, respectively, for the low, medium and high fuel price level cases during the period of fiscal years 1987-1991. These average increases in average wholesale rates do not reflect prospective refunds that may be received by wholesale customers through final order of the FERC 1982 and 1984 rate cases.

16. The 1986 average revenue per unit of energy sales, based on 1986 revenues from the sales of electricity and total energy sales, as provided by all Project Participants other than the Department, will continue at the same level for the projected energy sales over the period of fiscal years ending June 30, 1987 through 1991.

17. The existing ratemaking authority of the cities of Riverside, Vernon, Burbank, Glendale, Pasadena, Azusa, Banning and Colton and the District to establish rates for the purpose of providing necessary revenues for their respective electric utility systems will not be adversely modified.

18. The capital expenditures and operation and maintenance expenses for the cities of Azusa, Banning and Colton will follow historical trends.

19. The operation and maintenance expenses for the City of Vernon will follow historical trends.

OPINIONS

Based upon our studies and analyses, the considerations and assumptions in this report and the information supplied by the Project Participants, the Department, acting as the Authority's agent, and Edison with respect to the Authority's acquisition, construction and placing into operation of the Authority Interest, we are of the opinion that:

1. The estimated cost of power from the Authority Interest is reasonable when compared with the cost of power expected from other long-term power supply resources which may be available to the Project Participants in the same time frame as the Project.
2. The output from the Authority Interest will provide long-term economic power supply benefits to the Project Participants in meeting increasing requirements, displacing base load oil- and gas-fired generation, or displacing wholesale purchases of power generated using a substantial amount of oil- and gas-fired generating resources.
3. The forecast revenue requirements from the sale of electricity for the cities of Riverside, Vernon, Burbank, Glendale, Pasadena, Azusa, Banning and Colton and the District during fiscal years ending June 30, 1987 through 1991 can reasonably be met.
4. The Department's use of its Project Entitlement to displace base load oil- and gas-fired generation will provide long-term economic power supply benefits to the Department as compared with the Department's projected cost of oil- and gas-fired generation.

Information appearing in the Official Statement, which was taken from or based upon data prepared by us, is accurately presented in the Official Statement.

Respectfully submitted,

/s/ R. W. BECK AND ASSOCIATES

PROJECT PARTICIPANTS

The information contained in this Appendix has been furnished to the Authority by the respective Project Participants. This Appendix presents information as of the respective dates set forth herein. Neither the Authority nor any Project Participant makes any representations regarding the accuracy of this information subsequent to such dates.

The Department of Water and Power of The City of Los Angeles

The Department of Water and Power of The City of Los Angeles (the "Department") is a separate proprietary agency controlling its own funds with full responsibility for meeting the water and electric requirements of its service area. There follows certain information concerning the Department prepared by the Department for inclusion in this appendix to the Official Statement. This information does not purport to cover all aspects of the Department's business, operations and financial position. During the initial offering period for the securities offered by this Official Statement a copy of the most recent annual report and the most recent official statement prepared by the Department for the issuance of securities for its power system may be obtained from: B C Monk, Room 466, Department of Water and Power, P. O. Box 111, Terminal Annex, Los Angeles, CA 90051.

Organization

The Department, the largest municipal utility in the United States, exists under and by virtue of the Charter of The City of Los Angeles adopted in January 1925, as amended. It provides water and electric services almost entirely within the boundaries of The City of Los Angeles, which encompasses some 465 square miles, to a population of approximately 3.2 million. The electric properties and operations of the Department are referred to herein as the "Power System".

Administration of the Department is under the direction of a five-member Board of Water and Power Commissioners (the "Board"), traditionally selected from among prominent business, professional and civic leaders in the City. They are appointed for terms of five years each by the Mayor and confirmed by the City Council. The members of the Board serve without compensation except for an attendance fee of fifty dollars each for each Board meeting they attend, not to exceed two hundred fifty dollars in any calendar month. Certain matters regarding the administration of the Department also require the approval of the City Council.

The management and operation of the Department is under the direction of the General Manager and Chief Engineer, Paul H. Lane. The Power System is directed by the Assistant General Manager-Power. Financial affairs are under the guidance of the Chief Financial Officer, and legal counsel is provided by the City Attorney and the Chief Assistant City Attorney for Water and Power.

The personnel functions of the Department are conducted in accordance with the civil service system established by the Los Angeles City Charter which is applicable to almost all Department employees. Under this system, appointments are made on the basis of merit through competitive examinations and civil service procedures. The position of General Manager and Chief Engineer and certain other management positions are specifically exempted from the classified civil service under provisions of the Charter.

Wages and salaries paid all Department employees are fixed by the City Council. In accordance with a State Act (the Meyers-Milias-Brown Act) and a conforming Los Angeles City Ordinance (the Employee Relations Ordinance), fourteen bargaining units covering approximately 10,400 persons, or 97% of all Department employees, have been established since 1975. Seven labor or professional organizations represent the employees' bargaining units. In the bargaining process, memoranda of understanding are developed which set forth wages, hours, overtime and other terms and conditions of

employment. After appropriate approval by the City Council, the memoranda are binding upon the Department, City Council and the respective employees' unions and organizations. Under State law, Department employees do not have a right to strike, and there is no provision in the Employee Relations Ordinance for binding arbitration. Memoranda of Understanding have been entered into with the various bargaining units extending through September 30, 1988.

The Power System

As of January 1, 1987 the Power System had a net dependable system capability of 7,244 megawatts ("MW") which is owned or operated generation. Steam electric generating capacity is equal to 65% of the System's total net capability, and owned or operated hydroelectric generating capacity accounts for 27% of such capability. The portion of the hydroelectric generating capability that can be depended upon for carrying system load is determined by water flow conditions and system load characteristics. The Power System's depreciated properties are valued in excess of $2.9 billion, as of June 30, 1986.

Steam Generation: There has been a notable expansion in steam powered generation under a continuous, long-range program of planning and construction. The Power System's largest generating facility is the Haynes Generating Station with a total plant capacity of 1,570 MW, situated in the City of Long Beach, California. The Haynes Generating Station represents 22% of the Power System's overall capability.

Three additional fossil-fuel plants generate a total of 1,682 MW: the Valley Generating Station in the San Fernando Valley, the Harbor Generating Station in Wilmington and the Scattergood Generating Station situated near El Segundo. The third unit at Scattergood is presently operated under a permit which limits its output to 358 MW using natural gas as a fuel source.

The Department shares ownership in two coal-fired generating stations, Mohave in Southern Nevada and Navajo in Northern Arizona. The Department's share of Mohave is 20% and amounts to 316 MW of capacity. The Department's share of Navajo is 21.2%, which, together with 73 MW layoff from the United States Bureau of Reclamation (subject to recall) amounts to 550 MW of capacity. On January 29, 1986, the Department obtained a 5.7% interest in the Palo Verde Nuclear Generating Station ("PVNGS") Units 1, 2, and 3, located approximately 50 miles west of Phoenix, Arizona. PVNGS Unit 2 attained commercial operation on September 18, 1986. The Department receives 139 MW of capacity from PVNGS Units 1 and 2 and purchases 70 MW of contingent capacity from Coronado during the period prior to PVNGS Unit 3 attaining commercial operation.

Natural gas, supplied by the Southern California Gas Company, is used as fuel for the Department's Los Angeles Basin steam plants whenever available and economical. Low-sulfur, low-ash residual oil is burned when gas is not used.

Hydroelectric Generation: The Department's major sources of hydroelectric capacity are Castaic Power Plant and Hoover Power Plant. These two plants represent 64% and 26% of the total hydroelectric capability of the system, respectively. Castaic Power Plant provides peaking capability only and is not a source of energy to meet base load requirements.

On August 17, 1984 the Hoover Power Plant Act of 1984 was signed into law, which law is designed to resolve questions of electric output entitlement involved in litigation. However, a number of matters relating to the implementation of the Act remain to be resolved, including the promulgation of administrative regulations by the Western Area Power Administration. (See Item (11) under "Litigation.")

An additional source of hydroelectric capability is provided by the Owens Gorge Hydroelectric Development, with an aggregate capacity of 119 MW. Situated on the northern rim of the Owens Valley in the Eastern High Sierra, this complex utilizes water resources of the Los Angeles-Owens River Aqueduct System. The utilization by the City of such water resources has been the subject of considerable controversy and is now the subject of litigation (see Item (5) under "Litigation").

Smaller hydroelectric facilities are located north of the City along the Aqueduct in San Francisquito Canyon and at Van Norman and Franklin Reservoirs. The net plant capability of these smaller units under average water conditions is 81 MW.

Purchased Capability: The Department purchases capacity and energy from Bonneville Power Administration ("BPA") and other Pacific Northwest Utilities to be delivered over the Pacific dc Intertie ± 500-kV high-voltage dc line ("Intertie"). These purchases are used by the Department during on-peak hours in conjunction with other resources for economic system operation. In addition, purchases of economy energy are made from utilities in Nevada, Arizona, New Mexico, and Colorado.

System Capability and Power Production

Power Source	Type of Unit	Number of Units	Net Capability (MW)	% of Total Net Capability	Production in gWh(A) — Twelve Months Ended June 30 1984(C)	1985	1986	September 30 1987
Haynes	Oil/Gas	6	1,570	21.7				
Scattergood	Oil/Gas	3	716	9.9				
Valley	Oil/Gas	4	517	7.1				
Harbor	Oil/Gas	9	449	6.2				
Subtotal	Oil/Gas	22	3,252	44.9	3,386	5,153	7,207	6,567
					(14.3%)	(21.8%)	(31.5%)	(28.3%)
Navajo	Coal	3	550	7.6				
Mohave	Coal	2	316	4.3				
Coronado(D)	Coal	2	70	1.0				
IPP	Coal	1	502	6.9				
Subtotal	Coal	8	1,438	19.8	6,895	7,124	5,972	7,147
					(29.2%)	(30.1%)	(26.1%)	(30.8%)
Palo Verde(E)	Nuclear	2	236	3.3				
Subtotal	Nuclear	2	236	3.3			116	263
							(0.5%)	(1.2%)
Castaic	Hydro	7	1,247(B)	17.2				
Hoover	Hydro	6	501	6.9				
Owens Gorge, Owens Valley and Aqueduct	Hydro	22	200	2.8				
Subtotal	Hydro	35	1,948	26.9	6,240	4,852	3,808	3,685
					(26.4%)	(20.5%)	(16.6%)	(15.9%)
Purchases(F)			370	5.1	7,106	6,527	5,774	5,521
Subtotal			370	5.1	(30.1%)	(27.6%)	(25.2%)	(23.8%)
Miscellaneous energy receipts					4	15	15	6
					(0%)	(0%)	(0.1%)	(0%)
Total		67	7,244(D)	100.0	23,631	23,671	22,892	23,189
					(100.0%)	(100.0%)	(100.0%)	(100.0%)

(A) One Gigawatt-Hour (gWh) equals one million kWh.

(B) Includes the State of California's contractual entitlement of up to 214 MW, with an average of 21 MW transferred to the state for December 1986.

(C) Oil and gas consumption declined as a result of increased purchases of economical hydroelectric power made available due to unusually high levels of precipitation.

(D) The Department purchases 70 MW of contingent capacity from Coronado prior to PVNGS Unit 3 attaining commercial operation pursuant to the exchange arrangement with Salt River Project Agricultural Improvement and Power District ("SRP").

(E) Includes Department's ownership of 139 MW and purchase through SCPPA of 97 MW. These values are based on an adjustment to the design electrical rating of Units 1 and 2 from 1,270 MW to 1,221 MW to reflect the licensed reactor thermal power level.

(F) The Department will typically purchase 370 MW from the Pacific Northwest.

Transmission and Distribution: Electricity from the Department's hydroelectric and steam power sources is delivered to customers over a complex, reliable transmission and distribution system. To deliver energy from generating plants to the customers, the Department owns and/or operates approximately 17,700 miles of transmission and distribution circuits operating at voltages ranging from 120 to 800,000 volts.

In addition to utilizing its transmission system for its resources located in other states, the Department transmits energy for others through its system when surplus transmission capacity is available. As the operating agent of the Intertie, the Department transmits energy for the co-owners of the Intertie.

Additional AC transmission capacity to deliver energy from generating plants in the southwest at 525-kV is being provided by the Victorville-Rinaldi Transmission Line 1 and the Victorville-Toluca Transmission Line 1. An additional line and associated facilities are to be constructed from Victorville, California to the Rinaldi Receiving Station in the San Fernando Valley. The total cost of the additional transmission projects is estimated at $149 million.

For a discussion of the Department's participation in the Mead-Phoenix DC Intertie Project see "Southern California Public Power Authority — Other Activities of the Authority" in the Official Statement to which this Appendix B is attached.

Power System Loads

As with most electric utilities in the United States, the Power System has experienced a marked decline in the rate of load growth since the early 1970s. The annual rate of growth of both system peak demand and net energy for load ("NEL"), the net system energy generated and purchased for Power System customers, was in the range of 7% to 8% for the twenty-year period through 1970. Growth in NEL continued at a slightly lower rate through 1972. In 1974, the Arab oil embargo and resulting mandatory curtailment program reduced the level of NEL to 1970 levels. A portion of this reduction, however, is attributed to the economic recession experienced during that period. Since 1974 the Power System's loads have reflected moderate increases resulting from both increased demand and economic recovery. The growth in the Power System's NEL averaged 2.7% for the period 1975-1985.

The estimated Power System load projection, dated June 1986, for the period through 2005 is summarized in the following table. The projected rate of growth is considerably below that experienced in the 1950s and 1960s. This reflects the modest rate of population growth within the City, the expected impact of higher consumer costs, and the implementation of conservation measures over the next twenty years. The variations in the indicated five-year compound growth rates reflect assumptions relative to the impact of conservation measures. The following table also shows the projected generating capacity in megawatts of the Power System through 2005.

Summary of Projected Power Resources and System Loads

Calendar Year	System Peak Demand		System Net Energy for Load		Load Factor	Resources (MW)
	MW	Growth Rate(1)	gWh	Growth Rate(1)		
1990	5,352	—	24,933	—	53.2%	6,944
1995	5,877	1.9%	27,383	1.9%	53.2%	7,396
2000	6,326	1.5%	29,560	1.5%	53.2%	7,952
2005	6,742	1.3%	31,483	1.3%	53.3%	8,375

(1) Five-Year Compound Annual Growth Rate.

Capital Additions and Financing Requirements

The Department's program of planning and construction to satisfy current power requirements and to meet future needs is continually being reviewed, updated and extended. Current estimates indicate that the Department will invest approximately $1,797 million in power generating and

distributing facilities in the 5-year period which began July 1, 1986. The Power System estimates that capital expenditures for the fiscal year 1986-87 will amount to $478 million.

Major components of the capital program over the 1986-87 through 1990-91 period include the following:

- Payments to SRP and Arizona Public Service Company in connection with the Coronado/Palo Verde Projects totaling approximately $140 million.
- Transmission system improvements related to required base load generation additions totaling approximately $149 million.
- Capacity increases to the Intertie totaling approximately $53 million.
- Continuing system additions and betterments and load-related distribution system improvements averaging approximately $194 million annually.

During this period, relatively low levels of expenditures are required in connection with other base load generation resource additions discussed below.

Following is a summary of the currently projected Power System capital program for the fiscal year 1986-87 through 1990-91 and the projected external financing requirements over that period.

Summary of Power System Capital Program and External Financing Requirements
(Millions of Dollars)

Fiscal Year Ending June 30:	Capital Program*	External Financing
1987	$ 478	$ 60
1988	373	205
1989	352	205
1990	291	145
1991	303	115
Total	$1,797	$730

* Net of reimbursements.

Power System Generation Resource Additions

The Power System has adequate peaking capability. It faces a need, however, for additional base load generation capacity to reduce dependence on natural gas and fuel oil, to replace existing gas- and oil-fueled units as they reach the ends of their useful operating lives and to meet the modest load growth presently expected. The Department seeks by 1990 to reduce its fuel oil and natural gas consumption by at least 50 percent from its 1974-78 consumption level.

In addition to its entitlement in the Southern California Public Power Authority's interest in PVNGS, the Department is engaged in or studying the following base load generation projects:

On January 29, 1986, the Department's ownership interest in Coronado was exchanged for the 5.7% interest in the PVNGS, a portion of SRP's original participation in the PVNGS project. Unit 2 attained commercial operation on September 18, 1986. Until such time as PVNGS Unit 3 is placed in commercial operation, SRP will so supplement the Department's ownership interest in PVNGS with 70 MW of such contingent capacity and energy. As of September 30, 1986, a total of $478 million had been disbursed by the Department for these projects, of which amount approximately $160 million was provided from bond funds.

Intermountain Power Project. In 1977, several Utah municipalities organized the Intermountain Power Agency ("IPA"), a political subdivision of the State of Utah. The purpose of IPA is to provide for the financing, constructing and operating of the Intermountain Power Project ("IPP").

In 1980, the Department and the cities of Anaheim, Burbank, Glendale, Pasadena and Riverside (the "California IPP Purchasers") each entered into a power sales contract with IPA which obligates each such Purchaser to purchase, on a "take or pay" basis, a percentage share of IPP capacity and energy. The Department and the cities of Burbank, Glendale and Pasadena also entered into an Excess Power Sales Agreement, also on a "take or pay" basis, with the Utah municipal and cooperative IPP purchasers pursuant to which IPP generation entitlement which is surplus to such Utah purchasers' needs will be made available to the Department and the cities of Burbank, Glendale and Pasadena.

In early 1983, each IPP Purchaser entered into an amendment to its power sales contract, the primary purpose of which was to reduce the size of IPP from four to two generating units. The parties thereto also entered into an amendment to the Excess Power Sales Agreement. All California IPP Purchasers except Glendale also entered into Lay-off Power Purchase Contracts (the "Lay-off Contracts") with IPA and Utah Power & Light Company ("UP&L") through which UP&L assigned portions of its entitlement to IPP capacity and energy to such Purchasers.

The IPP generation entitlement of each of the California IPP Purchasers resulting from the power sales contracts, as amended, and the Lay-off Contracts is shown in the following table:

	Percentage Share	Generating Capability (kW)
Los Angeles Department of Water and Power	44.617%	696,471
City of Anaheim	13.225	206,442
City of Riverside	7.617	118,901
City of Pasadena	4.409	68,825
City of Burbank	3.371	52,621
City of Glendale	1.704	26,600
Total	74.943%	1,169,860

Based on the uprated capacity of 800 MW net for IPP Unit 1 and the original design rating of 761 MW net for IPP Unit 2, and subsequent to both IPP Units achieving an assumed 70% plant factor the California IPP Purchasers will receive, pursuant to the power sales contracts, as amended, and the Lay-off Contracts, approximately 1,141 MW of capacity and 6,995,678 MWh of energy annually, after losses, at the Adelanto point of delivery. The amounts of generating capability that will be available pursuant to the Excess Power Sales Agreement, as amended, will vary in accord with the provisions of that Agreement. Quantities of capacity and energy that will be available at the Adelanto point of delivery as a result of the Excess Power Sales Agreement, as amended, will vary between approximately 164 and 321 MW and 863,447 and 1,965,600 MWh annually, based on amounts presently established. These values will be subject to annual adjustment.

The Department is Project Manager and Operating Manager for IPP.

For discussion of the current status of IPP, see "The Project Participants — Other Projects of the Project Participants" in the Official Statement to which this Appendix is attached. For a discussion of certain litigation relating to IPP, see item (13) under "Litigation" herein.

White Pine Power Project: The Department, in cooperation with White Pine County, Nevada, the California municipalities of Anaheim, Burbank, Glendale, Pasadena, Riverside, and several Nevada utilities, has begun studies to establish the feasibility of and proceed with the licensing activities necessary for constructing a coal-fired generating station near Ely, Nevada. This project would provide approximately 1,500 MW of base load capacity. It is contemplated that White Pine County would own all or a major portion of and finance this project through bonds issued by White Pine County which would be secured by power sales contracts entered into with the various purchasers of power from the

project. The project participants entered into agreements with White Pine County in the fall of 1980 for the purpose of conducting a feasibility study. The Department's entitlement percentage share for the feasibility study is approximately 39%. In November 1980, White Pine County issued a note in the principal amount of $14,994,000 for such purposes. In October 1984, White Pine County issued a note in the principal amount of $2,000,000. In August 1985, White Pine County issued an additional note in the principal amount of $2,935,000. Such notes mature on December 31, 1987 and will be payable from the proceeds of long-term bonds to be issued by White Pine County or from payments by the participants under such agreements on the basis of entitlement shares. The present estimated commercial operation date for each of the 750 MW generating units, if built, is in the early 1990's.

In addition to the projects described above, the Department is involved in preliminary studies relative to geothermal development and in purchasing electric energy from privately developed cogeneration projects.

Geothermal: In May 1981, the Department entered into an agreement with Union Oil Company which gives the Department and others the right of first refusal for up to 450 MW of geothermal generation from a geothermal field north of Brawley, California. As part of the arrangement, the Department obtained an interest in a 10 MW demonstration unit. The five-year test period ended in June 1985 and the unit was shut down. Because of unsolved technical problems associated with the Union Oil Company's extraction of geothermal steam from highly saline fluids, the various parties have mutually agreed to terminate the project. Termination negotiations for the 10 MW demonstration unit are currently taking place.

In September 1981, the Department bid for and acquired leases from the Bureau of Land Management to develop the geothermal potential on three parcels in the Coso Known Geothermal Resource Area ("KGRA"). The Coso KGRA is located approximately 40 miles south of Lone Pine, in the Owens Valley. Three exploratory wells were drilled during the first half of 1985 to obtain information to assess the quality and viability of the resource. Two of the wells are successful and the third well is used for reinjection. Additional exploratory wells are being permitted and will be drilled in 1988. The probable reserves on the Department's leases are currently estimated to be in the 200 to 400 MW range. A 10MW demonstration unit is planned for operation in 1990. Following successful operation of the demonstration unit, commercial operations could be in the mid-1990's.

Cogeneration: Cogeneration projects totaling 89 MW are currently in operation within the Department's service area. Some of these projects are selling excess electric energy to the Department under negotiated agreements. An additional estimated 115 MW of cogeneration are currently in active development and are expected to be operational by 1989.

Fuel Supply

As a result of the availability of economical hydroelectric generation and participation by the Department in new nuclear and coal-fired projects, the Department's Los Angeles Basin annual oil and gas requirements are estimated to range during the period 1987 through 1989 between 5 to 9 million equivalent barrels per year. Natural gas is expected to be available to supply 100% of these requirements during that period. Natural gas is supplied to the Department by the Southern California Gas Company; 20% is take-or-pay with the balance on a curtailable basis at the lowest priority level.

The fuel oil requirements are expected to be minimal under average weather conditions and could be 4.0 million barrels under adverse weather conditions. The Department has terminated all long-term fuel oil contracts and expects to supply all requirements from short-term contracts as needed and anticipates no problem in meeting the requirements under average weather conditions. The Department's fuel oil inventory of 2.3 million barrels can be used to protect the Department during adverse weather conditions. During periods in which the Department's natural gas purchase price exceeds its fuel oil purchase price, the Department has displaced natural gas with fuel oil to the extent possible.

Limitations on the use of natural gas as a utility boiler fuel under the Power Plant and Industrial Fuel Use Act of 1978 were repealed in August 1982. Regulations of the South Coast Air Quality Management District ("SCAQMD") have required the use of fuel oil with no more than a maximum sulfur content of 0.25% by weight. SCAQMD's rules also require the use of all available natural gas on any predicted or attained air pollution episode day. (See also "Environmental and Regulatory Factors", relative to additional limits on the sulfur content of fuel oil.)

Coal-fired steam-generated projects in which the Department has an ownership interest are supplied with coal under contracts.

Water

Water required for steam plant operations is secured from a number of sources. Three Los Angeles Basin steam plants, Harbor, Scattergood and Haynes, utilize the waters of the Pacific Ocean for power plant cooling purposes. A fourth Basin plant, the Valley Generating Station, utilizes groundwater pumped from the San Fernando Valley. The California Supreme Court has upheld the rights of The City of Los Angeles to the native waters of the San Fernando Basin, and to certain other contested water rights.

The Mohave and Navajo Generating Stations utilize water taken from the Colorado River for cooling purposes, the Navajo plant extracts water from Lake Powell, which was created by the construction of the Glen Canyon Dam. The rights to use such waters from the river rest upon the Colorado River compact, the decree of the U.S. Supreme Court in the case of *Arizona v. California,* and upon contracts entered into pursuant to the rights granted by such compact and decree. Certain small Indian tribes have announced claims to additional waters of the Colorado River beyond those granted in the decree, and the Navajo Indian Nation has indicated it will make substantial claims to the waters of the river. In December 1978, the United States and several Indian tribes along the Colorado River asked the United States Supreme Court to reopen the case of *Arizona v. California* to hear their claims of additional water rights over and beyond those previously granted. A Special Master was appointed to hear those claims, and on March 18, 1982 rendered a decision in favor of the Indian tribes. On March 30, 1983, the Supreme Court issued its decision which rejected to a large extent the Master's recommendations that the tribes be awarded additional water rights. However, the court deferred certain claims to be determined by a lower federal court at a future time. Although the tribes may ultimately prevail on their claims in the future, the Department is confident that these pending matters, even if determined adversely to the Department, do not pose a threat to the operation of the generating stations.

Electric Rates

The Board is obligated by the City Charter and each Final Resolution pursuant to which the Department has issued revenue bonds or notes, to establish electric rates and collect charges in an amount sufficient to service the Department's Power System indebtedness and to meet its expenses of operation and maintenance. Rates are subject to the approval of the City Council by ordinance, but are not regulated by the Public Utilities Commission of California or by any other state agency. See "Certain Factors Affecting the Utility Industry and Take or Pay Power Supply Agreements" in the Official Statement.

Although its rates are not subject to approval by any federal agency, the Department is subject to certain ratemaking provisions of the Public Utility Regulatory Policies Act of 1978. The Department is operating in compliance with the Act.

The Power System's electric rates ordinance contains an energy cost adjustment formula, under which the cost to the Department of fuel for generation of electric energy and purchased energy costs are recovered by direct adjustment to customers' bills.

Emergency Energy Curtailment Plan and Conservation

In 1973 Los Angeles enacted an Emergency Energy Curtailment Plan which mandated certain designated electricity conservation measures. The implementation of this plan was suspended in 1974 when the Department's fuel situation improved. However, the plan remains as part of the Municipal Code for possible future use. In addition, a revised and supplemented Plan, redesignated the Emergency Energy and Capacity Curtailment Plan of The City of Los Angeles, became effective on June 16, 1981.

The City Charter authorizes the Department to engage in and finance activities related to the conservation of electricity and water.

Operating Statistics

The Department's service area consists of Los Angeles City, where over a million customers are now served, and certain areas of Inyo and Mono counties in California, where over 4,000 customers are served. In the twelve months ending September 30, 1986, approximately 27% of the total energy sales were to residential customers, 70% to commercial and industrial customers, and the remainder to miscellaneous minor classifications. The portions of operating revenues from the two major customer classes were in the proportions of approximately 28% and 70%, respectively.

Operating Statistics	Twelve Months Ended September 30, 1986	Fiscal Year Ended June 30 1986	1985	1984
Net Energy for Load (Thousands of kWh)	22,320,286	22,262,629	22,529,539	21,848,064
Net Hourly Peak Demand (kW)	4,744,000	4,713,000	4,882,000	4,444,000
Annual Load Factor (%)	53.7	53.9	52.7	56.1
Electric Energy Generation, Purchases and Interchanges (Thousands of kWh)				
Generation (A)	17,661,276	17,103,208	17,129,279	16,521,157
Purchases	5,521,074	5,774,422	6,526,861	7,106,442
Miscellaneous Energy Receipts	6,306	14,750	15,081	3,556
Total Energy Production (A)	23,188,656	22,892,380	23,671,221	23,631,155
Less:				
Miscellaneous Energy Deliveries	123,749	137,803	68,458	102,593
Losses and System Uses	2,951,021	2,618,656	3,387,774	4,492,672
On-System Sales	20,113,886	20,135,921	20,214,989	19,035,890
Transactions Among Other Utilities for Department (Thousands of kWh)				
Purchases	0	101,520	953,419	1,773,043
Deliveries	0	101,520	953,419	1,773,043
Sales of Energy (Thousands of kWh)				
Residential	5,445,693	5,499,851	5,545,726	5,503,231
Commercial and Industrial	14,214,793	14,097,269	13,573,224	14,007,309
All Other	680,118	653,375	773,761	710,793
Total	20,340,604	20,250,495	19,892,711	20,221,334
Number of Customers — Average:				
Residential	1,080,394	1,078,074	1,069,622	1,060,963
Commercial and Industrial	178,184	177,717	175,610	176,213
All Other	5,255	6,181	5,974	5,916
Total	1,263,833	1,261,972	1,251,206	1,243,092
Operating Revenue (C):				
Residential	$ 371,106,000	$ 379,488,000	$ 372,959,000	$ 331,641,568
Commercial and Industrial	935,992,000	932,187,000	859,200,000	797,730,677
Street Lighting and Other	35,395,000	37,904,000	48,473,000	41,580,616
Total	1,342,493,000	1,349,579,000	1,280,632,000	1,170,952,861
Miscellaneous Revenues	9,180,000	8,555,000	7,335,000	6,516,161
Total	$1,351,673,000	$1,358,134,000	$1,287,967,000	$1,177,469,022 (B)
Average Revenue per kWh Sold:				
Residential	6.81¢	6.90¢	6.73¢	6.03¢
Commercial and Industrial	6.58¢	6.61¢	6.33¢	5.70¢
Average Annual kWh Use per Residential Customer	5,040	5,102	5,185	5,187

(A) Not including energy generated at Hoover Power Plant for plant use, and for the use of the United States Bureau of Reclamation, and the cities of Boulder City, Burbank, Glendale and Pasadena.

(B) See Note A to Financial Statements for change in accounting method.

(C) All operating revenue amounts for twelve months ended September 30, 1986 are unaudited.

Environmental and Regulatory Factors

Environmental considerations and regulatory restrictions relative to the operation of the Power System's existing facilities, and to the location, design and construction of new facilities, may adversely affect the adequacy of electric service in the future.

For the fiscal year 1986-87, $5 million has been budgeted to meet environmental quality standards and minimize any adverse impact of the Department's operations upon the environment. Additional expenditures will be required in subsequent years for such purposes.

The SCAQMD has adopted an "Emergency Episode Plan" ("Plan") which defines three so-called air quality Emergency Episode Stages and requires the Department to submit a plan demonstrating measures it will take during Stage I, Stage II and Stage III episodes. The Plan requires the Department to burn natural gas to the extent available, instead of fuel oil, during Stage I Episodes. During a Stage II or Stage III Episode, the Department must also reduce generation in power plants within the Los Angeles Basin by shifting generation to plants outside the basin to the extent consistent with health, safety and welfare. The Basin has never experienced a Stage III Episode.

In March 1980, the California State Air Resources Board ("ARB") adopted a rule providing for the reduction of emissions of nitrogen oxides ("NOx") from utility power plants in the South Coast Air Basin. The Department intervened in a lawsuit brought by Edison against the ARB challenging this new rule. Subsequently, negotiations among the parties produced a settlement which was implemented through a court ordered judgment on March 10, 1982. The basic terms of the settlement are (i) mandatory rescission of ARB's modified rule, thus avoiding the expenditure by the Department of approximately $257 million, and (ii) compliance by the Department with annual NOx emission limits as provided in the settlement. The Power System's estimates predict NOx emissions will likely be below these limits. Compliance with the limits will not require the mandatory installation of any NOx control equipment and will not require the payment of any emission fees. Under the terms of the settlement, compliance will not require any other action by the Department.

In 1984, the Resource Conservation and Recovery Act was amended by Congress to be more restrictive on the transportation, treatment, storage and disposal of hazardous wastes including actual bans on certain existing waste handling practices. The California Legislature during 1985 and 1986 continued its active support of environmental legislation for the control of hazardous substances. The California State Water Resources Control Board and the State Department of Health Services continued their regulatory efforts to control transportation, treatment, storage, and disposal of hazardous substances. The full fiscal impact on Department operations cannot be determined at this time. The Department has budgeted approximately $10 million to address underground storage of hazardous substances and surface impoundments to comply with California and Federal environmental legislation enacted in 1984 and 1985.

The President, in 1986, signed into law the Superfund Amendments and Reauthorization Act. In addition, current efforts by California and Federal agencies to investigate and improve Superfund sites may impact the Department as a result of previous disposal practices. Previously approved disposal methods or sites may become candidates for Superfund classification which may require substantial expenditures by the Department as a participant in the cleanup/remedial action required for the site.

The Service Area

The City of Los Angeles, encompassing an area of 465 square miles, is served exclusively by the Department. As indicated in the following chart, the population of the service area has risen from

102,479 at the turn of the century to an estimated 3.2 million residents as of December 31, 1985 to become the second largest city in the United States and the nucleus of the second most populous Standard Metropolitan Statistical Area ("SMSA"), Los Angeles County.

Population Trends

Dec. 31 Year	City of Los Angeles	Metropolitan Area (Los Angeles County)
1900	102,479	170,298
1910	319,198	510,131
1920	576,673	936,455
1930	1,238,048	2,208,492
1940	1,504,277	2,785,643
1950	1,970,358	4,151,687
1960	2,481,595	6,042,431
1970	2,809,967	7,040,335
1974	2,735,600	6,925,000
1975	2,739,140	6,963,609
1976	2,761,805	7,042,538
1977	2,780,800	7,091,000
1978	2,787,900	7,077,000
1979 (Revised 5-1-81)	2,954,300	7,446,900
1980 (Revised 5-1-81)	2,994,900	7,562,200
1981	3,038,800	7,699,400
1982	3,071,100	7,763,800
1983	3,108,400	7,866,900
1984	3,144,800	7,955,700
1985	3,215,500	8,165,300

Source: Los Angeles County Regional Planning Agency, California Department of Finance, and U.S. Bureau of the Census.

The U.S. Department of Commerce in the 1982 Annual Census of Manufacturers reported that the number of persons employed in manufacturing constituted about one-fourth of the area's labor force. Value added by manufacturers to 1982 aggregated over $40 billion, ranking the Los Angeles area as the Nation's second largest SMSA in this respect, having moved up from fifth place in 1947. During the interval from 1947 to 1982, a net gain of $38.2 billion in value was added by manufacturing.

Los Angeles has important production facilities for most major branches of industry. It is the site of the largest industrial concentration in the Western United States, not only serving the local area and the region, but also participating in the national markets. In retail sales Los Angeles ranks second nationally as a city and first as a metropolitan area. With over 810 banks and branches, the Los Angeles SMSA is the leading financial center in the Western United States. The Nation's seven largest savings and loan associations are headquartered in the Los Angeles SMSA. In addition, Los Angeles leads in employment and payrolls of banks, savings and loan associations, insurance carriers and agents, and security and commodity brokers.

Litigation

The Department is engaged in routine litigation incidental to the conduct of its business. In the opinion of The City of Los Angeles City Attorney, counsel to the Department, except as set forth below, the aggregate amounts recoverable by plaintiffs, together with any other remedies likely to be granted to the plaintiffs, are not material.

(1) An action was filed in the U.S. District Court in October 1978 on behalf of black personnel against the Department and International Brotherhood of Electrical Workers, Local Union No. 18, containing broad general allegations of racial discrimination in employment practices, seeking declaratory, injunctive and "make whole" relief and requesting punitive damages and damages for emotional distress. An amended complaint was filed by the plaintiffs which alleges racial discrimination throughout the government of The City of Los Angeles. In June 1981, the Court limited the class of plaintiffs to those black craft employees of the Department specifically affected by the alleged discrimination and to those who can show that they have been personally damaged. The case was dismissed as to all other plaintiffs. In February, 1983, the U.S. District Court consolidated this case with another class action case (*Anderson, et al. v. Department of Water and Power, et al.*) which also alleges racial and ethnic discrimination by the Department, The City of Los Angeles and the Board of Civil Service Commissioners. The named plaintiffs in the latter class action are draftsmen, engineers, and architects who are challenging promotional testing on a Department-wide basis. Injunctive and monetary relief are sought. In May 1985, the class was certified and the plaintiffs' motion for partial summary judgment was taken under submission. In March 1986, the plaintiffs motion was denied. (*Leon (formerly Worthen), et al. v Department of Water and Power, et al.*)

(2) The Navajo Tribe through its Navajo Tax Commission has issued regulations for a business activity tax and a possessory interest tax. The Department has filed an exemption certificate with the Tax Commission with regard to the activities of the Navajo Generating Station on both taxes based on Navajo covenants not to tax contained in the lease indenture. As the Mohave Generating Station does not have the same lease protection as the Navajo Generating Station, negotiations are continuing by the Project Manager, Southern California Edison Company, as to the tax liability on coal purchased for that station. Costs of such taxes could significantly affect the cost of power generated from the Mohave Generating Station.

The Hopi Tribe adopted two tax ordinances affecting coal mined on its reservation. The participants of the Navajo and Mohave Generating Stations objected to the tax ordinances on two grounds: first, that the Hopi Tribe did not have tax jurisdiction over the area in question; and second, that the Secretary of the Interior had not approved the ordinances. The Secretary of the Interior vetoed the ordinances for lack of authority to tax. It is not clear what action the Hopi Tribe will take but, if valid, the tax would substantially increase the costs of coal used at the Navajo and Mohave Generating Stations.

In 1984, a provision of the coal lease on the Navajo reservation providing for an increase of royalties by the United States took effect. The local Director of the Bureau of Indian Affairs for the Navajo Nation issued a decision increasing the royalty to be paid on coal extracted from the Navajo reservation from $.50 per ton to 20 percent of the present mine price (approximately $16.00 per ton). The participants have appealed that action to the Secretary. During the pendency of the appeal, the participants are pursuing settlement arrangements with the Tribe.

On November 15, 1985, the Mohave participants directed Peabody Coal Co. to file Business Activity Tax returns on the Navajo lease area from July 1978 to December 1984, and a return on the same area for 1985. The Black Mesa Pipeline Co. was instructed to file returns on the same basis. However, Peabody Coal Co. and Black Mesa Pipeline Co. were also instructed to pay only the 1985 return. These amounts were $6,061 and $25,773, respectively.

On January 15, 1986, the Mohave participants directed Peabody Coal Co. and Black Mesa Pipeline Co. to file a return for the Possessory Interest Tax for 1985. Peabody Coal Co., the participants, the Hopi Tribe and the Navajo Tribe are engaged in negotiations relating to back taxes, settlement of the claims of the Hopi Tribe, royalty payments on the Navajo reservation and the area formerly called the joint use area, where the coal is owned jointly by the Hopi and Navajo Tribes, but where governance of most of the area involved in the Kayenta and Black Mesa Mines is governed by the Navajo Tribe. The Possessory Interest Tax assessment paid was $1,507,846. Black Mesa Pipeline Co. was directed to make a corresponding payment of $8,982.

(Salt River Project Agricultural Improvement and Power District, et al. v. Navajo Tribe of Indians, et al.)

(3) In October 1978 a major brush fire burned several homes and other structures in the Mandeville Canyon area of the City. Claims were consolidated in two lawsuits seeking $7.9 million in damages alleging maintenance of a dangerous condition in the operation of overhead electrical transmission lines. A further cause of action arising from the same facts was alleged in inverse condemnation. Trial took place in January and February 1983. On the issue of maintenance of a dangerous condition in the operation of overhead electrical transmission lines, the jury found for the Department. However, under the inverse condemnation theory, the Court, ruling without a jury, found for the plaintiffs and granted damages in the amount of $10,600,000, which included prejudgment interest, costs and attorneys' fees. Subsequently, the Court also ruled in favor of the plaintiffs on the dangerous condition cause of action, notwithstanding the jury verdict. The Department appealed and obtained a writ from the Court of Appeal of the State of California staying enforcement of the judgment during the appeal. On July 31, 1985, the Court of Appeal affirmed the decision, with the exception of reversing the attorney's fee award. The Department filed a petition for hearing in the California Supreme Court which was denied. Therefore, the only issue which remained to be determined in the case was the question of attorney's fees, and the judgment (except for attorney's fees) has been paid. In November 1986, the court awarded attorney's fees of $2.116 million to the plaintiffs. *(Aetna Life and Casualty Company, et al. v. Department of Water and Power, et al.)*

(4) On October 31, 1981, six residences were totally destroyed by fire in the Chatsworth area and, subsequently, damage claims have been received by the Department in an amount in excess of $5.2 million alleging the fire was caused by downed power lines resulting from strong winds. In September 1982 a complaint was filed seeking damages based on allegations of dangerous conditions, and inverse condemnation. Trial commenced in October 1986. In November 1986, the judge issued a preliminary ruling against the Department on inverse condemnation, the jury found in favor of the Department on the dangerous conditions cause of action, removing the potential for mental distress damages. The jury awarded the plaintiffs $1.371 million in damages on the inverse condemnation issue. The court may also award attorney's fees and pre-judgement interest. *(Farrens, et al. v. Department of Water and Power.)*

(5) A petition for injunction and declaratory relief was filed in Superior Court, seeking to require the Department's water diversions from four streams in the Mono Basin to cease or to be substantially decreased until such time as the water level in Mono Lake — a saline lake — reaches a higher level. About 15% to 20% of the City's water comes from the Mono Basin diversions, and if the plaintiffs were to prevail, there would be a decrease of hydroelectric generation capability. On a department motion, the case was transferred to Alpine County, and the Department filed an answer denying the allegations of the complaint. The Department has cross-complained against a number of parties, including the United States of America and the State of California, asserting water rights in the Mono Basin. Following a removal of the case to the federal courts, the non-federal causes of action were remanded to the state court system.

The State of California, joined by the Department, moved for summary judgment which motion was granted. The plaintiffs petitioned the California Supreme Court to review the lower court's decision and on February 17, 1983, the Supreme Court issued an opinion which held that the plaintiffs could challenge the Department's existing water rights based upon the "public trust doctrine". The Supreme Court's decision does not now limit any of the Department's water rights; however, it calls for a further hearing to weigh the interests of Mono Basin under the public trust doctrine against the City's needs which are served by the appropriative water rights system. This subsequent hearing or adjudication will result in a decision which could result in all, some or none of the City's water rights in the Mono Basin being curtailed. The plaintiffs moved in Federal Court for an injunction to require the Department to maintain the lake level at 6,378 feet until August 1984, pending a resolution of the action. The present level is above that height. That motion for

injunctive relief was held in abeyance while the court considered separate motion by the Department to remove the proceedings back to the state court. In December 1984, the federal court issued a ruling removing all of the proceedings back to the superior court in Alpine County, except for an alleged federal common law nuisance for air pollution which it indicated it would retain. In July 1985, the United States Court of Appeals, Ninth Circuit, agreed to consider appeals by the plaintiffs and the State of California. The plaintiffs are appealing the transfer of the primary case to the state court and the State of California is appealing the retention of the federal nuisance action by the federal court. Oral arguments on these appeals were heard on April 18, 1986.

In related matters which could also affect power generation out of the Mono Basin, petitions for three writs of mandate were filed in October 1985 in the State Court of Appeal against the State Water Resources Control Board, with the Department as the real party in interest, the plaintiffs taking the position that the Department's license to divert waters tributary to Mono Lake should be revoked pending a determination as to whether the court should order compulsory water releases downstream of the Department's diversion works in order to provide water allegedly necessary to restore fisheries. In December 1985, the State Court of Appeal denied all three writs. However, two of the writs were denied without prejudice to the petitions being refiled in State Superior Court. The third petition was denied with prejudice and a like petition was similarly denied by the State Supreme Court. In January 1986, the plaintiffs filed two new petitions in the State Superior Court which were heard in April 1986. At the hearing, the court determined that the plaintiffs had stated a cause of action and deferred any ruling on the merits of the petition. In addition, to the four creeks tributary to Mono Lake (Lee Vining, Walker, Parker and Rush) the writs also seek to effect flow in the Owens Gorge. (*National Audubon Society v. State Water Resources Control Board; California Trout v. State Water Resources Control Board; National Audubon Society, et al. v. Department of Water and Power.*)

(6) A dispute with the State of California and other utilities over the contracts to supply the State Water Project with surplus electrical energy arose out of the continuing escalation of the price of fuel oil during the contract term. In 1979, the Department notified the State and other utilities of its intention to end its participation due to the commercial impracticability of continuing to provide the low-cost energy. In 1980, Southern California Edison Company and Pacific Gas & Electric Company brought lawsuits alleging breach of contract, with the former obtaining a preliminary injunction to prevent cessation of service pending the outcome of trial. The issuance of the injunction was conditioned on the plaintiffs posting a $14 million bond; however, and subsequently, the plaintiffs stipulated with the Department to indemnify the Department in the event of a decision in the Department's favor without further posting of bond being required. The State of California has intervened in the lawsuit. The contract terminated on March 31, 1983. In early 1985, a motion for summary judgment was filed by the San Diego Gas & Electric Company (a co-defendant in the action) on the grounds that the case was moot, since the contract was terminated in 1983. That motion was denied. If the Department prevails in the lawsuit, it will be entitled to seek additional payment for providing the low-cost energy. The case has been tentatively set for trial in June 1987. (*Southern California Edison Co.* v. *Department of Water and Power, et al.*, and *Pacific Gas & Electric Co. v. Department of Water and Power, et al.*) (2 cases)

(7) The Department is a party defendant in the action entitled *Salt River Pima-Maricopa Indian Community v. United States, et al.* described in the Official Statement under the caption "Litigation — Project-Related Litigation."

(8) The Department is a party defendant in the action entitled *A Tumbling T Ranches, et al. v. City of Phoenix, et al.* described in the Official Statement under the caption "Litigation — Project-Related Litigation."

(9) The Bonneville Power Administration (the "BPA") has acted in recent years to increase significantly the price of electric power and energy sold to its customers. The Department, together with other cities, has intervened in proceedings before the Federal Energy Regulatory

Commission ("FERC") involving the BPA 1981 and 1982 non-regional rate increases and has challenged the rate-setting methods used by the BPA in determining rate increases. FERC has determined it has certain limited jurisdiction to review the rate actions of the BPA. However, the BPA questioned the jurisdiction of FERC to decide certain issues and brought the matter before the Ninth Circuit of the U.S. Court of Appeals, the court of original jurisdiction for FERC review. On February 9, 1984, the Ninth Circuit upheld the determination of FERC regarding FERC's jurisdiction but ruled that the Ninth Circuit lacks jurisdiction to review FERC's interim approval of the BPA 1981 and 1982 non-regional rates. An administrative law judge for FERC rendered a decision in January 1985 on the 1981 rates essentially supporting the BPA decisions. A brief of exceptions has been filed by the California parties. However, no final decision has yet been rendered by the Commission. The Department has also challenged the setting of the 1983 and 1985 BPA rates before an administrative law judge of FERC. In addition, the Department has filed an action, together with other California utilities, against the BPA, in the U.S. District Court for the District of Columbia, challenging the ruling by FERC regarding a 1979 rate increase by the BPA. In May 1986, the Department filed an action in the United States Court of Appeals for the Ninth Circuit challenging BPA's reopening and changing of the 1985 rates without compliance with the hearing requirements of the Pacific Power Planning and Conservation Act. *Central Lincoln People's Utility District v. Johnson, et al. Department of Water and Power, et al. v. BPA.)*

(10) See "Litigation" in the Official Statement for a description of certain litigation, entitled *Thurston et al. v. Southern California Public Power Authority et al.*, concerning the Department's participation in the Southern California Public Power Authority interest in the Palo Verde Project.

(11) A lawsuit was filed in August 1982 by the State of Nevada in the U.S. District Court for the District of Nevada against the United States, the Western Area Power Administration and the California allottees of power from Hoover Dam seeking declaratory and injunctive relief, the principal aim of which is to obtain a declaration that the State of Nevada is entitled to one-third of the total electrical output of Hoover Dam from and after June 1, 1987 for a period of 50 years. The Department and other California allottees of Hoover Dam power who presently receive 65% of such power intend to resist vigorously this claim of the State of Nevada. The State of Arizona has intervened in this case, making a similar claim to that of the State of Nevada. A motion to intervene in the lawsuit filed by the California cities of Anaheim, Azusa, Banning, Colton and Riverside was granted. The litigation was placed off calendar and the parties entered into negotiations which culminated on August 17, 1984, when the President signed into law the Hoover Power Plant of 1984 in which a settlement of the above litigation was approved by Congress. The act provides for a stipulation to be filed by all parties agreeing to dismiss the case when contracts for Hoover are executed. Negotiations are continuing in an effort to finalize such contracts. *(Nevada v. United States, et al.)*

(12) The Department is a party defendant in the action entitled *Long et al. v. Salt River Project, et al.)* described in the Official Statement under the caption "Litigation — Project-Related Litigation."

(13) In February 1986, litigation was initiated in the United States District Court for the District of Oregon by ASEA, Inc. (ASEA), the contractor for the design and construction of the AC/dc converter stations of the Southern Transmission System, against two of its subcontractors, CH2M Hill, Inc. ("CH2M Hill") and CH2M Hill Northwest, Inc., alleging that fraud and breaches of contract by such subcontractors damaged ASEA in connection with the Project as well as in connection with work that ASEA had separately contracted to perform for the Department at the Sylmar Converter Station, the southern terminus of the Pacific dc Intertie.

The CH2M Hill filed an answer and counter-claims against ASEA and its parent corporation, ASEA, A.B., alleging, among other things, that any injury so suffered by ASEA relating to the Project resulted from various acts including the decision to change the planned Southern Transmission System from a double bipole to a single bipole system. The CH2M Hill then filed a

motion seeking to join the Department as a third-party defendant in this litigation. (*ASEA, Inc.* v. *CH2M Hill Northwest, Inc. et al.*)

ASEA was the prime contractor for IPA on a contract for about $270 million for the design and construction of converter stations for the Southern Transmission System portion of the IPP. The Department was the administrator of such contract for IPA. ASEA was also the prime contractor for the Sylmar Converter Station in connection with the upgrade of the Intertie. The defendants named in the Oregon action, CH2M Hill, were subcontractors of ASEA in connection with both such contracts.

Shortly after the suit was filed, CH2M Hill filed with the Department's Commission a claim for indemnity for its liability to ASEA as alleged in the Oregon Court, in an amount in excess of $24 million. Investigations of the claim by the Department disclosed that ASEA and CH2M Hill may be liable to the Department and to IPA for compensatory damages in excess of $85 million and punitive damages of $50 million, and that ASEA sought in the Oregon action to be reimbursed by its subcontractors for claims by IPA and the Department. Accordingly, the claim filed with the Department was rejected. An action was commenced by the Department on May 30, 1986, in the U.S. District Court for the Central District of California to recover such damages from ASEA and CH2M Hill. An additional related action was filed against IPA by ASEA in the U.S. District Court in Utah, and IPA has counterclaimed for damages in that action. In addition, CH2M Hill has filed a third party complaint naming the Department as a defendant in the Oregon suit. Another ASEA subcontractor, Mark Steel Corporation, has filed a suit against ASEA but it has also named IPA and the Department as defendants. As a consequence, the Department filed a motion with the Judicial Panel on Multidistrict Litigation to have the cases consolidated for pretrial in the U.S. District Court for the Central District of California which motion was granted. All cases have now been consolidated. (*Department of Water and Power* v. *ASEA Inc.*, v *CH2M Hill Inc.*, *ASEA Inc.*, v *IPA.*)

(14) In June 1985, an explosion at the Mohave Generating Station destroyed the control room and caused the deaths of several Mohave employees. The Department holds a 20% share pursuant to the Mohave Operating Agreement (the "Agreement") and would be liable for that portion of any settlement or judgment. Pursuant to the Agreement, Southern California Edison Company, the Project Manager, had obtained insurance for the participants covering up to a maximum of $30 million with a self-insured residual of $2 million (The Department's 20% share of which would be $400,000). The Department has received more than 30 claims from over 50 individuals and corporations seeking in excess of $70 million. The participants allege that they are immune from civil liability to the employees as employers pursuant to the workers compensation laws of California and Nevada. The Mohave participants are proceeding against the manufacturers for property damage and indemnity. Litigation has already commenced related to this incident. (*Russell C. Allen* v. *Bechtel Power Corp.*)

(15) Other claims and suits arising out of the ownership and operation of the Power System of the Department are pending against the Department for alleged deaths, personal injuries and property damage, and for alleged liabilities arising out of other matters, all of which are of a nature usually incident to the conduct of such a utility business. Until these claims and suits are disposed of, the Department's liability, if any, in these matters cannot be determined. Realistic evaluation of total exposure is complicated by the fact that California courts have adopted the rule of pure comparative negligence.

Financial

The following Summary of Financial Operations and Summary Balance Sheet have been prepared by the Department based upon audited financial statements and accounting records of the Power System for the fiscal years ended June 30, 1984 through 1986, and upon unaudited financial statements and accounting records for the twelve months ended September 30, 1986.

Power System Summary of Financial Operations

	Twelve Months Ended September 30, 1986 (Unaudited)	Fiscal Year Ended June 30 1986	1985	1984
Operating Revenues				
Sales of Electric Energy:				
Residential	$ 371,106,000	$ 379,488,000	$ 372,959,000	$ 331,641,568
Commercial and Industrial	935,992,000	932,187,000	859,200,000	797,730,677
Street lighting and other	35,395,000	37,904,000	48,473,000	41,580,616
Miscellaneous	9,180,000	8,555,000	7,335,000	6,516,161
Total Operating Revenues	1,351,673,000	1,358,134,000	1,287,967,000	1,177,469,022°
Operating Expenses				
Production:				
Fuel	291,526,000	348,069,000	347,591,000	313,849,389
Purchased power	259,060,000	203,116,000	181,961,000	169,615,372
Energy Cost	550,586,000	551,185,000	529,552,000	483,464,761
Other Production	37,120,000	37,452,000	34,429,000	31,963,787
Transmission and distribution	67,057,000	63,300,000	57,127,000	51,201,938
Maintenance	142,858,000	142,461,000	129,425,000	110,597,763
General	90,717,000	98,938,000	73,441,000	67,547,766
Less — Expenses charged to construction	(10,177,000)	(10,038,000)	(10,540,000)	(8,458,624)
Customer accounting	34,556,000	33,831,000	29,883,000	27,961,931
Customer services	3,747,000	3,456,000	2,807,000	3,414,301
Taxes on property outside the City	8,190,000	8,660,000	8,896,000	10,965,017
Contributions to retirement plan funds	81,309,000	79,800,000	69,057,000	75,181,163
Less — Contributions charged to construction	(18,431,000)	(17,785,000)	(16,114,000)	(16,287,039)
Total Operating Expenses (except Depreciation)	987,532,000	991,260,000	907,963,000	837,552,764
Operating Income before Depreciation	364,141,000	366,874,000	380,004,000	339,916,258
Allowance for funds used during construction	6,031,000	3,610,000	3,208,000	575,247
Other Income — net	27,480,000	27,984,000	31,976,000	22,032,115
Income before Depreciation and Interest	397,652,000	398,468,000	415,188,000	362,523,620
Debt Service				
Interest	98,358,000	96,784,000	95,525,000	97,447,522
Principal	50,396,000	84,996,000	79,126,000	71,811,000
Total Debt Service on bonds	148,754,000	181,780,000	174,651,000	169,258,522
Balance	248,898,000	216,688,000	240,537,000	193,265,098
Transfers to the City	65,249,000	64,353,000	58,867,000	55,320,000
Balance Available for Construction	$ 183,649,000	$ 152,335,000	$ 181,670,000	$ 137,945,098
Depreciation	$ 106,837,000	$ 107,419,000	$ 105,483,000	$ 98,521,416

° See Note A to Financial Statements for change in accounting method.

Under the provisions of the Charter of The City of Los Angeles, revenues of the Power System are deposited into the Power Revenue Fund. The Fund receives all revenues from the sale of power and all other commodities and services sold, furnished or supplied by the Department through its ownership, operation and management of all properties and facilities constituting the Power System, including all additions and betterments, and represents the source of payment, without priority, of all bonded indebtedness of the Power System, the necessary expenses of operating and maintaining the Power System, and all other obligations and indebtedness payable out of such Fund.

Power System Summary Balance Sheet

ASSETS

	Septmeber 30, 1986 (Unaudited)	June 30, 1986	June 30, 1985
Utility plant, at original cost, less accumulated provision for depreciation and amortization	$2,973,583,000	$2,943,900,000	$2,656,056,000
Current assets	710,159,000	757,549,000	722,553,000
Deferred debits	1,009,000	1,045,000	2,118,000
Total	$3,684,751,000	$3,702,494,000	$3,380,727,000

LIABILITIES AND EQUITY

Equity	$1,706,122,000	$1,646,096,000	$1,511,781,000
Long-term debt, excluding advance refunding bonds and portion due within one year	1,471,311,000	1,476,139,000	1,440,204,000
Current liabilities	507,318,000	580,259,000	428,742,000
Total	$3,684,751,000	$3,702,494,000	$3,380,727,000

Bonded indebtedness payable from the Power Revenue Fund as of September 30, 1986 was comprised of 57 issues of Electric Plant Revenue Bonds and one issue of Electric Plant Revenue Notes. The principal amount of the total bonded indebtedness outstanding at September 30, 1986 totaled $1,543,087,000.

In February and March 1981, the Department issued its first Electric Plant Short-Term Revenue Certificates. At September 30, 1986, $90,000,000 principal value of such certificates were outstanding.

Report of Independent Accountants

Price Waterhouse
Simpson & Simpson

Los Angeles, California

October 10, 1986

To the Board of Water and Power Commissioners
Department of Water and Power
The City of Los Angeles

We have examined the balance sheet of the Power System of the Department of Water and Power of the City of Los Angeles as of June 30, 1986 and 1985, and the related statements of income, of retained income reinvested in the business and of changes in financial position for each of the three years in the period ended June 30, 1986. Our examinations were made in accordance with generally accepted auditing standards and accordingly included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

As more fully described in Note A to the financial statements, effective June 30, 1984, the Power System of the Department changed its method of accounting for unbilled revenues and the method of recognizing energy costs. Adoption of these new accounting policies, with which we concur, had no effect on net income for 1984.

In our opinion, the financial statements examined by us present fairly the financial position of the Power System of the Department of Water and Power of the City of Los Angeles at June 30, 1986 and 1985, and the results of its operations and the changes in its financial position for each of the three years in the period ended June 30, 1986, in conformity with generally accepted accounting principles consistently applied.

Price Waterhouse
Simpson & Simpson

DEPARTMENT OF WATER AND POWER — CITY OF LOS ANGELES

POWER SYSTEM

STATEMENT OF INCOME
(In Thousands)

	Year Ended June 30		
	1986	1985	1984
Operating revenues:			
Sales of electric energy	$1,349,579	$1,280,632	$1,170,953
Other operating revenues	8,555	7,335	6,516
Total operating revenues	1,358,134	1,287,967	1,177,469
Operating expenses:			
Fuel for generation	348,069	347,591	313,850
Purchased power	203,116	181,961	169,615
Energy costs	551,185	529,552	483,465
Other operation	288,954	240,090	232,525
Maintenance	142,461	129,425	110,598
Provision for depreciation	107,419	105,483	98,521
Taxes on property outside the City	8,660	8,896	10,965
Total operating expenses	1,098,679	1,013,446	936,074
Operating income	259,455	274,521	241,395
Other income — net	27,984	31,976	22,032
Income before debt expenses	287,439	306,497	263,427
Debt expenses:			
Interest on debt	97,464	96,075	98,548
Allowance for borrowed funds used during construction	(3,610)	(3,208)	(575)
Net debt expenses	93,854	92,867	97,973
Net income	$ 193,585	$ 213,630	$ 165,454

STATEMENT OF RETAINED INCOME REINVESTED IN THE BUSINESS

	1986	1985	1984
Balance at beginning of year	$1,432,156	$1,277,393	$1,167,259
Net income for the year	193,585	213,630	165,454
	1,625,741	1,491,023	1,332,713
Less — Payments to the reserve fund of the City	64,353	58,867	55,320
Balance at end of year	$1,561,388	$1,432,156	$1,277,393

The accompanying notes are an integral part of these financial statements.

DEPARTMENT OF WATER AND POWER — CITY OF LOS ANGELES

POWER SYSTEM

BALANCE SHEET
(In Thousands)

	June 30 1986	June 30 1985
ASSETS		
Utility plant, at original cost:		
Production	$1,379,279	$1,483,086
Transmission	501,453	508,148
Distribution	1,571,148	1,471,489
General	235,012	210,213
	3,686,892	3,672,936
Less — Accumulated provision for depreciation	1,157,138	1,106,040
	2,529,754	2,566,896
Construction work in progress	383,904	89,160
Nuclear fuel, at amortized cost	30,242	—
	2,943,900	2,656,056
Current assets:		
Deposits with City Treasurer —		
Revenue fund	355,565	283,118
Bond redemption and interest funds	17,226	40,872
Cash on hand and revolving funds	1,166	1,222
Customer and other accounts receivable, less $3,300 and $2,900 allowance for losses	140,043	148,752
Accrued unbilled revenue	83,729	57,483
Materials and supplies, at average cost	61,820	57,149
Fuel for generation	61,819	83,851
Deferred energy costs	26,784	40,537
Prepayments and other current assets	9,397	9,569
	757,549	722,553
Unamortized debt expenses	1,045	2,118
	$3,702,494	$3,380,727
LIABILITIES AND EQUITY		
Equity:		
Retained income reinvested in the business, per accompanying statement	$1,561,388	$1,432,156
Contributions in aid of construction	84,708	79,625
	1,646,096	1,511,781
Long-term debt, excluding advance refunding bonds:		
Revenue bonds	1,512,710	1,465,200
Revenue notes	24,955	60,000
	1,537,665	1,525,200
Less — Long-term debt due within one year (see below)	61,526	84,996
	1,476,139	1,440,204
Current liabilities:		
Long-term debt due within one year (see above)	61,526	84,996
Revenue certificates	90,000	90,000
Accrued interest	26,504	23,746
Accounts payable and accrued expenses	315,519	209,934
Over-recovered energy costs	69,261	13,102
Extension and other deposits	17,449	6,964
	580,259	428,742
	$3,702,494	$3,380,727

The accompanying notes are an integral part of these financial statements.

DEPARTMENT OF WATER AND POWER — CITY OF LOS ANGELES

POWER SYSTEM

STATEMENT OF CHANGES IN FINANCIAL POSITION
(In Thousands)

	Year Ended June 30		
	1986	1985	1984
Financial resources provided by:			
Operations —			
Net Income	$ 193,585	$ 213,630	$ 165,454
Charges and credits to income not affecting working capital —			
Depreciation	115,599	113,328	104,832
Amortization of nuclear fuel	925	—	—
Other, net	(32)	385	582
Resources provided by operations	310,077	327,343	270,868
Sale of revenue bonds	98,566	49,586	—
Amount received from escrow account	72,920	88,786	—
Contributions in aid of construction	5,083	15,489	4,576
	486,646	481,204	275,444
Financial resources used for:			
Expenditures for plant and equipment	404,368	177,674	150,926
Reduction of long-term debt	61,526	84,996	79,126
Long-term debt redeemed, including call premium	72,920	88,786	—
Payments to the reserve fund of the City	64,353	58,867	55,320
	603,167	410,323	285,372
Increase (decrease) in working capital	$(116,521)	$ 70,881	$ (9,928)
Increase (decrease) in components of working capital:			
Deposits with City Treasurer —			
Revenue fund	$ 72,447	$ 71,000	$ 35,038
Bond redemption and interest funds	(23,646)	32,534	(7,273)
Cash on hand and revolving funds	(56)	(5)	318
Customer and other accounts receivable	(8,709)	44,738	1,054
Accrued unbilled revenue	26,246	(4,397)	61,880
Materials and supplies	4,671	1,919	1,515
Fuel for generation	(22,032)	6,174	(14,242)
Deferred energy costs	(13,753)	(10,481)	(59,213)
Prepayments and other current assets	(172)	475	207
Net change in current assets	34,996	141,957	19,284
Long-term debt due within one year	23,470	(5,870)	(7,315)
Accrued interest	(2,758)	(169)	8,399
Accounts payable and accrued expenses	(105,585)	(49,352)	(28,909)
Over-recovered energy costs	(56,159)	(13,102)	—
Extension and other deposits	(10,485)	(2,583)	(1,387)
Net change in current liabilities	(151,517)	(71,076)	(29,212)
Increase (decrease) in working capital	$(116,521)	$ 70,881	$ (9,928)

The accompanying notes are an integral part of these financial statements.

DEPARTMENT OF WATER AND POWER — CITY OF LOS ANGELES

POWER SYSTEM

NOTES TO FINANCIAL STATEMENTS

NOTE A — Summary of significant accounting policies:

The Department — The Department of Water and Power of the City of Los Angeles exists under and by virtue of the City Charter enacted in 1925 as a separate proprietary agency of the City. The Power System is responsible for delivering electric power to the City's inhabitants.

Financial statement presentation — The financial statements of the Power System are presented in conformity with generally accepted accounting principles, and substantially in conformity with accounting principles prescribed by the Federal Energy Regulatory Commission and the California Public Utilities Commission except for the method of accounting for contributions in aid of construction described below. The Department is not subject to regulations of such commissions.

Utility plant and depreciation — The costs of additions to utility plant and replacements of retired units of property are capitalized. Costs include labor, materials and allocated indirect charges such as engineering, supervision, transportation and construction equipment, retirement plan contributions and other fringe benefits, and certain administrative and general expenses.

For projects over a specified dollar amount, the Power System capitalizes an allowance for funds used during construction equivalent to the cost of long-term debt incurred to finance plant under construction. Research and development costs directly related to current and future construction projects are capitalized and all other such costs are expensed as incurred. The cost of relatively minor replacements is included in maintenance expense. The original cost of property retired, together with removal cost, less salvage, is charged to accumulated depreciation when property is removed from service.

Utility plant depreciation is provided for a large portion of the facilities by the 5% sinking fund method based on the estimated service lives. The straight-line method is used for major projects completed after July 1, 1973 and for all office and shop structures, related furniture and equipment, and transportation and construction equipment. The aggregate provision was 3.27%, 3.24% and 3.13% of average depreciable plant for the years ended June 30, 1986, 1985 and 1984. Nuclear fuel is amortized and charged to Fuel for Generation on the basis of actual thermal energy produced relative to total thermal energy expected to be produced over the life of the fuel. A contract has been entered into with the United States Department of Energy for the disposal of the spent fuel.

Nuclear decommissioning — Decommissioning of the Palo Verde Nuclear Generating Station (PVNGS) is projected to commence in approximately 35 to 40 years. The Power System is providing for estimated future decommissioning costs over the life of the PVNGS through annual charges to expense.

Deposits with City Treasurer — Of the deposits with the City Treasurer, $337,034,000 and $279,025,000 at June 30, 1986 and 1985 were invested in short-term securities under the City Treasurer's pooled investment program, whereby available funds of the City and its independent operating departments are invested on a combined basis. These investments are valued at cost, which approximates market.

Fuel for generation — Coal inventories are stated at average cost. Fuel oil inventories are stated at cost, using the last-in, first-out method.

Contributions in aid of construction — Under the provisions of the City Charter, amounts received from customers and others for constructing utility plant are combined with retained income reinvested in the business to represent equity for purposes of computing the Power System's borrowing limits. Accordingly, contributions in aid of construction are shown in the accompanying balance sheet as an

equity account and are not offset against utility plant; depreciation provided for the related utility plant is expensed.

Revenues — The Power System's rates are fixed by the Department and approved by the City Council. Revenues include amounts resulting from an energy cost adjustment formula designed to permit the full recovery of energy costs. The Department projects these costs to establish the energy cost recovery component of customer billings. Any difference between amounts billed and actual energy costs results in over- or under-recovery of energy costs, which are adjusted in subsequent billings.

Under the rate ordinance approved August 30, 1983, the Power System changed its method of recognizing energy costs to expense and bill these costs in the period incurred; previously, billable energy costs were deferred until actually billed. Also, to provide a better matching of costs and revenues, effective June 30, 1984, the Power System changed its accounting policy for recognizing revenue to a method which provides for accruing estimated unbilled revenues for energy sold but not billed at the end of a fiscal period; previously, revenues were recognized when billed. At June 30, 1984, as required by the rate ordinance, an amount of deferred energy cost equal to the accrued unbilled revenues was charged to expense and, therefore, has no effect on net income. Deferred energy costs will be billed in future periods.

The Power System sells electric energy to other departments of the City at regular rates provided in the ordinance.

Shared operating expenses — The Power System shares certain administrative functions with the Department's Water System. Generally, the cost of these functions is allocated on the basis of benefits provided to the Systems.

Debt expenses — Debt premium, discount, and issue expenses are deferred and amortized to income over the lives of the related issues.

Payments to the reserve fund of the City — Under the provisions of the City Charter, the Power System transfers funds at its discretion to the reserve fund of the City. Such payments are not in lieu of taxes and are recorded as distributions of retained income.

NOTE B — Revenue Certificates:

At June 30, 1986 and 1985, the average interest rate of revenue certificates outstanding was 4.55% and 4.80% with maturities ranging from 19 to 152 days and 34 to 180 days, respectively. The Department has an unsecured standby line of credit of $90,000,000 which can be used if the certificates cannot be refinanced as they mature.

NOTE C — Jointly-owned electric utility plant:

The Power System has an undivided interest in several electrical generating stations and transmission systems which are jointly-owned with various utilities. Each participant provides its own construction financing. The Power System's proportionate share of construction and improvement costs is included in the appropriate categories of utility plant. The Power System will incur certain minimum operating costs on jointly-owned facilities, whether or not it is able to take delivery of its share of energy generated. The proportionate share of these expenses incurred is included in the appropriate categories of operating expenses. At June 30, 1986 and 1985, the Power System's investment in such projects totaled $853,748,000 and $671,917,000.

NOTE D — Long-term debt:

Long-term debt outstanding at June 30, 1986, consisted of revenue bonds and notes due serially in varying annual amounts through 2026. Interest rates, which vary among individual maturities, averaged approximately 6.56% and 6.29% at June 30, 1986 and 1985. The revenue bonds are callable generally ten

years after issuance. Scheduled principal maturities during the five years succeeding June 30, 1986 are $61,526,000, $67,916,000, $53,545,000, $51,930,000 and $53,180,000, respectively.

In the fiscal year ended June 30, 1977, the Power System sold advance refunding bonds totaling $161,700,000. Until the bonds to be refunded were called, interest on the advance refunding bonds was payable from interest earned on securities of the United States Government purchased out of the proceeds of the sales and held in escrow accounts with Citibank, N.A., New York. At June 30, 1986, all refunded bonds had been called and the related escrow accounts liquidated; the advance refunding bonds are now payable from Power System revenues. During the years ended June 30, 1986 and 1985, $70,800,000 and $86,200,000 face value of the refunded bonds were redeemed.

NOTE E — Shared operating expenses:

Operating expenses shared with the Water System were $216,276,000, $197,265,000 and $165,089,000 for the years ended June 30, 1986, 1985 and 1984, of which $141,929,000, $130,126,000 and $114,056,000 were allocated to the Power System.

NOTE F — Employees' retirement plan:

The Department has a funded contributory retirement, disability and death benefit insurance plan covering substantially all of its employees. The Power System was allocated approximately 74% of the plan's total costs for the years ended June 30, 1986, 1985 and 1984 amounting to $90,677,000, $82,983,000 and $86,744,000. These costs include amortization of prior service costs generally over a 30-year period ending June 30, 2003. The Department funds retirement plan costs in accordance with the recommendations of the plan's independent actuary. In 1986, no significant amendments were made to the plan.

The actuarially computed present value of accumulated retirement plan benefits attributable to the Power System aggregated $1,151,000,000 and $1,084,000,000 at June 30, 1986 and 1985, of which $1,147,000,000 and $1,080,000,000 were vested. An assumed rate of return of 8% was used in determining these actuarially computed values. The retirement plan's assets at market value allocated to the Power System were $992,000,000 and $783,000,000 at such dates.

NOTE G — Commitments and contingencies:

Capital Program and other — The Department's budget for the year ending June 30, 1987 provides for capital expenditures of approximately $478,000,000 in the Power System. Also, the Department has budgeted payments of $67,913,000 for the year ending June 30, 1987 from the Power System's revenue fund to the reserve fund of the City.

Long-term purchased power and transmission contracts — The Department has entered into a number of energy and capacity contracts which involve substantial commitments. These include an agreement with the Intermountain Power Agency (IPA), a Utah State Agency, and two agreements with the Southern California Public Power Authority (SCPPA), a California public authority. Under the IPA agreement, as amended, the Power System has committed to purchase 62.8%, of which 44.6% is a "take-or-pay" obligation, of the energy generated by the Intermountain Power Project (IPP), a coal-fueled generating station that became operational July 1, 1986. At June 30, 1986, IPA had issued $5,120,142,000 of Power Supply Revenue Bonds and had made expenditures of approximately $2,592,000,000. Subsequent to June 30, 1986, IPA issued an additional $1,635,000,000 of Special Obligation Crossover Bonds, the proceeds of which will be used to redeem $1,532,000,000 of Power Supply Revenue Refunding Bonds.

Under a power sales agreement with SCPPA, the Power System will purchase 67% of SCPPA's entitlement to the Palo Verde Nuclear Project. At June 30, 1986, SCPPA had issued $1,033,000,000 of Power Project Bond Anticipation Notes and Power Project Revenue Bonds and had made expenditures of approximately $584,873,000.

Under a transmission service contract with SCPPA, the Power System is to purchase 59.5% of the capacity of the Southern Transmission System, a 500kV DC transmission line, which will transmit energy from IPP to Southern California. At June 30, 1986, SCPPA had issued $1,058,000,000 of Transmission Project Bond Anticipation Notes and Transmission Project Revenue Bonds and had made expenditures of approximately $636,706,000.

All these agreements require the Power System to make certain minimum payments whether or not power is produced or it is able to take delivery of the power. Minimum payments are based upon debt service requirements plus production costs and, therefore, cannot presently be determined.

Litigation — A number of claims and suits are pending against the Department for alleged damages to persons and property and for other alleged liabilities arising out of its operations. In the opinion of management, the uninsured liability under these actions would not materially affect the Power System's financial position as of June 30, 1986.

Imperial Irrigation District

There follows certain information concerning the Imperial Irrigation District and its Electric System, prepared by the Imperial Irrigation District for inclusion in this Official Statement. This information does not purport to cover all aspects of the Electric System's business, operations and financial position. During the initial offering period for the securities offered by this Official Statement, a copy of the most recent Imperial Irrigation District annual report may be obtained from Charles Shreves, Imperial Irrigation District, P. O. Box 937, Imperial, California 92251.

Certain additional information relating to the Imperial Irrigation District may be found in Appendix A to the Official Statement under the caption "Project Participants — Imperial Irrigation District".

IMPERIAL IRRIGATION DISTRICT STATISTICS
(Electric System)

	Year Ended December 31				
	1981	1982	1983	1984	1985
Electric Plant:					
Net Utility Plant	$ 73,905,187	$ 81,442,880	$121,379,593	$139,371,493	$157,201,398
Miles of Lines:					
Transmission	971	979	996	1,021	1,037
Distribution	3,075	3,100	3,102	3,028	3,135
Bonded Indebtedness	$ 1,645,000	$ 1,165,000	$ 670,000	$ 0	$ 0
Power Supply (MWh):					
Purchases	804,369	810,212	747,462	833,723	770,003
Generation	709,428	589,664	661,370	671,784	777,076
Customers:					
Residential	45,269	46,475	47,401	48,528	49,305
Commercial	8,164	8,268	8,643	8,872	9,064
Industrial	—	—	—	—	2
Other	1,773	1,833	1,866	1,891	2,072
Energy Sold (MWh):					
Residential	569,039	525,864	550,868	585,402	596,897
Commercial	651,852	596,117	588,849	625,246	654,446
Industrial	—	—	—	—	5,736
Other	110,200	110,451	105,778	113,713	123,235
Peak Demand (MWe)	382	363	370	396	404
Summary of Operations:					
Operating Revenues:					
Electric Sales	$ 59,668,869	$ 70,462,870	$ 78,239,650	$ 80,557,097	$ 85,237,447
Other	599,455	653,552	1,078,707	936,069	1,060,434
Total	$ 60,268,324	$ 71,116,422	$ 79,318,357	$ 81,493,166	$ 86,297,881
Operating Expenses:					
Purchased Power	$ 25,158,000	$ 31,757,957	$ 28,558,349	$ 31,761,503	$ 28,444,068
Generation	22,344,000	23,493,903	19,317,963	17,104,826	20,863,459
Transmission and Distribution	3,778,000	3,492,729	4,761,773	3,728,458	3,793,897
Other	5,971,000	6,251,949	6,245,461	6,428,383	11,136,170
Total	$ 57,251,000	$ 64,996,538	$ 58,883,546	$ 59,023,170	$ 64,237,594
Other Income	1,596,971	472,735	2,914,399	4,823,493	4,938,001
Net Available for Depreciation and Debt Service	$ 4,614,295	$ 6,592,619	$ 23,349,210	$ 27,293,489	$ 26,998,288
Debt Service	$ 607,265	$ 596,415	$ 5,110,801	$ 8,865,071	$ 8,576,144

City of Riverside

There follows certain information concerning the City of Riverside and its Electric System, prepared by the City of Riverside for inclusion in this Official Statement. This information does not purport to cover all aspects of the Electric System's business, operation and financial position. During the initial offering period for the securities offered by this Official Statement, a copy of the most recent annual report of the Electric System may be obtained from James H. Harmon, Assistant Director Finance/Administration, City of Riverside Utilities Department, Riverside City Hall, 3900 Main Street, Riverside, California 92522.

Certain additional information relating to the City's Electric System may be found in Appendix A to the Official Statement under the caption "Project Participants — Cities of Riverside, Vernon, Azusa, Banning and Colton".

CITY OF RIVERSIDE STATISTICS

	Year Ended June 30				
	1982	1983	1984	1985	1986
Electric Plant:					
Net Utility Plant	$39,372,839	$ 39,928,525	$133,085,067(1)	$140,069,138	$144,521,455
Overhead Circuit Miles(2)	648	650	615	618	623
Underground Circuit Miles(2)	645	647	279	304	335
Street Lights(2)	—	—	700	702	711
Bonded Indebtedness	$88,740,000	$123,170,000	$122,720,000	$121,740,000	$153,265,000
Power Supply (MWh):					
Purchases:					
Edison	1,043,544	951,326	929,425	892,973	803,388
Other	51,384	111,617	103,635	153,025	236,132
Generation	—	—	102,163	159,397	168,410
Customers:					
Residential	62,974	63,723	64,160	64,506	68,579
Commercial	5,416	5,586	5,697	5,974	6,282
Industrial	182	174	220	243	301
Other	175	174	173	255	252
Energy Sold (Millions of kWh):					
Residential	401	369	394	427	421
Commercial	218	208	227	249	265
Industrial	399	393	407	425	449
Other	38	31	35	40	38
Peak Demand (MWe)	319	299	293	332	323
Summary of Operations:					
Operating Revenues:					
Electric Sales	$78,460,327	$ 84,356,079(3)	$ 87,515,668(3)	$105,940,884(3)	$102,228,610(3)
Other	310,995	353,142	267,629	358,054	598,130
Total	$78,771,322	$ 84,709,221	$ 87,783,297	$106,298,938	$102,826,740
Operating Expenses:					
Purchased Power	$60,790,964	$ 64,006,166	$ 63,449,536	$ 74,775,376	$ 74,673,776
Generation	—	—	2,977,642(4)	6,904,059(4)	4,928,039(4)
Transmission	124,194	99,374	155,691	89,679	1,072,826
Distribution	2,502,195	2,803,810	2,615,052	2,661,077	2,662,753
Other	4,301,460	5,263,179	6,770,468	6,710,455	7,409,800
Total(5)	$67,718,813	$ 72,172,529	$ 75,968,389	$ 91,140,646	$ 90,747,194
Other Income	4,963,753	2,524,935	5,342,298	4,465,903	5,962,635
Net Available for Depreciation and Debt Service	$16,016,262	$ 15,061,627	$ 17,157,206	$ 19,624,195	$ 18,042,181
Debt Service	$ 1,220,151(6)	$ 1,220,151(6)	$ 6,465,383	$ 12,588,632	$ 13,213,347

(1) Reflects integration of the electric system's 1.79% share of San Onofre Nuclear Generating Station Units 2 and 3.

(2) Accounting change adopted as of fiscal year 1984 separates miles of street lights from other types of circuit miles.

(3) Pursuant to an accounting change initiated by the City as of June 30, 1983, 40% of the succeeding July revenues from electric sales are accounted for as current fiscal year revenues. These are revenues which are normally collected in July but which correspond to June consumption. July 1983 revenues included in the fiscal year 1983 amount to $2,948,989. July 1984 revenues included in the fiscal year 1984 amount to $3,168,910. July 1985 revenues included in fiscal year 1985 amount to $3,867,697. July 1986 revenues included in the fiscal year 1986 amount to $3,787,953. Electric Sales also include Power Cost Adjustments of ($4,556,026), ($4,469,473), $7,412,736 and $(5,271,833) for the years 1983, 1984, 1985 and 1986, respectively.

(4) Includes transmission expenses associated with San Onofre energy.

(5) Does not include contributions to the City's General Fund of $4,471,581, $4,768,179, $4,991,000, $5,166,155 and $5,537,627 for the years 1982 through 1986.

(6) Does not include debt service on 1980 Electric Revenue Bonds, 1980 Electric Refunding Revenue Bonds and 1983 Electric Revenue Bonds which was funded from bond proceeds.

City of Vernon

There follows certain information concerning the City of Vernon and its Electric System, prepared by the City of Vernon for inclusion in this Official Statement. This information does not purport to cover all aspects of the Electric System's business, operations and financial position. During the initial offering period for the securities offered by this Official Statement, a copy of the most recent City of Vernon annual report may be obtained from Lewis Adams, City of Vernon, 4305 Santa Fe Avenue, Vernon, California 90058.

Certain additional information relating to the City of Vernon may be found in Appendix A to the Official Statement under the caption "Project Participants — Cities of Riverside, Vernon, Azusa, Banning and Colton."

CITY OF VERNON STATISTICS

	Year Ended June 30				
	1982	1983	1984	1985	1986(1)
Electric Plant:					
Net Utility Plant	$ 4,700,570	$ 5,005,277	$ 5,101,515	$ 6,659,377	$ 9,705,310
Miles of Lines:					
Transmission	13	13	13	13	13
Distribution	203	203	203	203	203
Bonded Indebtedness	-0-	-0-	-0-	-0-	-0-
Power Supply (MWh):					
Purchases	1,173,250	1,065,131	1,056,149	1,097,271	1,141,562
Generation	—	824	4,394	9,357	9,547
Customers:					
Residential	34	32	31	30	31
Commercial	1,415	1,446	1,467	1,461	1,489
Industrial	560	532	507	497	497
Other	79	76	75	73	72
Energy Sold (MWh):					
Residential	116	119	127	125	121
Commercial	181,352	175,087	189,486	196,289	198,146
Industrial	949,102	847,915	795,114	882,199	888,563
Other	8,586	8,415	7,852	7,506	7,434
Peak Demand (MWe)	238	236	191	192	193
Summary of Operations:					
Operating Revenues:					
Electric Sales	$69,739,000	$64,141,459	$62,675,177	$75,325,348	$77,475,949
Other	23,208	23,208	23,208	28,455	55,944
Total	$69,762,208	$64,164,667	$62,698,385	$75,353,803	$77,531,893
Operating Expenses:					
Power Supply	$61,730,339	$59,392,583	$59,912,567	$71,182,880	$68,177,475
Transmission and Distribution	887,868	1,074,192	1,219,056	1,304,003	3,147,383
Other	3,138,460	3,560,195	3,987,990	5,480,569	5,436,374
Total	$65,756,667	$64,026,970	$65,119,613	$77,967,452	$76,761,232
Net Available for Depreciation and Debt Service(2)	$ 4,005,541	$ 137,697	$(2,421,228)	$(2,613,649)	$ 770,661

(1) Unaudited data.

(2) Non-operating income, not included as revenues in the above table, for fiscal years 1982, 1983, 1984, 1985 and 1986 amounted to $6,440,726, $4,889,957, $4,441,275, $6,281,624 and $7,223,868, respectively.

City of Burbank

There follows certain information concerning the City of Burbank and its Public Service Department, prepared by the City of Burbank for inclusion in this Official Statement. This information does not purport to cover all aspects of the Public Service Department's business, operations and financial position. During the initial offering period for the securities offered by this Official Statement, a copy of the most recent City of Burbank annual report may be obtained from Goodwin Glance, Burbank Public Service Department, 164 West Magnolia Boulevard, Burbank, California 91503.

Certain additional information relating to the City of Burbank's Public Service Department may be found in Appendix A to the Official Statement under the caption "Project Participants — Cities of Burbank, Glendale and Pasadena".

CITY OF BURBANK STATISTICS

	Year Ended June 30				
	1982	1983	1984	1985	1986
Electric Plant:					
Net Utility Plant	$28,722,396	$28,371,356	$31,647,407	$43,575,791	$46,140,136
Miles of Lines:					
Transmission	49	49	53	53	53
Distribution	290	290	290	310	310
Bonded Indebtedness	$ 2,925,000	$ 2,600,000	$ 2,275,000	$ 1,775,000	$28,935,900
Power Supply (MWh):					
Purchases	459,010	579,910	641,650	735,780	798,110
Generation	408,765	279,113	289,313	237,396	183,432
Customers:					
Residential	37,738	37,717	37,718	37,955	38,340
Commercial	5,670	5,713	5,809	5,871	5,906
Industrial	142	149	152	164	174
Other	594	583	595	625	636
Energy Sold (MWh):					
Residential	182,723	180,778	191,641	199,159	194,572
Commercial	180,168	177,656	197,580	203,270	212,471
Industrial	437,520	422,709	461,066	484,128	498,547
Other	35,276	32,529	32,336	34,899	32,441
Peak Demand (MWe)	220	210	217	234	228
Summary of Operations:					
Operating Revenues:					
Electric Sales	$54,733,000	$52,728,000(*)	$58,396,400	$63,187,391	$61,612,602
Other	—	—	—	—	—
Total	$54,733,000	$52,728,000	$58,396,400	$63,187,391	$61,612,602
Operating Expenses:					
Purchased Power	$12,460,000	$15,127,000	$17,325,363	$23,969,205	$25,614,532
Generation	26,931,000	23,867,000	24,256,054	20,114,796	15,566,895
Transmission and Distribution	3,116,000	3,798,000	4,023,795	3,991,955	4,318,848
Other	3,936,000	4,274,000	4,281,913	4,673,078	5,055,853
Total	$46,443,000	$47,066,000	$49,887,125	$52,749,034	$50,556,128
Net Available for Depreciation and Debt Service	$ 8,290,000	$ 5,662,000	$ 8,509,275	$10,438,357	$11,056,474
Debt Service	$ 847,723	$ 817,473	$ 791,573	$ 520,050	$ 3,214,750

(*) Reflects addition of $2,664,000 to previously reported electric sales revenues of $50,064,000, due to change in accounting policy regarding recognition of unbilled revenues.

City of Glendale

There follows certain information concerning the City of Glendale and its Public Service Department, prepared by the City of Glendale for inclusion in this Official Statement. This information does not purport to cover all aspects of the Public Service Department's business, operations and financial position. During the initial offering period for the securities offered by this Official Statement, a copy of the most recent Glendale Public Service Department annual report may be obtained from Lawrence Silva of the Glendale Public Service Department, 119 North Glendale Avenue, Glendale, California 91206.

Certain additional information relating to the City of Glendale may be found in Appendix A to the Official Statement under the caption "Project Participants — Cities of Burbank, Glendale and Pasadena."

CITY OF GLENDALE STATISTICS

	Year Ended June 30				
	1982	1983	1984	1985	1986(1)
Electric Plant:					
Net Utility Plant	$70,368,000	$73,718,000	$77,515,000	$71,673,025	$75,268,000
Miles of Lines:					
Transmission	72	72	72	72	72
Distribution	382	394	394	394	394
Bonded Indebtedness	$43,645,000	$42,035,000	$40,340,000	$38,555,000	$36,675,000
Power Supply (MWh):					
Purchases	437,696	623,295	670,898	737,207	760,393
Generation	353,683	174,391	191,065	154,557	134,684
Customers:					
Residential	57,393	57,835	57,946	58,463	59,378
Commercial	9,912	10,049	10,220	10,322	10,640
Industrial	109	111	118	120	124
Other	42	44	43	43	42
Energy Sold (MWh):					
Residential	255,760	256,031	273,481	292,175	283,416
Commercial	298,030	294,922	317,309	320,036	330,153
Industrial	176,644	174,368	192,838	201,351	208,467
Other	24,778	24,340	25,785	23,087	20,561
Peak Demand (MWe)	211	207	208	232	232
Summary of Operations:					
Operating Revenues:					
Electric Sales	$55,061,000	$47,676,000	$52,904,556	$60,813,833	$60,808,000
Other	1,326,000	582,000	558,371	725,310	625,000
Total	$56,387,000	$48,258,000	$53,462,927	$61,539,143	$61,433,000
Operating Expenses:					
Purchased Power	$10,167,000	$14,864,000	$13,466,739	$20,965,103	$20,083,000
Generation	22,654,000	16,612,000	17,443,512	14,519,210	13,975,000
Transmission and Distribution	2,653,000	3,185,000	3,368,190	3,257,620	3,222,000
Other	4,644,000	5,513,000	6,109,702	6,256,801	6,604,000
Total	$40,118,000	$40,174,000	$40,388,143	$44,998,734	$43,884,000
Net Available for Depreciation and Debt Service	$16,269,000	$ 8,084,000	$13,074,784	$16,540,409	$17,549,000
Debt Service	$ 4,161,000	$ 4,164,000	$ 4,163,000	$ 4,162,000	$ 4,159,000

(1) Unaudited data.

City of Pasadena

There follows certain information concerning the City of Pasadena and its Power Department, prepared by the City of Pasadena for inclusion of this Official Statement. This information does not purport to cover all aspects of the Power Department's business, operations and financial position. During the initial offering period for the securities offered by this Official Statement, a copy of the most recent Pasadena Water and Power Department annual report may be obtained from Roland Zeigler, Pasadena Water and Power Department, 100 North Garfield Avenue, Pasadena, California 92251.

Certain additional information relating to the City of Pasadena may be found in Appendix A to the Official Statement under the caption "Project Participants — Cities of Burbank, Glendale and Pasadena."

CITY OF PASADENA STATISTICS

	Year Ended June 30				
	1982	1983	1984	1985	1986(1)
Electric Plant:					
Net Utility Plant	$59,971,874	$67,463,651	$71,925,257	$77,647,390	$81,126,009
Miles of Lines:					
Transmission	85	85	85	86	86
Distribution	322	322	322	324	327
Electric Revenue Bonds	$24,500,000	$23,750,000	$23,000,000	$21,825,000	$40,229,220
Power Supply (MWh):					
Purchases	499,410	536,858	618,544	639,801	665,261
Generation	383,003	341,335	317,536	353,155	341,637
Customers:					
Residential	45,548	45,782	46,066	46,487	46,734
Commercial	6,280	6,288	6,305	6,443	6,533
Industrial	603	644	675	705	720
Other	166	167	169	169	169
Energy Sold (MWh):					
Residential	219,606	214,358	223,706	243,234	237,579
Commercial	121,540	119,833	126,223	131,603	131,547
Industrial	448,278	450,837	486,818	505,212	541,747
Other	44,757	42,986	44,081	42,687	45,469
Peak Demand (MWe)	212	208	214	238	231
Summary of Operations:					
Operating Revenues:					
Electric Sales	$50,734,000	$54,617,543	$56,056,504	$60,473,076	$57,180,039
Other	—	—	—	—	—
Total	$50,734,000	$54,617,543	$56,056,504	$60,473,076	$57,180,039
Operating Expenses:					
Purchased Power	$14,135,000	$14,083,931	$15,886,535	$18,971,508	$20,040,770
Generation	22,098,000	24,016,101	22,978,336	22,644,602	18,501,579
Transmission and Distribution	2,418,000	2,603,901	2,737,958	3,237,410	3,352,469
Other	3,445,000	3,478,744	4,180,082	4,010,050	4,607,050
Total	$42,096,000	$44,182,677	$45,782,911	$48,863,570	$46,501,868
Net Available for Depreciation and Debt Service	$ 8,638,000	$10,434,866	$10,273,593	$11,609,506	$10,678,171
Debt Service	$ 2,824,000	$ 2,336,943	$ 2,303,732	$ 2,660,420	$ 3,685,249

(1) Unaudited data.

City of Azusa

There follows certain information concerning the City of Azusa and its Municipal Light Department, prepared by the City of Azusa for inclusion in this Official Statement. This information does not purport to cover all aspects of the Municipal Light Department's business, operations and financial position. During the initial offering period for the securities offered by this Official Statement, a copy of the most recent Municipal Light Department annual report may be obtained from Joseph F. Hsu, Director of Utilities, Municipal Light Department, 777 No. Alameda Avenue, Azusa, California 91702.

Certain additional information relating to the City's Municipal Light Department may be found in Appendix A to the Official Statement under the caption "Project Participants — Cities of Riverside, Vernon, Azusa, Banning and Colton".

CITY OF AZUSA STATISTICS

	Year Ended June 30				
	1982	1983	1984	1985	1986(1)
Electric Plant:					
Net Utility Plant	$ 3,382,293	$ 3,391,876	$ 3,372,374	$ 3,342,163	$ 3,400,000
Miles of Lines:					
Transmission	—	—	—	—	—
Distribution	N/A(2)	123	125	130	131
Bonded Indebtedness	-0-	-0-	-0-	-0-	-0-
Power Supply (MWh):					
Purchases from Edison	155,399	152,756	163,570	170,460	177,768
Customers:					
Residential	10,410	10,444	10,536	10,621	11,207
Commercial	1,227	1,228	1,271	1,274	1,318
Industrial	33	35	35	33	34
Other	47	46	46	45	47
Energy Sold (MWh):					
Residential	49,288	48,026	50,503	52,715	53,133
Commercial	50,875	46,348	49,492	50,878	54,533
Industrial	47,135	47,324	52,500	53,347	56,992
Other	2,543	2,559	2,544	2,499	2,437
Peak Demand (MWe)	41.5	40.3	40.2	44.5	43.1
Summary of Operations:					
Operating Revenues:					
Electric Sales	$ 7,927,738	$12,621,823	$14,878,100	$14,440,167	$15,511,655
Other(3)	158,836	28,550	329,577	36,743	93,316
Total	$ 8,086,574	$12,650,373	$15,207,677	$14,476,910	$15,604,971
Operating Expenses:					
Purchased Power	$ 8,737,282(4)	$ 9,216,478	$10,099,838	$12,185,881	$12,606,258
Transmission and Distribution	299,860	396,658	530,691	595,488	607,089
Other	603,299	674,409	551,665	638,944	637,911
Total	$ 9,640,441	$10,287,545	$11,182,194	$13,420,313	$13,851,258
Net Available for Depreciation and Debt Service	$(1,553,867)	$ 2,362,828	$ 4,025,483	$ 1,056,597	$ 1,753,713

(1) Unaudited data.

(2) Not available.

(3) Does not include $783,791, $1,266,731 and $2,037,241 refunds from Edison for 1984, 1985 and 1986, respectively.

(4) Has not been decreased to reflect a refund of $952,910 received from Edison for prior years.

City of Banning

There follows certain information concerning the City of Banning's Electric System, prepared by the City of Banning for inclusion in this Official Statement. This information does not purport to cover all aspects of the Electric System's business, operations and financial position. During the initial offering period for the securities offered by this Official Statement, a copy of the most recent annual report may be obtained from Eldridge Sinclair, 176 East Lincoln Street, Banning, California 92220.

Certain additional information relating to the City's Public Utilities Department may be found in Appendix A to the Official Statement under the caption "Project Participants — Cities of Riverside, Vernon, Azusa, Banning and Colton."

CITY OF BANNING STATISTICS

	Year Ended June 30				
	1982	1983	1984	1985	1986
Electric Plant:					
Net Utility Plant	$2,070,300	$2,025,621	$2,174,670	$3,442,629	$3,724,741
Miles of Lines:					
Transmission	12	12	12	12	12
Distribution	82	83	84	87	89
Bonded Indebtedness	-0-	-0-	-0-	-0-	$1,250,000
Power Supply (MWh):					
Purchases from Edison	66,695	66,108	69,474	74,104	70,729
Customers:					
Residential	4,942	5,097	5,325	5,491	5,519
Commercial	592	578	600	595	600
Industrial	5	6	6	6	6
Other	64	95	104	111	100
Energy Sold (MWh):					
Residential	26,841	26,325	28,003	30,040	30,157
Commercial	23,983	22,773	24,227	22,898	22,470
Industrial	9,183	8,668	10,368	12,151	10,749
Other	2,589	3,709	3,568	2,855	2,525
Peak Demand (MWe)	17.8	16.8	18.1	18.3	18.6
Summary of Operations:					
Operating Revenues:					
Electric Sales	$5,038,226	$5,169,376	$5,867,683	$7,197,764	$6,760,732
Other	93	—	9,350	11,661	87,658
Total	$5,038,319	$5,169,376	$5,877,033	$7,209,425	$6,848,390
Operating Expenses:					
Purchased Power	$3,621,563	$4,015,949	$4,379,611	$5,311,922	$4,975,930
Transmission and Distribution	769,726	843,263	720,761	689,371	513,434
Other(1)	862,167	587,539	606,650	733,800	919,228
Total	$5,253,456	$5,446,751	$5,707,022	$6,735,093	$6,408,592
Net Available for Depreciation and Debt Service	$ (215,137)	$ (277,375)	$ 170,011	$ 474,332	$ 439,798
Debt Service(2)	—	—	—	$ 46,493	$ 16,342

(1) Transfers to the City's General Fund are accounted for as an operating expense. Transfers for 1982, 1983, 1984, 1985 and 1986 amounted to $800,924, $564,440, $555,896 and $630,000 and $719,800, respectively.

(2) Interest and Principal on Note for 1985; interest on Certificates of Participation for 1986.

City of Colton

There follows certain information concerning the City of Colton's Utility System, prepared by the City of Colton for inclusion in this Official Statement. This information does not purport to cover all aspects of the System's business, operations and financial position. During the initial offering period for the securities offered by this Official Statement, a copy of the most recent annual report may be obtained from Gale Drews, Utility Director, 650 North La Cadena, Colton, California 92324.

Certain additional information relating to the City may be found in Appendix A to the Official Statement under the caption "Project Participants — Cities of Riverside, Vernon, Azusa, Banning and Colton."

CITY OF COLTON STATISTICS

	Year Ended June 30				
	1982	1983	1984	1985	1986(1)
Electric Plant:					
Net Utility Plant	$ 2,456,846	$ 2,526,427	$ 2,686,093	$ 3,086,734	$ 3,551,507
Miles of Lines:					
Transmission	1.5	1.5	1.5	1.5	1.5
Distribution	86	91	93	97	106
Bonded Indebtedness	$ 1,100,000	$ 1,080,000	$ 1,060,000	$ 1,035,000	$ 1,010,000
Power Supply (MWh):					
Purchases from Edison	120,100	120,877	136,396	138,749	143,247
Customers:					
Residential	7,637	7,996	8,172	8,312	9,811
Commercial	1,027	1,072	1,084	1,123	1,218
Industrial	9	10	11	11	11
Other	84	87	94	93	95
Energy Sold (MWh):					
Residential	38,783	38,979	41,996	42,636	43,690
Commercial	44,932	45,721	51,883	53,072	53,304
Industrial	22,324	25,012	29,420	29,710	29,753
Other	6,070	6,006	4,913	6,504	7,024
Peak Demand (MWe)	30.8	30.0	30.2	35.2	34.6
Summary of Operations:					
Operating Revenues:					
Electric Sales	$ 8,286,175	$ 9,866,115	$10,744,457	$11,566,843	$11,853,772
Other	28,438	23,783	30,081	35,176	55,382
Total	$ 8,314,613	$ 9,889,898	$10,774,538	$11,602,019	$11,909,154
Operating Expenses:					
Purchased Power	$ 5,619,398	$ 7,100,537	$ 8,114,476	$ 9,540,786	$ 9,845,240
Transmission/Distribution	295,938	274,904	333,468	332,458	273,895
Other	979,372	1,124,767	1,202,698	1,231,201	1,364,237
Total	$ 6,894,708	$ 8,500,208	$ 9,650,642	$11,104,445	$11,483,372
Net Available for Depreciation and Debt Service	$ 1,419,905	$ 1,389,690	$ 1,123,896	$ 497,574	$ 425,782
Debt Service	$ 89,348	$ 87,948	$ 86,638	$ 90,342	$ 88,764

(1) Unaudited data.

APPENDIX C

SUMMARIES OF CERTAIN DOCUMENTS

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SUMMARY OF CERTAIN PROVISIONS OF THE BOND INDENTURE

The following is a summary of certain provisions of the Bond Indenture. This summary is not to be considered a full statement of the terms of the Bond Indenture and accordingly is qualified by reference thereto and is subject to the full text thereof. Capitalized terms not defined in this summary or in the Official Statement have the respective meanings set forth in the Bond Indenture.

Pledge Effected by the Bond Indenture

Under the Bond Indenture, the Authority has pledged and assigned to the Trustee, for the benefit of the Bondholders, (1) the proceeds of the sale of the Bonds, (2) the Revenues, and (3) all Funds established by the Bond Indenture (excluding the Decommissioning Account in the Reserve and Contingency Fund), including the investments, if any, of the moneys therein, subject only to the provisions of the Bond Indenture permitting the application thereof for the purpose and on the terms and conditions set forth in the Bond Indenture (including application of the moneys on deposit in certain refunding escrow funds).

Nature of Obligation

The Bond Indenture provides that the principal and Redemption Price of, and interest on, the Bonds shall be payable solely from the Revenues and other funds pledged by the Authority under the Bond Indenture. The Bonds are not an obligation of the State of California or any public agency thereof, other than the Authority, or any member of the Authority or any Project Participant and neither the faith and credit nor the taxing power of the State of California or any public agency thereof or any Project Participant is pledged for the payment of the Bonds.

Application of Revenues

Revenues are pledged by the Bond Indenture to payment of principal and Redemption Price of and interest on the Bonds, subject to the provisions of the Bond Indenture permitting application for other purposes. The Bond Indenture establishes the following Funds and Accounts for the application of Revenues:

Funds	Held By
Construction Fund	Trustee
Revenue Fund	Trustee
Operating Fund	Trustee
Debt Service Fund	Trustee
Debt Service Account	
Debt Service Reserve Account	
Bond Anticipation Note Fund	Trustee
Reserve and Contingency Fund	Trustee
Renewal and Replacement Account	
Decommissioning Account	
Reserve Account	
General Reserve Fund	Trustee

All Revenues received are to be deposited promptly in the Revenue Fund upon receipt thereof. Amounts in the Revenue Fund are to be paid monthly in the following order of priority for application therefrom as follows:

1. To the Operating Fund, a sum which, together with any amount in the Operating Fund not set aside as a general reserve for Authority Operating Expenses or as a reserve for the acquisition of fuel or as a reserve for working capital, is equal to the total moneys appropriated for Authority Operating Expenses in the Annual Budget for the then current month. Such sum shall be paid to the Operating Fund as soon as practicable in each month after deposit of Revenues in the Revenue Fund, but not later than the last business day of such month. In addition, if the Supplemental Indenture authorizing a Series of Bonds so provides, amounts from the proceeds of such Bonds may be deposited in the Operating Fund and set aside as a reserve for the acquisition of fuel and as a reserve for working capital. At the requisition of the Authority, signed by an Authorized Authority Representative, amounts in the Operating Fund shall be paid out from time to time by the Trustee for reasonable and necessary Authority Operating Expenses. Additional amounts may be paid out from the appropriate separate Account in the Operating Fund to establish a revolving fund with a maximum balance of $250,000 for the payment of Authority Operating Expenses not conveniently paid as described in the previous sentence. The Bond Indenture provides for the application of excess amounts in the Operating Fund to make up any deficiences in certain other funds established under the Bond Indenture with any balance to be deposited in the General Reserve Fund.

2. To the Debt Service Account and the Debt Service Reserve Account in the Debt Service Fund, the respective amounts required so that the balances in such Accounts equal the Accrued Aggregate Debt Service and the Debt Service Reserve Requirement, respectively. The Trustee will apply amounts in the Debt Service Account to the payment of principal of and interest on the Bonds. In addition, the Trustee may, and if directed by the Authority must, apply certain amounts in the Debt Service Account to the purchase or redemption of Bonds to satisfy sinking fund requirements prior to the due date of any Sinking Fund Installment. The Trustee must pay out of the Debt Service Account the amount required for the redemption of Bonds called for redemption pursuant to sinking fund requirements, or maturing, on any redemption or maturity date.

In the event of the refunding of one or more Series of Bonds, the Trustee shall, upon the direction of the Authority with the advice of Bond Counsel, withdraw from the Debt Service Account in the Debt Service Fund amounts accumulated therein with respect to Debt Service on the Bonds being refunded and hold such amounts for the payment of the principal or Redemption Price, if applicable, and interest on the Series of Bonds being refunded; provided that such withdrawal shall not be made unless (a) immediately thereafter the Series of Bonds being refunded shall be deemed to have been paid pursuant to the Bond Indenture, and (b) the amount remaining in the Debt Service Account after such withdrawal shall not be less than the requirement of such Account pursuant to the Bond Indenture.

Amounts in the Debt Service Reserve Account are to be applied on the last business day of each month to make up any deficiency in the Debt Service Account. Whenever the amount in the Debt Service Reserve Account, together with the amount in the Debt Service Account, is sufficient to pay in full all Outstanding Bonds in accordance with their terms, the funds on deposit in the Debt Service Reserve Account shall be transferred to the Debt Service Account. As long as the amount in the Debt Service Fund is sufficient to pay all then Outstanding Bonds in full (including principal or applicable sinking fund Redemption Price and interest thereon), no deposits shall be required to be made in the Debt Service Reserve Account. Whenever moneys on deposit in the Debt Service Reserve Account exceed the Debt Service Reserve Requirement, the excess will be deposited in the Revenue Fund.

Deposits from the Revenue Fund into the Debt Service Fund, the Bond Anticipation Note Fund, the Reserve and Contingency Fund and the General Reserve Fund are to be made as soon as practicable in each month after the deposit of Revenues into the Revenue Fund and the payment to the Operating Fund have been made for such month, but not later than the last business day of such month.

3. To the Bond Anticipation Note Fund, the amount, if any, required so that the balance in said Fund shall equal all interest on Outstanding Bond Anticipation Notes accrued and unpaid and to accrue to the end of the then current calendar month. The Trustee will apply amounts in the Bond Anticipation Note Fund to the payment of interest on Bond Anticipation Notes in accordance with the provisions of the resolution, agreement or contract relating to the issuance of such Bond Anticipation Notes. However, if at any time the amounts in the Debt Service Account or the Debt Service Reserve Account are less than the amounts required by the Bond Indenture, and there is not on deposit in the General Reserve Fund or in the Renewal and Replacement Account or the Reserve Account in the Reserve and Contingency Fund available moneys sufficient to cure such deficiency, the Trustee shall transfer from the Bond Anticipation Note Fund the amount necessary to make up such deficiency.

4. To the Reserve and Contingency Fund, for credit to (a) the Renewal and Replacement Account, the amount, if any, provided for deposit therein during the then current month in the current Annual Budget; (b) the Decommissioning Account, the amount, if any, provided for deposit therein for the then current month as set forth in the current Annual Budget; and (c) the Reserve Account, the amount, if any, provided for deposit therein during the then current month provided in the current Annual Budget.

Amounts in the Renewal and Replacement Account will be applied to the costs of Capital Improvements.

Amounts in the Decommissioning Account will be held as a reserve for the retirement from service, decommissioning or disposal of the generation facilities of the Project.

To the extent not provided for in the then current Annual Budget or by reserves in the Operating Fund or from the proceeds of Bonds, amounts in the Reserve Account will be applied to the costs of Capital Improvements to the extent amounts in the Renewal and Replacement Account are not sufficient therefor, and to the payment of extraordinary operation and maintenance costs of the Project, and contingencies.

If at any time the amounts in the Debt Service Account or in the Debt Service Reserve Account are less than the amounts required by the Bond Indenture, and there are not on deposit in the General Reserve Fund available moneys sufficient to cure such deficiency, then the Trustee will transfer from the Reserve Account and the Renewal and Replacement Account, in that order, the amount necessary to make up such deficiency.

Amounts in the Renewal and Replacement Account or the Reserve Account not required to meet any deficiencies in the Debt Service Fund or for any of the purposes for which such Accounts or the Decommissioning Account were established shall be transferred to the Operating Fund to the extent, if any, deemed necessary by the Authority to make up any deficiencies therein. Any remaining excess shall be deposited into the General Reserve Fund.

5. To the General Reserve Fund, the balance, if any, in the Revenue Fund. The Trustee shall transfer from the General Reserve Fund amounts in the following order of priority: (a) to the Debt Service Account and the Debt Service Reserve Account the amount necessary to make up any deficiencies in required payments to said Accounts, (b) to the Debt Service Reserve Account the amount of any deficiency in such Account resulting from any transfer to the Debt Service Account, and (c) to the Renewal and Replacement Account, the Decommissioning Account and the Reserve Account in the Reserve and Contingency Fund the amount necessary (or all moneys in the General Reserve Fund if less than the amount necessary) to make up any deficiencies in payments to said Accounts.

Amounts in the General Reserve Fund not required to meet any of the deficiencies described above or not required by the Bond Indenture for the purchase or redemption of Bonds will upon determination of the Authority be applied to or set aside for any one or more of the following: (a) transfer to the Revenue Fund; (b) the purchase or redemption of any Bonds, and expenses and reserves in connection therewith; (c) Authority Operating Expenses or reserves therefor; (d) payments into any separate account or accounts established in the Construction Fund; (e) Costs of

Acquisition and Construction attributable to Capital Improvements or reserves therefor; (f) reduction in the cost of the Project power and energy to Project Participants under the Power Sales Contracts; (g) payment of principal of Bond Anticipation Notes; and (h) any other lawful purpose of the Authority related to the Project. Bonds purchased or redeemed with amounts in the General Reserve fund shall be credited to Sinking Fund Installments thereafter to become due (other than the next due).

Construction Fund

The Bond Indenture establishes a Construction Fund, to be held by the Trustee, into which will be paid amounts required by the provisions of the Bond Indenture and any Supplemental Indenture and any moneys received for or in connection with the Project by the Authority, unless required to be otherwise applied as provided in the Bond Indenture. In addition, proceeds of insurance for physical loss or damage to the Project, including proceeds of any self-insurance fund, or of contractors' performance bonds pertaining to the period of construction of the Project will be paid into the Construction Fund. Within the Construction Fund, separate accounts will be established for (i) the Initial Facilities and (ii) any Capital Improvements, the costs of which are to be paid out of the Construction Fund.

The Trustee will pay, upon the requisitions of the Authority therefor, from the Construction Fund the Cost of Acquisition and Construction of the Project. Each such payment shall be made by the Trustee upon the filing by the Authority with the Trustee of a requisition for such payment, except that the Trustee will, during the construction of the Project, pay to the Authority a sum or sums aggregating not more than $250,000 to be used as a revolving fund. The Authority is to use the moneys in such revolving fund to pay such items of the Cost of Construction and Acquisition of the Project which cannot be conveniently paid through the filing with the Trustee prior to payment of requisitions by the Authority. Upon requisition by the Authority, the Trustee will, so long as the amount in such fund is less than $250,000, reimburse such fund by payments from the Construction Fund for expenses paid by the Authority.

Upon completion of the Initial Facilities or any Capital Improvements, the balance in the separate account in the Construction Fund established therefor not required to complete payment for the Cost of Acquisition and Construction of such Initial Facilities or Capital Improvements will be transferred to the Debt Service Reserve Account to the extent necessary to make the amount in such Account equal to the Debt Service Reserve Requirement, and the excess, if any, will be transferred to the General Reserve Fund for application to the retirement of Bonds by purchase or redemption. To the extent that other moneys are not available therefor, amounts in the Construction Fund will be applied, in priority to the other applications described above, to the payment of principal of and interest on Bonds when due.

Debt Service Reserve Requirement and Certain Other Definitions Pertaining to the Issuance of Bonds

Debt Service Reserve Requirement means, as of any date of calculation, an amount equal to the greatest amount of Adjusted Aggregate Debt Service for the then current or any future Fiscal Year; provided, however, that, for purposes of this definition, Adjusted Aggregate Debt Service shall be computed in accordance with the definition of said term given below with the exception that Aggregate Debt Service or Adjusted Debt Service with respect to a Series of Lender Bonds shall not be included in such computation unless the Supplemental Indenture authorizing such Series of Lender Bonds shall specify that such Aggregate Debt Service or Adjusted Debt Service shall be included in said computation; and provided further, that if such a computation shall include one or more Series of Lender Bonds, each such Lender Bond shall be deemed to bear at all times to the maturity date thereof the Assumed Interest Rate applicable thereto.

Adjusted Aggregate Debt Service means, as of any date of calculation and with respect to any period, the sum of (i) the sum of the amounts of Adjusted Debt Service during such period for all Series of Bonds and (ii) the Aggregate Debt Service during such period for all Series of Bonds not

included in the computation of Adjusted Debt Service on such date of calculation; provided, however, that in computing such Aggregate Debt Service, any particular Lender Bonds shall be deemed to bear at all times to the maturity thereof the Assumed Interest Rate applicable thereto.

Adjusted Debt Service means, with respect to any Series of Bonds, as of any date of calculation and with respect to any period, the Debt Service for such Series of Bonds for such period which would result if the Principal Installment for such Series due on the final maturity date of such Series were adjusted over the period specified pursuant to the next sentence so that the Bonds of such Series would have Substantially Equal Debt Service for each Fiscal Year of such period and that such Principal Installment would be fully paid at the end of such period, assuming timely payment of all principal of and premium, if any, and interest on the Bonds of such Series in accordance with such adjustments and computing the interest component of Debt Service on the basis of the true interest cost actually incurred on such Series of Bonds (determined by the true, actuarial method of calculation). Such adjustment shall be made over a period which shall begin with the final maturity date of such Series and end on a date which shall be specified in the Supplemental Indenture authorizing such Series of Bonds, which date shall be not later than the earlier to occur of (i) 35 years after the date of such Bonds or (ii) the termination date of the Power Sales Contracts. For purposes of computing such true interest cost for any Series of Bonds containing Lender Bonds, each such Lender Bond shall be deemed to bear at all times to the maturity date thereof the Assumed Interest Rate applicable thereto.

Assumed Interest Rate means, as to any Lender Bonds with a Variable Interest Rate, the interest rate for such Bonds assumed for purposes of determining their maturity schedule, and as to any Lender Bonds not having a Variable Interest Rate, the stated interest rate for each such Lender Bond.

Lender Bonds means Bonds which: (i) are issued in exchange for Bond Anticipation Notes, (ii) are issued pursuant to the requirements of a lending or credit facility or agreement and (iii) will be held by a bank, trust company or similar financial institution, domestic or foreign. To the extent such Bonds are not included in the computation of the Debt Service Reserve Requirement, the Supplemental Indenture pursuant to which such Bonds are issued shall specify that such Bonds shall not have a lien on or pledge of or be payable from, any moneys on deposit in the Debt Service Reserve Account notwithstanding any other provision of the Bond Indenture to the contrary.

Substantially Equal Adjusted Aggregate Debt Service means, with respect to any period of similar Fiscal Years for all Series of Bonds, that the greatest Adjusted Aggregate Debt Service for any Fiscal Year in such period is not in excess of one hundred and twenty-five per cent of the Adjusted Aggregate Debt Service for any preceding Fiscal Year in such period.

Substantially Equal Debt Service means, with respect to any period of Years for any Series of Bonds, that the greatest Debt Service for any Year in such period is not in excess of one hundred and twenty-five per cent of the smallest Debt Service for any Year in such period; provided, however, that in computing Debt Service for the purpose of this definition, any particular Lender Bond shall be deemed to bear at all times prior to the maturity thereof the Assumed Interest Rate applicable thereto.

Certain Requirements of and Conditions to Issuance of Bonds

Bonds shall be authenticated by the Trustee pursuant to the Bond Indenture upon compliance with certain requirements and conditions, including the following:

(a) The Trustee shall have received an Opinion of Bond Counsel to the effect that the Bonds of the Series being issued have been duly and validly authorized and issued and are valid and binding obligations of the Authority and as to certain other matters concerning the Bond Indenture.

(b) The Trustee shall have received the amount, if any, necessary for deposit in the Debt Service Reserve Account in the Debt Service Fund so that the balance in such Account shall equal the Debt Service Reserve Requirement calculated immediately after authentication and delivery of such Series of Bonds.

(c) Except in the case of Lender Bonds and Refunding Bonds, the Authority shall have certified that it is not in default in the performance of its agreements under the Bond Indenture.

The Bond Indenture also authorizes the issuance of Bonds known as "Initial Facilities Issue" to be issued in Series from time to time to pay all or a portion of the Cost of Acquisition and Construction of the Initial Facilities. Proceeds, including accrued interest, of each Series of Bonds of the Initial Facilities Issue are to be applied as determined by the Supplemental Indenture authorizing such Series.

The Bond Indenture also provides that Principal Installments will be established at the time of issuance for each Series of Bonds of the Initial Facilities Issue and each Series of Additional Bonds and Refunding Bonds so as to comply with the following:

(a) Principal Installments shall commence not later than the later of (A) the first day of the eighth Fiscal Year following the end of the Fiscal Year of authentication and delivery of such Series of Bonds or (B) the first day of the fifth Fiscal Year following the end of the Fiscal Year in which the Project Manager estimates that the last generation unit of the Project will first reach its Date of Firm Operation, and shall terminate not later than the date on which the Power Sales Contracts terminate.

(b) Such Principal Installments shall result in either (A) Substantially Equal Debt Service for the Bonds of such Series for the Year immediately preceding the due date of the first such Principal Installment to occur subsequent to the Date of Firm Operation of the last generating unit of the Project and for each Year thereafter to and including the final maturity date of such Series or (B) Substantially Equal Adjusted Aggregate Debt Service for all Outstanding Bonds, including such Series being issued, for the first Fiscal Year in which Principal Installments become due on all Series of Bonds then Outstanding, including such Series being issued, beginning however no earlier than the Fiscal Year immediately preceding the due date of the first Principal Installment to occur subsequent to the Date of Firm Operation of the last generating unit of the Project, and for each Fiscal Year thereafter to and including the Fiscal Year immediately preceding the latest maturity of any Series of Bonds Outstanding immediately prior to the issuance of such Series being issued or the Fiscal Year immediately preceding the latest maturity of such Series being issued, whichever is earlier (using in the case of any Series of Bonds sold by competitive bidding a net effective interest rate for the Bonds of such Series as estimated by the Authority); provided, that, if the first Principal Installment for any Series of Bonds shall be less than 12 months after the date of issuance thereof, it shall be assumed, for purposes of this calculation, that interest accrued on such Series for the entire 12-month period preceding the first Principal Installment at the same rate as interest accrued for the actual portion of such period during which such Series of Bonds was Outstanding.

Additional Bonds

The Authority may issue one or more Series of Additional Bonds for the purpose of paying all or a portion of the Cost of Acquisition and Construction of any Capital Improvements upon compliance with the following in addition to the conditions to issuance described above:

(a) In the case of Additional Bonds being issued to finance the Cost of Acquisition and Construction of Capital Improvements which are determined necessary by the Board of Directors under the Power Sales Contracts to keep the Project in good operating condition or to prevent a loss of revenue therefrom or to prevent an increase in Authority Operating Expenses, the Trustee shall have received an opinion of the Consulting Engineer to such effect.

(b) In the case of Additional Bonds being issued to finance the Cost of Acquisition and Construction of Capital Improvements either required by any governmental agency having jurisdiction over the Project, required by the Participation Agreement or required by the Bond Indenture, the Trustee shall have received an Opinion of Bond Counsel to the effect that such Capital Improvements are either required by such governmental agency or are an obligation of

the Authority arising out of the Power Sales Contracts, the Participation Agreement or the Bond Indenture, respectively.

Refunding Bonds

One or more Series of Refunding Bonds may be issued to refund all Outstanding Bonds of one or more Series or one or more maturities within a Series. Refunding Bonds shall be authenticated and delivered by the Trustee pursuant to the Bond Indenture upon compliance with certain requirements and conditions, including the receipt by the Trustee of either (i) moneys sufficient to pay the applicable Redemption Price of the refunded Bonds to be redeemed plus the amount required to pay principal on refunded Bonds not to be redeemed together with accrued interest on such Bonds or (ii) Investment Securities in such amounts and having such terms as required by the Bond Indenture to pay, the principal or Redemption Price, if applicable, and interest due on the redemption date or maturity date, as the case may be.

Notice of Redemption

The Bond Indenture requires the Trustee to give notice of any redemption of the Bonds by publication once a week for at least two successive weeks in newspapers customarily published at least once a day for at least five days (other than legal holidays) in each calendar week in the English language and of general circulation, respectively, in Los Angeles, California and in the Borough of Manhattan, City and State of New York. The first such publication is required to be made not less than 30 days nor more than 60 days prior to the redemption date. The Trustee is also required to mail a copy of such notice not less than 25 days before the redemption date to the holders of any registered Bonds which are to be redeemed, but failure to do so will not affect the validity of any redemption.

Interchangeability

Bonds in coupon form, upon surrender thereof at the principal corporate trust office of the Trustee, acting as Bond Registrar pursuant to the Bond Indenture, with all unmatured coupons attached, may, at the option of the holder thereof, be exchanged for an equal aggregate principal amount of fully registered Bonds of the same Series and maturity and of any authorized denominations.

Bonds in fully registered form, upon surrender thereof at the principal corporate trust office of the Bond Registrar with a written instrument of transfer satisfactory to the Bond Registrar, duly executed by the registered owner or his duly authorized attorney, may, at the option of the registered owner thereof, be exchanged for an equal aggregate principal amount of Bonds in coupon form, of the same Series and maturity with appropriate coupons attached, or of Bonds in registered form of the same Series and maturity and of any other authorized denomination.

In all cases in which the privilege of exchanging the Bonds or transferring the registered Bonds is exercised, the Authority shall execute and the Trustee shall authenticate and deliver the Bonds in accordance with the provisions of the Bond Indenture. For every such exchange or transfer of the Bonds, the Authority or the Bond Registrar may make a charge sufficient to reimburse it for any tax, fee or other governmental charge required to be paid with respect to such exchange or transfer. Neither the Authority nor the Bond Registrar shall be required to transfer or exchange any Bond (a) for a period of 20 days next preceding an interest payment date or next preceding any selection of the Bonds to be redeemed or thereafter until after the first publication or mailing of any notice of redemption or (b) if such Bond has been called for redemption.

Investment of Certain Funds and Accounts

The Bond Indenture provides that certain Funds and Accounts held thereunder may, and in the case of the Debt Service Account and the Debt Service Reserve Account in the Debt Service Fund and the Bond Anticipation Note Fund, subject to the terms of agreements relating to the issuance of Bond

Anticipation Notes, must, be invested to the fullest extent practicable in Investment Securities. The Bond Indenture provides that such investments will mature no later than such times as shall be necessary to provide moneys when needed for payments from such Funds and Accounts and provides specific limitations on the term of investments for moneys in certain Funds and Accounts.

Interest (net of the return of accrued interest paid in connection with the purchase of any investment) earned on any moneys or investments in such Funds or Accounts, other than the Construction Fund, will be paid into the Revenue Fund except that interest shall be paid into the Construction Fund to the extent provided in the Supplemental Indenture authorizing the first Series of Bonds issued under the Bond Indenture. Interest on moneys or investments in each separate account in the Construction Fund will be held in such account for the purposes thereof.

The Trustee may deposit moneys in all Funds and Accounts held under the Bond Indenture in banks or trust companies organized under the laws of any state of the United States or national banking associations ("Depositaries"). All moneys held under the Bond Indenture by the Trustee or any Depositary must be (1) either (a) continuously and fully insured by the Federal Deposit Insurance Corporation, or (b) continuously and fully secured by lodging with the Trustee or any Federal Reserve Bank, as custodian, as collateral security, such securities as are described in clauses (i) through (iv), inclusive, of the definition of "Investment Securities" having a market value (exclusive of accrued interest) not less than the amount of such moneys, and (2) held in such other manner as may then be required by applicable Federal or State of California laws and regulations and applicable state laws and regulations of the state in which the Trustee or such Depositary is located, regarding security for the deposit of trust funds; provided, however, that it shall not be necessary for the Trustee or any Paying Agent to give security for the deposit of any moneys held in trust by it and set aside by it for the payment of principal or Redemption Price of or interest on any Bonds or for the Trustee or any Depositary to give security for any moneys which are represented by obligations or certificates of deposit purchased as an investment of such moneys.

In computing the amount in any Fund created under the Bond Indenture, obligations purchased as an investment of moneys therein shall be valued at the amortized cost of such obligations or the market value thereof, whichever is lower, exclusive of accrued interest. Such computations shall be determined as of January 1 and July 1 in each year.

Encumbrances; Disposition of Properties

The Authority will not issue bonds, notes, debentures or other evidences of indebtedness, other than the Bonds, payable out of or secured by a pledge or assignment of the Revenues or other moneys, securities or funds held or set aside by the Authority, the Trustee or the Paying Agents under the Bond Indenture, nor will it create, or cause to be created any lien or charge thereon, except, to the extent permitted by law, (1) evidences of indebtedness (a) payable out of moneys in the Construction Fund as part of the Cost of Acquisition and Construction of the Project or (b) payable out of, or secured by a pledge and assignment of, Revenues to be derived on and after the discharge of the pledge of Revenues provided in the Bond Indenture or (2) Bond Anticipation Notes issued in accordance with the provisions of the Bond Indenture.

The Authority may, however, acquire, construct or finance through the issuance of its bonds, notes or other evidences of indebtedness any facilities which do not constitute a part of the Project for the purposes of the Bond Indenture and may secure such bonds, notes or other evidences of indebtedness by a mortgate of the facilities so financed or by a pledge of, or other security interest in, the revenues therefrom or any lease or other agreement with respect thereto or any revenues derived from such lease or other agreement; provided that such bonds, notes or other evidences of indebtedness shall not be payable out of or secured by the Revenues or any Fund or Account held under the Bond Indenture and neither the cost of such facilities nor any expenditure in connection therewith or with the financing thereof shall be payable from the Revenues or from any such Fund or Account.

The Authority will not sell, lease, mortgage or otherwise dispose of any part of the Project, except for sales or exchanges of property or facilities (1) which are not useful in the operation of the Project, or (2) for which the proceeds received are, or the fair market value of the subject property (as certified by an Authorized Authority Representative) is, less than $100,000, or (3) as to which the Consulting Engineer certifies that the ability of the Authority to comply with the rate covenant described under the caption "Rate Covenant" below will not be impaired. The proceeds of any such transaction not used to acquire other property necessary or desirable for the operation of the Project will be deposited in the General Reserve Fund.

The Authority will not lease or make contracts or grant licenses for the operation or use of, or grant easements or any other rights with respect to, any part of the Project, which would (1) impede the operation of the Project and (2) impair or adversely affect the rights or security of Bondholders under the Bond Indenture. If the depreciated costs of the subject property exceeds $500,000, the Consulting Engineer must certify that the proposed action of the Authority does not result in a breach of the above mentioned conditions. Any payments to the Authority in connection with any such transaction will constitute Revenues.

Rate Covenant

The Authority covenants in the Bond Indenture that as long as any Bonds are Outstanding it will have good right and lawful power to establish and collect rates and charges with respect to the use of the capability of the Project and the sale of the capacity, output or service thereof, subject to the terms of the Project Agreements. The Authority covenants in the Bond Indenture that it will at all times establish and collect rates and charges for the use of the capability of the Project or the sale of the output, capacity or service of the Project which provide Revenues at least sufficient in each Fiscal Year, together with other available funds, for the payment of all the following:

(a) Authority Operating Expenses during such Fiscal Year;

(b) An amount equal to the Aggregate Debt Service for such Fiscal Year;

(c) The amount, if any, to be paid during such Fiscal Year into the Debt Service Reserve Account in the Debt Service Fund;

(d) The amount, if any, to be paid during such Fiscal Year into the Bond Anticipation Note Fund;

(e) The amount to be paid during such Fiscal Year into the Reserve and Contingency Fund for credit to the Renewal and Replacement Account, the Decommissioning Account and the Reserve Account therein; and

(f) All other charges or liens whatsoever payable out of Revenues during such Fiscal Year.

The Authority will not furnish any use, output, capacity, or service of the Project free of charge to any person, firm or corporation, public or private, and the Authority will enforce the payment of any and all accounts owing to the Authority by reason of its ownership and operation of the Project by discontinuing such use, output, capacity, or service or by filing suit therefor as soon as practicable after 120 days after any such accounts are due, or by both such discontinuance and by filing suit.

Covenants with Respect to Power Sales Contracts and Project Agreements

The Trustee covenants that it will collect and deposit in the Revenue Fund all amounts payable to it under the Power Sales Contracts or otherwise payable to it pursuant to any contract for use of the capability of the Project or the sale of the output, capacity or service of the Project or any part thereof. The Authority will enforce the provisions of the Power Sales Contracts and duly perform its covenants and agreements thereunder, and will not agree to or permit any rescission of or amendment to, or otherwise take any action under or in connection with, the Power Sales Contracts which would reduce

the payments required thereunder or which would in any manner materially impair or materially adversely affect the rights or security of Bondholders under the Bond Indenture.

The Authority will enforce the provisions of the Project Agreements and duly perform its covenants and agreements thereunder. The Authority will not consent or agree to or permit any rescission of or amendment to or otherwise take any action under or in connection with the Project Agreements which will in any manner materially impair or materially adversely affect the rights of the Authority thereunder or the rights or security of the Bondholders under the Bond Indenture; however, the Authority is not thereby prohibited from amending any Power Sales Contract with respect to Points of Delivery.

Annual Budget

The Authority will file with the Trustee an Annual Budget prepared in accordance with the Power Sales Contracts for each Fiscal Year commencing with the Fiscal Year which begins on the earliest of (i) the date to which all interest is capitalized with respect to all Bonds and Bond Anticipation Notes, (ii) the date which is one year prior to the first Principal Installment date for any Bonds, or (iii) the Date of Firm Operation of the first generating unit to be placed in service. The Annual Budget will set forth the estimated Revenues and Authority Operating Expenses of the Project, by month for such Fiscal Year and shall include monthly appropriations for the estimated amount to be deposited in each month of such Fiscal Year in the Revenue Fund, the Operating Fund, including provision for any general reserve for Authority Operating Expenses and the estimated amount to be deposited in the Renewal and Replacement Account, the Decommissioning Account and the Reserve Account in the Reserve and Contingency Fund and the requirements, if any, for the amounts estimated to be expended from each Fund and Account. The Authority shall review quarterly its estimates set forth in the Annual Budget and in the event such estimates do not substantially correspond with the actual Revenues, Authority Operating Expenses or other requirements, the Authority shall adopt an amended Annual Budget for the remainder of such Fiscal Year. The Authority is also required to adopt such an amended Annual Budget if there are at any time during such Fiscal Year extraordinary receipts or payments of unusual costs. The Authority may also at any time in accordance with the provisions of the Power Sales Contracts, adopt an amended Annual Budget for the remainder of the then current Fiscal Year.

Insurance

The Authority will at all times keep or cause to be kept the properties of the Project which are of an insurable nature and of the character usually insured by those constructing or operating properties similar to the Project insured against loss or damage by fire and from other causes customarily insured against and in such amounts as are usually obtained. The Authority will also use its best efforts to maintain or cause to be maintained any additional or other insurance which the Authority deems necessary or advisable to protect its interests and those of the Bondholders. If any useful portion of the Project is damaged or destroyed, the Authority shall diligently prosecute the reconstruction or replacement thereof, unless the Authority decides not to so repair or replace. The proceeds of any insurance, including the proceeds of any self-insurance fund, paid on account of damage or destruction (other than any business interruption loss insurance) unless held and applied under the Participation Agreement, shall be held by the Trustee and applied, to the extent necessary, to pay the costs of reconstruction or replacement. The proceeds of any business interruption loss insurance shall be paid into the Revenue Fund unless otherwise required by the Participation Agreement.

Accounts and Reports

The Authority will keep or cause to be kept proper and separate books of records and accounts relating to the Project and each Fund and Account established by the Bond Indenture and relating to the costs and charges under the Power Sales Contracts. Such books, together with all other books and papers of the Authority relating to the Project, will at all times be subject to the inspection of the

Trustee and the Holders of an aggregate of not less than 5% in principal amount of Bonds then Outstanding.

The Authority will file annually with the Trustee an annual report for each Fiscal Year, accompanied by an Accountant's Certificate, relating to the Project, including a statement of assets and liabilities as of the end of such Fiscal Year, a statement of Revenues and Authority Operating Expenses, a statement of receipts and disbursements with respect to Funds and Accounts established by the Bond Indenture, and a statement as to the existence of any default under the provisions of the Bond Indenture.

The Authority will cause the Consulting Engineer to file with it and the Trustee after each three year period a report or survey with respect to the operation and maintenance of the properties constituting the Project, the making of necessary and proper renewals and replacements thereof and the status of the Annual Budget and any construction budget of the Project.

The Authority will notify the Trustee forthwith of any Event of Default or default in the performance of any provision of the Bond Indenture. The Authority will file annually with the Trustee a certificate of an Authorized Authority Representative stating whether, to the best of the signer's knowledge and belief, the Authority has complied with its covenants and obligations in the Bond Indenture and whether there is then existing an Event of Default or other event which would become an Event of Default upon the lapse of time and if any such default or Event of Default so exists, specifying the same and the nature and the status thereof.

The reports, statements and other documents required to be furnished to the Trustee pursuant to any provisions of the Bond Indenture will be available for inspection of Bondholders at the office of the Trustee and will be mailed to each Bondholder who files a written request therefor with the Trustee. The Trustee may charge each Bondholder requesting such reports, statements and other documents a reasonable fee to cover reproduction, handling and postage.

Extension of Payment of Bonds and Coupons

The Authority covenants in the Bond Indenture that it will not extend or assent to the extension of the maturity of any of the Bonds or the time of payment of any of the coupons or claims for interest. If the maturity of any of the Bonds or the time for payment of such coupons or claims for interest is extended, such Bonds, coupons or claims for interest shall not be entitled, in the case of any default under the Bond Indenture, to the benefit of the Bond Indenture or any payment out of Revenues, Funds or the moneys held by the Trustee or by any Paying Agent (except moneys held in trust for the payment of particular Bonds, coupons or claims for interest) except upon the prior payment of the principal of all Bonds Outstanding the maturity of which has not been extended and of the portion of accrued interest on the extended Bonds which is not represented by such extended coupons or claims for interest.

Amendments and Supplemental Indentures

Any of the provisions of the Bond Indenture may be amended by the Authority by a Supplemental Indenture upon the consent of the Holders of at least two-thirds in principal amount in each case of (1) all Bonds then Outstanding and (2) if less than all of the several Series of Outstanding Bonds are affected, the Bonds of each affected Series; excluding, in each case, from such consent, and from the Outstanding Bonds, the Bonds of any specified Series and maturity if such amendment by its terms will not take effect so long as any of such Bonds remain Outstanding. Any such amendment may not permit a change in the terms of any Sinking Fund Installment or the terms of redemption or maturity of the principal of or interest on any Outstanding Bond or make any reduction in principal, Redemption Price or interest rate without the consent of each affected Holder, or reduce the percentages of consents required for a further amendment.

The Authority may adopt (without the consent of any Holders of the Bonds or the Trustee) Supplemental Indentures to close the Bond Indenture against, or impose additional limitations upon,

issuance of Bonds or other evidences of indebtedness; to authorize Bonds of a Series; to add to the restrictions contained on the Bond Indenture; to add to the covenants of the Authority contained in the Bond Indenture; to confirm any security interest or pledge under the Bond Indenture; to authorize the establishment of a fund or funds for self-insurance; and to modify any of the provisions of the Bond Indenture in any other respect if such modification shall be, and be expressed to be, effective only after all Bonds then Outstanding cease to be Outstanding and all Bonds authenticated and delivered after the adoption of such Supplemental Indenture specifically refer to such Supplemental Indenture in the text of such Bonds. The Authority may adopt Supplemental Indentures which shall be effective upon the consent of the Trustee (without the consent of any Holders of the Bonds) to cure any ambiguity; supply any omission or correct any defect or inconsistent provision in the Bond Indenture; or to clarify matters or questions arising under the Bond Indenture and not contrary to or inconsistent with the Bond Indenture.

Notwithstanding any other provision of the Bond Indenture, certain provisions of the supplemental indentures authorizing the issuance of certain refunding Bonds may not be amended or supplemented in any manner if such amendment or supplement adversely affects the interest of the holders of such Bonds in the respective Escrow Funds or in any other manner.

Trustee; Paying Agents

The Trustee may at any time resign on 60 days' written notice to the Authority. Such resignation will take effect on the date specified in such notice, or, if a successor Trustee has been appointed by the Authority with the approval of the Bondholders pursuant to the Bond Indenture prior to such date, such resignation will take effect immediately upon the appointment of such successor. The Trustee may at any time be removed by the Holders of a majority in principal amount of the Bonds then Outstanding. Successor Trustees may be appointed by the Holders of a majority in principal amount of Bonds then Outstanding, and failing such an appointment the Authority shall appoint a successor to hold office until the Bondholders act. The Trustee and each successor Trustee, if any, must be a bank, trust company or national banking association doing business and having its principal office in either New York, New York, Chicago, Illinois, Los Angeles, California or San Francisco, California and having capital stock and surplus aggregating at least $50,000,000, if there be such an entity willing and able to accept appointment. The Bond Indenture requires the appointment by the Authority of one or more Paying Agents (which may include the Trustee).

Pursuant to the Bond Indenture, the Trustee, prior to the occurrence of an Event of Default and after the curing of all Events of Default which may have occurred, undertakes to perform only such duties as are specifically set forth in the Bond Indenture. If an Event of Default has occurred and has not been cured, the Trustee shall exercise such of the rights and powers vested in it by the Bond Indenture, and use the same degree of care and skill in their exercise, as a prudent man would exercise or use under the circumstances in the conduct of his own affairs. Subject to the above, neither the Trustee nor any Paying Agent shall be liable in connection with the performance of its duties under the Bond Indenture except for its own negligence, misconduct or default.

The Authority is required to pay to each Fiduciary reasonable compensation for all services rendered under the Bond Indenture and all reasonable expenses, charges, counsel fees and other disbursements, incurred in the performance of its duties under the Bond Indenture. Each Fiduciary has a lien on any and all funds held by it under the Bond Indenture securing its rights to compensation. The Authority also agrees to indemnify and save each Fiduciary harmless against any liabilities which it may incur in the exercise and performance of its powers and duties under the Bond Indenture, and which are not due to its negligence, misconduct or default.

Defeasance

If the Authority shall pay or cause to be paid, or there shall otherwise be paid, to the Holders of all Bonds and coupons the principal or Redemption Price, if applicable, and interest due or to become due thereon, at the times and in the manner stipulated therein and in the Bond Indenture, then the lien of the Bond Indenture and all covenants, agreements and other obligations of the Authority to the

Bondholders, shall thereupon cease, terminate and become void and be discharged and satisfied. In such event, the Trustee shall cause an accounting for such period or periods as shall be requested by the Authority to be prepared and filed with the Authority and, upon the request of the Authority shall execute and deliver to the Authority all such instruments as may be desirable to evidence such discharge and satisfaction, and the Fiduciaries shall pay over or deliver, as directed by the Authority, all moneys or securities held by them pursuant to the Bond Indenture which are not required for the payment of principal or Redemption Price, if applicable, on Bonds or payment of coupons not theretofore surrendered for such payment or redemption. If the Authority shall pay or cause to be paid, or there shall otherwise be paid, to the Holders of all Outstanding Bonds of a particular Series, or of a particular maturity within a Series, and the coupons appertaining thereto the principal or Redemption Price, if applicable, and interest due or to become due thereon, at the times and in the manner stipulated therein and in the Bond Indenture, such Bonds shall cease to be entitled to any lien, benefit or security under the Bond Indenture, and all covenants, agreements and obligations of the Authority to the Holders of such Bonds shall thereupon cease, terminate and become void and be discharged and satisfied.

Bonds or coupons or interest installments for the payment or redemption of which moneys shall have been set aside and shall be held in trust by the Paying Agents (through deposit pursuant to the Bond Indenture of funds for such payment or redemption or otherwise) at the maturity or redemption date thereof shall be deemed to have been paid within the meaning and with the effect expressed in the above paragraph. All Outstanding Bonds of any Series, or of any maturity within a Series, and all coupons appertaining to such Bonds shall prior to the maturity or redemption date thereof be deemed to have been paid within the meaning and with the effect expressed in the above paragraph if (a) in case any of said Bonds are to be redeemed on any date prior to their maturity, the Authority shall have given to the Trustee irrevocable instructions accepted in writing by the Trustee to publish as provided in the Bond Indenture notice of redemption of such Bonds on said date, (b) there shall have been deposited with the Trustee either moneys in an amount which shall be sufficient, or Investment Securities (including any Investment Securities issued or held in book-entry form on the books of the Department of the Treasury of the United States) the principal of and the interest on which when due will provide moneys which, together with the moneys, if any, deposited with the Trustee at the same time, shall be sufficient, to pay when due the principal or Redemption Price, if applicable, and interest due and to become due on said Bonds on or prior to the redemption date or maturity date thereof, as the case may be, and (c) the Authority shall have given the Trustee in form satisfactory to it irrevocable instructions to publish, as soon as practicable, at least twice, at an interval of not less than seven days between publications, in the Authorized Newspapers a notice to the Holders of such Bonds and coupons that the deposit required by (b) above has been made with the Trustee and that said Bonds and coupons are deemed to have been paid in accordance with the Bond Indenture and stating such maturity or redemption date upon which moneys are to be available for the payment of the principal or Redemption Price, if applicable, on said Bonds. Neither Investment Securities nor moneys deposited with the Trustee pursuant to the Bond Indenture nor principal or interest payments on any such Investment Securities shall be withdrawn or used for any purpose other than, and shall be held in trust for, the payment of the principal or Redemption Price, if applicable, and interest on said Bonds; provided that any cash received from such principal or interest payments on such Investment Securities deposited with the Trustee, (A) to the extent such cash will not be required at any time for such purpose, as determined by the Trustee, shall be paid over upon the direction of the Authority as received by the Trustee, free and clear of any trust, lien, pledge or assignment securing said Bonds or otherwise existing under the Bond Indenture, and (B) to the extent such cash will be required for such purpose at a later date, shall, to the extent practicable, be reinvested in Investment Securities maturing at times and in amounts sufficient to pay when due the principal or Redemption Price, if applicable, and interest to become due on said Bonds, on or prior to such redemption date or maturity date thereof, as the case may be, and interest earned from such reinvestments shall be paid over as received by the Trustee, free and clear of any lien, pledge or security interest securing said Bonds or otherwise existing under the Bond Indenture. For the purposes of defeasance, Investment Securities shall mean

and include only such securities as are described in clause (i) of the definition of "Investment Securities" in the Bond Indenture which shall not be subject to redemption prior to their maturity other than at the option of the holder thereof.

Any request, consent, revocation of consent or other instrument which the Bond Indenture may require or permit to be signed and executed by the Bondholders may be in one or more instruments of similar tenor, and shall be signed or executed by such Bondholders in person or by their attorneys appointed in writing. Proof of (i) the execution of any such instrument, or of an instrument appointing any such attorney, or (ii) the holding by any person of the Bonds or coupons appertaining thereto, shall be sufficient for any purpose of the Bond Indenture (except as otherwise therein expressly provided) if made in accordance with the Bond Indenture, or in any other manner satisfactory to the Trustee, which may nevertheless in its discretion require further or other proof in cases where it deems the same desirable.

Events of Default and Remedies

Events of Default specified in the Bond Indenture include failure to pay principal or Redemption Price of any Bond when due; failure to pay any interest installment on any Bond or the unsatisfied balance of any Sinking Fund Installment thereon when due; and default for 120 days after written notice thereof from the Trustee or the Holders of not less than 10% in principal amount of the Bonds then Outstanding in the observance or performance of any other covenants, agreements or conditions contained in the Bond Indenture or in the Bonds. Upon the happening of any such Event of Default the Trustee or the Holders of not less than 25% in principal amount of the Bonds then Outstanding may declare the principal of and accrued interest on all Bonds then Outstanding due and payable (subject to a rescission of such declaration upon the curing of such default before the Bonds have matured).

Upon the occurrence of any Event of Default which has not been remedied, the Authority will, if demanded by the Trustee, (1) account, as if it were the trustee of an express trust, for all Revenues and other moneys, securities and funds pledged or held under the Bond Indenture, and (2) cause to be paid over to the Trustee (a) forthwith, all moneys, securities and funds held by the Authority in any Fund under the Bond Indenture and (b) as received, all Revenues. The Trustee will apply all moneys, securities, funds and Revenues received during the continuance of an Event of Default in the following order: (1) to payment of the reasonable and proper charges, expenses and liabilities of the Trustee and Paying Agents, (2) to the payment of Authority Operating Expenses, and (3) to the payment of interest and principal or Redemption Price on the Bonds without preference or priority of interest over principal or principal over interest, unless the principal of all Bonds has not been declared due and payable, in which case first to the payment of interest and second to the payment of principal or Redemption Price on those Bonds which have become due and payable in order of their due dates, and if the amount available shall not be sufficient for such payment thereof, ratably, according to the amounts of interest or principal or Redemption Price, respectively, due on such date. In addition, the Trustee will have the right to apply in an appropriate proceeding for appointment of a receiver of the Project.

If an Event of Default has occurred and has not been remedied the Trustee may, or on request of the Holders of not less than 25% in principal amount of Bonds Outstanding must, proceed to protect and enforce its rights and the rights of the Bondholders under the Bond Indenture forthwith by a suit or suits in equity or at law, whether for the specific performance of any covenant in the Bond Indenture or in aid of the execution of any power granted in the Bond Indenture or any remedy granted under the Act, or for an accounting against the Authority, as if it were trustee of an express trust, or in the enforcement of any other legal or equitable rights, as the Trustee deems most effectual to enforce any of its rights or to perform any of its duties under the Bond Indenture. The Trustee may, and upon the request of the Holders of a majority in principal amount of the Bonds then Outstanding and upon being furnished with reasonable security and indemnity must, institute and prosecute proper actions to prevent any impairment of the security under the Bond Indenture or to preserve or protect the interests of the Trustee and of the Bondholders.

No Bondholder will have any right to institute any suit, action or proceeding for the enforcement of any provision of the Bond Indenture or the execution of any trust under the Bond Indenture or for any remedy under the Bond Indenture, unless (1) such Bondholder previously has given the Trustee written notice of an Event of Default, (2) the Holders of at least 25% in principal amount of the Bonds then Outstanding have filed a written request with the Trustee and have afforded the Trustee a reasonable opportunity either to exercise its powers under the Bond Indenture, the Act or the laws of the State of California or to institute such suit, action or proceeding, (3) there have been offered to the Trustee adequate security and indemnity against its costs, expenses and liabilities to be incurred and (4) the Trustee has refused to comply with such request within 60 days after receipt by it of such notice, request and offer of indemnity. The Bond Indenture provides that nothing therein or in the Bonds affects or impairs the Authority's obligation to pay the Bonds and interest thereon when due or the right of any Bondholder to enforce such payment of his Bonds.

The Holders of not less than a majority in principal amount of Bonds then Outstanding may direct the time, method and place of conducting any proceeding for any remedy available to the Trustee or exercising any trust or power conferred upon the Trustee, subject to the Trustee's right to decline to follow such direction upon advice of counsel as to the unlawfulness thereof or upon its good faith determination that such action would involve the Trustee in personal liability or would be unjustly prejudicial to Bondholders not parties to such direction.

The Insurer shall be deemed to be the Holder of any Bonds for which the Insurer has issued a municipal bond insurance policy.

Notice of Default

Notice of the occurrence of any Event of Default will be given to each registered owner of Bonds then Outstanding and to each Holder of coupon Bonds who shall have filed with the Trustee within two years preceding the mailing of such notice an address for notices.

Unclaimed Moneys

Any moneys held by a Fiduciary in trust for the payment of any of the Bonds or coupons which remain unclaimed for six years after the date when such Bonds have become due and payable, either at their stated maturity dates or by call for redemption, shall, at the written request of the Authority and after meeting certain publication requirements, be repaid to the Authority, and the Fiduciary shall thereupon be released and discharged with respect thereto and the Bondholders shall look only to the Authority for the payment of such Bonds and coupons.

SUMMARY OF CERTAIN PROVISIONS OF THE POWER SALES CONTRACTS

The following is a summary of certain provisions of the Power Sales Contracts entered into between the Authority and each of the Project Participants. Except as described in this summary, all of the Power Sales Contracts are identical in all material respects. This summary is not to be considered a full statement of the terms of such Power Sales Contracts and accordingly is qualified by reference thereto and is subject to the full text thereof. Capitalized terms not defined in the Official Statement have the meanings set forth in the Power Sales Contracts.

Entitlement to Capacity

During the Start-up Period and any Base Load Period of any generating unit of the Project, each Project Participant is obligated to take delivery of its Project Entitlement Share of the product of the Authority Percentage multiplied by the Net Energy Generation of such generating unit. After the Date of Firm Operation of each generating unit of the Project, each Project Participant is entitled to schedule for its account capacity and energy of each generating unit of the Project up to the amount obtained by multiplying its Project Entitlement Share by the Authority Percentage and the Available

Generating Capability of each generating unit of the Project; provided that such scheduling shall not reduce the Project Participant's obligations described in the preceding sentence. A Project Participant may arrange to dispose of capacity or energy from the Project to which it is entitled, but any such arrangements will not affect its obligations under its Power Sales Contract. The delivery of capacity and energy from the Generating Station will be scheduled by (or on behalf of) the Authority and the Project Participants in advance with the Operating Agent and accounted for on the basis of such advance schedules. Whenever any Project Participant schedules for its account capacity and energy from a generating unit of the Project, the Agent, acting on behalf of the Authority, unless otherwise established under the Participation Agreement, shall additionally schedule for each Project Participant a percentage of the Zero Net Load as effective during the period that such generating unit is operated to meet such schedule, equal to the product of the Project Participant's Project Entitlement Share multiplied by the Authority Percentage. The capacity and energy of the Project shall be scheduled or controlled by the Project Participants under practices and procedures approved by the Board of Directors, subject to the provisions of the Participation Agreement.

Nature of Obligation

Each Project Participant is obligated to make the payments required under its Power Sales Contract solely from the revenues of its electric system as a cost of purchased electric capacity and energy and an operating expense. Each such Project Participant has covenanted to include in its annual power system budget for each fiscal year during the term of its Power Sales Contract an appropriation from the revenues of its electric system sufficient to pay all amounts required to be paid during such fiscal year under such Power Sales Contract. The Project Participants' obligations, which are several and not joint, to make payments of Monthly Power Costs under their respective Power Sales Contracts are not subject to reduction or offset if the Project is not operating or operable (or has been completed) or if its output is suspended, interfered with, reduced or curtailed or terminated in whole or in part. In addition, the Project Participants' payment obligations under the Power Sales Contracts are not subject to any reduction or offset and are not conditional upon the performance or nonperformance by any party of any agreement for any cause whatever.

Term

The Power Sales Contracts shall constitute a binding obligation of the parties thereto from and after the effective date and the term of such Power Sales Contracts shall end on October 31, 2030 or such later date as all Bonds and the interest thereon shall have been paid in full or adequate provision for such payment shall have been made, unless terminated sooner in accordance with provisions for termination or amendment described below.

Required Payments

For a discussion on Monthly Power Costs and the payment obligations of the respective Project Participants with respect thereto, see "Security and Sources of Payment for the Bonds — Power Sales Contracts".

Rate Covenants of Project Participants

Each Project Participant has covenanted in its Power Sales Contract to establish, maintain and collect rates and charges for the electric service it furnishes so as to provide revenues which, together with its available electric system reserves, are sufficient to enable it to pay all amounts payable under its Power Sales Contract and to pay all other amounts payable from, and all lawful charges against or liens on, its electric system revenues.

The Board of Directors

The Authority is administered by a Board of Directors comprised of the chief executive officer (or his designee) of the electric utility of each member of the Authority. The Project Participants are entitled to participate in Project matters in accordance with voting rights given to them as members of the Authority. See "Southern California Public Power Authority — Organization and Management" in the Official Statement. The Authority, through its Board of Directors, has the following duties and responsibilities, among others: (1) provide liaison among the Project Participants, (2) attempt to resolve any disputes among the Authority, the Project Participants, the Agent, and the Project Manager or the Operating Agent relating to the Project, (3) review, modify and approve (i) the practices and procedures to be followed by the Project Participants relating to the scheduling and controlling of capacity and energy from the Project, (ii) all Capital Improvements and the budgets therefor and provisions for financing thereof, (iii) all amendments and supplements to the Project Agreements and (iv) the Project's insurance program, (4) approve all consultants or advisors on financial and legal matters that may be retained by the Authority, (5) approve the issuance of each series of Bonds and evidences of indebtedness issued in anticipation of the issuance of Bonds and (6) perform other functions provided for in the Power Sales Contracts and the other Project Agreements.

Restrictions on Disposition

A Project Participant may not sell, lease or otherwise dispose of all or substantially all of its electric system except upon the satisfaction of certain conditions, including, among others, that (i) the Project Participant assigns its interest under its Power Sales Contract to the purchaser or lessee of its electric system and said purchaser or lessee assumes all obligations of the Project Participant under the Power Sales Contract, (ii) the senior debt of the purchaser or lessee is rated in one of the two highest categories by at least one nationally recognized bond rating agency, (iii) an independent engineer selected by the Authority delivers an opinion that such purchaser or lessee is reasonably able to charge and collect rates and charges required to meet its obligations under the Power Sales Contract, (iv) it is determined by the Board of Directors that the disposition will not adversely affect the value of such Power Sales Contract as security for the Bonds and (v) Bond Counsel has rendered an opinion that such disposition will not adversely affect the Federal Tax Exemption.

Defaults and Remedies

The failure of a Project Participant to perform any of its obligations, including the obligation to make required payments, under its Power Sales Contract will constitute a default. In the event of a default or inability to perform by a Project Participant under its Power Sales Contract, the Authority may proceed to enforce the Project Participant's covenants or obligations thereunder, or seek damages for the breach thereof, by action at law or equity, or if a payment due under the Power Sales Contract remains unpaid when due, the Authority may, upon 120 days' written notice to the Project Participant, discontinue the delivery of capacity and energy to, and the use of Project facilities by, such Project Participant while the default continues. Except as a result of a transfer of the defaulting Project Participant's rights to delivery of capacity and energy and the use of Project facilities described below, the discontinuance of delivery of capacity and energy to, and the use of Project facilities by, a defaulting Project Participant by the Authority will not reduce the obligation of such Project Participant to make payments under its Power Sales Contract. In the event the delivery of capacity and energy to, and use of Project facilities by, a Project Participant in default is discontinued, the Authority shall transfer to all other Project Participants which are not in default and which so request, a pro rata portion of the defaulting Project Participant's rights to delivery of capacity and energy and use of Project facilities. In the case of such a transfer, the Project Participants accepting additional rights to delivery of capacity and energy and use of Project facilities shall assume the defaulting Project Participant's obligations with respect to the rights which are transferred to them. In the event less than all of a defaulting Project Participant's rights to delivery of capacity and energy and use of Project facilities are transferred to non-defaulting Project Participants, the Authority shall, to the

extent possible, dispose of such remaining rights on the best terms readily available, and in such a manner as, in the opinion of Bond Counsel, does not adversely affect the eligibility for exemption from federal income taxes of the interest payable on the Bonds. The obligation of the defaulting Project Participant to the Authority shall be reduced to the extent that the Authority receives payments with respect to the rights of such Project Participant which are transferred.

Termination or Amendment

As long as any Bonds issued under the Bond Indenture are outstanding or until provision has been made for the payment of any Bonds outstanding in accordance with the Bond Indenture, the Power Sales Contracts may not be terminated or amended in any manner which will reduce the amount of or extend the time for the payments which are pledged as security for the Bonds or which will impair or adversely affect the rights of the holders of the Bonds. Each Power Sales Contract also provides that the Authority may not, without the consent of each of the Project Participants, amend or supplement the Bond Indenture (except to provide for the issuance of additional Bonds), to affect the rights and obligations of the Project Participants under the Power Sales Contracts or to be to the disadvantage of the Project Participants or to result in increased Monthly Power Costs to the Project Participants.

Contracts Subject to Bond Indenture

It has been recognized by the Project Participants in the Power Sales Contracts that the Authority, in planning, financing, acquiring, constructing and operating the Project, must comply with the requirements of the Bond Indenture and the other Project Agreements and all licenses, permits and regulatory approvals necessary therefor, and the Project Participants have therefore agreed that the Power Sales Contracts are subject to the provisions of the Bond Indenture and the other Project Agreements and such licenses, permits and approvals.

SUMMARY OF CERTAIN PROVISIONS OF THE PARTICIPATION AGREEMENT

The following is a summary of certain provisions of the Arizona Nuclear Power Project Participation Agreement, as amended (the "Participation Agreement"). This summary is not to be considered a full statement of the terms of the Participation Agreement and accordingly is qualified by reference thereto and is subject to the full text thereof. Capitalized terms not defined in this summary or in the Official Statement have the respective meanings set forth in the Participation Agreement.

Definitions

Arizona Nuclear Power Project: One or more nuclear steam electric Generating Units, together with all facilities, structures and Nuclear Fuel used or to be used therewith or related thereto, including the Nuclear Plant Site, all facilities and rights-of-way for the collection, transportation, treatment, storage and disposal of water required for Construction Work, Operating Work and Capital Improvements and for rail access wherever such facilities and rights-of-way are located, but excluding the ANPP High Voltage Switchyard(s), and all transmission facilities connected thereto, which may be revised from time to time by the Administrative Committee.

Base Load Period: Any period of time during which any Generating Unit is scheduled to be operated to achieve and maintain its then Maximum Generating Capability.

Date of Firm Operation: The date with respect to each Generating Unit on which the Engineering and Operating Committee determines it to be reliable as a source of Power and on which such Generating Unit can reasonably be expected to operate steadily at any load up to its Target Capacity.

Fuel Assembly: An integral unit of fabricated Nuclear Fuel prepared for insertion into a Reactor, including all hardware incorporated in such integral unit.

Generating Unit: A complete system of ANPP for generating electricity, including without limitation, the nuclear steam supply system and its containment, resident Fuel Assemblies, the turbine-generator, all auxiliary structures, system facilities and equipment necessary for or useful in the operation of the unit and any structures, systems, facilities and equipment shared with any other Generating Unit at the Nuclear Plant Site, such as the radioactive waste treatment systems, fire protection systems, water supply and treatment systems.

Generation Entitlement Share: The percentage entitlement of each Participant to the Net Energy Generation and to the Available Generating Capability.

Nuclear Fuel Agreement: Any agreement entered into by the Project Manager or the Operating Agent relating to the purchase, sale, lease, transfer, disposition, storage, transportation, mining, conversion, milling, enrichment, processing, fabrication and reprocessing of any Nuclear Fuel for use in, used in or removed from a Reactor.

Project Agreements: The Participation Agreement, any Construction Agreement, any Nuclear Fuel Agreement, but excluding any Nuclear Fuel Agreements concerning uranium concentrates to which all Participants are not parties, and any agreements between the Participants or any of them and any third party for land, land rights or water rights for ANPP, as such agreements are originally executed or as they may thereafter be supplemented or amended and any other agreements as the Participants agree to designate as Project Agreements.

Start-Up Period: The period with respect to each Generating Unit commencing with the date on which the first Fuel Assembly is inserted into the Generating Unit's Reactor and terminating with its Date of Firm Operation.

Target Capacity. The Maximum Generating Capability established by the Administrative Committee for each Generating Unit at which such Generating Unit is expected to be capable of operating continuously with new, undamaged Fuel Assemblies.

The Agreement

Arizona Public Service Company, Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, Public Service Company of New Mexico and El Paso Electric Company have entered into the Participation Agreement, as amended, pursuant to which each of them and the Authority as Participants will accept, acquire and own undivided interests as tenants in common in the Arizona Nuclear Power Project (the "ANPP") and all Project Agreements in proportion to its Generation Entitlement Shares, excluding (i) the Option and Purchase of Effluent Agreement, dated April 23, 1973, except to the extent only that such agreement governs the rights and obligations for the purchase and delivery of wastewater effluent required for Construction Work, Operating Work and Capital Improvements and (ii) any Project Agreement which by its terms establishes an ownership interest or rights of any Participant in the subject matter thereof which differs from its Generation Entitlement Shares under the Participation Agreement.

Energy Entitlements

The Participation Agreement does not constitute a joint venture. Each Participant is responsible for its own covenants, obligations and liabilities.

During the Start-Up Period and any Base Load Period, each Participant shall schedule and be obligated to take delivery of its Generation Entitlement Share. At all times after the Date of Firm Operation, each Participant shall be entitled to schedule generation of power and energy from each Generating Unit up to the amount of its Generation Entitlement Share of the available operating capacity of such Generating Unit and shall be entitled to receive all energy attributable thereto for its account in accordance with the provisions of the Participation Agreement, and each Participant shall be obligated to provide its own reserve requirements. Whenever any Participant schedules for its account power from a Generating Unit, the Operating Agent, unless otherwise established by the

Administrative Committee, shall additionally schedule for each Participant a percentage, equal to its Generation Entitlement Share of the available operating capacity of each Generating Unit, of the Zero Net Load effective during the period that such Generating Unit is operated to meet such schedule.

Administration

Arizona Public Service Company has been designated the Project Manager for construction and Operating Agent for operation and maintenance of the ANPP, and is responsible, as agent for the Participants, for the construction, operation and maintenance of the ANPP. For purposes of Project direction, three (3) committees are established as follows:

1. *Administrative Committee:* responsible, among other things, for providing liaison among the Participants; providing liaison among the Participants and the Project Manager and the Operating Agent with respect to progress, performance and completion of construction and operation of the ANPP; acting on certain recommendations of the Project Manager or the Operating Agent; acting upon disputes among the Participants arising under the Project Agreements; providing general supervision of the other committees established under the Participation Agreement; and for reviewing and acting upon issues and problems referred to it by another committee.

2. *Engineering and Operating Committee:* responsible, among other things, for providing liaison between the Participants and the Project Manager with regard to the construction of ANPP; establishing the Date of Firm Operation for each Generating Unit; acting upon the recommendations of the Operating Agent concerning the operation of the ANPP or the making of Capital Improvements, including among other things, the annual capital expenditures budget, annual manpower tables and budget and the annual operation and maintenance budget; developing a plan providing for coordination between the Participants, Federal, State and local authorities in the event of an abnormal occurrence at the plant site minimizing exposure of the public to radiation.

3. *Auditing Committee:* responsible, among other things, for developing accounting and auditing procedures, including the development of procedures for making forecasts and requests for funds; making periodic audits of the records maintained for the ANPP and establishing the minimum amounts for the Construction Account and the Operating Account.

Actions Pending Resolution of Disputes

If a dispute arises which is not resolved by the Administrative Committee or the higher authorities within the Participant's organizations, then, pending the resolution of the dispute by arbitration or judicial proceedings, the Project Manager or Operating Agent shall proceed with Construction Work, Operating Work or Capital Improvements in a manner consistent with the Project Agreements. If a dispute arises between any of the Participants under the Project Agreements, any Participant may call for submission of the dispute to binding arbitration.

Interconnections and Transmission Lines

Power and Energy generated by ANPP shall be delivered to the Participants by means of (i) one or more ANPP High Voltage Switchyards to be constructed and (ii) such high voltage transmission lines as the Participants or any of them determines to construct, operate and maintain to interconnect ANPP with either existing or planned transmission systems owned or to be owned, and operated, by one or more Participants or any other party with whom any Participant has or will have a right to interconnect according to the principles established in the Participation Agreement.

Construction, Operation and Maintenance Costs

The Operating Agent will establish a separate Operating Account for the payment of all costs of operation and Capital Improvements of the ANPP. Each Participant shall advance payments to the Operating Account on the basis of bills it receives which reflect such Participant's share of the costs of

Operating Work and Capital Improvements determined in accordance with the terms of the Participation Agreement. All payments due under any Nuclear Fuel Agreement, and for operating emergencies, shall be advanced to the Operating Account as required by each Participant. Each Participant is obligated to advance funds to the Operating Agent to make payments of operating and maintenance costs when due.

During the construction period each Participant is obligated to advance to the Project Manager its share of funds required for construction for deposit to the Construction Account. Each Participant shall pay weekly in advance its share (equal to its Generation Entitlement Share) of all construction costs in accordance with monthly forecasts of estimated weekly expenses prepared by the Project Manager. Upon completion of all construction, the Project Manager will prepare a final completion report of all costs of construction and the Participants will make such payments or adjustments as required so that the costs of construction are shown on the basis of ownership interests.

If a Participant shall dispute any portion of any amount specified in a request for the funds, the Participant shall make the total payment specified in the request pending a protest of such payment. If it is determined that a Participant has made advances which are greater or less than its share of the costs, the difference shall be paid or refunded to such Participant.

Transfer of Interest

Each Participant shall have the right to transfer or assign all or part of its Generation Entitlement Share, together with an equal interest in the ownership of ANPP and in the Project Agreements, to any person or entity engaged in the generation, transmission or distribution of energy.

Operating Emergency

The Operating Agent will advise the Participants when an emergency occurs, and shall submit an estimate of expenses required to restore the availability of each Generating Unit affected. If the uninsured costs of restoration exceed 10% of the original costs, the Operating Agent shall obtain the approval of the Administrative Committee before committing any expenses. The Operating Agent, however, may incur any expense which in its sole discretion it deems necessary to protect the health and safety of the public.

Damage to Project

If ANPP or any portion thereof should be damaged or destroyed to the extent that the costs of repairs or reconstruction is estimated to be less than 150% of the aggregate amount of Project Insurance coverage carried and covering the cost of such repairs or reconstruction, then the Project Manager or the Operating Agent shall cause such repairs or reconstruction to be made so that ANPP is restored to substantially the same general condition, character or use as existed prior to such damage or destruction and the Participants shall share the costs of such repairs or reconstruction in the proportion to their Generation Entitlement Share.

If ANPP or any portion thereof should be damaged or destroyed to the extent that the costs of repairs or reconstruction are estimated to be 150% or more of the aggregate amount of Project Insurance coverage carried and covering the cost of such repairs or reconstruction, then upon agreement of all Participants the Project Manager or the Operating Agent shall cause such repairs or reconstruction to be made as may be agreed and the Participants shall share the costs of such repairs or reconstruction in proportion to their Generation Entitlement Share; provided, however, that should all of the Participants not agree to restore or reconstruct the damaged portion of ANPP, but some of the Participants nevertheless desire to do so, then any Participant who does not agree to restore or reconstruct shall sell its share and ownership interest in ANPP to the remaining Participants for a price equal in amount to its share in the salvage value thereof. The Participants agreeing to repair or reconstruct such Generating Unit shall share the costs of repair or reconstruction in the proportion that the share of each bears to the total shares of such Participants.

Term of Agreement

The contract became effective September 1, 1973 and extends for a period of 50 years from its effective date or 40 years from the date on which the last Generating Unit can be reasonably expected to operate continuously at its Target Capacity, whichever is later.

Defaults and Covenants

In the event of a Default by any Participant of any obligation, including the obligation to make payments when due, under the Project Agreements the non-defaulting parties shall remedy such default, either by advancing the necessary funds and/or commencing to render the necessary performance. Each non-defaulting party agrees to contribute to such remedy in the ratio of its Generation Entitlement Share to the total of the Generation Entitlement Shares of all non-defaulting parties. The defaulting party, upon notice by a non-defaulting party of a default or alleged default under the Project Agreements, shall remedy such default or alleged default, and shall pay promptly upon demand to each non-defaulting party the total amount of money, if any, together with interest thereon, paid by each such non-defaulting party. If the defaulting party disputes the default, it shall pay the disputed payment or perform the disputed obligation but may do so under protest, in which event the matter in dispute is to be submitted to arbitration and if so submitted the decision of the arbitrator or board of arbitrators shall be binding upon the parties.

DEBT SERVICE REQUIREMENTS

(Accrual Basis)

Fiscal Year Ending June 30	Prior Series Bonds*		1987 Refunding Series A		Combined Total Debt Service
	Principal	Interest	Principal	Interest	
1987	$ —	$ 26,210,362	$ —	$ 11,362,516	$ 37,572,878
1988	9,405,000	52,420,724	3,690,000	22,725,031	88,240,755
1989	10,040,000	51,794,422	3,830,000	22,581,121	88,245,543
1990	12,090,000	51,084,538	2,655,000	22,412,601	88,242,139
1991	13,015,000	50,170,166	2,775,000	22,285,161	88,245,327
1992	14,045,000	49,145,108	2,910,000	22,142,943	88,243,051
1993	15,200,000	47,999,388	3,055,000	21,986,530	88,240,918
1994	16,500,000	46,716,764	3,210,000	21,818,505	88,245,269
1995	17,940,000	45,282,430	3,385,000	21,633,930	88,241,360
1996	19,545,000	43,683,114	3,580,000	21,434,215	88,242,329
1997	15,990,000	47,243,410	3,790,000	21,219,415	88,242,825
1998	17,520,000	45,706,200	4,030,000	20,987,278	88,243,478
1999	19,045,000	44,182,824	4,280,000	20,735,403	88,243,227
2000	20,675,000	42,558,330	4,545,000	20,462,553	88,240,883
2001	20,795,000	40,777,990	6,505,000	20,167,128	88,245,118
2002	22,420,000	39,154,320	6,930,000	19,737,798	88,242,118
2003	16,240,000	37,383,770	15,345,000	19,273,488	88,242,258
2004	17,530,000	36,094,838	16,390,000	18,231,313	88,246,151
2005	11,570,000	34,792,338	24,775,000	17,104,500	88,241,838
2006	12,435,000	33,929,386	26,475,000	15,401,219	88,240,605
2007	13,365,000	33,001,638	28,260,000	13,616,125	88,242,763
2008	14,380,000	31,987,432	30,155,000	11,722,833	88,245,265
2009	15,475,000	30,895,906	32,170,000	9,702,531	88,243,437
2010	27,685,000	29,720,912	23,345,000	7,490,844	88,241,756
2011	34,065,000	27,670,056	20,620,000	5,885,875	88,240,931
2012	45,220,000	25,049,700	13,505,000	4,468,250	88,242,950
2013	58,770,000	21,404,024	4,530,000	3,539,781	88,243,805
2014	58,565,000	16,753,588	9,695,000	3,228,344	88,241,932
2015	65,415,000	12,196,008	8,070,000	2,561,813	88,242,821
2016	59,540,000	7,114,864	19,580,000	2,007,000	88,241,864
2017	63,000,000	3,657,912	20,560,000	1,028,000	88,245,912
Total	$ 757,480,000	$1,105,782,462	$ 352,645,000	$ 468,954,044	$2,684,861,506

* Excludes Refunded Bonds.

PROPOSED FORM OF BOND COUNSEL OPINION REGARDING 1987 BONDS

Upon the delivery of the 1987 Bonds in definitive form, Mudge Rose Guthrie Alexander & Ferdon, Los Angeles, California, Bond Counsel, proposes to render its final approving opinion with respect to such Bonds in substantially the following form:

(Closing Date)

Board of Directors
Southern California Public Power Authority
613 East Broadway
Glendale, California 91205

Gentlemen:

We have examined (i) a record of proceedings relating to the issuance of $352,645,000 aggregate principal amount of Power Project Revenue Bonds, 1987 Refunding Series A (the "Bonds"), of Southern California Public Power Authority (the "Authority"), a public entity of the State of California; (ii) the Power Sales Contracts hereinafter referred to; and (iii) such other matters of law as we have deemed necessary to enable us to render the opinions expressed herein. The Bonds are issued under and pursuant to the provisions relating to the joint exercise of powers found in Chapter 5 of Division 7 of Title 1 of the Government Code of California, as amended (the "Act"), and under and pursuant to the Indenture of Trust, dated as of July 1, 1981, by and between the Authority and First Interstate Bank of California, as trustee, as amended and supplemented by the First Supplemental Indenture of Trust, dated as of August 1, 1982, and as supplemented by the Ninth Supplemental Indenture of Trust (the "Ninth Supplemental Indenture"), dated as of January 1, 1987 (such Indenture of Trust as heretofore amended and supplemented being herein called the "Indenture").

The Bonds will mature on the dates and in the principal amounts, and bear interest at the respective rates per annum, shown below.

Due July 1	Amount Maturing	Interest Rate	Due July 1	Amount Maturing	Interest Rate
1988	$ 3,690,000	3.900%	1998	$ 4,030,000	6.250%
1989	3,830,000	4.400	1999	4,280,000	6.375
1990	2,655,000	4.800	2000	4,545,000	6.500
1991	2,775,000	5.125	2001	6,505,000	6.600
1992	2,910,000	5.375	2002	6,930,000	6.700
1993	3,055,000	5.500	2003	10,235,000	6.750
1994	3,210,000	5.750	2006	60,000,000	6.875
1995	3,385,000	5.900	2008	50,000,000	6.600
1996	3,580,000	6.000	2015	133,100,000	6.875
1997	3,790,000	6.125	2017	40,140,000	5.000

The Bonds are dated, and shall bear interest from, January 1, 1987, except as otherwise provided in the Indenture. Interest on the Bonds is payable on January 1 and July 1 in each year, commencing July 1, 1987. The Bonds are subject to redemption prior to maturity in the manner and upon the terms set forth in the Indenture. The Bonds are in fully registered form without interest coupons in the denominations of $5,000 or any integral multiple thereof, are interchangeable and transferable as provided in the Indenture and are lettered as provided for each maturity in the Indenture and numbered from one upward within each maturity.

The Bonds are issued to (i) advance refund $120,820,000 aggregate principal amount of the Authority's Power Project Revenue Bonds, 1985 Refunding Series A, maturing July 1, 2012; $62,390,000 aggregate principal amount of the Authority's Power Project Revenue Bonds, 1985 Refunding Series B,

maturing July 1, 2011; and $50,000,000 aggregate principal amount of the Authority's Power Project Revenue Bonds, 1985 Refunding Series B, maturing July 1, 2017 (collectively, the "Refunded Bonds"); and (ii) provide moneys necessary to pay the principal, at maturity, and accrued interest, if any, of $75,000,000 aggregate principal amount of the Authority's Power Project Bond Anticipation Notes, 1984 Series A; all of which were issued to finance costs of acquisition and construction of the Initial Facilities (as defined in the Indenture). The Authority reserves the right to issue additional bonds under the Indenture on the terms and conditions and for the purposes stated in the Indenture. Under the provisions of the Indenture all such bonds may rank equally as to security and payment with the Authority's Outstanding (as defined in the Indenture) Power Project Revenue Bonds, 1982 Series A and B, 1983 Series A, 1984 Series A, 1985 Refunding Series A and B and 1986 Refunding Series A and B (the "Prior Series Bonds") and the Bonds.

The Authority has entered into ten separate Power Sales Contracts (the "Power Sales Contracts") with the following purchasers (the "Purchasers") of capability of the Project (as defined in the Indenture): Department of Water and Power of The City of Los Angeles (the "Department"), Imperial Irrigation District, and the Cities of Riverside, Vernon, Burbank, Glendale, Pasadena, Azusa, Banning and Colton.

We are of the opinion that:

1. The Authority is duly created and validly existing under the provisions of the Act and has good right and lawful authority under the Act to acquire and construct the Initial Facilities and provide for the operation and maintenance thereof.

2. The Authority has the right and power under the Act to enter into the Indenture, and the Indenture has been duly and lawfully authorized by the Authority, is in full force and effect in accordance with its terms and is valid and binding upon the Authority and enforceable in accordance with its terms, and no other authorization for the Indenture is required. The Indenture creates the valid pledge which it purports to create of (i) the proceeds of the sale of the Bonds and any other parity bonds issued under the Indenture, (ii) the Revenues (as defined in the Indenture), and (iii) all funds established by the Indenture (excluding the Decommissioning Account in the Reserve and Contingency Fund) including the investments, if any, thereof, subject only to the provisions of the Indenture permitting the application thereof for the purposes and on the terms and conditions set forth in the Indenture.

3. The Authority is duly authorized and entitled to issue the Bonds, and the Bonds have been duly and validly authorized and issued by the Authority in accordance with the Constitution and statutes of the State of California, including the Act, and the Indenture. The Bonds constitute valid and binding obligations of the Authority as provided in the Indenture, are enforceable in accordance with their terms and the terms of the Indenture and are entitled to the benefits of the Act and the Indenture. The Bonds are not an obligation of the State of California, any public agency thereof (other than the Authority), or any member of the Authority or any Purchaser and neither the faith and credit nor the taxing power of the State of California or any public agency thereof or any member of the Authority or any Purchaser is pledged for the payment of the Bonds. The Bonds rank equally as to security and payment with the Prior Series Bonds.

4. The Authority has the right and power to enter into and carry out its obligations under the Power Sales Contracts and has duly authorized, executed and delivered the Power Sales Contracts which constitute valid and binding agreements of the Authority enforceable in accordance with their terms.

5. Under the Constitution and laws of the State of California, each Power Sales Contract constitutes a valid and binding agreement of the Purchaser party thereto enforceable in accordance with its terms. In rendering the foregoing opinion, we have made no investigation of, and do not express any opinion with respect to, the following as they may relate to the valid, binding and enforceable nature of such Power Sales Contracts: (i) the legal existence or formation of any

Purchaser or the incumbency of any official or officer thereof; (ii) any local or special acts or any ordinance, resolution or other proceedings of any Purchaser, including, without limitation, any proceedings relating to the negotiation or authorization of any Power Sales Contract or the execution, delivery or performance thereof (except that we have examined the ordinances pursuant to which the respective Power Sales Contracts were authorized by the respective Purchasers); (iii) any bond resolution, indenture, contract, debt instrument, agreement or other instrument (other than such Power Sales Contracts) or any governmental order, regulation or rule of or applicable to any Purchaser; (iv) any judicial order, judgment or decree in a proceeding to which any Purchaser is a party; or (v) any approval, consent, filing, registration or authorization by or with any regulatory authority or other governmental or public agency, authority or person which may be or has been required for the authorization, execution, delivery or performance by any Purchaser of its Power Sales Contract. The Authority has received, independent from this opinion, opinions with respect to, among other things, the validity and enforceability of the Power Sales Contracts rendered by legal counsel to the respective Purchasers.

6. The Internal Revenue Code of 1986 (the "Code"), establishes certain requirements which must be met subsequent to the issuance and delivery of the Bonds for interest thereon to be and remain excluded from Federal gross income. Non-compliance with such requirements could cause the interest on the Bonds to be included in Federal gross income retroactive to the date of issuance of the Bonds. These requirements include, but are not limited to, provisions which prescribe yield and other limits within which the proceeds of the Bonds and other amounts are to be invested and require that certain investment earnings on the foregoing must be rebated on a periodic basis to the Treasury Department of the United States. Pursuant to the Indenture, the Authority has covenanted to maintain the exclusion from Federal gross income of the interest on the Bonds.

Assuming compliance with the aforementioned covenant, we are of the opinion that, under existing statutes, regulations, rulings and court decisions, interest on the Bonds is excluded from gross income for Federal income tax purposes.

We are further of the opinion that under existing statutes, regulations, rulings and court decisions, the Bonds are not "specified private activity bonds" within the meaning of Section 57(a)(5) of the Code and, therefore, the interest on the Bonds will not be treated as a preference item for purposes of computing the alternative minimum tax imposed on individuals by Section 55 of the Code. For taxable years beginning after December 31, 1986, however, the interest on the Bonds may be taken into account in computing: (i) the alternative minimum tax on corporations imposed by Section 55 of the Code; (ii) the environmental tax on corporations imposed by Section 59A of the Code; and (iii) the branch profits tax imposed by Section 884 of the Code when such Bonds are owned by, and interest thereon is effectively connected with the trade or business of, United States branches of foreign corporations.

Furthermore, in our opinion, under the Act, interest on the Bonds is exempt from personal income taxes of the State of California.

7. The difference between the principal amount of the Bonds maturing July 1, 2006, 2008, 2015 and 2017, respectively, and the initial offering price to the public (excluding bond houses and brokers) at which price a substantial amount of such Bonds of the same maturity was sold represents interest which is excluded from Federal gross income. Further, such interest accrues on an actuarial basis (*i.e.*, on the basis of a geometric progression over the term of such Bonds), and the basis in such Bonds of an owner who acquires such Bonds in this offering will be increased by the amount of such accrued interest. However, such interest may be taken into account in determining the amount of the alternative minimum tax, the environmental tax and the branch profits tax described in Paragraph 6 above.

8. The Authority has paid (within the meaning of the Indenture) the Redemption Price and interest due and to become due on the Refunded Bonds, at the times and in the manner stipulated therein and in the Indenture, and the Refunded Bonds are no longer Outstanding. Except for the rights of the holders of the Refunded Bonds to payments from the Escrow Fund established by the Ninth Supplemental Indenture, the Refunded Bonds have ceased to be entitled to any lien, benefit or security under the Indenture, and all covenants, agreements and obligations of the Authority to the holders of the Refunded Bonds have ceased, terminated, become void and been discharged and satisfied.

The opinions expressed in paragraphs 2, 3, 4 and 5 hereof are qualified to the extent that the enforceability of the Indenture, the Bonds and the Power Sales Contracts, respectively, may be limited by any applicable bankruptcy, insolvency, debt adjustment, moratorium, reorganization or other similar laws affecting creditors' rights generally or as to the availability of any particular remedy.

We have examined the executed Bond in registered form numbered R-1, and in our opinion the form of such Bond and its execution are regular and proper.

On July 27, 1982, three individual plaintiffs filed an action entitled *Thurston et al. v. Southern California Public Power Authority et al.* in the Superior Court for the County of Los Angeles against the Authority, the Department and other unnamed defendants. In this action, the plaintiffs have (i) raised certain issues concerning the validity and legality of revenue bonds (which could include the Bonds) proposed to be issued to finance the acquisition and construction by the Authority of an interest in the Palo Verde Project, and certain terms and provisions thereof, and (ii) alleged, among other things, that under the Constitution and statutes of the State of California and/or the Los Angeles City Charter, the obligations undertaken by the Department under its Power Sales Contract constitute (a) a debt requiring approval of the voters of the City under the Constitution of the State of California, which vote was not obtained, (b) a pledge of the Department's revenues in violation of the Los Angeles City Charter and (c) unsound or unlawful business practices, an unsound business venture or are otherwise illegal. As to the issues raised by the plaintiffs concerning the validity and legality of such revenue bonds and certain terms and provisions thereof, described in (i) above, we are of the opinion that such issues are without merit. As to the issues raised by the plaintiffs concerning the obligations undertaken by the Department under its Power Sales Contract, described in (ii) above, the Los Angeles City Attorney is rendering his opinion to the effect that such issues are without merit.

Very truly yours,

APPENDIX F

Department of Water and Power the City of Los Angeles

January 29, 1987

Board of Directors
Southern California Public Power Authority
613 East Broadway
Glendale, California 91205

Gentlemen:

In connection with the Department's purchase from the Southern California Power Public Authority (the "Authority") of a 67% entitlement to the output of the Authority Interest in the Palo Verde Nuclear Generating Station, the Department has conducted certain studies and analyses which have included projections with respect to, among other things, the estimated cost of power from Authority Interest as contained in the Report of the Consulting Engineer set forth as Appendix A to the Official Statement to which this letter is attached (the "Official Statement"), the estimated cost and availability of oil and natural gas, future load growth in The City of Los Angeles, and the estimated future power system revenue requirements necessary to satisfy its cost of such purchase. The Department has also compared the projected cost of power from the Authority Interest with the projected cost of power from its existing facilities. In addition, the Department has reviewed, among other documents, the Official Statement, such Report of the Consulting Engineer, the Note Resolution, the Bond Indenture, the Power Sales Contracts and the Assignment Agreement. As used herein, "Authority Interest", "Project", "Note Resolution", "Bond Indenture", "Power Sales Contracts" and "Assignment Agreement" have the respective meanings given thereto in the Official Statement.

Based upon these studies and analyses, we are of the opinion that:

1. The Department's share of the output from the Authority Interest will, over time, be economically beneficial to the Department in displacing base load oil- and natural gas-fired generation in the Los Angeles basin;

2. The projected cost of power to the Department from the Authority Interest makes such power economically attractive in the long term to the Department when compared with the projected price levels of oil and natural gas and with the projected cost of power from other alternative resources which may be available to the Department; and

3. For the period through June 30, 1991, the Department's electric system revenues will be sufficient to enable it to pay the Authority all amounts payable under the Department's Power Sales Contract and to pay all other amounts payable from, and all liens on and lawful charges against, the Department's power system revenues.

Respectfully submitted,

DEPARTMENT OF WATER AND POWER
OF THE CITY OF LOS ANGELES

By: /s/ NORMAN E. NICHOLS
Assistant General Manager — Power

By: /s/ NORMAN J. POWERS
Chief Financial Officer

Municipal Bond Insurance Policy

AMBAC Indemnity Corporation
c/o CT Corporation Systems
222 W. Washington Ave., Madison, WI 53703
Administrative Office:
One State Street Plaza, New York, NY 10004

Issuer:

Policy Number:

Bonds:

Premium:

AMBAC

AMBAC Indemnity Corporation (AMBAC) A Wisconsin Stock Insurance Company

in consideration of the payment of the premium and subject to the terms of this Policy, hereby agrees to pay to the United States Trust Company of New York, as trustee, or its successor (the "Insurance Trustee"), for the benefit of Bondholders, that portion of the principal of and interest on the above-described debt obligations (the "Bonds") which shall become Due for Payment but shall be unpaid by reason of Nonpayment by the Issuer.

AMBAC will make such payments to the Insurance Trustee within 5 days following notification to AMBAC of Nonpayment. Upon a Bondholder's presentation and surrender to the Insurance Trustee of such unpaid Bonds or appurtenant coupons, uncanceled and in bearer form and free of any adverse claim, the Insurance Trustee will disburse to the Bondholder the face amount of principal and interest which is then Due for Payment but is unpaid. Upon such disbursement, AMBAC shall become the owner of the surrendered Bonds and coupons and shall be fully subrogated to all of the Bondholder's rights to payment.

In cases where the Bonds are issuable only in a form whereby principal is payable to registered Bondholders or their assigns, the Insurance Trustee shall disburse principal to a Bondholder as aforesaid only upon presentation and surrender to the Insurance Trustee of the unpaid Bond, uncanceled and free of any adverse claim, together with an instrument of assignment, in form satisfactory to the Insurance Trustee, duly executed by the Bondholder or such Bondholder's duly authorized representative, so as to permit ownership of such Bond to be registered in the name of AMBAC or its nominee. In cases where the Bonds are issuable only in a form whereby interest is payable to registered Bondholders or their assigns, the Insurance Trustee shall disburse interest to a Bondholder as aforesaid only upon presentation to the Insurance Trustee of proof that the claimant is the person entitled to the payment of interest on the Bond and delivery to the Insurance Trustee of an instrument of assignment, in form satisfactory to the Insurance Trustee, duly executed by the claimant Bondholder or such Bondholder's duly authorized representative, transferring to AMBAC all rights under such Bond to receive the interest in respect of which the insurance disbursement was made. AMBAC shall be subrogated to all of the Bondholders' rights to payment on registered Bonds to the extent of the insurance disbursements so made.

SPECIMEN

As used herein, the term "Bondholder" means any person other than the Issuer who, at the time of Nonpayment, is the owner of a Bond or of a coupon appertaining to a Bond. "Due for Payment", when referring to the principal of Bonds, is when the stated maturity date or a mandatory redemption date for the application of a required sinking fund installment has been reached and does not refer to any earlier date on which payment is due by reason of call for redemption (other than by application of required sinking fund installments), acceleration or other advancement of maturity; and, when referring to interest on the Bonds, is when the stated date for payment of interest has been reached. "Nonpayment" means the failure of the Issuer to have provided sufficient funds to the paying agent for payment in full of all principal of and interest on the Bonds which are Due for Payment.

This Policy is noncancelable. The premium on this Policy is not refundable for any reason, including payment of the Bonds prior to maturity. This Policy does not insure against loss of any redemption, prepayment or acceleration premium which at any time may become due in respect of any Bond, nor against risk other than Nonpayment.

In witness whereof, AMBAC has caused this Policy to be affixed with a facsimile of its corporate seal and to be signed by its duly authorized officers in facsimile to become effective as its original seal and signatures and binding upon AMBAC by virtue of the counter-signature of its duly authorized representative.

President

AMBAC INDEMNITY CORPORATION CORPORATE SEAL WISCONSIN

Secretary

Effective Date:

Authorized Representative

UNITED STATES TRUST COMPANY OF NEW YORK acknowledges that it has agreed to perform the duties of Insurance Trustee under this Policy.

Cynthia Chaney
Authorized Officer

Form # 66-0003 (2/85)