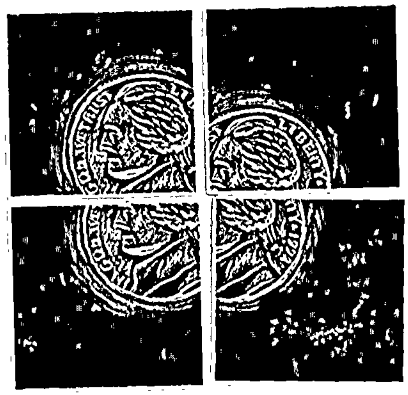
THE 60 MILLION DOLLAR NICKEL



PINNACLE WEST CAPITAL CORPORATION
1998 Annual Report

ABOUT THE COVER AND THIS ANNUAL REPORT

THE 60 MILLION DOLLAR NICKEL

Our theme this year focuses on an understanding among the employees of this company that when we increase earnings, through savings or increased revenues, we create shareholder value. The $60 million simply represents the value of five cents of earnings per share multiplied by a commonly applied price-earnings ratio of 14 and our 85 million shares outstanding. (We rounded.) Our theme is just a way of saying that the work and creativity of our men and women create shareholder wealth. We could have called this report the $120 million dime.

A NOTE TO READERS

Since the early 1990's, we have been working to make the financial portion of our annual report easier to read and understand while providing all the important information our readers need. The Securities and Exchange Commission (SEC) has been a strong advocate of "plain English" for disclosure documents like annual reports. In 1996, the SEC published plain English guidelines to help improve the readability of shareholder communications. This year we are incorporating some of these guidelines. We welcome your comments.

ABOUT THE COMPANY

Pinnacle West Capital Corporation is a Phoenix-based company with consolidated assets of approximately $7 billion and consolidated revenues of approximately $2 billion. Pinnacle West's major subsidiary is Arizona Public Service Company, which generates, sells and delivers electricity and energy-related products and services to wholesale and retail customers in the western United States. Pinnacle West's other two subsidiaries are SunCor Development Company, with residential, commercial and industrial real estate projects under development, and El Dorado Investment Company, an investment firm with a diversified portfolio.

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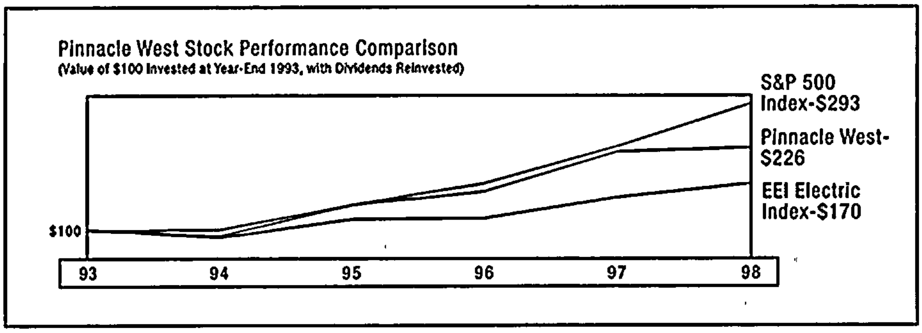
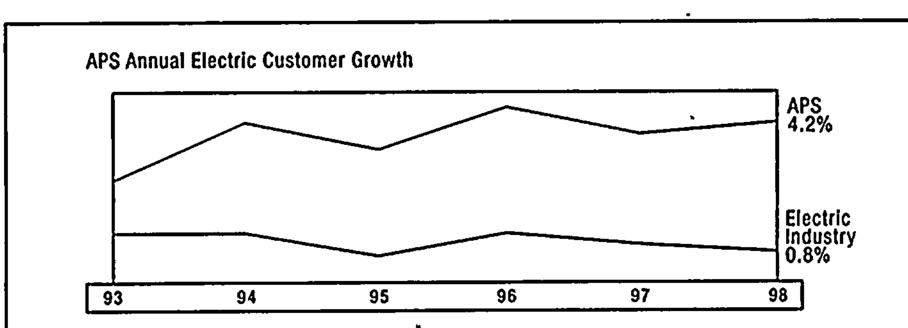


FINANCIAL HIGHLIGHTS

(Dollars in Thousands, Except Per Share Amounts)	1998	1997	1996	*Selected Growth Rates* 1998 vs. 1997	1997 vs. 1996
INCOME HIGHLIGHTS					
Operating Revenues	$ 2,130,586	$ 1,995,026	$ 1,817,760	6.8%	9.8%
Income From Continuing Operations	$ 242,892	$ 235,856	$ 211,059	3.0%	11.7%
BALANCE SHEET HIGHLIGHTS					
Total Assets	$ 6,824,546	$ 6,850,417	$ 6,989,289	(0.4)%	(2.0)%
Common Stock Equity	$ 2,163,351	$ 2,027,436	$ 1,970,323	6.7%	2.9%
PER SHARE HIGHLIGHTS					
Earnings Per Share from Continuing Operations – Diluted	$ 2.85	$ 2.74	$ 2.40	4.0%	14.2%
Dividends Paid Per Share	$ 1.225	$ 1.125	$ 1.025	8.9%	9.8%
Stock Price Per Share – Year-End	$ 42.375	$ 42.375	$ 31.75	—	33.5%
STOCK PERFORMANCE					
Market Capitalization – Year-End	$ 3,594,457	$ 3,594,457	$ 2,778,628	—	29.4%
Total Return	2.8%	38.0%	14.2%		
Stock Price Appreciation	—	33.5%	10.4%		



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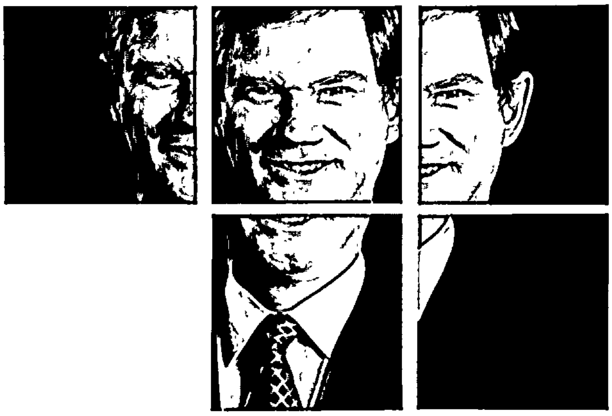


True to his word, as always, Dick Snell has turned this space over to me this year as chief executive officer, a position I assumed in February 1999. Dick retired from management that same month but will continue as chairman, and I welcome his insights. During his tenure at Pinnacle West, our market value increased fourfold to $3.6 billion. His performance set a high standard — one we intend to continue.

1998 and the early months of this year have been a time of considerable achievement and some frustration. I'll get the latter out of the way, sketch some highlights and then address how we plan to increase the long-term value of your company.

We are accustomed to being among the leaders in our industry for total shareholder return. In 1998 we were not, and that is unacceptable. Late in the year, the Arizona Supreme Court stayed the regulatory agreement we had reached earlier with the Arizona Corporation Commission Staff, effectively denying its approval. The associated regulatory uncertainty stemming from this "go and stop" launch of competition in the state (and much attending political intrigue) contributed to this reduced performance.

Lately, market realities and rising interest rates have affected our stock price and those of our peer group. We can't control the stock market, but effectively managing our businesses, including the company's relationships with regulators, is something shareholders should expect from us, and over the years it's something we have done very well. Although our relationships remain good, internal forces at the Arizona Corporation Commission have stalled, for now, the movement toward competition. However, we remain committed to competition in Arizona and will continue our efforts to work with regulators and others toward that goal.

None of this — stock price swoons or temporary regulatory missteps — should overshadow another strong performance by the men and women of this organization. Earnings were up; prices to customers were down for the fourth time in five years; and we experienced exceptional sales growth at Arizona Public Service and SunCor in a market that continues to be one of the nation's growth leaders. We expanded our power marketing and trading activities, and they contributed to earnings. APS set production, reliability and safety records.

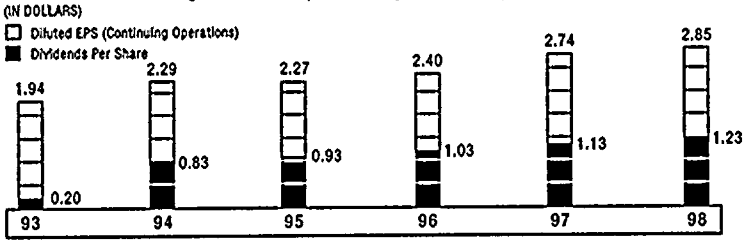
We increased the common stock dividend and reiterated that we expect to continue to do so at a pace well above the average for our industry. Our balance sheet strengthened. We used strong free cash flow to reduce outstanding debt and preferred stock by $164 million in 1998 and eliminated all our preferred stock in 1999.

Early in 1998, we reached a historic agreement with a local public power competitor, Salt River Project, designed to facilitate customer choice and provide cost reduction opportunities. Getting this agreement in place exponentially decreased the complexity of opening electricity markets in Arizona.

This overall performance is great history, but more importantly it indicates the starting point for future expectations. One of the reasons we chose the theme on the cover of this report is that we want to emphasize that our employees understand that small increments gained throughout the organization translate into significant market value.

If you are looking for the creation of value, you will find it in the details of putting our resources to their best use. You will find it among employees who are mastering the details of ongoing agility and in a company that believes that success is determined by today's performance, not yesterday's record.

Pinnacle West Earnings Per Share (Continuing Operations) and Dividends Per Share
(IN DOLLARS)



Creating this value will require growth — growth in existing markets, growth in emerging markets, growth in markets where we have a presence and growth in markets we do not even contemplate today.

This growth and value creation will take place under a new structure at the utility that separates regulated and unregulated businesses. Our new structure increases clarity of direction and responsibility, posturing the organization to capture growth and create value. These new businesses have everything to do with accountability and integration, very little to do with internal division and categorization.

With respect to *generation,* our goal is to add considerably to our generation capacity to meet the needs of growing markets. Current plans call for expanding our generating resources within the next five years by purchasing greater interests in facilities we operate, buying existing facilities, or building new capacity. These generation assets will be organized in a newly created non-regulated affiliate under the parent.

Our *energy delivery* business is expected to create efficiencies while delivering superior service. Under performance regulation, we have been able to capture the benefits of productivity improvements flowing from cost management and efficient utilization of assets. We know how to do both, as our record indicates, resulting in stable earnings growth and strong cash flow. With this half of our business growing every day, we are in a very advantageous position from which to capture growth and create value.

APS Energy Services is our unregulated customer development business. It begins life with the spirit of a start-up company, but is disciplined in its goals for profitability. This is a business whose market characteristics are thin margins and significant competitors who buy market share at a loss, something we are not compelled to do. APS Energy Services has already delivered new customers and new knowledge from Western markets and has earned a reputation in California based on its intellectual capital and a competitive drive. We expect modest earnings in this business over the next five years.

These businesses and our power marketing and trading business define how we, as a multifaceted energy company, will attack the 21st Century. While it may seem that you recognize some of the parts in our new structure, the old monolithic, vertically oriented utility for us is dead. In its place is an integrated portfolio of operations, each with different customer markets, among which we will invest capital based on our overriding criteria for decision making: will it make money for our shareholders.

At SunCor, our real estate development subsidiary, we have continued to enhance the value of our holdings in Arizona and have realized improved earnings. New projects in northern New Mexico and southern Utah hold strong promise for the future.

These are exciting times in our industry and for our company. Our future success will require repeat performances in areas such as maximization of resources, cost management, cooperative regulatory relations, operational excellence throughout the company and cash and earnings contributions from all subsidiaries.

Future success also requires high-level performance in new areas. Most importantly, I am looking for new activities to capture growth in energy markets in both generation and energy services. Continued and expanded performance regulation agreements must be gained for our delivery business. And, our real estate operations need to continue to improve earnings while contributing significantly to cash flow.

We are a growing company. Customer expansion, performance regulation, asset utilization and cost management will continue to propel our performance. Generation and energy services expansion, combined with the less obvious investments we've made in improving our operational capabilities (such as the completion of our new comprehensive information technology platform) will give us the ability to take advantage of tomorrow's opportunities.

The speed at which our industry is changing offers us exciting opportunities. We are well positioned to turn the opportunities we have into greater value. My coworkers and the management of your company will do just that.

Sincerely,

William J. Post
Chief Executive Officer

FROM THE CHAIRMAN

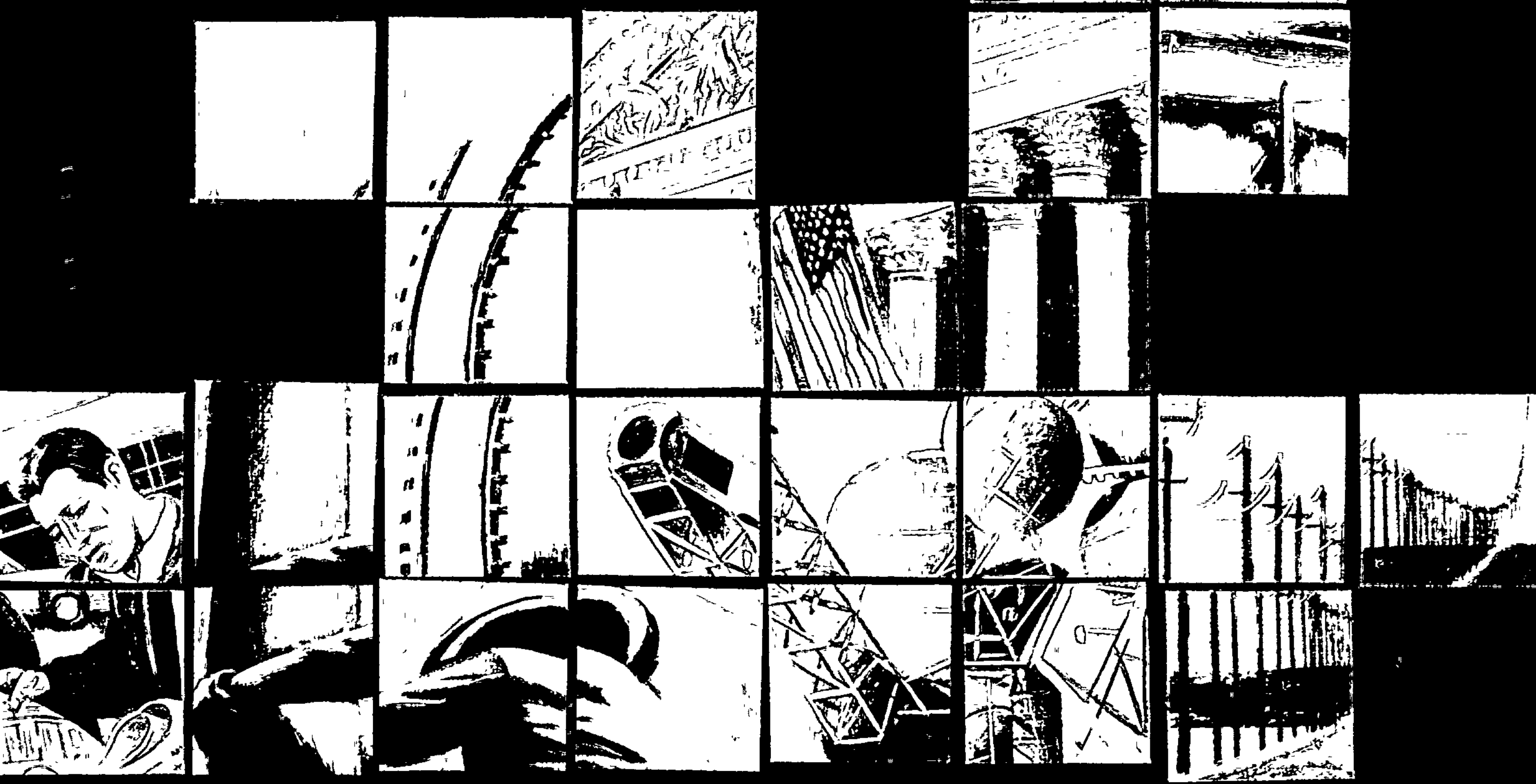
That Bill Post does, in fact, occupy the space ahead of me here is further evidence of a management succession that has gone very smoothly.

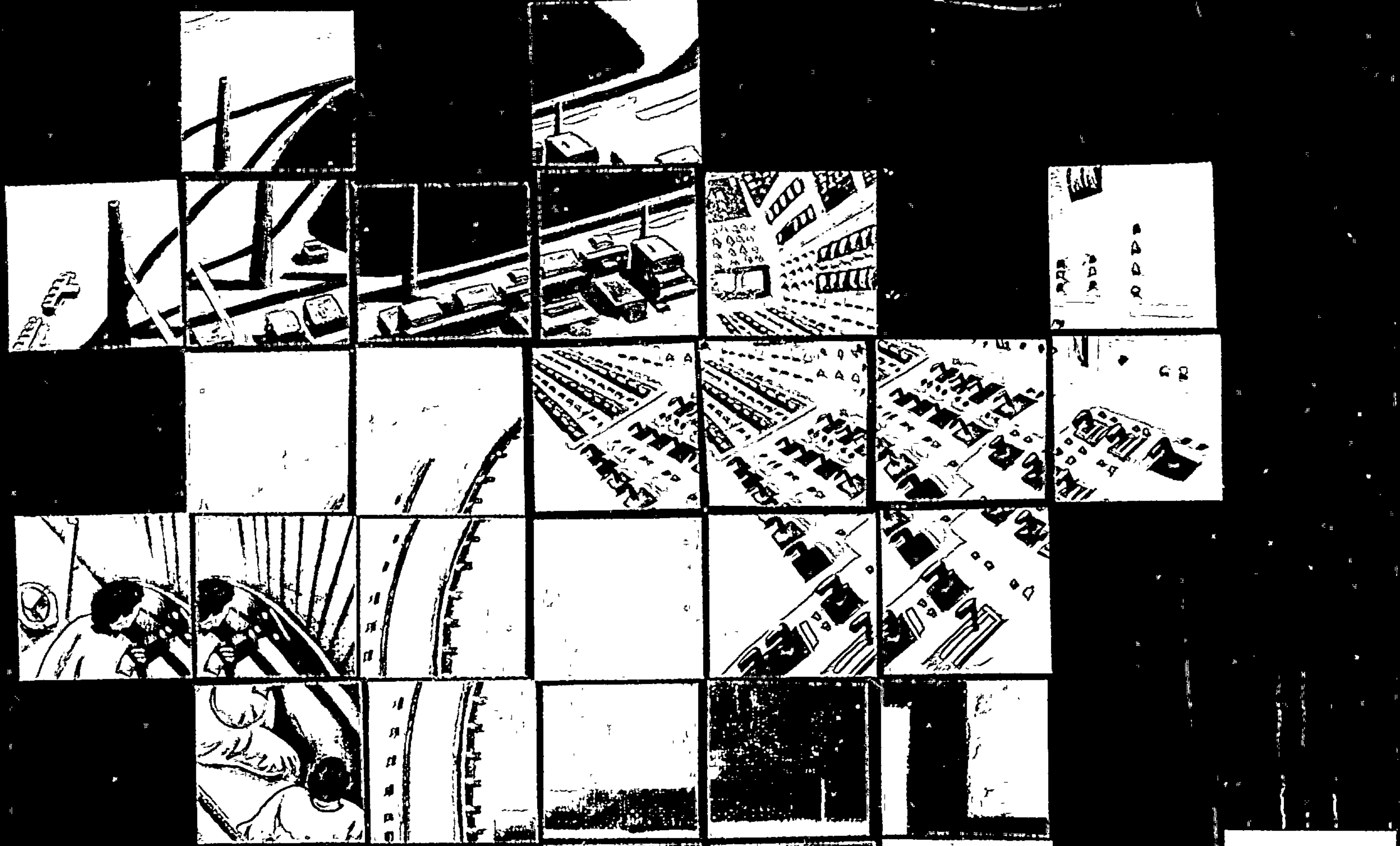
Even through the regulatory uncertainties he mentions, there is continuing focus on preserving and building shareholder value. I will lend my ongoing support to that focus.

Richard Snell
Chairman of the Board

strong cash flow to the parent company. These subsidiaries paid cash dividends to the parent in 1998 totaling $42 million. SunCor's operations are described in greater detail on page 14.

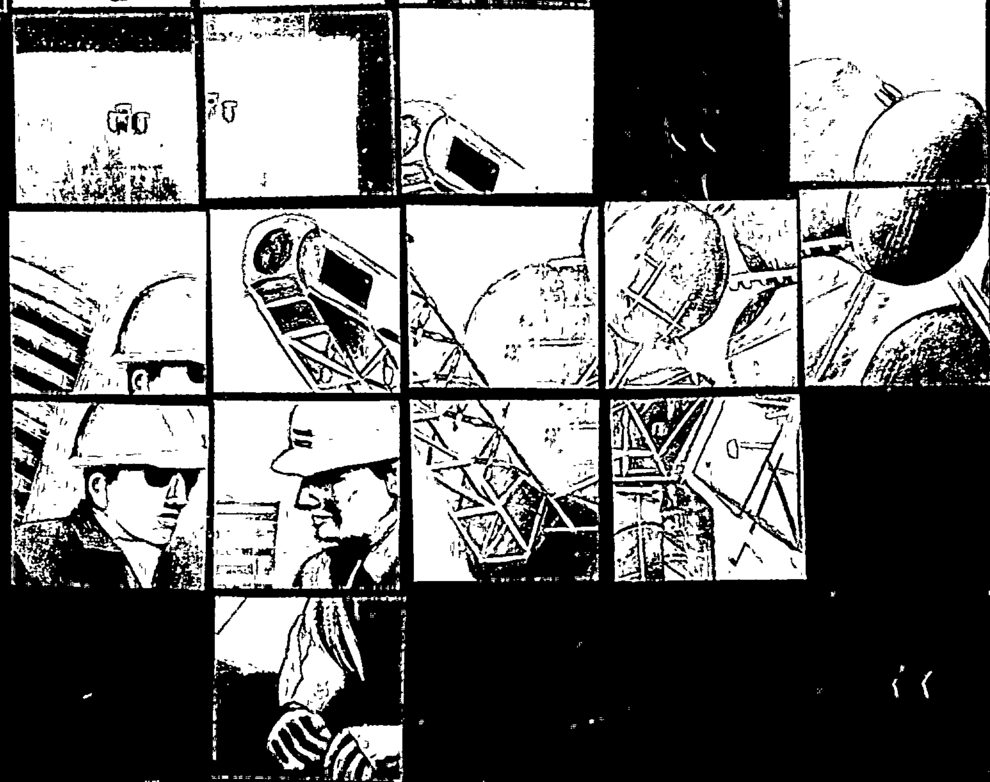
El Dorado, Pinnacle West's investment company, has total assets of $27 million invested in venture capital and other investments. Its primary goal is currently to convert the venture capital portfolio to cash as quickly and advantageously as possible. Over the long-term, we may use El Dorado for investing in new ventures that are strategically important to our primary energy business.



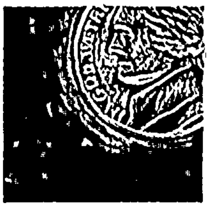


GENERATION HIGHLIGHTS

- FOR THE FOURTH CONSECUTIVE YEAR, PALO VERDE NUCLEAR OPERATIONS OUT-PRODUCED ALL U.S. POWER STATIONS.
- THE THREE PALO VERDE REACTORS RAN SIMULTANEOUSLY FOR 153 DAYS, A SITE RECORD, AND OPERATED AT A COMBINED CAPACITY FACTOR OF 92.5 PERCENT FOR THE YEAR.
- ALL THREE PALO VERDE UNITS WERE RANKED AMONG THE WORLD'S TOP 25 PRODUCERS IN 1998. (THERE ARE 435 NUCLEAR UNITS WORLDWIDE.)
- PALO VERDE ACHIEVED ITS LOWEST-EVER PRODUCTION COST IN 1998.
- CHOLLA COAL-FIRED UNITS 1, 2 AND 3 GENERATED MORE MEGAWATT-HOURS IN THE MONTH OF AUGUST THAN IN ANY PREVIOUS MONTH IN THE STATION'S 36-YEAR HISTORY.



OVERVIEW



STOCK AND FINANCIAL PERFORMANCE

Growth and operational excellence continue to anchor the strong performance of the company.

For the five years 1994 through 1998, total return on Pinnacle West common stock was 126 percent, or 17.7 percent annually, ranking us 14th among the U.S. electric companies. This record compared very favorably with the industry, which returned a total of 70 percent, or 11.2 percent annually for the same period. Although total return for 1998 was only 2.8 percent, business development goals are in place to produce superior long-term returns for our shareholders.

Effective December 1, 1998, the common stock dividend increased by 8.3 percent. The policy of increasing the dividend annually by consistent dollar amounts continues, with growth at a pace well above the industry average and conservative payout ratios well below those of the industry.

Earnings per share increased four percent in 1998 to $2.85 per diluted share of common stock. Consolidated net income for the year was $242.9 million, up $7 million from 1997. APS earnings were $245.5 million compared with $238.7 million in 1997. Pinnacle West's real estate and investment subsidiaries contributed a combined $12 million to consolidated results, compared with $13.5 million for the prior year.

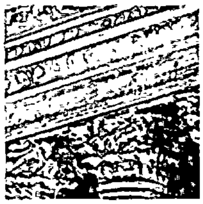
Earnings growth came from increased electricity sales related to 4.2 percent customer growth and higher usage per customer, expanded power marketing and trading activities and lower financing costs. These positive earnings effects were partially offset by the effects of milder, more normal weather and electricity price reductions in 1998 and 1997. Operating expenses were up primarily because of customer growth, initiatives relating to competition and expansion of our power marketing and trading function. The year-to-year earnings comparisons would have been even more positive, except for the beneficial effects in 1997 of two non-recurring fuel-related settlements that contributed approximately $21 million before income taxes.

OPERATIONAL ADVANTAGES

Pinnacle West operates in markets that are experiencing significant growth. In 1998, Arizona's population growth was 3.4 percent, almost four times the national average, and job growth was 4.6 percent, nearly twice the U.S. average.

A number of other factors represent competitive strengths, including low-cost generation, extensive knowledge of the western U.S. electricity markets, excellence in customer care and operations, state-of-the-art technology systems, modest concentration of large commercial and industrial customers and prices that are competitive with those in our region. Free cash flow and a strengthening balance sheet also provide financial resources to support future growth and agility.

Excellent operation of generation facilities as measured by production costs and plant output continue the solid record of achievement. Current plans will expand our generation resources to meet growing customer needs and to facilitate future earnings growth. Managing the growth of the energy delivery business is a challenge that is being successfully met. Our power marketing and trading group is growing — literally and in its strategic, operational importance —



providing energy marketing and procurement services. APS Energy Services is capturing opportunities in various markets in the western United States as they open to competitive choice.

ELECTRIC INDUSTRY RESTRUCTURING

The transition of regulated monopolies to competitive suppliers has been underway for a number of years and can be expected to continue to evolve for years to come.

Investor-owned electricity providers in Arizona are regulated by the Arizona Corporation Commission (ACC), which is developing the framework for introducing retail electricity competition in the state. The ACC initially adopted rules in 1996 that provided a basis for competitive choice, and further refinement of this process to determine final rules is described in some detail starting on page 35.

The Arizona Legislature passed a law in May 1998 that establishes the process for government-operated electricity providers to open their markets to competition. At the federal level, several pieces of legislation related to industry restructuring are expected. We believe the pace of competition throughout the nation is already increasing and that the actions of state regulators in Arizona and other states will precipitate more change in the near future.

We have been working — and are continuing to work — with regulators, legislators and other interested parties to achieve a transition to competition in Arizona that will be constructive for our shareholders, our customers and the public. Final outcome is expected around the end of 1999.

In April 1998, APS and Salt River Project, a public power entity operating in central Arizona, reached a historic agreement designed to facilitate customer choice in Arizona and to provide cost reduction opportunities.

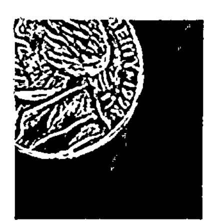
The agreement furthered the process of establishing competitive electricity markets in Arizona by putting to rest long-standing issues.

The company is taking part in discussions of public policy issues, the outcome of which could impact its business and the progress of electric industry restructuring. These include:

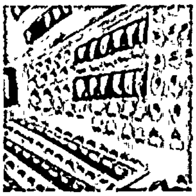
- The rulemaking process at the Federal Energy Regulatory Commission (FERC) with respect to pricing, constraints, congestion and "federalization" of the transmission system.
- Proposals regarding environmental and global climate issues, some of which could result in considerable disruption of the American economy and our industry. The company supports market-based solutions to global climate concerns.
- Market power and antitrust determinations and the impact on incumbent electric companies and on new competitors.

In many respects, competition in Arizona is not waiting for final determination of rules at state or federal levels. Various energy companies are already offering services even as they seek regulatory approval to sell electricity in the state. During the year, APS restructured into Generation, Energy Delivery and Energy Services. A non-regulated generation affiliate will be organized under the parent.

SunCor, our real estate subsidiary, and El Dorado, our investment subsidiary, are continuing to pursue strategies that provide



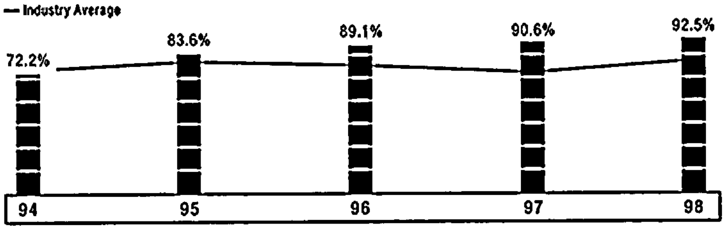
GENERATION

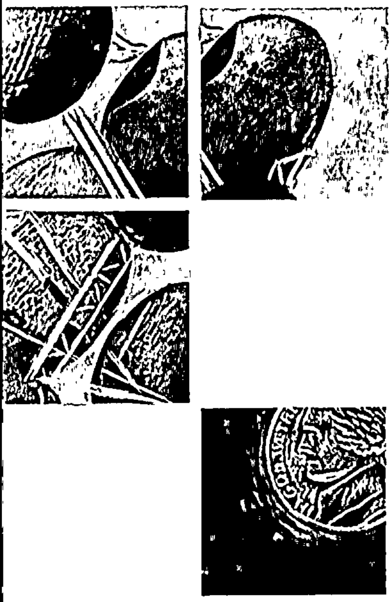


Generating electricity is a competitive advantage for the company. Based on a production cost per kilowatt-hour comparison, the company's generation assets are competitive with other generating facilities in the western United States and are particularly so with those in the Southwest. The company's generation business is well positioned to capture market share in the wholesale electricity markets.

With 39 generating units totaling about 8,000 megawatts, APS ranks second among investor-owned companies operating generation facilities in the western United States. These facilities include nuclear, coal and gas generating capacity. Operational performance has been considerably above industry averages and additional cost management opportunities are expected to enhance profitability in electricity markets in the fast-growing West.

Palo Verde Site Average Capacity Factors





The generation business highlights for 1998, mentioned on the previous page, underscore the excellent performance achieved to date. Palo Verde's 1998 production record represents the first time any American power plant has generated more than thirty billion kilowatt-hours in a year. Improved capacity factors and reduced production costs are results of lowering fuel costs, improving heat rates, reducing the length of outages and maintaining high operational performance to capture opportunities when prices peak in the spot market.

Attention to details at all levels and a focus on profitability are evident throughout the generation group. For example:

- Newly negotiated fuel contracts involving coal supply, rail transportation and uranium enrichment services will soon yield annual pretax savings of $20 million.

Palo Verde engineers have reduced the duration of refueling outages through several efficiency-improving techniques, including speedier methods of reinforcing water pipelines that are vital to Palo Verde's operation.

At the Four Corners plant, about $1 million was saved as a result of reducing the length of a major overhaul at Unit 2.

The capability of the Yucca plant increased five percent following the rebuilding of cooling components.

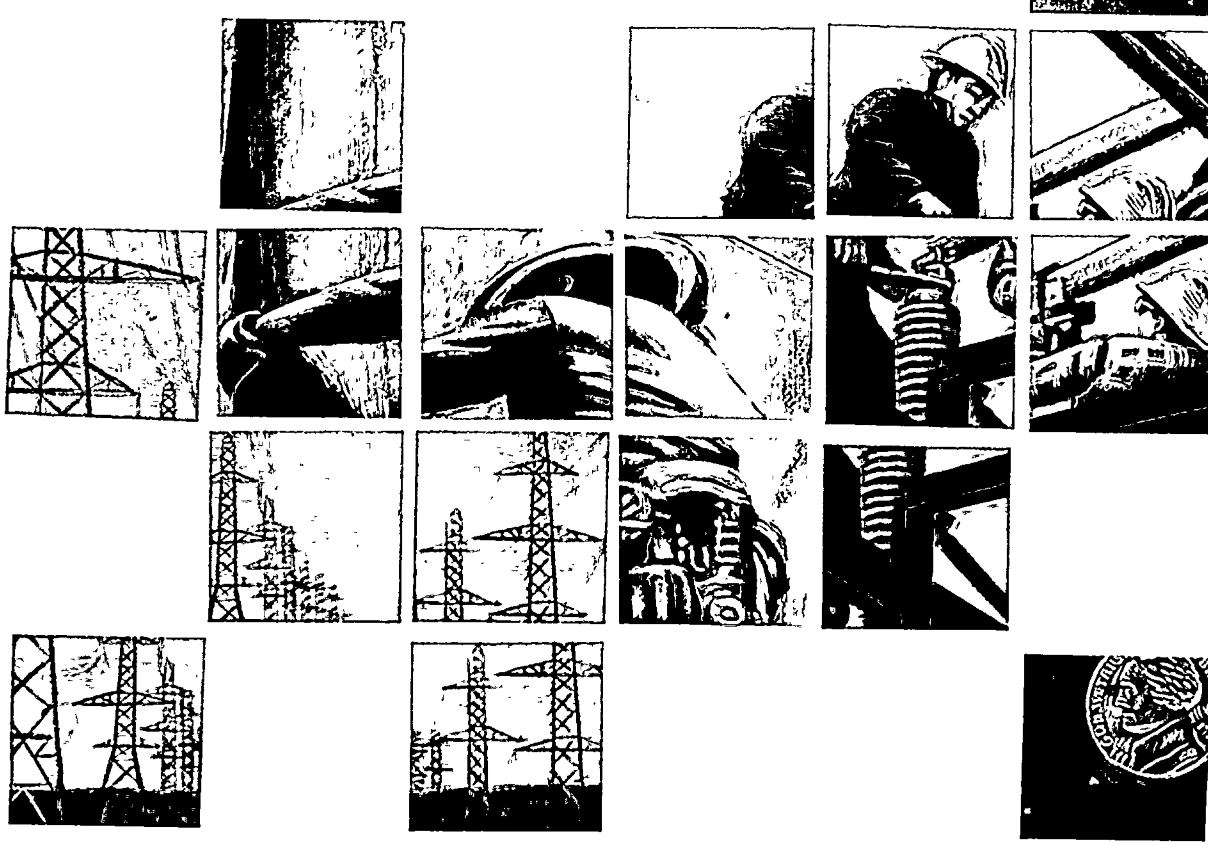
DELIVERY

The Energy Delivery business manages the transmission and distribution of electricity to APS' customers.

Population growth in Arizona has been and is expected to continue to be three to four times the United States average. More than 32,000 customers were added to the APS system in 1998 for a growth rate of 4.2 percent. On average, four customers were connected every hour of every day in 1998.

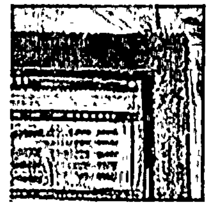
Managing this growth through cost management and efficient deployment of capital led to a 1.1 percent electricity price decrease in July. This was the fourth price decrease in the last five years, bringing the total to nearly 8.4 percent. Our retail electricity prices are currently average to below average when compared with neighboring utilities in the southwestern United States.

The performance pricing mechanism contained in the 1996 regulatory agreement with the Arizona Corporation Commission allows shareholders and customers to share cost-savings benefits. These price decreases are important ingredients to enhancing APS' position as the electricity market opens to competition. Although retail electric competition in Arizona has been delayed from its initially planned implementation in January 1999, we are continuing to work with the ACC and other parties to achieve a comprehensive transition to competitive markets.



replaced or added. These systems were brought on to further our competitive

ENERGY SERVICES



APS Energy Services provides energy, metering, billing and energy management services to markets in the western U.S. Incorporated in late 1998, this group is actively pursuing business opportunities in Arizona and California and is exploring markets in Nevada and New Mexico. Targeted market share acquisition, at a profit, is the primary goal of this business. As a start-up company, APS Energy Services has not yet accomplished its objective, but progress is being made.

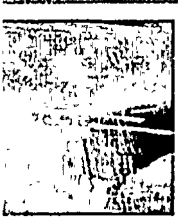
The long-term objective for this business is to contribute to corporate profitability by capturing strategically targeted segments of existing and newly competitive markets.

APS Energy Services was the first direct access electricity provider in the U.S. Customers now under contract throughout California have a combined peak load of more than 185 megawatts. Customer services in this business go well beyond selling power and include developing alternatives to reduce energy costs through energy efficiency solutions. These solutions include competitive metering and billing, lighting retrofits and chiller replacements for major public institutions.

Profit margins in this business are razor thin. Profitable operations will result from employing value-added services to meet customer needs. Doing this while increasing revenues is the key to success. This is a difficult formula because APS Energy Services will not buy market share — profitability will not be sacrificed. In fact, we exited one specific northern California market in mid-1998 because new competition rules made that market unprofitable.

Overall, in the world of undifferentiated competitors, APS Energy Services is off to a solid start in a very tough market. Progress to date and future success depend on intellectual capital and anticipating markets and customers' needs.

☐ Based on a demonstrated knowledge of the complexities of California's power market exchange and connection with retail tariffs, APS Energy Services' performance in 1998 underscored the potential for providing additional revenues from deregulated markets.



POWER MARKETING

The primary goals of the Power Marketing and Trading group are to maximize sales of electricity generated by APS, to obtain additional power needed by the company for growing customer needs, to manage fuel costs and to capture trading opportunities. This group actively trades physical quantities of electricity and gas as well as financial contracts relating to these commodities. Further, APS is one of the leading traders of emissions allowances.

Electricity trading activities are concentrated in the Western markets. Emissions trading is national in scope. This business is managed with the oversight of the Energy Risk Management Committee that establishes and monitors trading practices, sets risk limits and implements credit policies.

1998 was the second full year of operations. Technology systems are being upgraded to state-of-the-art capabilities. Power Marketing is expected to build off the profitable operations of 1998 through an expansion plan that contemplates adding additional resources through the end of 2000.

Success to date has been based on a thorough knowledge of, and experience in, the physical markets of the western United States, combined with analytical and risk disciplines.

□ In 1998, Power Marketing team members implemented a 24-hour marketing and schedule coordination desk to capture opportunities in the new California market structure. This significantly increased Power Marketing's contribution to APS earnings.

SUNCOR

Our real estate subsidiary, SunCor, is one of the premier real estate developers in the southwestern United States. Its divisions focus on master-planned communities, retail office and industrial properties, and golf course development and management.

Strategically, SunCor seeks to improve its overall profitability while building value, controlling its commitments and providing a cash return to the parent company. In 1998, SunCor contributed $7.5 million to our consolidated results, a 41 percent increase over the prior year, and paid $30 million in dividends to the parent. At the end of 1998, SunCor had assets with a total book value of $407 million.

With almost 34,000 single-family building permits issued in the metropolitan Phoenix area in 1998, the market is extremely healthy. Such growth has brought pressures on transportation, education, neighborhoods and the labor force. SunCor seeks to responsibly balance environmental and public policy issues as it plans and develops its various projects.

SunCor's assets consist primarily of six master-planned communities and numerous commercial properties in Arizona, predominantly the metropolitan Phoenix area. It also is developing master-planned communities in northern New Mexico and southern Utah.

In 1998, SunCor added two new master-planned communities to its development portfolio. Coral Canyon is an 1,800-acre development with a planned 18-hole championship golf course in Utah near

- CAPTURED SIGNIFICANT OPPORTUNITIES IN CALIFORNIA MARKETS FOR SPOT POWER AND ANCILLARY SERVICES.
- CONTROLLED AND MITIGATED EXPOSURE TO RISING AND SPIKING FUEL COSTS.
- ADDED TRADING AND INFRASTRUCTURE PERSONNEL AND INCREASED TECHNOLOGY TO MEET THE GROWING NEEDS OF APS' EXPANDING BUSINESS.

St. George. Northeast of Phoenix, Hidden Hills is a 400-acre community that complements SunCor's nearby Scottsdale Mountain and SunRidge Canyon developments.

The Palm Valley master-planned community has become a driving force in the western metropolitan Phoenix area. Within its remaining 8,000 acres, SunCor has brought its newest residential phase online. The project also includes PebbleCreek, a 2,600-acre adult community being developed by Robson Communities; shopping centers; apartments; schools and medical facilities. In the heart of this area, SunCor also manages the renowned Wigwam Resort in Litchfield Park.

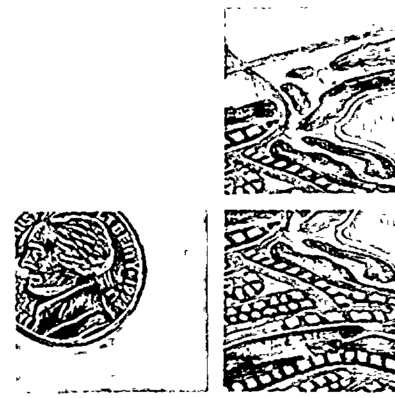
Development and sales are progressing at SunCor's other master-planned communities as well. Activity has been strong at SunRidge Canyon, northeast of Phoenix in Fountain Hills, and Sedona Golf Resort, 90 miles north of Phoenix in the scenic "red rock" country of northern Arizona. As planned, models opened and sales began at Rancho Viejo, near Santa Fe, New Mexico.

Tatum Ranch in north Phoenix is nearly built out, and all remaining residential lots are under contract. In the foothills northeast of Phoenix, Scottsdale Mountain is in its last phase.

SunCor's commercial, office and industrial properties performed well in 1998, with activity at both Marketplace, southeast of Phoenix, and Talavi, northwest of Phoenix. The last commercial parcels at Sedona Golf Resort were sold during the year.

Golden Heritage Homes is SunCor's homebuilding operation. Although SunCor uses a number of homebuilders in its residential developments, it is able to capture a greater share of the profit on homes sold at its communities through Golden Heritage.

The SunCor golf division currently manages six golf courses and is now developing two new courses. One of these, the Sanctuary golf course in Scottsdale, will be the first Audubon Signature course in the state, built to the strict environmental standards of the Audubon Society.



1998 FINANCIALS

SELECTED CONSOLIDATED DATA

(Dollars in Thousands, Except Per Share Amounts)	1998	1997	1996	1995	1994
OPERATING RESULTS					
Operating revenues					
Electric	$ 2,006,398	$ 1,878,553	$ 1,718,272	$ 1,614,952	$ 1,626,168
Real estate	124,188	116,473	99,488	54,846	59,253
Income from continuing operations	$ 242,892	$ 235,856	$ 211,059(a)	$ 199,608	$ 200,619(b)
Loss from discontinued operations – net of income tax (c)	—	—	(9,539)	—	—
Extraordinary charge for early retirement of debt – net of income tax (d)	—	—	(20,340)	(11,571)	—
Net income	$ 242,892	$ 235,856	$ 181,180	$ 188,037	$ 200,619
COMMON STOCK DATA					
Book value per share – year-end	$ 25.50	$ 23.90	$ 22.51	$ 21.49	$ 20.32
Earnings (loss) per average common share outstanding					
Continuing operations – basic	$ 2.87	$ 2.76	$ 2.41(a)	$ 2.28	$ 2.30(b)
Discontinued operations	—	—	(0.11)	—	—
Extraordinary charge	—	—	(0.23)	(0.13)	—
Net income – basic	$ 2.87	$ 2.76	$ 2.07	$ 2.15	$ 2.30
Continuing operations – diluted	$ 2.85	$ 2.74	$ 2.40(a)	$ 2.27	$ 2.29(b)
Net income – diluted	$ 2.85	$ 2.74	$ 2.06	$ 2.14	$ 2.29
Dividends declared per share	$ 1.225	$ 1.125	$ 1.025	$ 0.925	$ 0.825
Indicated annual dividend rate – year-end	$ 1.30	$ 1.20	$ 1.10	$ 1.00	$ 0.90
Average common shares outstanding – basic	84,774,218	85,502,909	87,441,515	87,419,300	87,410,967
Average common shares outstanding – diluted	85,345,946	86,022,709	88,021,920	87,884,226	87,671,451
TOTAL ASSETS	$ 6,824,546	$ 6,850,417	$ 6,989,289	$ 6,997,052	$ 6,909,752
LIABILITIES AND EQUITY					
Long-term debt less current maturities	$ 2,048,961	$ 2,244,248	$ 2,372,113	$ 2,510,709	$ 2,588,525
Other liabilities	2,516,993	2,407,572	2,428,180	2,336,695	2,276,249
	4,565,954	4,651,820	4,800,293	4,847,404	4,864,774
Minority interests					
Non-redeemable preferred stock of APS	85,840	142,051	165,673	193,561	193,561
Redeemable preferred stock of APS	9,401	29,110	53,000	75,000	75,000
Common stock equity	2,163,351	2,027,436	1,970,323	1,881,087	1,776,417
Total liabilities and equity	$ 6,824,546	$ 6,850,417	$ 6,989,289	$ 6,997,052	$ 6,909,752

(a) Includes an after-tax charge of $18.9 million ($0.22 per share) for a voluntary severance program and about $12 million ($0.13 per share) of income tax benefits related to capital loss carryforwards.

(b) Includes after-tax Palo Verde Unit 3 accretion income of $20.3 million ($0.23 per share) and a non-recurring income tax benefit of $26.8 million ($0.31 per share) related to a change in tax law.

(c) Charges associated with the settlement of a legal matter related to MeraBank, A Federal Savings Bank.

(d) Charges associated with the repayment or refinancing of the parent company's high-coupon debt.

(Dollars in Thousands, Except Per Share Amounts)	1998	1997	1996	1995	1994
ELECTRIC OPERATING REVENUES					
Residential	$ 766,378	$ 746,937	$ 721,877	$ 669,762	$ 675,153
Commercial	699,016	687,988	678,130	653,425	631,212
Industrial	172,296	164,696	162,324	156,501	166,457
Irrigation	7,288	8,706	9,448	9,596	10,538
Other	10,644	11,842	13,078	12,631	12,729
Total retail	1,655,622	1,620,169	1,584,857	1,501,915	1,496,089
Sales for resale	300,698	226,828	98,560	86,510	95,158
Transmission for others	11,058	10,295	10,240	9,390	9,506
Miscellaneous services	39,020	21,261	24,615	17,137	16,107
Electric operating revenues	2,006,398	1,878,553	1,718,272	1,614,952	1,616,860
Retail rate refund reversal	—	—	—	—	9,308
Net electric operating revenues	$ 2,006,398	$ 1,878,553	$ 1,718,272	$ 1,614,952	$ 1,626,168
ELECTRIC SALES (MWh)					
Residential	8,310,689	7,970,309	7,541,440	6,848,905	6,873,300
Commercial	8,697,397	8,524,882	8,233,762	7,768,289	7,456,049
Industrial	3,279,430	3,123,283	3,039,357	2,933,459	2,926,318
Irrigation	84,640	112,363	121,775	119,580	132,340
Other	90,927	86,090	84,362	78,478	76,827
Total retail	20,463,083	19,816,927	19,020,696	17,748,711	17,464,834
Sales for resale	10,317,391	9,233,573	3,367,234	2,720,704	2,764,223
Total electric sales	30,780,474	29,050,500	22,387,930	20,469,415	20,229,057
ELECTRIC CUSTOMERS - END OF YEAR					
Residential	709,111	680,478	654,602	625,352	603,989
Commercial	84,745	81,246	78,178	75,105	72,740
Industrial	3,159	3,192	3,055	2,913	2,976
Irrigation	710	764	841	837	897
Other	895	851	828	786	762
Total retail	798,620	766,531	737,504	704,993	681,364
Sales for resale	67	50	48	39	44
Total electric customers	798,687	766,581	737,552	705,032	681,408

See "Financial Review" on pages 20-27 for a discussion of certain information in the table above.

QUARTERLY STOCK PRICES AND DIVIDENDS

Stock Symbol: PNW

1998	*High*	*Low*	*Close*	*Dividends Per Share(a)*	1997	*High*	*Low*	*Close*	*Dividends Per Share(a)*
1st Quarter	45	39 3/8	44 7/16	$ 0.300	1st Quarter	32 7/8	30 1/8	30 1/8	$ 0.275
2nd Quarter	46 3/16	42	45	$ 0.600	2nd Quarter	30 3/4	27 5/8	30 1/16	$ 0.550
3rd Quarter	45 9/16	40 1/16	44 13/16	$ —	3rd Quarter	34 7/8	29 13/16	33 5/8	$ —
4th Quarter	49 1/4	41 5/8	42 3/8	$ 0.325	4th Quarter	42 3/4	33 3/16	42 3/8	$ 0.300

(a) Dividends for the 3rd quarter of 1998 and 1997 were declared in June.

FINANCIAL REVIEW

In this section, we explain the results of operations, general financial condition, and outlook for Pinnacle West and our subsidiaries: APS, SunCor, and El Dorado, including:

- the changes in our earnings from 1997 to 1998 and from 1996 to 1997
- the factors impacting our business, including competition and electric industry restructuring
- the effects of regulatory agreements on our results and outlook
- our capital needs and resources – both for APS and our non-utility operations and
- Year 2000 technology issues.

Throughout this Financial Review, we refer to specific "Notes" in the Notes to Consolidated Financial Statements that begin on page 33. These Notes add further details to the discussion.

RESULTS OF OPERATIONS

1998 Compared with 1997

Our 1998 consolidated net income was $242.9 million compared with $235.9 million in 1997 – a 3.0% increase. Net income increased by $7.0 million primarily because of increased earnings at the subsidiaries and lower financing costs as we paid down debt and took advantage of lower interest rates.

APS' 1998 earnings increased $6.9 million – a 2.9% increase – over 1997 earnings primarily because of an increase in customers, expanded power marketing and trading activities, and lower financing costs. In the comparison, these positive factors more than offset the effects of milder weather, two fuel-related settlements recorded in 1997, and two retail price reductions. See Note 3 for additional information about the price reductions.

In 1998, electric operating revenues increased $128 million primarily because of:

- increased power marketing and trading revenues ($94 million)
- increases in the number of customers and the amount of electricity used by customers ($77 million) and
- miscellaneous factors ($8 million).

As mentioned above, these positive factors were partially offset by the effects of milder weather ($33 million) and reductions in retail prices ($18 million).

Power marketing and trading activities are predominantly short-term opportunity wholesale sales. The increase in power marketing revenues resulted from higher prices, increased activity in Western bulk power markets, and increased sales to large customers in California. The increase in power marketing and trading revenues was accompanied by related increases in purchased power expenses.

The two fuel-related settlements increased 1997 pretax earnings by about $21 million. The income statement reflects these settlements as reductions in fuel expense and as other income.

Operations and maintenance expense increased $15 million because of customer growth, initiatives related to competition, and expansion of our power marketing and trading function.

Depreciation and amortization expense increased $11 million because APS had more plant in service.

APS decreased its financing costs by $9 million primarily because of lower amounts of outstanding debt and preferred stock.

Our real estate subsidiary, SunCor Development, and our investment subsidiary, El Dorado, contributed a combined $12.0 million to consolidated net income in 1998 compared with $13.5 million in 1997. SunCor's contribution increased $2.2 million as a result of an increase in land sales. El Dorado's contribution decreased $3.7 million as a result of a decrease in investment sales.

SunCor's stand-alone net income was $44.7 million, of which $37.2 million represents income related to the recognition of a deferred tax asset. The deferred tax asset relates to net operating losses and book/tax basis differences. SunCor is expected to realize these benefits in subsequent periods pursuant to an intercompany tax allocation agreement. On a consolidated basis, Pinnacle West had already recognized the income tax benefits, therefore, there was no impact on consolidated net income in 1998.

1997 Compared with 1996

Our 1997 consolidated net income was $235.9 million compared with $181.2 million in 1996. The following is a summary:

(Thousands of Dollars)	1997	1996
Income from continuing operations	$ 235,856	$ 211,059
Loss from discontinued operations – net of income tax	—	(9,539)
Extraordinary charge for early retirement of debt – net of income tax	—	(20,340)
Net income	$ 235,856	$ 181,180

Our earnings from continuing operations increased from 1996 to 1997 by $24.8 million, or 11.7%, primarily because of increased earnings at the subsidiaries and lower financing costs as we paid down debt and took advantage of lower interest rates. The 1996 loss from discontinued operations related to remnants of MeraBank legal matters.

APS' 1997 earnings increased $12.3 million – a 5.4% increase – over 1996 earnings primarily because of:

- an increase in customers
- a $32 million pretax charge in 1996 for a voluntary severance program
- two fuel-related settlements in 1997 and
- lower financing costs.

These positive factors more than offset the effects of the 1996 regulatory agreement with the Arizona Corporation Commission (ACC), which during 1997 resulted in about $60 million of additional regulatory asset amortization and a $35 million revenue decrease caused by two retail price reductions. See Note 3 and "Results of Operations – Regulatory Agreements" below for additional information. In addition, APS recognized $12 million of income tax benefits in 1996 that were not repeated in 1997.

In 1997, electric operating revenues increased $160 million primarily because of:

- increased power marketing revenues ($128 million)
- an increase in the number of customers ($58 million) and
- weather effects ($7 million).

As mentioned above, these positive factors were partially offset by a $35 million revenue decrease caused by retail price reductions. The increase in power marketing revenues resulted from increased activity in Western bulk power markets. This did not significantly affect our earnings because the increase was substantially offset by higher purchased power expenses.

Two fuel-related settlements in 1997 increased pretax earnings by about $21 million. The income statement shows these settlements as reductions in fuel expense and as other income. About $16 million of the settlements related to years prior to 1997 and $5 million related to 1997. APS expects the total annual savings from the settlements for at least the next several years to be about $10 million before income taxes. APS does not have a fuel adjustment clause as part of its retail rate structure. As a result, APS shows changes in fuel and purchased power expenses in current earnings.

APS lowered its operations and maintenance expenses in 1997 by putting in place a voluntary severance program in late 1996, with related savings reflected in 1997. These savings were partially offset by increased expenses for marketing, information technology, and power plant maintenance.

APS decreased its financing costs by $12 million during 1997 by lowering the amounts of outstanding debt and preferred stock.

SunCor Development and El Dorado contributed a combined $13.5 million to consolidated net income in 1997 compared with $4.6 million in 1996. SunCor's contribution increased as a result of increased land and home sales. El Dorado's contribution increased as a result of an increase in investment sales.

Regulatory Agreements

Regulatory agreements with the ACC affect the results of APS' operations. The following discussion focuses on two agreements: a 1996 agreement to accelerate the amortization of APS' regulatory assets and a 1994 settlement to accelerate amortization of APS' deferred investment tax credits (ITCs).

Under the 1996 agreement with the ACC, APS is recovering substantially all of its present regulatory assets through accelerated amortization. The recovery of these assets is taking place over an eight-year period that will end June 30, 2004. For more details, see Note 3. This accelerated amortization increased annual amortization expense by approximately $120 million ($72 million after taxes).

Also, as part of the 1996 regulatory agreement, APS reduced its retail prices by 3.4% effective July 1, 1996. This reduces revenue by about $48.5 million annually ($29 million after taxes). APS also agreed to share future cost savings with its customers, which resulted in the following additional retail price reductions:

- $17.6 million annually ($10.5 million after income taxes), or 1.2%, effective July 1, 1997, and
- $17 million annually ($10 million after income taxes), or 1.1%, effective July 1, 1998.

APS expects to file with the ACC for another retail price decrease of approximately $10.8 million annually ($6.5 million after income taxes) to become effective July 1, 1999. The amount and timing of the price decrease are subject to ACC approval. This will be the last price decrease under the 1996 regulatory agreement.

We discuss above, in "Results of Operations," the factors that offset the earnings impact of the accelerated regulatory asset amortization and the price decreases.

As part of the 1994 rate settlement, APS accelerated amortization of substantially all deferred investment tax credits (ITCs) over a five-year period that ends on December 31, 1999. The amortization of ITCs decreases annual consolidated income tax expense by approximately $24 million. Beginning in 2000, no further benefits will be reflected in income tax expense. See Note 4.

CAPITAL NEEDS AND RESOURCES

Pinnacle West (Parent Company)

We have reduced our debt over the last three years as follows: 1998, $113 million; 1997, $45 million; and 1996, $60 million. We have a $250 million line of credit, under which we had $42 million of borrowings outstanding at December 31, 1998. We do not have any debt repayment obligations until 2001.

During the past three years, our primary cash needs were for:

- dividends for our shareholders
- interest payments and
- optional and mandatory repayment of principal on our long-term debt.

In addition, as part of the 1996 agreement with the ACC, we invested $50 million in APS in 1998, 1997, and 1996 and will invest the same amount in 1999. This will be the last payment under the 1996 regulatory agreement. See Note 3. During 1997, we repurchased $80 million of common stock, reducing our shares outstanding at year-end by 2.7 million shares.

Our primary source of cash is from APS dividends. During 1998, APS paid $170 million in dividends. In 1998, SunCor provided cash of $30 million and El Dorado provided cash of $12 million. We expect both SunCor and El Dorado to contribute to our cash flow in 1999. Tax allocation payments from our subsidiaries, in excess of payments we made to taxing authorities, were an additional source of cash in 1998, 1997, and 1996. This is not expected to be a source of cash for Pinnacle West in the future.

APS

APS' capital requirements consist primarily of capital expenditures and optional and mandatory redemptions of long-term debt and preferred stock. APS pays for its capital requirements with:

- cash from operations
- annual cash payments from Pinnacle West of $50 million annually from 1996 through 1999 (see Note 3) and
- to the extent necessary, external financing.

During the period from 1996 through 1998, APS paid for all of its capital expenditures with cash from operations. APS expects to do so in 1999 through 2001, as well.

APS' capital expenditures in 1998 were $327 million. APS' projected capital expenditures for the next three years are: 1999, $328 million; 2000, $317 million; and 2001, $300 million. These amounts include about $30-$35 million each year for nuclear fuel. In general, most of the projected capital expenditures are for:

- expanding transmission and distribution capabilities to meet customer growth
- upgrading existing utility property and
- environmental purposes.

In addition, APS is considering expanding certain of its operations over the next several years, which may result in additional expenditures. APS currently believes that there will be opportunities to expand its investment in generating assets in the next five years. It is expected that these generating assets would be organized in a newly created non-regulated affiliate under the parent.

During 1998, APS redeemed about $145 million of long-term debt and $76 million of preferred stock, including premiums, with cash from operations and long- and short-term debt. APS' long-term debt and preferred stock redemption requirements and payment obligations on a capitalized lease for the next three years are: 1999, $260 million; 2000, $115 million; and 2001, $2 million. On March 1, 1999, APS redeemed all $95 million of its outstanding preferred stock. Based on market conditions and optional call provisions, APS may make optional redemptions of long-term debt from time to time.

As of December 31, 1998, APS had credit commitments from various banks totalling about $400 million, which were available either to support the issuance of commercial paper or to be used as bank borrowings. At the end of 1998, APS had about $179 million of commercial paper and $125 million of long-term bank borrowings outstanding.

In 1998, APS issued $100 million of unsecured long-term debt and in February 1999, APS issued $125 million of unsecured long-term debt.

Although provisions in APS' first mortgage bond indenture, articles of incorporation, and ACC financing orders establish maximum amounts of additional first mortgage bonds that APS may issue, APS does not expect any of these provisions to limit its ability to meet its capital requirements.

Non-Utility Subsidiaries

During the past three years, SunCor and El Dorado each funded all of their cash requirements with cash from operations and their own financing.

SunCor's capital needs consist primarily of capital expenditures for land development and home construction. On the basis of projects now under development, SunCor expects capital needs over the next three years to be: 1999, $58 million; 2000, $53 million; and 2001, $43 million. Capital resources to meet these requirements include funds from operations and SunCor's own external financings.

As of December 31, 1998, SunCor had a $55 million line of credit, under which $38 million of borrowings were outstanding. SunCor's debt repayment requirements for the next three years are: 1999, $4 million; 2000, $26 million; and 2001, $51 million.

COMPETITION AND INDUSTRY RESTRUCTURING

The electric industry is undergoing significant change. It is moving to a competitive, market-based structure from a highly-regulated, cost-based environment in which companies have been entitled to recover their costs and to earn fair returns on their invested capital in exchange for commitments to serve all customers within designated service territories. In December 1996, the ACC adopted rules that provide a framework for the introduction of retail electric competition in Arizona and adopted amendments to the rules in August 1998. On January 11, 1999, the ACC issued an order which stayed the amended rules and granted waivers from compliance with the rules to all affected utilities (including APS) pending further ACC decisions. On February 5, 1999, ACC hearing officers issued recommendations for changes to the amended rules. See Note 3 for additional information about these rules and other competitive developments, including an agreement with Salt River Project Agricultural Improvement and Power District (Salt River Project). We cannot currently predict when or if the amended rules will be further modified, when the stay of the amended rules will be lifted, or when retail electric competition will be introduced in Arizona with respect to affected utilities.

The rules as recommended indicate that the ACC will allow affected utilities the opportunity to fully recover unmitigated stranded costs, but do not set forth the mechanisms for determining and recovering such costs. On June 22, 1998, the ACC issued an order on stranded cost determination and recovery and on February 5, 1999, an ACC hearing officer issued recommended changes to that order. See Note 3 for additional information on proposed modifications to the stranded cost order.

An Arizona joint legislative committee studied electric utility restructuring issues in 1996 and 1997. In May 1998, a law was enacted to facilitate implementation of retail electric competition in the state. Additionally, legislation related to electric competition has been proposed in the United States Congress. See Note 3 for a discussion of legislative developments.

We believe that further ACC decisions, legislation at the Arizona and federal levels, and perhaps amendments to the Arizona Constitution will ultimately be required before significant implementation of retail electric competition can lawfully occur in Arizona. Until it has been determined how competition will be implemented in Arizona, including the manner in which stranded costs will be addressed, we cannot accurately predict the impact of full retail competition on our financial position, cash flows, or results of operations. As competition in the electric industry continues to evolve, we will continue to evaluate strategies and alternatives that will position us to compete effectively in a restructured industry.

APS prepares its financial statements in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in its financial statements. APS' existing regulatory orders and the current regulatory environment support its accounting practices related to regulatory assets, which amounted to about $900 million at December 31, 1998. Under the 1996 regulatory agreement, the ACC accelerated the amortization of substantially all of APS' regulatory assets to an eight-year period that will end June 30, 2004. If APS ceases to be cost-based regulated, it would no longer be able to apply the provisions of SFAS No. 71 to part or all of its operations, which could have a material impact on our financial statements. See Note 1 for additional information on regulatory accounting.

YEAR 2000 READINESS DISCLOSURE

Overview

As the year 2000 approaches, many companies face problems because many computer systems and equipment will not properly recognize calendar dates beginning with the year 2000. We are addressing the Year 2000 issue as described below. APS initiated a comprehensive company-wide Year 2000 program during 1997 to review and resolve all Year 2000 issues in mission critical systems (systems and equipment that are key to business function, health, and safety) in a timely manner to ensure the reliability of electric service to our customers. This included a company-wide awareness program of the Year 2000 issue.

The following chart shows Year 2000 readiness of our mission critical systems as of January 31, 1999:

	Inventory	Assessment	Remediation & Testing
APS	100%	100%	70% (1)
Pinnacle West and other subsidiaries (excluding APS)	100%	100%	80% (2)

(1) Estimated to be at 100% by June 30, 1999, except one Palo Verde unit as discussed below.
(2) Estimated to be at 100% by June 30, 1999.

Discussion

APS has been actively implementing and replacing systems and technology since 1995 for general business reasons unrelated to the Year 2000, and these actions have resulted in substantially all of its major information technology (IT) systems becoming Year 2000 ready. The major IT systems that were, and are being, implemented and replaced include the following:

- Work Management
- Materials Management
- Energy Management

- Payroll
- Financial
- Human Resources
- Trouble Call Management
- Computer and Communications Network Upgrades
- Geographic Information Management
- Customer Information System and
- Palo Verde Site Work Management.

We and our subsidiaries have made, and will continue to make, certain modifications to computer hardware and software systems and applications, including IT and non-IT systems, in an effort to ensure they are capable of handling changing business needs, including dates in the year 2000 and thereafter. In addition, other APS IT systems and non-IT systems, including embedded technology and real-time process control systems, are being analyzed for potential modifications.

Pinnacle West, APS, SunCor, and El Dorado have inventoried and assessed essentially all mission critical IT and non-IT systems and equipment. APS is 70% complete and Pinnacle West and its other subsidiaries are 80% complete with the remediation and testing of these systems. Remediation and testing is expected to be completed by June 30, 1999 for all mission critical systems, except for those items that can only be completed during maintenance outages at Palo Verde, which will be completed for the last unit, which is substantially identical to the other two units, during the last half of 1999. APS has an internal audit/quality review team that is periodically reviewing the individual Year 2000 projects and their Year 2000 readiness.

APS currently estimates that it will spend approximately $5 million relating to Year 2000 issues, about $3 million of which has been spent to date. This includes an estimated allocation of payroll costs for APS employees working on Year 2000 issues, and costs for consultants, hardware, and software. We do not separately track other internal costs. This does not include any expenditures incurred since 1995 to implement and replace systems for reasons unrelated to the Year 2000, as discussed above. Our cost to address the Year 2000 issue is charged to operating expenses as incurred and has not had, and is not expected to have, a material adverse effect on our financial position, cash flows, or results of operations. We expect to fund this cost with available cash balances and cash provided by operations.

Pinnacle West and its subsidiaries are communicating with their significant suppliers, business partners, other utilities, and large customers to determine the extent to which they may be affected by these third parties' plans to remediate their own Year 2000 issues in a timely manner. These companies have been interfacing with suppliers of systems, services, and materials in order to assess whether their schedules for analysis and remediation of Year 2000 issues are timely and to assess their ability to continue to supply required services and materials.

APS is also working with the North American Electric Reliability Council (NERC) through the Western Systems Coordinating Council (WSCC) to develop operational plans for stable grid operation that will be utilized by APS and other utilities in the western United States. These plans are expected to be completed by June 30, 1999. However, APS cannot currently predict the effect on APS if the systems of these other companies are not Year 2000 ready.

We currently expect that our most reasonably likely worst case Year 2000 scenario would be intermittent loss of power to APS customers, similar to an outage during a severe weather disturbance. In this situation, APS would restore power as soon as possible by, among other things, re-routing power flows. We do not currently expect that this scenario would have a material adverse effect on our financial position, cash flows, or results of operations.

We are working to develop our own contingency plans to handle Year 2000 issues, including the most reasonably likely worst case scenario discussed above, and we expect these plans to be completed by June 30, 1999. As discussed above, APS has also been working with NERC and WSCC to develop contingency plans related to grid operation.

ACCOUNTING MATTERS

We describe two new accounting rules in Note 2. First, the new rule on energy trading and risk management is effective in 1999. We do not expect it to have a material impact on our financial results. Secondly, the new standard on derivatives is effective for us in 2000. We are currently evaluating what impact it will have on our financial statements. Also, see Note 13 for a description of a proposed standard on accounting for certain liabilities related to closure or removal of long-lived assets.

RISK MANAGEMENT

Our operations include managing market risks related to changes in interest rates, commodity prices, and investments held by the nuclear decommissioning trust fund.

Interest Rate and Equity Risk

Our major financial market risk exposure is changing interest rates. Changing interest rates will affect interest paid on variable rate debt and interest earned by the nuclear decommissioning trust fund. Our policy is to manage interest rates through the use of a combination of fixed and floating rate debt. The nuclear decommissioning fund also has risks associated with changing market values of equity investments. Nuclear decommissioning costs are recovered in rates.

The tables below present contractual balances of our long-term and short-term debt at the expected maturity dates as well as the fair value of those instruments on December 31, 1998 and December 31, 1997. The weighted average interest rates for the various debt presented are actual as of December 31, 1998 and December 31, 1997.

Expected Maturity/Principal Repayment - December 31, 1998

	Short-Term		Variable Long-Term		Fixed Long-Term	
(Thousands of Dollars)	*Interest Rates*	*Amount*	*Interest Rates*	*Amount*	*Interest Rates*	*Amount*
1999	6.21%	$ 178,830	7.30%	$ 3,268	7.24%	$ 164,777
2000	—	—	7.32%	25,756	5.79%	114,711
2001	—	—	6.57%	93,472	6.70%	27,488
2002	—	—	10.25%	119	8.13%	125,000
2003	—	—	5.69%	125,131	6.87%	25,000
Years thereafter	—	—	3.43%	459,803	7.75%	1,058,963
Total		$ 178,830		$ 707,549		$ 1,515,939
Fair Value		$ 178,830		$ 707,549		$ 1,577,365

Expected Maturity/Principal Repayment - December 31, 1997

	Short-Term		Variable Long-Term		Fixed Long-Term	
(Thousands of Dollars)	*Interest Rates*	*Amount*	*Interest Rates*	*Amount*	*Interest Rates*	*Amount*
1998	6.27%	$ 130,750	7.95%	$ 3,064	7.59%	$ 105,631
1999	—	—	7.98%	28,598	7.25%	164,378
2000	—	—	7.99%	54,133	5.83%	104,711
2001	—	—	6.25%	155,079	6.70%	27,488
2002	—	—	6.25%	150,088	8.13%	125,000
Years thereafter	—	—	3.67%	443,178	7.89%	998,628
Total		$ 130,750		$ 834,140		$ 1,525,836
Fair Value		$ 130,750		$ 834,140		$ 1,556,697

Commodity Price Risk

APS utilizes a variety of derivative instruments including exchange-traded futures, options, and swaps as part of its overall risk management strategies and for trading purposes. In order to reduce the risk of adverse price fluctuations in the electricity and natural gas markets, APS enters into futures and/or option transactions to hedge certain natural gas held in storage as well as certain expected purchases and sales of natural gas and electricity. The changes in market value of such contracts have a high correlation to the price changes in the hedged commodity. Gains and losses related to derivatives that qualify as hedges of expected transactions are recognized in income when the underlying hedged physical transaction closes (deferral method). Gains and losses on derivatives utilized for trading are recognized in income on a current basis (the mark to market method).

APS has prepared a sensitivity analysis to estimate its exposure to the market risk of its derivative position for natural gas and electricity. With respect to these derivatives, a potential adverse price movement of 10% in the market price of natural gas and electricity from the December 31, 1998 levels would decrease the fair value of these instruments by approximately $1 million. This analysis does not include the favorable impact that the same hypothetical price movement would have on expected physical purchases and sales of natural gas and electricity.

APS is exposed to credit losses in the event of non-performance or non-payment by counterparties. APS uses a credit management process to assess and monitor the financial viability of its counterparties. APS does not expect counterparty defaults to materially impact its financial condition, results of operations, or net cash flows.

FORWARD-LOOKING STATEMENTS

The above discussion contains forward-looking statements that involve risks and uncertainties. Words such as "estimates," "expects," "anticipates," "plans," "believes," "projects," and similar expressions identify forward-looking statements. These risks and uncertainties include, but are not limited to, the ongoing restructuring of the electric industry; the outcome of the regulatory proceedings relating to the restructuring; regulatory, tax, and environmental legislation; the ability of APS to successfully compete outside its traditional regulated markets; regional economic conditions, which could affect customer growth; the cost of debt and equity capital; weather variations affecting customer usage; technological developments in the electric industry; Year 2000 issues; and the strength of the real estate market.

These factors and the other matters discussed above may cause future results to differ materially from historical results, or from results or outcomes we currently expect or seek.

REPORT OF MANAGEMENT AND INDEPENDENT AUDITORS' REPORT

REPORT OF MANAGEMENT

The primary responsibility for the integrity of the Company's financial information rests with management, which has prepared the accompanying financial statements and related information. Such information was prepared in accordance with generally accepted accounting principles appropriate in the circumstances, and based on management's best estimates and judgments. Materiality was given due consideration. These financial statements have been audited by independent auditors and their report is included.

Management maintains and relies upon systems of internal accounting controls. A limiting factor in all systems of internal accounting control is that the cost of the system should not exceed the benefits to be derived. Management believes that the Company's system provides the appropriate balance between such costs and benefits.

Periodically the internal accounting control system is reviewed by both the Company's internal auditors and its independent auditors to test for compliance. Reports issued by the internal auditors are released to management, and such reports or summaries thereof are transmitted to the Audit Committee of the Board of Directors and the independent auditors on a timely basis.

The Audit Committee, composed solely of outside directors, meets periodically with the internal auditors and independent auditors (as well as management) to review the work of each. The internal auditors and independent auditors have free access to the Audit Committee, without management present, to discuss the results of their audit work.

Management believes that the Company's systems, policies and procedures provide reasonable assurance that operations are conducted in conformity with the law and with management's commitment to a high standard of business conduct.

William J. Post
Chief Executive Officer

George A. Schreiber, Jr.
President

INDEPENDENT AUDITORS' REPORT

We have audited the accompanying consolidated balance sheets of Pinnacle West Capital Corporation and its subsidiaries as of December 31, 1998 and 1997 and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1998. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Pinnacle West Capital Corporation and its subsidiaries at December 31, 1998 and 1997 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1998 in conformity with generally accepted accounting principles.

Deloitte & Touche LLP

Deloitte & Touche LLP
Phoenix, Arizona
March 4, 1999

CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31, (Dollars in Thousands, Except Per Share Amounts)	1998	1997	1996
OPERATING REVENUES			
Electric	$ 2,006,398	$ 1,878,553	$ 1,718,272
Real estate	124,188	116,473	99,488
Total	2,130,586	1,995,026	1,817,760
OPERATING EXPENSES			
Fuel and purchased power	537,501	436,627	325,523
Utility operations and maintenance	414,041	399,434	430,714
Real estate operations	115,331	111,628	96,080
Depreciation and amortization (Note 1)	379,679	368,285	299,507
Taxes other than income taxes	116,906	121,546	122,077
Total	1,563,458	1,437,520	1,273,901
OPERATING INCOME	567,128	557,506	543,859
OTHER INCOME (EXPENSE)			
Allowance for equity funds used during construction	—	—	5,209
Preferred stock dividend requirements of APS	(9,703)	(12,803)	(17,092)
Net other income and expense	609	4,569	(6,748)
Total	(9,094)	(8,234)	(18,631)
INCOME BEFORE INTEREST AND INCOME TAXES	558,034	549,272	525,228
INTEREST EXPENSE			
Interest charges	169,145	182,838	198,569
Capitalized interest	(18,596)	(19,703)	(12,856)
Total	150,549	163,135	185,713
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	407,485	386,137	339,515
INCOME TAXES (NOTE 4)	164,593	150,281	128,456
INCOME FROM CONTINUING OPERATIONS	242,892	235,856	211,059
Loss from discontinued operations – net of income tax of $6,461	—	—	(9,539)
Extraordinary charge for early retirement of debt – net of income tax of $13,777	—	—	(20,340)
NET INCOME	$ 242,892	$ 235,856	$ 181,180
AVERAGE COMMON SHARES OUTSTANDING – BASIC	84,774,218	85,502,909	87,441,515
AVERAGE COMMON SHARES OUTSTANDING – DILUTED	85,345,946	86,022,709	88,021,920
EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING			
Continuing operations – basic	$ 2.87	$ 2.76	$ 2.41
Net income – basic	2.87	2.76	2.07
Continuing operations – diluted	2.85	2.74	2.40
Net income – diluted	2.85	2.74	2.06
DIVIDENDS DECLARED PER SHARE	$ 1.225	$ 1.125	$ 1.025

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

December 31, (Thousands of Dollars)	1998	1997
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 20,538	$ 27,484
Customer and other receivables – net	233,876	183,507
Accrued utility revenues	67,740	58,559
Materials and supplies (at average cost)	69,074	70,634
Fossil fuel (at average cost)	13,978	9,621
Deferred income taxes (Note 4)	3,999	57,887
Other current assets	47,594	41,408
Total current assets	456,799	449,100
INVESTMENTS AND OTHER ASSETS		
Real estate investments – net (Note 6)	331,021	365,921
Other assets (Note 13)	236,562	215,027
Total investments and other assets	567,583	580,948
UTILITY PLANT (NOTES 6, 10 AND 11)		
Electric plant in service and held for future use	7,265,604	7,009,059
Less accumulated depreciation and amortization	2,814,762	2,620,607
Total	4,450,842	4,388,452
Construction work in progress	228,643	237,492
Nuclear fuel, net of amortization of $68,569 and $66,081	51,078	51,624
Net utility plant	4,730,563	4,677,568
DEFERRED DEBITS		
Regulatory asset for income taxes (Note 4)	400,795	458,369
Rate synchronization cost deferral	303,660	358,871
Other deferred debits	365,146	325,561
Total deferred debits	1,069,601	1,142,801
TOTAL ASSETS	$ 6,824,546	$ 6,850,417

See Notes to Consolidated Financial Statements.

December 31, (Thousands of Dollars)	1998	1997
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 155,800	$ 117,429
Accrued taxes	62,520	84,610
Accrued interest	31,866	32,974
Short-term borrowings (Note 5)	178,830	130,750
Current maturities of long-term debt (Note 6)	168,045	108,695
Customer deposits	28,510	30,672
Other current liabilities	14,632	18,534
Total current liabilities	640,203	523,664
LONG-TERM DEBT LESS CURRENT MATURITIES (NOTE 6)	2,048,961	2,244,248
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	1,343,536	1,363,461
Deferred investment tax credit (Note 4)	27,345	50,861
Unamortized gain – sale of utility plant	77,787	82,363
Other	428,122	387,223
Total deferred credits and other	1,876,790	1,883,908
COMMITMENTS AND CONTINGENCIES (NOTES 3 AND 12)		
MINORITY INTERESTS (NOTE 7)		
Non-redeemable preferred stock of APS	85,840	142,051
Redeemable preferred stock of APS	9,401	29,110
COMMON STOCK EQUITY (NOTE 8)		
Common stock, no par value; authorized 150,000,000 shares; issued and outstanding 84,824,947 at end of 1998 and 1997	1,550,643	1,553,771
Retained earnings	612,708	473,665
Total common stock equity	2,163,351	2,027,436
TOTAL LIABILITIES AND EQUITY	$ 6,824,546	$ 6,850,417

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31, (Thousands of Dollars)	1998	1997	1996
CASH FLOWS FROM OPERATING ACTIVITIES			
Income from continuing operations	$ 242,892	$ 235,856	$ 211,059
Items not requiring cash			
Depreciation and amortization	379,679	368,285	299,507
Nuclear fuel amortization	32,856	32,702	33,566
Deferred income taxes – net	41,262	24,809	13,392
Allowance for equity funds used during construction	—	—	(5,209)
Deferred investment tax credit	(23,516)	(23,518)	(23,518)
Other – net	1,190	(3,854)	1,370
Changes in current assets and liabilities			
Customer and other receivables – net	(50,369)	(14,270)	(38,106)
Accrued utility revenues	(9,181)	(3,089)	(1,951)
Materials, supplies and fossil fuel	(2,797)	7,793	11,945
Other current assets	(6,186)	(109)	(8,949)
Accounts payable	34,386	(54,882)	65,586
Accrued taxes	(22,090)	2,197	(7,088)
Accrued interest	(1,108)	(6,678)	(9,306)
Other current liabilities	(5,235)	(23,087)	1,515
Decrease in land held	33,405	33,010	19,894
Other - net	(39,350)	48,254	2,576
Net Cash Flow Provided By Operating Activities	605,838	623,419	566,283
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(319,142)	(307,876)	(258,598)
Capitalized interest	(18,596)	(19,703)	(12,856)
Other – net	(2,144)	(3,124)	(6,345)
Net Cash Flow Used For Investing Activities	(339,882)	(330,703)	(277,799)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	148,229	146,013	557,067
Short-term borrowings – net	48,080	113,850	(160,900)
Dividends paid on common stock	(103,849)	(96,160)	(89,614)
Repurchase and retirement of common stock	—	(79,997)	—
Repayment of long-term debt	(286,314)	(325,526)	(575,332)
Redemption of preferred stock	(75,517)	(47,201)	(50,360)
Extraordinary charge for early retirement of debt	—	—	(20,340)
Other – net	(3,531)	(2,897)	(1,858)
Net Cash Flow Used For Financing Activities	(272,902)	(291,918)	(341,337)
NET CASH FLOW	(6,946)	798	(52,853)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	27,484	26,686	79,539
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 20,538	$ 27,484	$ 26,686

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year Ended December 31, (Thousands of Dollars)	1998	1997	1996
Retained Earnings at Beginning of Year	$ 473,665	$ 333,969	$ 242,403
Net Income	242,892	235,856	181,180
Common Stock Dividends	(103,849)	(96,160)	(89,614)
Retained Earnings at End of Year	$ 612,708	$ 473,665	$ 333,969

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Consolidation and Nature of Operations

The consolidated financial statements include the accounts of Pinnacle West and our subsidiaries: APS, SunCor, and El Dorado.

APS, our major subsidiary and Arizona's largest electric utility, with 799,000 customers, provides wholesale or retail electric service to the entire state with the exception of Tucson and about one-half of the Phoenix area. SunCor is a developer of residential, commercial, and industrial projects on some 12,400 acres in Arizona, New Mexico, and Utah. El Dorado is a venture capital firm with a diversified portfolio.

Accounting Records

Our accounting records are maintained in accordance with generally accepted accounting principles (GAAP). The preparation of financial statements in accordance with GAAP requires the use of estimates by management. Actual results could differ from those estimates.

Regulatory Accounting

APS is regulated by the Arizona Corporation Commission (ACC) and the Federal Energy Regulatory Commission (FERC). The accompanying financial statements reflect the rate-making policies of these commissions. APS prepares its financial statements in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in its financial statements.

APS' major regulatory assets are deferred income taxes (see Note 4) and rate synchronization cost deferrals (see "Rate Synchronization Cost Deferrals" in this Note). These items, combined with miscellaneous regulatory assets and liabilities, amounted to approximately $900 million at December 31, 1998 and $1.0 billion at December 31, 1997. Most of these items are included in "Deferred Debits" on the Balance Sheets. Under the 1996 regulatory agreement (see Note 3), the ACC accelerated the amortization of substantially all of APS' regulatory assets to an eight-year period that will end June 30, 2004. APS records the accelerated portion of the regulatory asset amortization, approximately $120 million pretax in 1998 and 1997 and $60 million pretax in 1996, in depreciation and amortization expense on the Statements of Income.

During 1997, the Emerging Issues Task Force (EITF) of the Financial Accounting Standards Board (FASB) issued EITF 97-4. EITF 97-4 requires that SFAS No. 71 be discontinued no later than when legislation is passed or a rate order is issued that contains sufficient detail to determine its effect on the portion of the business being deregulated, which could result in write-downs or write-offs of physical and/or regulatory assets. Additionally, the EITF determined that regulatory assets should not be written off if they are to be recovered from a portion of the entity which continues to apply SFAS No. 71.

Although rules have been proposed for transitioning generation services to competition, there are many unresolved issues. APS continues to apply SFAS No. 71 to its generation operations. If rate recovery of regulatory assets is no longer probable, whether due to competition or regulatory action, APS would be required to write off the remaining balance as an extraordinary charge to expense.

Utility Plant and Depreciation

Utility plant is the term APS uses to describe the business property and equipment that supports electric service. APS reports utility plant at its original cost, which includes:

- material and labor
- contractor costs
- construction overhead costs (where applicable) and
- capitalized interest or an allowance for funds used during construction.

APS charges retired utility plant, plus removal costs less salvage realized, to accumulated depreciation. See Note 13 for information on a proposed accounting standard that impacts accounting for removal costs.

APS records depreciation on utility property on a straight-line basis. For the years 1996 through 1998 the rates, as prescribed by our regulators, ranged from a low of 1.51% to a high of 20%. The weighted-average rate for 1998 was 3.32%. APS depreciates non-utility property and equipment over the estimated useful lives of the related assets, ranging from 3 to 50 years.

Capitalized Interest

In 1997, APS began capitalizing interest in accordance with SFAS No. 34, "Capitalization of Interest Cost." Capitalized interest represents the cost of debt funds used to finance construction of utility plant. Plant construction costs, including capitalized interest, are recovered in authorized rates through depreciation when completed projects are placed into commercial operation. Capitalized interest does not represent current cash earnings. The rate used to calculate capitalized interest for 1998 was 6.88% and for 1997 was 7.25%.

Prior to 1997, APS accrued an allowance for funds used during construction (AFUDC). AFUDC represented the cost of debt and equity funds used to finance construction of utility plant. AFUDC did not represent current cash earnings. AFUDC has been calculated using a composite rate of 7.75% for 1996.

Revenues

APS records electric operating revenues on the accrual basis, which includes estimated amounts for service rendered but unbilled at the end of each accounting period.

Rate Synchronization Cost Deferrals

As authorized by the ACC, operating costs (excluding fuel) and financing costs of Palo Verde Units 2 and 3 were deferred from the commercial operation dates (September 1986 for Unit 2 and January 1988 for Unit 3) until the date the units were included in a rate order (April 1988 for Unit 2 and December 1991 for Unit 3). Beginning July 1, 1996, the deferrals are being amortized over an eight-year period in accordance with the 1996 regulatory agreement (see Note 3). Prior to July 1, 1996, the deferrals were amortized over thirty-five year periods. Amortization of the deferrals is included in depreciation and amortization expense on the Statements of Income.

Nuclear Fuel

APS charges nuclear fuel to fuel expense by using the unit-of-production method. The unit-of-production method is an amortization method that is based on actual physical usage. APS divides the cost of the fuel by the estimated number of thermal units that APS expects to produce with that fuel. APS then multiplies that rate by the number of thermal units that it produces within the current period. This provides APS with current period nuclear fuel expense.

APS also charges nuclear fuel expense for the permanent disposal of spent nuclear fuel. The United States Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel, and it charges APS $0.001 per kWh of nuclear generation. See Note 12 for information about spent nuclear fuel disposal. In addition, Note 13 has information on nuclear decommissioning costs.

Income Taxes

We file our federal income tax return on a consolidated basis and we file our state income tax returns on a consolidated or unitary basis. In accordance with our intercompany tax sharing agreement, federal and state income taxes are allocated to each subsidiary as though each subsidiary filed a separate income tax return. Any difference between the aforementioned allocations and the consolidated (and unitary) income tax liability is attributed to the parent company.

Reacquired Debt Costs

When APS incurs gains or losses on debt that it retires prior to maturity, APS amortizes those gains or losses over the remaining original life of the debt. In accordance with the 1996 regulatory agreement (see Note 3), the ACC accelerated APS' amortization of the regulatory asset for reacquired debt costs to an eight-year period that will end June 30, 2004. The accelerated portion of the regulatory asset amortization is included in depreciation and amortization expense in the Statements of Income.

Statements of Cash Flows

We consider temporary cash investments and marketable securities to be cash equivalents for purposes of reporting cash flows. During 1998, 1997, and 1996 we paid interest, net of amounts capitalized, income taxes, and dividends on preferred stock of APS.

Interest paid, net of amounts capitalized, was:

- $143.9 million in 1998
- $163.0 million in 1997 and
- $185.9 million in 1996.

Income taxes paid were:

- $164.9 million in 1998
- $146.2 million in 1997 and
- $121.0 million in 1996.

Dividends paid on preferred stock of APS were:

- $10.3 million in 1998
- $13.3 million in 1997 and
- $17.4 million in 1996.

Segments

APS is Pinnacle West's only reportable segment. Unless otherwise identified, APS represents substantially all of the consolidated information being reported.

Reclassifications

We have reclassified certain prior year amounts for comparison purposes with 1998.

2. ACCOUNTING MATTERS

In 1998 we adopted SFAS No. 130, "Reporting Comprehensive Income." This standard changes the reporting of certain items previously reported in the common stock equity section of the balance sheet. The effects of adopting SFAS No. 130 were not material to our financial statements.

In November 1998, the Financial Accounting Standards Board's Emerging Issues Task Force issued EITF 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," which is effective for us in 1999. EITF 98-10 requires energy trading contracts to be measured at fair value as of the balance sheet date with the gains and losses included in earnings and separately disclosed in the financial statements or footnotes. We have evaluated the impact of this rule and believe the effects are not material to our financial statements.

In June 1998, the Financial Accounting Standards Board issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," which is effective for us in 2000. SFAS No. 133 requires that entities recognize all derivatives as either assets or liabilities on the balance sheet and measure those instruments at fair value. The standard also provides specific guidance for accounting for derivatives designated as hedging instruments. We are currently evaluating what impact this standard will have on our financial statements.

3. REGULATORY MATTERS

Electric Industry Restructuring

STATE

In December 1996, the ACC adopted rules that provide a framework for the introduction of retail electric competition in Arizona. The rules, as amended, became effective on August 10, 1998, and on December 10, 1998, the ACC adopted the amended rules without any modifications that would have a significant impact on us. We believe that certain provisions of the 1996 ACC rules and the amended rules are deficient and APS has filed lawsuits to protect its legal rights regarding the 1996 rules and the amended rules. These lawsuits are pending but two related cases filed by other utilities have been partially decided in a manner adverse to those utilities' positions.

On January 11, 1999, the ACC issued an order which stayed the amended rules, granted reconsideration of the decision to make the rules permanent, and directed the hearing division of the ACC to establish a procedural order for further action on these rules. The order also granted waivers from compliance with the rules for APS, and all affected utilities.

On February 5, 1999, the ACC hearing officers issued recommendations for changes to the amended rules. The recommended rules include the following major provisions:

- They would apply to virtually all Arizona electric utilities regulated by the ACC, including APS.
- Each utility must make at least 20% of its 1995 retail peak demand available for competitive generation supply.
- The rules become effective when the ACC makes a final decision on each utility's stranded costs and unbundled rates (Final Decision Date) or January 1, 2001, whichever comes first.
- Subject to the 20% requirement, all utility customers with single premise loads of one megawatt or greater will be eligible for competitive electric services on the Final Decision Date. Customers with single premise loads of 40 kilowatts or greater may aggregate loads to meet this one megawatt requirement.
- When effective, residential customers will be phased in at 1-1/4% per quarter calculated beginning on January 1, 1999, subject to the 20% requirement above.
- Electric service providers that get Certificates of Convenience and Necessity (CC&Ns) from the ACC can supply only competitive services, including electric generation, but not electric transmission and distribution.
- Affected utilities must file ACC tariffs with separate pricing for electric services provided for noncompetitive services.

- ACC shall allow a reasonable opportunity for recovery of unmitigated stranded costs (see "Stranded Costs" below).
- Absent an ACC waiver, prior to January 1, 2001, each affected utility must transfer all competitive generation assets and services either to an unaffiliated party or to a separate corporate affiliate.
- Affiliate transaction rules prohibit a utility or certain electric service providers and their competitive affiliates from sharing certain assets, employees, and information.

If approved by the ACC, the rules would be subject to the formal rulemaking process under Arizona statute. In compliance with statutory procedural requirements, ACC oral proceedings on the matter would be scheduled no sooner than 30 days after the proposed rules are published by the Secretary of State.

We cannot currently predict when or if the amended rules will be further modified, when the stay of the amended rules will be lifted, or when retail electric competition will be introduced in Arizona.

Stranded Costs

On June 22, 1998, the ACC issued an order on stranded cost determination and recovery. APS believes that certain provisions of the stranded cost order are deficient and in August 1998, APS filed two lawsuits to protect its legal rights relating to the order.

On February 5, 1999, ACC hearing officers issued recommended changes to the June 1998 stranded cost order. The recommended changes to the stranded cost order would be effective upon approval of the ACC. The recommended order allows each affected utility to choose from four options for the recovery of stranded costs:

- Net Revenues Lost Methodology is the difference between generation revenues under traditional regulation and generation revenues under competition. This option provides for declining recovery percentages for stranded costs over a five-year recovery period. Regulatory assets are to be fully recovered under their presently authorized amortization schedule. In accordance with a 1996 regulatory agreement, the ACC accelerated the amortization of substantially all of APS' regulatory assets to an eight-year period that ends June 30, 2004.
- Divestiture/Auction Methodology allows a utility to divest all or substantially all of its generating assets, including regulatory assets associated with generation, in order to collect 100 percent of the difference between net sales price and book value of generating assets divested over a ten-year period, with no return on the unamortized balance.
- Financial Integrity Methodology allows a utility "sufficient revenues to meet minimum financial ratios" for a period of ten years.
- Settlement Methodology allows a settlement to be agreed upon by the ACC and a utility.

Legislative Initiatives

An Arizona joint legislative committee studied electric utility industry restructuring issues in 1996 and 1997. In conjunction with that study, the Arizona legislative counsel prepared memoranda in late 1997 related to the legal authority of the ACC to deregulate the Arizona electric utility industry. The memoranda raise a question as to the degree to which the ACC may, under the Arizona Constitution, deregulate any portion of the electric utility industry and allow rates to be determined by market forces. This latter issue has been subsequently decided by lower courts in favor of the ACC in four separate lawsuits, two of which are unrelated.

In May 1998, a law was enacted to facilitate implementation of retail electric competition in Arizona. The law includes the following major provisions:

- Arizona's largest government-operated electric utility (Salt River Project) and, at their option, smaller municipal electric systems must (i) make at least 20% of their 1995 retail peak demand available to electric service providers by December 31, 1998 and for all retail customers by December 31, 2000; (ii) decrease rates by at least 10% over a ten-year period beginning as early as January 1, 1991; (iii) implement procedures and public processes comparable to those already applicable to public service corporations, for establishing the terms, conditions, and pricing of electric services as well as certain other decisions affecting retail electric competition;
- describes the factors which form the basis of consideration by Salt River Project in determining stranded costs; and
- metering and meter reading services must be provided on a competitive basis during the first two years of competition only for customers having demands in excess of one megawatt (and that are eligible for competitive generation services), and thereafter for all customers receiving competitive electric generation.

In addition, the Arizona legislature will review and make recommendations for the 1999 legislature on certain competitive issues.

Agreement with Salt River Project

On April 25, 1998, APS entered into a Memorandum of Agreement with Salt River Project in anticipation of, and to facilitate, the opening of the Arizona electric industry. The Agreement contains the following major components:

- Both parties would amend the Territorial Agreement to remove any barriers to the provision of competitive electricity supply and non-distribution services.
- Both parties would amend the Power Coordination Agreement to lower the price that APS will pay Salt River Project for purchased power by approximately $17 million (pretax) during the first full year that the Agreement is effective and by lesser annual amounts during the next seven years.
- Both parties agreed on certain legislative positions regarding electric utility restructuring at the state and federal level.

Certain provisions of the Agreement (including those relating to the amendments of the Territorial Agreement and the Power Coordination Agreement) are affected by the timing of the introduction of competition. See "ACC Rules" above. On February 18, 1999, the ACC approved the Agreement.

General

We believe that further ACC decisions, legislation at the Arizona and federal levels, and perhaps amendments to the Arizona Constitution (which would require a vote of the people) will ultimately be required before significant implementation of retail electric competition can lawfully occur in Arizona. Until the manner of implementation of competition, including addressing stranded costs, is determined, we cannot accurately predict the impact of full retail competition on our financial position, cash flows, or results of operation. As competition in the electric industry continues to evolve, we will continue to evaluate strategies and alternatives that will position us to compete in the new regulatory environment.

FEDERAL

The Energy Policy Act of 1992 and recent rulemakings by FERC have promoted increased competition in the wholesale electric power markets. APS does not expect these rules to have a material impact on its financial statements.

Several electric utility reform bills have been introduced during recent congressional sessions, which as currently written would allow consumers to choose their electricity suppliers by 2000 or 2003. These bills, other bills that are expected to be introduced, and ongoing discussions at the federal level suggest a wide range of opinion that will need to be narrowed before any substantial restructuring of the electric utility industry can occur.

1996 Regulatory Agreement

In April 1996, the ACC approved a regulatory agreement between the ACC Staff and APS. The major provisions of this agreement are:

- An annual rate reduction of approximately $48.5 million ($29 million after income taxes), or 3.4% on average for all customers except certain contract customers, effective July 1, 1996.
- Recovery of substantially all of APS' present regulatory assets through accelerated amortization over an eight-year period that will end June 30, 2004, increasing annual amortization by approximately $120 million ($72 million after income taxes). See Note 1.
- A formula for sharing future cost savings between customers and shareholders (price reduction formula) referencing a return on equity (as defined) of 11.25%.
- A moratorium on filing for permanent rate changes prior to July 2, 1999, except under the price reduction formula and under certain other limited circumstances.
- Infusion of $200 million of common equity into APS by the parent company, in annual payments of $50 million starting in 1996.

Based on the price reduction formula, the ACC approved retail price decreases of approximately $17.6 million ($10.5 million after income taxes), or 1.2%, effective July 1, 1997, and approximately $17 million ($10 million after income taxes), or 1.1%, effective July 1, 1998. APS expects to file with the ACC for another retail price decrease of approximately $10.8 million annually ($6.5 million after income taxes) to become effective July 1, 1999. The amount and timing of the price decrease are subject to ACC approval. This will be the last price decrease under the 1996 regulatory agreement.

4. INCOME TAXES

Investment Tax Credit

Because of a 1994 rate settlement agreement, we are amortizing almost all of our investment tax credits (ITCs) over 5 years (1995-1999).

Income Taxes

Certain assets and liabilities are reported differently for income tax purposes than they are for financial statements. The tax effect of these differences is recorded as deferred taxes. We calculate deferred taxes using the current income tax rates.

APS has recorded a regulatory asset on its Balance Sheet in accordance with SFAS No. 71. This regulatory asset is for certain temporary differences, primarily AFUDC equity. APS amortizes this amount as the differences reverse. APS has been able to accelerate its amortization of the regulatory asset for income taxes to an eight-year period that will end June 30, 2004. This is a result of a 1996 regulatory agreement with the ACC. We are including this accelerated amortization in depreciation and amortization expense on the Statements of Income.

The components of income tax expense are:

Year Ended December 31, (Thousands of Dollars)	1998	1997	1996
Current			
Federal	$ 105,922	$ 105,818	$ 105,312
State	40,621	43,172	35,052
Total current	146,543	148,990	140,364
Deferred	41,566	28,729	23,752
Change in valuation allowance	—	(3,920)	(12,142)
ITC amortization	(23,516)	(23,518)	(23,518)
Total expense	$ 164,593	$ 150,281	$ 128,456

Multiplying income before income taxes by the statutory federal income tax rate does not equal the amount recorded as income tax expense because of the following:

Year Ended December 31, (Thousands of Dollars)	1998	1997	1996
Federal income tax expense at 35% statutory rate	$ 142,620	$ 135,148	$ 118,830
Increases (reductions) in tax expense resulting from:			
Tax under book depreciation	17,848	14,694	19,229
Preferred stock dividends of APS	3,396	4,481	5,982
ITC amortization	(23,516)	(23,518)	(23,518)
State income tax net of federal income tax benefit	22,764	24,497	19,565
Change in valuation allowance	—	(3,400)	(10,525)
Other	1,481	(1,621)	(1,107)
Income tax expense	$ 164,593	$ 150,281	$ 128,456

The components of the net deferred income tax liability were as follows:

December 31, (Thousands of Dollars)	1998	1997
Deferred tax assets		
Alternative minimum tax	$ —	$ 53,601
Deferred gain on Palo Verde Unit 2 sale/leaseback	31,285	33,257
Other	86,795	91,701
Total deferred tax assets	118,080	178,559
Deferred tax liabilities		
Plant-related	1,112,897	1,096,222
Regulatory asset for income taxes	161,836	185,084
Rate synchronization deferrals	122,130	144,908
Other	60,754	57,919
Total deferred tax liabilities	1,457,617	1,484,133
Accumulated deferred income taxes – net	$ 1,339,537	$ 1,305,574

5. LINES OF CREDIT

APS had committed lines of credit with various banks of $400 million at December 31, 1998 and 1997, which were available either to support the issuance of commercial paper or to be used for bank borrowings. The commitment fees at December 31, 1998 and 1997 for these lines of credit ranged from .07% to .15% per annum. APS had long-term bank borrowings of $125 million outstanding at December 31, 1998, and $150 million outstanding at December 31, 1997.

APS had commercial paper borrowings outstanding of $178.8 million at December 31, 1998, and $130.8 million at December 31, 1997. The weighted average interest rate on commercial paper borrowings was 6.21% on December 31, 1998, and 6.27% on December 31, 1997. By Arizona statute, APS' short-term borrowings cannot exceed 7% of its total capitalization unless approved by the ACC.

Pinnacle West had a revolving line of credit of $250 million at December 31, 1998 and 1997. The commitment fees were 0.10% in 1998 and ranged from 0.10% to 0.125% in 1997. Outstanding amounts at December 31, 1998 were $42 million and at December 31, 1997 were $155 million.

SunCor had revolving lines of credit totalling $55 million at December 31, 1998 and 1997. The commitment fees were 0.125% in 1998 and 1997. SunCor had $38.1 million outstanding at December 31, 1998, and $40.6 million outstanding at December 31,1997.

6. LONG-TERM DEBT

Borrowings under the APS mortgage bond indenture are secured by substantially all utility plant; SunCor's debt is collateralized by interests in certain real property; Pinnacle West's debt is unsecured. The following table presents the components of consolidated long-term debt:

December 31, (Thousands of Dollars)	*Maturity Dates (a)*	*Interest Rates*	1998	1997
APS				
First mortgage bonds	1998	7.625%	$ —	$ 100,000
	1999	7.625%	100,000	100,000
	2000	5.75%	100,000	100,000
	2002	8.125%	125,000	125,000
	2004	6.625%	85,000	85,000
	2020	10.25%	100,550	109,550
	2021	9.5%	45,140	45,140
	2021	9%	72,370	72,370
	2023	7.25%	91,900	97,150
	2024	8.75%	121,668	121,918
	2025	8%	88,300	88,500
	2028	5.5%	25,000	25,000
	2028	5.875%	154,000	154,000
Unamortized discount and premium			(6,482)	(7,033)
Pollution control bonds	2024-2033	Adjustable rate(b)	456,860	439,990
Collateralized loan	1999-2000	5.375%-6.125%	20,000	10,000
Unsecured note	2005	6.25%	100,000	—
Senior notes (c)	1999	6.72%	50,000	50,000
Senior notes (c)	2006	6.75%	100,000	100,000
Debentures	2025	10%	75,000	75,000
Bank loans	2003	Adjustable rate(d)	125,000	150,000
Capitalized lease obligation	1998-2001	7.48%(e)	11,612	15,645
			2,040,918	2,057,230
SunCor				
Revolving credit	2001	(f)	38,139	40,600
Bank loan	2001	(g)	42,061	45,000
Notes payable	1998-2006	(h)	3,888	5,113
			84,088	90,713
Pinnacle West				
Revolving credit	2001	(i)	42,000	155,000
Senior notes	2001-2003	(j)	50,000	50,000
			92,000	205,000
Total long-term debt			2,217,006	2,352,943
Less current maturities			168,045	108,695
Total long-term debt less current maturities			$ 2,048,961	$ 2,244,248

(a) This schedule does not reflect the timing of redemptions that may occur prior to maturity.

(b) The weighted-average rate for the year ended December 31, 1998 was 3.39% and for December 31, 1997 was 3.62%. Changes in short-term interest rates would affect the costs associated with this debt.

(c) APS has issued $150 million of first mortgage bonds ("senior note mortgage bonds") to the senior note trustee as collateral for the senior notes. The senior note mortgage bonds have the same interest rate, interest payment dates, maturity, and redemption provisions as the senior notes. APS' payments of principal, premium, and/or interest on the senior notes satisfy its corresponding payment obligations on the senior note mortgage bonds. As long as the senior note mortgage bonds secure the senior notes, the senior notes will effectively rank equally with the first mortgage bonds. On the date that APS has repaid all of its first mortgage bonds, other than those that secure senior notes, the senior note mortgage bonds will no longer secure the senior notes and will cease to be outstanding.

(d) The weighted-average rate at December 31, 1998 was 5.69% and at December 31, 1997 was 6.25%. Changes in short-term interest rates would affect the costs associated with this debt.

(e) Represents the present value of future lease payments (discounted at an interest rate of 7.48%) on a combined cycle plant that was sold and leased back (see Note 10).

(f) The weighted-average rate at December 31, 1998 was 8.21% and at December 31, 1997 was 8.60%. Interest for 1998 and 1997 was based on LIBOR plus 2% or prime plus 0.5%.

(g) The weighted-average rate at December 31, 1998 was 7.76% and at December 31, 1997 was 8.44%. Interest for 1998 and 1997 was based on LIBOR plus 2% or prime plus 0.5%.

(h) Multiple notes primarily with variable interest rates based mostly on the lenders' prime.

(i) The weighted-average rate at December 31, 1998 was 5.66% and at December 31, 1997 was 6.25%. Interest for 1998 was based on LIBOR plus 0.33% and for 1997 was LIBOR plus 0.33%-0.4%.

(j) Includes two series of notes: $25 million at 6.62% due 2001, and $25 million at 6.87% due 2003.

The following is a list of principal payments due on total long-term debt and sinking fund requirements through 2003:

- $168.0 million in 1999
- $140.4 million in 2000
- $121.0 million in 2001
- $125.1 million in 2002 and
- $150.1 million in 2003.

First mortgage bondholders share a lien on substantially all utility plant assets (other than nuclear fuel, transportation equipment, and the combined cycle plant). The mortgage bond indenture includes provisions that would restrict the payment of common stock dividends under certain conditions. These conditions did not exist at December 31, 1998.

7. PREFERRED STOCK OF APS

On March 1, 1999, APS redeemed all of its preferred stock.

Preferred stock balances of APS at December 31, 1998 and 1997 are shown below:

(Dollars in Thousands, Except Per Share Amount)	*Authorized*	*Number of Shares Outstanding December 31,* 1998	1997	*Par Value Per Share*	*Par Value Outstanding December 31,* 1998	1997	*Call Price Per Share (a)*
Non-Redeemable:							
$1.10 preferred	160,000	139,030	145,559	$ 25.00	$ 3,476	$ 3,639	$ 27.50
$2.50 preferred	105,000	86,440	97,252	50.00	4,322	4,863	51.00
$2.36 preferred	120,000	32,520	38,506	50.00	1,626	1,925	51.00
$4.35 preferred	150,000	62,986	68,386	100.00	6,299	6,839	102.00
Serial preferred:	1,000,000						
$2.40 Series A		200,587	234,839	50.00	10,029	11,742	50.50
$2.625 Series C		214,895	231,572	50.00	10,745	11,579	51.00
$2.275 Series D		90,691	164,101	50.00	4,534	8,205	50.50
$3.25 Series E		304,475	312,991	50.00	15,224	15,649	51.00
Serial preferred:	4,000,000(b)						
Adjustable rate							
Series Q		295,851	352,851	100.00	29,585	35,285	(c)
Serial preferred:	10,000,000						
$1.8125 Series W		—	1,693,016	25.00	—	42,325	
Total		1,427,475	3,339,073		$ 85,840	$ 142,051	
Redeemable:							
Serial preferred:							
$10.00 Series U		94,011	291,098	$ 100.00	$ 9,401	$ 29,110	

(a) The actual call price per share is the indicated amount plus any accrued dividends.

(b) This authorization covers all outstanding redeemable preferred stock.

(c) Dividend rate adjusted quarterly to 2% below that of certain United States Treasury securities, but in no event less than 6% or greater than 12% per annum. Redeemable at par.

APS cannot pay common stock dividends or acquire shares of common stock if preferred stock dividends or sinking fund requirements are in arrears.

Redeemable preferred stock transactions of APS during each of the three years in the period ended December 31, 1998 are as follows:

(Dollars in Thousands)	*Number of Shares*	*Par Value Amount*
Balance, December 31, 1995	750,000	$ 75,000
Retirements		
$10.00 Series U	(90,000)	(9,000)
$7.875 Series V	(130,000)	(13,000)
Balance, December 31, 1996	530,000	53,000
Retirements		
$10.00 Series U	(118,902)	(11,890)
$7.875 Series V	(120,000)	(12,000)
Balance, December 31, 1997	291,098	29,110
Retirements		
$10.00 Series U	(197,087)	(19,709)
Balance, December 31, 1998	94,011	$ 9,401

8. COMMON STOCK

Our common stock issued during each of the three years in the period ended December 31, 1998 is as follows:

(Dollars in Thousands)	*Number of Shares*	*Amount (a)*
Balance, December 31, 1995	87,515,847	$ 1,638,684
Common stock issued	—	(2,330)
Balance, December 31, 1996	87,515,847	1,636,354
Common stock issued	—	(2,586)
Common stock retired	(2,690,900)	(79,997)
Balance, December 31, 1997	84,824,947	1,553,771
Common stock issued	—	(3,128)
Balance, December 31, 1998	84,824,947	$ 1,550,643

(a) Including premiums and expenses of preferred stock issues of APS.

9. RETIREMENT PLANS AND OTHER BENEFITS

Voluntary Severance Plan

APS sponsored a voluntary severance plan in 1996. There was a pretax charge of $31.7 million in 1996 recorded mostly as operations and maintenance expense. This pretax charge included additional pension and postretirement benefit expense. Employees who participated in the plan were credited with an additional year of age and service when their pension and postretirement benefits were calculated. The additional expenses recorded in 1996 for this plan were $2.3 million for pension and $5.4 million for postretirement benefits.

Pension Plans

Pinnacle West and its subsidiaries sponsor defined benefit pension plans for their employees. A defined benefit plan specifies the amount of benefits a plan participant is to receive using information about the participant. The plan covers nearly all of our employees. Our employees do not contribute to this plan. Generally, we calculate the benefits under these plans based on age, years of service, and pay. We fund the plan by contributing at least the minimum amount required under Internal Revenue Service regulations but no more than the maximum tax-deductible amount. The assets in the plan at December 31, 1998 were mostly domestic and international common stocks and bonds and real estate. Pension expense, including administrative and severance costs, was:

- $10.5 million in 1998
- $9.3 million in 1997 and
- $15.5 million in 1996.

The following table shows the components of net pension cost before consideration of amounts capitalized or billed to others and excluding severance costs of $2.9 million in 1996:

(Thousands of Dollars)	1998	1997	1996
Service cost – benefits earned during the period	$ 24,817	$ 20,435	$ 23,397
Interest cost on projected benefit obligation	51,524	48,402	45,124
Expected return on plan assets	(54,513)	(47,959)	(42,404)
Amortization of:			
Transition asset	(3,226)	(3,226)	(3,226)
Prior service cost	2,078	2,078	1,735
Net actuarial losses	—	—	728
Net periodic pension cost	$ 20,680	$ 19,730	$ 25,354

The following table shows a reconciliation of the funded status of the plans to the amounts recognized in the balance sheets:

(Thousands of Dollars)	1998	1997
Funded status – pension plan assets less than projected benefit obligation	$ (41,034)	$ (88,732)
Unrecognized net transition asset	(23,235)	(26,462)
Unrecognized prior service cost	22,715	24,792
Unrecognized net actuarial losses/(gains)	(38,668)	16,943
Net pension amount recognized in the balance sheets	$ (80,222)	$ (73,459)

The following table sets forth the defined benefit pension plans' change in projected benefit obligation for the plan years 1998 and 1997:

(Thousands of Dollars)	1998	1997
Projected pension benefit obligation at beginning of year	$ 708,144	$ 608,675
Service cost	24,817	20,435
Interest cost	51,524	48,402
Benefit payments	(29,636)	(29,965)
Plan amendments	—	5,537
Actuarial losses/(gains)	(23,544)	55,060
Projected pension benefit obligation at end of year	$ 731,305	$ 708,144

The following table sets forth the defined benefit pension plans' change in the fair value of plan assets for the plan years 1998 and 1997:

(Thousands of Dollars)	1998	1997
Fair value of pension plan assets at beginning of year	$ 619,412	$ 539,179
Actual return on plan assets	86,527	88,620
Employer contributions	13,968	21,578
Benefit payments	(29,636)	(29,965)
Fair value of pension plan assets at end of year	$ 690,271	$ 619,412

We made the assumptions below to calculate the pension liability:

	1998	1997
Discount rate	7.00%	7.25%
Rate of increase in compensation levels	3.50%	4.50%
Expected long-term rate of return on assets	10.00%	9.00%

Employee Savings Plan Benefits

We also sponsor a defined contribution savings plan that is offered to nearly all employees. In a defined contribution plan, the benefits a participant is to receive result from regular contributions to a participant account. Under this plan, we make matching contributions to participant accounts. We recorded expenses for this plan of:

- $4.1 million in 1998
- $3.9 million in 1997 and
- $3.6 million in 1996.

Postretirement Plans

We provide medical and life insurance benefits to retired employees. Employees must retire to become eligible for these retirement benefits, which are based on years of service and age. For the medical insurance plans, retirees make contributions to cover a portion of the plan costs. For the life insurance plan, retirees do not make contributions to cover a portion of the plan costs. We retain the right to change or eliminate these benefits.

Funding is based upon actuarially determined contributions that take tax consequences into account. Plan assets consist primarily of domestic stocks and bonds. The postretirement benefit expense was:

- $9.1 million for 1998
- $9.8 million for 1997 and
- $16.2 million for 1996.

The following table shows the components of net periodic postretirement benefit costs before consideration of amounts capitalized or billed to others and excluding severance costs of $9.6 million in 1996:

(Thousands of Dollars)	1998	1997	1996
Service cost – benefits earned during the period	$ 7,890	$ 7,046	$ 8,168
Interest cost on accumulated benefit obligation	15,763	14,441	13,525
Expected return on plan assets	(12,001)	(8,706)	(6,696)
Amortization of:			
Transition obligation	7,698	7,698	8,269
Net actuarial gains	(2,952)	(2,685)	(1,345)
Net periodic postretirement benefit cost	$ 16,398	$ 17,794	$ 21,921

The following table shows a reconciliation of the funded status of the plan to the amounts recognized in the balance sheets:

(Thousands of Dollars)	1998	1997
Funded status – postretirement plan assets less than projected benefit obligation	$ (24,269)	$ (48,202)
Unrecognized net obligation at transition	107,842	115,541
Unrecognized net actuarial gains	(86,692)	(79,013)
Net postretirement amount recognized in the balance sheets	$ (3,119)	$ (11,674)

The following table sets forth the postretirement benefit plans' change in accumulated benefit obligation for the plan years 1998 and 1997:

(Thousands of Dollars)	1998	1997
Accumulated postretirement benefit obligation at beginning of year	$ 199,348	$ 181,405
Service cost	7,890	7,046
Interest cost	15,763	14,441
Benefit payments	(10,378)	(6,745)
Actuarial losses	25,056	3,201
Accumulated postretirement benefit obligation at end of year	$ 237,679	$ 199,348

The following table sets forth the postretirement benefit plans' change in the fair value of plan assets for the plan years 1998 and 1997:

(Thousands of Dollars)	1998	1997
Fair value of postretirement plan assets at beginning of year	$ 151,146	$ 109,763
Actual return on plan assets	47,284	30,846
Employer contributions	25,327	17,269
Benefit payments	(10,347)	(6,732)
Fair value of postretirement plan assets at the end of year	$ 213,410	$ 151,146

We made the assumptions below to calculate the postretirement liability:

	1998	1997
Discount rate	7.00%	7.25%
Expected long-term rate of return on assets – after tax	8.73%	7.75%
Initial health care cost trend rate – under age 65	7.50%	8.00%
Initial health care cost trend rate – age 65 and over	6.50%	7.00%
Ultimate health care cost trend rate (reached in the year 2002)	5.00%	5.00%

Assuming a 1% increase in the health care cost trend rate, the 1998 cost of postretirement benefits other than pensions would increase by approximately $4.6 million and the accumulated benefit obligation as of December 31, 1998 would increase by approximately $37.8 million.

Assuming a 1% decrease in the health care cost trend rate, the 1998 cost of postretirement benefits other than pensions would decrease by approximately $3.8 million and the accumulated benefit obligation as of December 31, 1998 would decrease by approximately $31.9 million.

10. LEASES

In 1986, APS sold about 42% of its share of Palo Verde Unit 2 and certain common facilities in three separate sale leaseback transactions. APS accounts for these leases as operating leases. The gain of approximately $140.2 million was deferred and is being amortized to operations expense over 29.5 years, the original term of the leases. There are options to renew the leases for two additional years and to purchase the property for fair market value at the end of the lease terms. Consistent with the ratemaking treatment, an amount equal to the annual lease payments is included in rent expense. A regulatory asset is recognized for the difference between lease payments and rent expense calculated on a straight-line basis.

The average amounts to be paid for the Palo Verde Unit 2 leases are as follows:

Year	*(In millions)*
1999	$ 40.1
2000	46.3
2001-2015	49.0

In accordance with the 1996 regulatory agreement (see Note 3), the ACC accelerated APS' amortization of the regulatory asset for leases to an eight-year period that will end June 30, 2004. The accelerated amortization is included in depreciation and amortization expense on the Statements of Income. The balance of this regulatory asset at December 31, 1998 was $48.5 million. Lease expense was approximately $42 million in each of the years 1997 through 1999.

APS has a capital lease on a combined cycle plant, which it sold and leased back. The lease requires semiannual payments of $2.6 million through June 2001, and includes renewal and purchase options based on fair market value. The plant is included in plant in service at its original cost of $54.4 million; accumulated amortization at December 31, 1998 was $48.6 million.

In addition, we lease certain land, buildings, equipment, and miscellaneous other items through operating rental agreements with varying terms, provisions, and expiration dates.

Approximate miscellaneous lease expense was:

- $13.1 million in 1998
- $11.2 million in 1997 and
- $12.8 million in 1996.

Estimated future minimum lease commitments, excluding the Palo Verde and combined cycle leases, are as follows:

Year	*(In millions)*
1999	$ 16.4
2000	16.4
2001	18.3
2002	19.3
2003	18.2
Thereafter	151.2
Total future commitments	$ 239.8

11. JOINTLY-OWNED FACILITIES

APS shares ownership of some of its generation and transmission facilities with other companies. The following table shows APS' interest in those jointly-owned facilities at December 31, 1998. APS' share of operating and maintaining the facilities is included in the Income Statement in utility operations and maintenance expense.

(Dollars in Thousands)	*Percent Owned by APS*	*Plant In Service*	*Accumulated Depreciation*	*Construction Work In Progress*
Generating Facilities				
Palo Verde Nuclear Generating Station Units 1 and 3	29.1%	$ 1,821,620	$ 670,403	$ 20,152
Palo Verde Nuclear Generating Station Unit 2 (see Note 10)	17.0%	568,184	224,502	9,839
Four Corners Steam Generating Station Units 4 and 5	15.0%	150,165	69,764	312
Navajo Steam Generating Station Units 1, 2, and 3	14.0%	203,356	90,237	25,560(a)
Cholla Steam Generating Station Common Facilities (b)	62.8%(c)	67,513	37,096	267
Transmission Facilities				
ANPP 500 KV System	35.8%(c)	66,547	20,282	1,384
Navajo Southern System	31.4%(c)	26,918	17,285	21
Palo Verde – Yuma 500 KV System	23.9%(c)	11,376	4,215	—
Four Corners Switchyards	27.5%(c)	3,071	1,780	143
Phoenix – Mead System	17.1%(c)	36,324	536	—

(a) The construction costs at Navajo are primarily related to the installation of scrubbers required by environmental legislation.

(b) PacifiCorp owns Cholla Unit 4 and APS operates the unit for them. The common facilities at the Cholla Plant are jointly-owned.

(c) Weighted average of interests.

12. COMMITMENTS AND CONTINGENCIES

Litigation

We are party to various claims, legal actions, and complaints arising in the ordinary course of business. In our opinion, the ultimate resolution of these matters will not have a material adverse effect on our financial statements.

Palo Verde Nuclear Generating Station

Under the Nuclear Waste Policy Act, the Department of Energy (DOE) was to develop the facilities necessary for the storage and disposal of spent fuel and to have the first such facility in operation by 1998. That facility was to be a permanent repository, but DOE has announced that such a repository now cannot be completed before 2010. In response to lawsuits filed over DOE's obligation to accept used nuclear fuel, the United States Court of Appeals for the D.C. Circuit has ruled that DOE had an obligation to begin accepting used nuclear fuel in 1998. However, the Court refused to issue an order compelling DOE to begin moving used fuel. Instead, the Court ruled that any damages to utilities should be sought under the standard contract signed between DOE and utilities, including APS. The United States Supreme Court has refused to grant review of the D.C. Circuit's decision. In July 1998, APS filed a Petition for Review regarding DOE's obligation to begin accepting spent nuclear fuel.

APS has capacity in existing fuel storage pools at Palo Verde which, with certain modifications, could accommodate all fuel expected to be discharged from normal operation of Palo Verde through 2002, and believes it could augment that wet storage with new facilities for on-site dry storage of spent fuel for an indeterminate period of operation beyond 2002, subject to obtaining any required governmental approvals. APS currently estimates that it will incur $113 million (in 1998 dollars) over the life of Palo Verde for its share of the costs related to the on-site interim storage of spent nuclear fuel. Beginning in 1999, APS will accrue these costs as a component of fuel expense, meaning the charges will be accrued as the fuel is burned. During 1998, APS recorded a liability and a regulatory asset of $35 million for on-site interim nuclear fuel storage costs related to nuclear fuel burned prior to 1999. APS currently believes that spent fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation beyond 2002.

The Palo Verde participants have insurance for public liability resulting from nuclear energy hazards to the full limit of liability under federal law. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $200 million and the balance by an industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the programs exceed the accumulated funds, APS could be assessed retrospective premium adjustments. The maximum assessment per reactor under the program for each nuclear incident is approximately $88 million, subject to an annual limit of $10 million per incident. Based upon APS' 29.1% interest in the three Palo Verde units, APS' maximum potential assessment per incident for all three units is approximately $77 million, with an annual payment limitation of approximately $9 million.

The Palo Verde participants maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.75 billion, a substantial portion of which must first be applied to stabilization and decontamination. APS has also secured insurance against portions of any increased cost of generation or purchased power and business interruption resulting from a sudden and unforeseen outage of any of the three units. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions and exclusions.

Fuel and Purchased Power Commitments

APS is a party to various fuel and purchased power contracts with terms expiring from 1999 through 2020 that include required purchase provisions. APS estimates its 1999 contract requirements to be about $132 million. However, this amount may vary significantly pursuant to certain provisions in such contracts that permit APS to decrease its required purchases under certain circumstances.

APS must reimburse certain coal providers for amounts incurred for coal mine reclamation. APS estimates its share of the total obligation to be about $103 million. The portion of the coal mine reclamation obligation related to coal already burned is about $62 million at December 31, 1998 and is included in "Deferred Credits-Other" in the Balance Sheet. A regulatory asset has been established for amounts not yet recovered from ratepayers. In accordance with the 1996 regulatory agreement (see Note 3), the ACC began accelerated amortization of APS' regulatory asset for coal mine reclamation costs over an eight-year period that will end June 30, 2004. Amortization is included in depreciation and amortization expense on the Statements of Income. The balance of the regulatory asset at December 31, 1998 was about $51 million.

Construction Program

Consolidated capital expenditures in 1999 are estimated at $386 million.

13. NUCLEAR DECOMMISSIONING COSTS

APS recorded $11.4 million for decommissioning expense in each of the years 1998, 1997, and 1996. APS estimates it will cost about $1.8 billion ($452 million in 1998 dollars) to decommission its 29.1% share of the three Palo Verde units. The decommissioning costs are expected to be incurred over a 14-year period beginning in 2024. APS charges decomissioning costs to expense over each unit's operating license term and includes them in the accumulated depreciation balance until each unit is retired. Nuclear decommissioning costs are recovered in rates.

APS' current estimates are based on a 1998 site-specific study for Palo Verde that assumes the prompt removal/dismantlement method of decommissioning. An independent consultant prepared this study. APS is required to update the study every three years.

To fund the costs APS expects to incur to decommission the plant, APS established external decommissioning trusts in accordance with Nuclear Regulatory Commission (NRC) regulations. The trust accounts are reported in "Investments and Other Assets" on the Consolidated Balance Sheets at their market value of $145.6 million at December 31, 1998 and $124.6 million at December 31, 1997. APS invests the trust funds primarily in fixed income securities and domestic stock and classifies them as available for sale. Realized and unrealized gains and losses are reflected in accumulated depreciation.

In February 1996, the FASB issued an exposure draft, "Accounting for Certain Liabilities Related to Closure or Removal of Long-Lived Assets." This proposed standard would require the estimated present value of the cost of decommissioning and certain other removal costs to be recorded as a liability, along with an offsetting plant asset when a decommissioning or other removal obligation is incurred. The FASB has indicated that a revised exposure draft will be issued in 1999.

14. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

Consolidated quarterly financial information for 1998 and 1997 is as follows:

(Dollars in Thousands, Except per Share Amounts)	1998			
Quarter Ended	*March 31*	*June 30*	*September 30*	*December 31*
Operating revenues				
Electric	$ 380,423	$ 441,715	$ 740,734	$ 443,526
Real estate	34,161	28,916	18,276	42,835
Operating income (a)	$ 90,837	$ 122,605	$ 251,838	$ 101,848
Net income	$ 31,086	$ 48,997	$ 127,281	$ 35,528
Earnings per average common share outstanding				
Net income – basic	$ 0.37	$ 0.58	$ 1.50	$ 0.42
Net income – diluted	$ 0.36	$ 0.57	$ 1.49	$ 0.42
Dividends declared per share (b)	$ 0.30	$ 0.60	$ —	$ 0.325

(Dollars in Thousands, Except per Share Amounts)	1997			
Quarter Ended	*March 31*	*June 30*	*September 30*	*December 31*
Operating revenues				
Electric	$ 379,021	$ 458,751	$ 632,821	$ 407,960
Real estate	19,543	30,166	30,929	35,835
Operating income (a)	$ 82,471	$ 150,024	$ 243,454	$ 81,557
Net income	$ 25,382	$ 67,182	$ 124,340	$ 18,952
Earnings per average common share outstanding				
Net income – basic	$ 0.29	$ 0.79	$ 1.47	$ 0.21
Net income – diluted	$ 0.29	$ 0.78	$ 1.46	$ 0.21
Dividends declared per share (b)	$ 0.275	$ 0.55	$ —	$ 0.30

(a) APS' utility business is seasonal in nature, with the peak sales periods generally occurring during the summer months. Comparisons among quarters of a year may not represent overall trends and changes in operations.

(b) Dividends for the quarters ending September 30, 1998 and September 30, 1997 were declared in June.

15. FAIR VALUE OF FINANCIAL INSTRUMENTS

We believe that the carrying amounts of our cash equivalents and commercial paper are reasonable estimates of their fair values at December 31, 1998 and 1997 due to their short maturities.

We hold investments in debt and equity securities for purposes other than trading. The December 31, 1998 and 1997 fair values of such investments, which we determine by using quoted market values or by discounting cash flows at rates equal to our cost of capital, approximate their carrying amount.

The carrying value of our long-term debt (excluding a capitalized lease obligation) was $2.21 billion on December 31, 1998, with an estimated fair value of $2.28 billion. On December 31, 1997, the carrying value of our long-term debt (excluding a capitalized lease obligation) was $2.34 billion, with an estimated fair value of $2.38 billion. The fair value estimates are based on quoted market prices of the same or similar issues.

16. EARNINGS PER SHARE

In 1997 we adopted SFAS No. 128, "Earnings Per Share." This statement requires the presentation of both basic and diluted earnings per share on the financial statements. The following table presents earnings per average common share outstanding (EPS):

	1998	1997	1996
Basic EPS:			
Continuing operations	$ 2.87	$ 2.76	$ 2.41
Discontinued operations	—	—	(0.11)
Extraordinary charge	—	—	(0.23)
Net income	$ 2.87	$ 2.76	$ 2.07
Diluted EPS:			
Continuing operations	$ 2.85	$ 2.74	$ 2.40
Discontinued operations	—	—	(0.11)
Extraordinary charge	—	—	(0.23)
Net income	$ 2.85	$ 2.74	$ 2.06

Dilutive stock options increased average common shares outstanding by 571,728 shares in 1998, 519,800 shares in 1997, and 580,405 shares in 1996. Total average common shares outstanding for the purposes of calculating diluted earnings per share were 85,345,946 shares in 1998, 86,022,709 shares in 1997, and 88,021,920 shares in 1996.

Options to purchase 244,200 shares of common stock at $46.78 per share were outstanding during the last quarter of 1998 but were not included in the computation of diluted EPS because the options' exercise price was greater than the average market price of the common shares.

17. STOCK OPTIONS

We offer several stock incentive plans for our officers, APS officers, and key employees.

The plans provide for the granting of new options or awards of up to 3.5 million shares at a price per option not less than fair market value on the date the option is granted. The plans also provide for the granting of any combination of stock appreciation rights or dividend equivalents. The awards outstanding under the various incentive plans at December 31, 1998 approximate 1,497,012 non-qualified stock options, 158,121 restricted shares, and no dividend equivalent shares, incentive stock options, or stock appreciation rights.

The FASB issued SFAS No. 123, "Accounting for Stock-Based Compensation" which was effective for 1996. The statement encourages, but does not require, that a company record compensation expense based on the fair value method. We continue to recognize expense based on Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees." If we had recorded compensation expense based on the fair value method, our net income would have been reduced to the following pro forma amounts:

(Dollars in Thousands, Except per Share Amounts)	1998	1997	1996
Net income			
As reported	$ 242,892	$ 235,856	$ 181,180
Pro forma (fair value method)	$ 242,177	$ 235,446	$ 180,969
Net income per share – basic			
As reported	$ 2.87	$ 2.76	$ 2.07
Pro forma (fair value method)	$ 2.86	$ 2.75	$ 2.07

We did not consider compensation costs for stock options granted before January 1, 1995. Therefore, future reported net income may not be representative of this compensation cost calculation.

In order to present the pro forma information above, we calculated the fair value of each fixed stock option in the incentive plans using the Black-Scholes option-pricing model. The fair value was calculated based on the date the option was granted. The following weighted-average assumptions were also used in order to calculate the fair value of the stock options:

	1998	1997	1996
Risk-free interest rate	4.54%	5.66%	5.77%
Dividend yield	3.03%	4.50%	4.50%
Volatility	18.80%	15.63%	17.10%
Expected life (months)	60	60	58

The following table is a summary of the status of our stock option plans as of December 31, 1998, 1997, and 1996 and changes during the years ending on those dates:

	1998 Shares	*1998 Weighted Average Exercise Price*	*1997 Shares*	*1997 Weighted Average Exercise Price*	*1996 Shares*	*1996 Weighted Average Exercise Price*
Outstanding at beginning of year	1,488,131	$ 24.60	1,673,076	$ 21.59	1,807,900	$ 19.78
Granted	244,200	46.78	260,450	39.56	260,500	31.44
Exercised	(217,317)	23.09	(409,975)	21.60	(363,400)	19.41
Forfeited	(18,002)	33.42	(35,420)	27.10	(31,924)	24.35
Outstanding at end of year	1,497,012	28.34	1,488,131	24.60	1,673,076	21.59
Options exercisable at year-end	1,039,664	22.21	1,008,514	19.53	1,135,032	18.60
Weighted average fair value of options granted during the year		8.15		5.83		4.24

The following table summarizes information about our stock option plans at December 31, 1998:

Range of exercise prices per share	*Outstanding*	*Weighted Average Remaining Contract Life*	*Options Exercisable*
$11.25	16,500	1.90	16,500
11.50	270,000	1.10	270,000
15.75	42,500	2.90	42,500
17.68	13,275	3.10	13,275
19.00	116,537	5.90	116,537
19.56	58,500	3.90	58,500
22.13	109,584	5.00	109,584
27.44	175,090	6.90	175,090
31.44	205,292	8.00	142,230
39.75	245,534	9.00	88,665
46.78	244,200	9.90	6,783
$11.25 – $46.78	1,497,012	6.29	1,039,664

BOARD OF DIRECTORS

Richard Snell
(68) 1975*
Chairman of the Board**

The Rev. Bill Jamieson, Jr.
(55) 1991
President,
Institute for Servant Leadership
of Asheville, North Carolina
Committees:
Audit
Finance and Planning

Douglas J. Wall
(71) 1976
Of Counsel to the Law Firm of
Mangum, Wall, Stoops & Warden
Committees:
Audit, Chairman
Human Resources

Roy A. Herberger, Jr.
(56) 1992
President,
Thunderbird, The American Graduate
School of International Management
Committees:
Audit
Finance and Planning

Pamela Grant
(60) 1980
Civic Leader
Committees:
Human Resources, Chairman
Finance and Planning

William J. Post
(48) 1994
Chief Executive Officer

John R. Norton III
(69) 1984
Chairman & Chief Executive Officer,
J.R. Norton Company
Committees:
Finance and Planning, Chairman
Human Resources

Humberto S. Lopez
(53) 1995
President,
HSL Properties, Inc.
Committees:
Human Resources
Audit

Martha O. Hesse
(56) 1991
President,
Hesse Gas Company
Committees:
Audit
Human Resources

George A. Schreiber, Jr.
(50) 1997
President

* The year in which the individual first joined the Board of a Pinnacle West company.
** Retired as Chief Executive Officer February 5, 1999.

OFFICERS

PINNACLE WEST

Richard Snell
(68) 1990*
Chairman of the Board**

William J. Post
(48) 1973
Chief Executive Officer

George A. Schreiber, Jr.
(50) 1997
President

James L. Kunkel
(61) 1997
Vice President

Faye Widenmann
(50) 1978
Vice President of Corporate Relations & Administration & Secretary

Michael V. Palmeri
(40) 1982
Treasurer

ARIZONA PUBLIC SERVICE

Richard Snell
Chairman of the Board

William J. Post
Chief Executive Officer

George A. Schreiber, Jr.
Executive Vice President & Chief Financial Officer

Jack E. Davis
(52) 1973
President,
Energy Delivery & Sales

William L. Stewart
(55) 1994
President, Generation

Armando B. Flores
(55) 1991
Executive Vice President,
Corporate Business Services

ARIZONA PUBLIC SERVICE (CONT.)

James M. Levine
(49) 1989
Senior Vice President,
Nuclear Generation

Jan H. Bennett
(51) 1967
Vice President, Distribution

John G. Bohon
(53) 1971
Vice President, Corporate Services & Human Resources

John R. Denman
(56) 1964
Vice President, Fossil Generation

Edward Z. Fox
(45) 1995
Vice President, Environmental/Health/Safety & New Technology Ventures

William E. Ide
(52) 1977
Vice President,
Nuclear Engineering

Nancy C. Loftin
(45) 1985
Vice President, Chief Legal Counsel & Secretary

Gregg R. Overbeck
(52) 1990
Vice President, Nuclear Production

Michael V. Palmeri
Treasurer

Chris N. Froggatt
(41) 1986
Controller

SUNCOR DEVELOPMENT

Richard Snell
Chairman of the Board

John C. Ogden
(53) 1972
President & Chief Executive Officer

Geoffrey L. Appleyard
(45) 1987
Vice President &
Chief Financial Officer

Duane S. Black
(46) 1989
Vice President &
Chief Operating Officer

Jay T. Ellingson
(49) 1992
Vice President, Development - Palm Valley

Steven Gervais
(43) 1987
Vice President & General Counsel

Margaret E. Kirch
(49) 1988
Vice President,
Commercial Development

Thomas A. Patrick
(45) 1995
Vice President, Golf Operations

John C. Pew
(44) 1996
Vice President, Homebuilding

EL DORADO INVESTMENT

Richard Snell
Chairman of the Board

James L. Kunkel
President

Brian N. Burns
(39) 1998
Vice President &
Chief Financial Officer

* The year in which the individual was first employed within the Pinnacle West group of companies.

** Retired as Chief Executive Officer February 5, 1999.

SHAREHOLDER INFORMATION

CORPORATE HEADQUARTERS
Street address:
400 East Van Buren Street
Phoenix, Arizona 85004

Mailing address:
P.O. Box 52132
Phoenix, Arizona 85072-2132

Main telephone number: (602) 379-2500

ANNUAL MEETING OF SHAREHOLDERS
Wednesday, May 19, 1999
10:30 a.m.
The Wigwam Resort
300 Wigwam Boulevard
Litchfield Park, Arizona 85340

STOCK LISTING
Ticker symbol: PNW on New York Stock Exchange and Pacific Stock Exchange
Newspaper financial listings: PinWst

FORM 10-K
Pinnacle West's Annual Report to the Securities and Exchange Commission on Form 10-K will be available after April 1, 1999 to shareholders upon written request, without charge. Write: Office of the Secretary.

INVESTORS ADVANTAGE PLAN
Pinnacle West offers a direct stock purchase plan. Any interested investor may purchase Pinnacle West common stock through the Investors Advantage Plan. Features of the Plan include a variety of options for reinvesting dividends, direct deposit of cash dividends, automatic monthly investment, certificate safekeeping, reduced brokerage commissions and more. An Investors Advantage Plan prospectus and enrollment materials may be obtained by calling the Company at the toll-free number listed on this page or by writing to:

Pinnacle West Capital Corporation
Shareholder Department
P.O. Box 52133
Phoenix, AZ 85072-2133

INTERNET HOME PAGE
http://www.pinnaclewest.com

STATISTICAL REPORT
A detailed Statistical Report for Financial Analysis for 1993-1998 will be available in April upon request.
Write: Investor Relations Department.

TRANSFER AGENTS AND REGISTRARS
Common Stock
Pinnacle West Capital Corporation
Stock Transfer Department
P.O. Box 52134
Phoenix, Arizona 85072-2134
Telephone: (602) 379-2519

BankBoston N.A.
c/o EquiServe
P.O. Box 8040
Boston, Massachusetts 02266-8040
Telephone: (781) 575-3120

SHAREHOLDER ACCOUNT AND ADMINISTRATIVE INFORMATION
Shareholder Department telephone number
(toll-free): 1-800-457-2983

INVESTOR RELATIONS CONTACT
Rebecca L. Hickman
Director, Investor Relations
Telephone: (602) 379-2568
Fax: (602) 379-2640

STATEWIDE ASSOCIATION FOR UTILITY INVESTORS
The Arizona Utility Investors Association represents the interests of investors in Arizona utilities.
If interested, send your name and address to:

Arizona Utility Investors Association
P.O. Box 34805
Phoenix, Arizona 85067
(602) 257-9200

IMPORTANT NOTICE FOR SHAREHOLDERS:
Pinnacle West now posts quarterly results and other important information on its web site (www.pinnaclewest.com). If you would like to receive news by regular mail, fax or e-mail, let us know by mail or phone at the addresses and numbers listed on this page. Also let us know if you would like to be kept abreast of legislative and regulatory activities at the state and federal levels, which could impact investor-owned utilities.

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 1998

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ______ to ______

Commission File Number 1-8962.

Pinnacle West Capital Corporation
(Exact name of registrant as specified in its charter)

ARIZONA
(State or other jurisdiction of incorporation or organization)

86-0512431
(I.R.S. Employer Identification No.)

400 East Van Buren Street, Suite 700
Phoenix, Arizona 85004
(Address of principal executive offices, including zip code)

(602) 379-2500
(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock, No Par Value	New York Stock Exchange Pacific Stock Exchange

Title of Each Class of Voting Stock	Shares Outstanding as of March 25, 1999	Aggregate Market Value of Shares Held by Non-affiliates as of March 25, 1999
Common Stock, No Par Value	84,644,979	$3,211,218,891(a)

(a) Computed by reference to the closing price on the composite tape on March 25, 1999, as reported by the Wall Street Journal.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes X No __

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. X

Documents Incorporated By Reference

Portions of the registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders to be held on May 19, 1999 are incorporated by reference into Part III hereof.

TABLE OF CONTENTS

GLOSSARY

ACC — Arizona Corporation Commission

ACC Staff — Staff of the Arizona Corporation Commission

AFUDC — Allowance for Funds Used During Construction

Amendments — Clean Air Act Amendments of 1990

ANPP — Arizona Nuclear Power Project, also known as Palo Verde

APS — Arizona Public Service Company

CC&N — Certificate of convenience and necessity

Cholla — Cholla Power Plant

Cholla 4 — Unit 4 of the Cholla Power Plant

Company — Pinnacle West Capital Corporation

CUC — Citizens Utilities Company

DOE — United States Department of Energy

EITF — Emerging Issues Task Force

EITF 97-4 — Emerging Issues Task Force Issue No. 97-4, "Deregulation of the Pricing of Electricity — Issues Related to the Applications of FASB Statements No. 71, Accounting for the Effects of Certain Types of Regulation, and No. 101, Regulated Enterprises — Accounting for the Discontinuation of Application of FASB Statement No. 71"

EITF 98-10 — Emerging Task Force Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities"

El Dorado — El Dorado Investment Company

Energy Act — National Energy Policy Act of 1992

EPA — United States Environmental Protection Agency

FASB — Financial Accounting Standards Board

FERC — Federal Energy Regulatory Commission

Four Corners — Four Corners Power Plant

GAAP — Generally accepted accounting principles

ITC — Investment tax credit

kW — Kilowatt, one thousand watts

kWh — Kilowatt-hour, one thousand watts per hour

Mortgage — Mortgage and Deed of Trust, dated as of July 1, 1946, as supplemented and amended

MW — Megawatt hours, one million watts

MWh — Megawatt hours, one million watts per hour

1935 Act — Public Utility Holding Company Act of 1935

NGS — Navajo Generating Station

NRC — Nuclear Regulatory Commission

PacifiCorp — An Oregon-based utility company

Palo Verde — Palo Verde Nuclear Generating Station

SEC — Securities and Exchange Commission

SFAS No. 34 — Statement of Financial Accounting Standards No. 34, "Capitalization of Interest Cost"

SFAS No. 71 — Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation"

SFAS No. 123 — Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation"

SFAS No. 130 — Statement of Financial Accounting Standards No. 130, "Reporting Comprehensive Income"

SFAS No. 133 — Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities"

Salt River Project — Salt River Project Agricultural Improvement and Power District

SunCor — SunCor Development Company

USEC — United States Enrichment Corporation

Waste Act — Nuclear Waste Policy Act of 1982, as amended

PART I

ITEM 1. BUSINESS

The Company

General

We were incorporated in 1985 under the laws of the State of Arizona and are engaged, through our subsidiaries, in the generation and distribution of electricity; in real estate development; and in venture capital investment. Our principal executive offices are located at 400 East Van Buren Street, Suite 700, Phoenix, Arizona 85004 (telephone 602-379-2500).

At December 31, 1998, we employed approximately 7,333 people, including the employees of our subsidiaries. Of these employees, 6,075 were employees of our major subsidiary, APS, and employees assigned to joint projects of APS where APS serves as a project manager, and approximately 1,258 were our employees and employees of our other subsidiaries.

Our other subsidiaries, in addition to APS, include SunCor and El Dorado. See "Business of SunCor Development Company" and "Business of El Dorado Investment Company" in this Item for further information regarding SunCor and El Dorado.

This document contains "forward-looking statements" that involve risks and uncertainties. Words such as "estimates," "expects," "anticipates," "plans," "believes," "projects," and similar expressions identify forward-looking statements. These risks and uncertainties include, but are not limited to, the ongoing restructuring of the electric industry; the outcome of the regulatory proceedings relating to the restructuring; regulatory, tax, and environmental legislation; the ability of APS to successfully compete outside its traditional regulated markets; regional economic conditions, which could affect customer growth; the cost of debt and equity capital; weather variations affecting customer usage; technological developments in the electric industry; Year 2000 issues; and the strength of the real estate market. See "Business of Arizona Public Service Company -- Competition" for a discussion of some of these factors.

Arizona Corporation Commission Affiliated Interest Rules. On March 14, 1990, the ACC issued an order adopting certain rules purportedly applicable only to a certain class of public utilities regulated by the ACC, including APS. The rules define the terms "public utility holding company" and "affiliate" with respect to public service corporations regulated by the ACC in such a manner as to include us and all of our non-public service corporation subsidiaries. By their terms, the rules, among other things, require public utilities, such as APS, to receive ACC approval prior to (1) obtaining an interest in, or guaranteeing or assuming the liabilities of, any affiliate not regulated by the ACC; (2) lending to any such affiliate (except for short-term loans in an amount less than $100,000); or (3) using utility funds to form a subsidiary or divest itself of any established subsidiary. The rules also prevent a utility from transacting business with an affiliate unless the affiliate agrees to provide the ACC "access to the books and records of the affiliate to the degree required to fully audit, examine or otherwise investigate transactions between the public utility and the affiliate." In addition, the rules provide that an "affiliate or holding company may not divest itself of, or otherwise relinquish control of, a public utility without thirty (30) days prior written notification to the [ACC]" and requires all public utilities subject to them and all public utility holding companies to annually "provide the [ACC] with a description of diversification plans for the current calendar year that have been approved by the Boards of Directors." The rules have not had, nor do we expect the rules to have, a material adverse impact on our business or operations.

BUSINESS OF ARIZONA PUBLIC SERVICE COMPANY

Following is a discussion of the business of APS, our major subsidiary.

General

APS was incorporated in 1920 under the laws of Arizona and is engaged principally in serving electricity in the State of Arizona. The principal executive offices of APS are located at 400 North Fifth Street, Phoenix, Arizona 85004 (telephone 602-250-1000). We own all of the outstanding shares of APS' common stock.

APS is Arizona's largest electric utility, with 799,000 customers, and provides wholesale or retail electric service to the entire state of Arizona with the exception of Tucson and about one-half of the Phoenix area. During 1998, no single purchaser or user of energy accounted for more than 2% of total electric revenues. At December 31, 1998, APS employed 6,075 people, which includes employees assigned to joint projects where APS is project manager.

Competition

Retail

General. Under current law, APS is not in direct competition with any other regulated electric utility for electric service in APS' retail service territory. Nevertheless, APS is subject to varying degrees of competition in certain territories adjacent to or within areas that it serves that are also currently served by other utilities in our region (such as Tucson Electric Power Company, Southwest Gas Corporation, and Citizens Utility Company) as well as cooperatives, municipalities, electrical districts, and similar types of governmental organizations (principally Salt River Project).

APS faces competitive challenges from low-cost hydroelectric power and natural gas fuel, as well as the access of some utilities to preferential low-priced federal power and other subsidies. In addition, some customers, particularly industrial and large commercial, may own and operate facilities to generate their own electric energy requirements. Such facilities may be operated by the customers themselves or by other entities engaged for such purpose.

Arizona Electric Industry Restructuring. See Note 3 of Notes to Consolidated Financial Statements in Item 8 for a discussion of the electric industry restructuring in Arizona, including ACC rules for the introduction of retail electric competition; stranded cost recovery; and Arizona legislative initiatives. See also "Financial Review - Competition and Industry Restructuring" in Item 7.

Wholesale

General. APS competes with other utilities, power marketers, and independent power producers in the sale of electric capacity and energy in the wholesale market. APS expects that competition to sell capacity will remain vigorous. APS' rates for wholesale power sales and transmission services are subject to regulation by the FERC. During 1998, approximately 16% of APS' electric operating revenues resulted from such sales and charges.

The National Energy Policy Act of 1992 (the "Energy Act") has promoted increased competition in the wholesale electric power markets. The Energy Act reformed provisions of the Public Utility Holding Company Act of 1935 (the "1935 Act") and the Federal Power Act to remove certain barriers to competition for the supply of electricity. For example, the Energy Act permits the FERC to order transmission access for third parties to transmission facilities owned by another entity so that independent suppliers and other third parties can sell at wholesale to customers wherever located. The Energy Act does not, however, permit the FERC to issue an order requiring transmission access to retail customers.

Effective July 9, 1996, a FERC decision requires all electric utilities subject to the FERC's jurisdiction to file transmission tariffs which provide competitors with access to transmission facilities comparable to the transmission owners' access for wholesale transactions, establishes information requirements, and provides for recovery of certain wholesale stranded costs. Retail stranded costs resulting from a state-authorized retail direct-access program are the responsibility of the states, unless a state lacks authority to impose rates to recover such costs, in which case FERC will consider doing so. APS has filed a revised open access tariff in accordance with this decision. APS does not believe that this decision will have a material adverse impact on its results of operations or financial position.

Regulatory Assets

APS' major regulatory assets are deferred income taxes and rate synchronization cost deferrals. These items, combined with miscellaneous regulatory assets and liabilities, amounted to approximately $900 million at December 31, 1998. Under a 1996 regulatory agreement, the ACC accelerated the amortization of substantially all of APS' regulatory assets to an eight-year period that will end June 30, 2004. APS' existing regulatory orders and the current regulatory environment support APS' accounting practices related to regulatory assets. If rate recovery of these assets is no longer probable, whether due to competition or regulatory action, APS would be required to write off the remaining balance as an extraordinary charge to expense. This could have a material impact on APS' financial statements. See Notes 1, 3, and 4 of Notes to Consolidated Financial Statements in Item 8 for additional information.

Competitive Strategies

APS is pursuing strategies to maintain and enhance its competitive position. These strategies include (i) cost management, with an emphasis on the reduction of variable costs (fuel, operations, and maintenance expenses) and on increased productivity through technological efficiencies; (ii) a focus on APS' core business through customer service, distribution system reliability, business segmentation, and the anticipation of market opportunities; (iii) an emphasis on good regulatory relationships; (iv) asset maximization (e.g., higher capacity factors and lower forced outage rates); (v) expanding APS' generation asset base to support growth in the competitive power marketing arena; (vi) strengthening APS' capital structure and financial condition; (vii) leveraging core competencies into related areas, such as energy management products and services; and (viii) establishing a trading floor and implementing a risk management program to provide for more stability of prices and the ability to retain or grow incremental margin through more competitive pricing and risk management. Underpinning APS' competitive strategies are the strong growth characteristics of APS' service territory. As competition in the electric utility industry continues to evolve, APS will continue to evaluate strategies and alternatives that will position us to compete effectively in a more competitive, restructured industry.

Generating Fuel and Purchased Power

1998 Energy Mix

APS' sources of energy during 1998 were: coal – 36.2%; nuclear – 27.5%; purchased power - 32.3%; and other – 4.0%.

Coal Supply

APS believes that Cholla has sufficient reserves of low sulfur coal committed to the plant through 2005. In 1998, the current supplier agreed to allow Cholla to test burn coal from other sources, which led to coal purchases on the spot market. The current supplier is expected to continue to provide substantially all of Cholla's low sulfur coal requirements. APS believes there are sufficient reserves of low sulfur coal available to allow the continued operation of Cholla for its useful life. APS also believes that Four Corners and NGS have sufficient reserves of low sulfur coal available for use by those plants to continue operating them for their useful lives.

The current sulfur content of coal being used at Four Corners, NGS, and Cholla is approximately 0.77%, 0.54%, and 0.44%, respectively. In 1998, average prices paid for coal supplied from the reserves dedicated under existing contracts were slightly lower, but still comparable to 1997. Escalation components of existing long-term coal contracts impact future coal prices. In addition, major price adjustments can occur from time to time as a result of contract renegotiation.

NGS and Four Corners are located on the Navajo Reservation and held under easements granted by the federal government as well as leases from the Navajo Nation. See "Properties- Plant Sites Leased from the Navajo Nation" in Item 2. APS purchases all of the coal which fuels Four Corners from a coal supplier with a long-term lease of coal reserves owned by the Navajo Nation and for NGS from a coal supplier with a long-term lease with the Navajo Nation and the Hopi Tribe. Coal is supplied to Cholla from a coal supplier who mines all of the coal under a long-term lease of coal reserves owned by the Navajo Nation, the federal government, and private landholders. See Note 12 of Notes to Consolidated Financial Statements in Item 8 for information regarding APS' obligation for coal mine reclamation.

Natural Gas Supply

APS is a party to contracts with a number of natural gas operators and marketers which allow APS to purchase natural gas in the method APS determines to be most economic. Currently, APS is purchasing the majority of its natural gas requirements from 25 companies pursuant to contracts. APS' natural gas supply is transported pursuant to a firm transportation service contract with El Paso Natural Gas Company. APS continues to analyze the market to determine the most favorable source and method of meeting its natural gas requirements.

Nuclear Fuel Supply

The fuel cycle for Palo Verde is comprised of the following stages:

- the mining and milling of uranium ore to produce uranium concentrates,
- the conversion of uranium concentrates to uranium hexafluoride,
- the enrichment of uranium hexafluoride,
- the fabrication of fuel assemblies,
- the utilization of fuel assemblies in reactors and
- the storage of spent fuel and the disposal thereof.

The Palo Verde participants have made contractual arrangements to obtain quantities of uranium concentrates anticipated to be sufficient to meet operational requirements through 2001. Existing contracts and options could be utilized to meet approximately 93% of requirements in 2002, 62% of requirements in 2003, 51% of requirements in 2004, and 44% of requirements from 2005 through 2007. Spot purchases on the uranium market will be made, as appropriate, in lieu of any uranium that might be obtained through contractual options.

The Palo Verde participants have contracted for 85% of conversion services required through 2002. The Palo Verde participants have an enrichment services contract and an enriched uranium product contract that furnish enrichment services required for the operation of the three Palo Verde units through 2003. In addition, existing contracts will provide fuel assembly fabrication services until at least 2003 for each Palo Verde unit, and through contract options, approximately fifteen additional years are available.

Spent Nuclear Fuel and Waste Disposal. Pursuant to the Nuclear Waste Policy Act of 1982, as amended in 1987 (the "Waste Act"), DOE is obligated to accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by all domestic power reactors. The NRC, pursuant to the Waste Act, requires operators of nuclear power reactors to enter into spent fuel disposal contracts with DOE. APS has done so on its behalf and on behalf of the other Palo Verde participants. Under the Waste Act, DOE was to develop the facilities necessary for the storage and disposal of spent nuclear fuel and to have the first such facility in operation by 1998. That facility was to be a permanent repository. DOE has announced that such a repository now cannot be completed before 2010. In July 1996, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) ruled that the DOE has an obligation to start disposing of spent nuclear fuel no later than January 31, 1998. By way of letter dated December 17, 1996, DOE informed APS and other contract holders that DOE anticipates that it will be unable to begin acceptance of spent nuclear fuel for disposal in a repository or interim storage facility by January 31, 1998. In November 1997, the D.C. Circuit issued a Writ of Mandamus precluding DOE from excusing its own delay on the grounds that DOE has not yet prepared a permanent repository or interim storage facility. On May 5, 1998, the D.C. Circuit issued a ruling refusing to order DOE to begin moving spent nuclear fuel. On July 24, 1998, APS filed a Petition for Review regarding DOE's obligation to begin accepting spent nuclear fuel. Arizona Public Service Company v. Department of Energy and United States of America, No. 98-1346 (D.C. Cir.). See "Palo Verde Nuclear Generating Station" in Note 12 of Notes to Financial Statements in Item 8 for a discussion of interim spent fuel storage costs.

Several bills have been introduced in Congress contemplating the construction of a central interim storage facility; however, there is resistance to certain features of these bills both in Congress and the Administration.

Facility funding is a further complication. While all nuclear utilities pay into a so-called nuclear waste fund an amount calculated on the basis of the output of their respective plants, the annual Congressional appropriations for the permanent repository have been for amounts less than the amounts paid into the waste fund (the balance of which is being used for other purposes). According to DOE spokespersons, the fund may now be at a level less than needed to achieve a 2010 operational date for a permanent repository. No funding will be available for a central interim facility until one is authorized by Congress.

APS has storage capacity in existing fuel storage pools at Palo Verde which, with certain modifications, could accommodate all fuel expected to be discharged from normal operation of Palo Verde through about 2002. APS also believes it could augment that wet storage with new facilities for on-site dry storage of spent fuel for an indeterminate period of operation beyond 2002, subject to obtaining any required governmental approvals. One way or another, APS currently believes that spent fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation beyond 2002.

A new low-level waste facility was built in 1995 on-site which could store an amount of waste equivalent to ten years of normal operation at Palo Verde. Although some low-level waste has been stored on-site, APS is currently shipping low-level waste to off-site facilities. APS currently believes that interim low-level waste storage methods are or will be available for use by Palo Verde to allow its continued operation and to safely store low-level waste until a permanent disposal facility is available.

APS believes that scientific and financial aspects of the issues of spent fuel and low-level waste storage and disposal can be resolved satisfactorily. However, APS also acknowledges that their ultimate resolution in a timely fashion will require political resolve and action on national and regional scales which APS is less able to predict.

Purchased Power Agreements

In addition to that available from APS' own generating capacity (see "Properties" in Item 2), APS purchases electricity from other utilities under various arrangements. One of the most important of these is a long-term contract with Salt River Project. This contract may be canceled by Salt River Project on three years' notice and requires Salt River Project to make available, and APS to pay for, certain amounts of electricity. The amount of electricity is based in large part on customer demand within certain areas now served by APS pursuant to a related territorial agreement. The generating capacity available to APS pursuant to the contract was 292 MW January through May 1998, and starting June 1998 increased to 316 MW. In 1998, APS received approximately 943,354 MWh of energy under the contract and paid about $43 million for capacity availability and energy received. See Note 3 of Notes to Consolidated Financial Statements for a discussion of amendments to agreements with Salt River Project.

In September 1990, APS entered into certain agreements with PacifiCorp relating principally to sales and purchases of electric power and electric utility assets. In July 1991 APS sold Cholla 4 to PacifiCorp. As part of the transaction, PacifiCorp agreed to make a firm system sale to APS for thirty years during our summer peak season. The amount of the sale for the first seven years was 175 MW and it increases after that at APS' option, up to a maximum amount of 380 MW. APS converted the firm system sales to one-for-one seasonal capacity exchanges with PacifiCorp on October 31, 1997. On January 1, 1999 APS' agreements with PacifiCorp provide for 275 MW capacity exchange and beginning in May 1999, an additional 205 MW capacity exchange begins. In 1998, APS had 275 MW of generating capacity available from PacifiCorp. APS received approximately 281,217 MWh of energy under the exchange.

During 1996, APS entered into an agreement with Citizens Utilities Company to build, own, operate, and maintain a combustion turbine in northwest Arizona. CUC terminated the combustion turbine project in February 1999. APS has notified CUC that it will retain the rights to the combustion turbine project.

Construction Program

During the years 1996 through 1998, APS incurred approximately $899 million in capitalized expenditures. Utility capitalized expenditures for the years 1999 through 2001 are expected to be primarily for expanding transmission and distribution capabilities to meet customer growth, upgrading existing facilities, and for environmental purposes. Capitalized expenditures, including expenditures for environmental control facilities, for the years 1999 through 2001 have been estimated as follows:

(Millions of Dollars)

By Year	
1999	$328
2000	317
2001	300
Total	$945

By Major Facilities	
Production	$236
Transmission and Distribution	564
General	113
Other Projects	32
Total	$945

The amounts for 1999 through 2001 exclude capitalized interest costs and include capitalized property taxes and about $30-$35 million each year for nuclear fuel. APS conducts a continuing review of its construction program. APS is considering expanding certain of its operations over the next several years, which may result in additional expenditures. APS currently believes that there will be opportunities to expand its investment in generating assets in the next five years. It is expected that these generating assets would be organized in a newly-created, non-regulated affiliate under us.

Mortgage Replacement Fund Requirements

So long as any of APS' first mortgage bonds are outstanding, APS is required for each calendar year to deposit with the trustee under its Mortgage cash in a formularized amount related to net additions to APS' mortgaged utility plant. APS may satisfy all or any part of this "replacement fund" requirement by utilizing redeemed or retired bonds, net property additions, or property retirements. For 1998, the replacement fund requirement amounted to approximately $138 million. Certain of the bonds APS has issued under the Mortgage that are callable prior to maturity are redeemable at their par value plus accrued interest with cash APS deposits in the replacement fund. This is subject in many cases to a period of time after the original issuance of the bonds during which they may not be so redeemed.

Environmental Matters

EPA Environmental Regulation

Clean Air Act. APS is subject to a number of requirements under the Clean Air Act. Pursuant to the 1977 amendments to the Clean Air Act, the EPA adopted regulations that address visibility impairment in certain federally-protected areas which can be reasonably attributed to specific sources. In September 1991, the EPA issued a final rule that limited sulfur dioxide emissions at NGS. One NGS unit had to comply with this rule in 1997, one in 1998, and the last unit in 1999. Salt River Project is the NGS operating agent. Salt River Project estimates a capital cost of $430 million and annual operations and maintenance costs of approximately $14 million for all three units, for NGS to meet these requirements. APS is required to fund 14% of these expenditures. Approximately 93% of these capital costs have been incurred through 1998.

The Clean Air Act Amendments of 1990 (the "Amendments") address, among other things:

- "acid rain,"
- visibility in certain specified areas,
- hazardous air pollutants and
- areas that have not attained national ambient air quality standards.

With respect to "acid rain," the Amendments establish a system of sulfur dioxide emissions "allowances." Each existing utility unit is granted a certain number of "allowances." For Phase II plants, which include APS' plants, allowances will be required beginning in the year 2000 to operate the plants. On March 5, 1993, the EPA promulgated rules listing allowance allocations applicable to APS' plants. Based on those allocations, APS will have sufficient allowances to permit continued operation of its plants at current levels without installing additional equipment.

In addition, the Amendments require the EPA to set nitrogen oxides emissions limitations. These limitations require certain plants to install additional pollution control equipment. In December 1996, the EPA issued rules for nitrogen oxides emissions limitations that may require APS to install additional pollution control equipment at Four Corners by January 1, 2000. On February 14, 1997, APS filed a Petition for Review in the United States Court of Appeals for the District of Columbia. APS alleged that the EPA improperly classified Four Corners Unit 4 in these rules, thereby subjecting Unit 4 to a more stringent emission limitation. Arizona Public Service Company v. United States Environmental Protection Agency, No. 97-1091. In February 1998, the Court vacated the Unit 4 emission limitation and remanded the issue to EPA for reconsideration. APS cannot currently predict how the EPA will respond. However, based on APS' initial evaluation, APS currently estimates its capital cost of complying with the rules may be approximately $4 million.

With respect to protection of visibility in certain specified areas, the Amendments require the EPA to conduct a study concerning visibility impairment in those areas and to identify sources contributing to such impairment. Interim findings of this study indicate that any beneficial effect on visibility as a result of the Amendments would be offset by expected population and industry growth. The Amendments also require EPA to establish a "Grand Canyon Visibility Transport Commission" to complete a study on visibility impairment in the "Golden Circle of National Parks" in the Colorado Plateau. NGS, Cholla, and Four Corners are located near the Golden Circle of National Parks. The Commission completed its study and on June 10, 1996 submitted its final recommendations to the EPA. The Commission recommended that, beginning in 2000 and every 5 years thereafter, if actual sulfur dioxide emissions from all stationary sources in an eight-state region (including Arizona, New Mexico, Utah, Nevada, and California) exceed the projected emissions, which are projected to decline under the current regulatory scheme, the projected total emissions will be changed to a "regional emissions cap" and an emissions trading program would be implemented to limit total sulfur dioxide emissions in the region. The EPA will consider these recommendations before promulgating final requirements on a regional haze regulatory program which the EPA proposed in July 1997 and which is expected to be finalized by mid-1999.

Under EPA's proposed regional haze program, states would be required to submit plans to meet "presumptive reasonable progress targets" for achieving perceptible improvements in visibility conditions in Federal Class I areas (e.g., national parks) every 10-15 years. The proposal also calls for states to conduct three year "best available retrofit technology" ("BART") reviews on point sources which became operational between 1962 and 1977 and which may normally be anticipated to contribute to regional haze visibility impairment.

Also, in July 1997, EPA promulgated final National Ambient Air Quality Standards for ozone and particulate matter. Pursuant to the rules, the ozone standard is more stringent and a new ambient standard for very fine particles has been established. Congress has enacted legislation that could delay the implementation of regional haze requirements and the particulate matter ambient standard. Because the actual level of emissions controls, if any, for any unit cannot be determined at this time, APS currently cannot estimate the capital expenditures, if any, which would result from the final rules. However, APS does not currently expect these rules to have a material adverse effect on its financial position or results of operations.

With respect to hazardous air pollutants emitted by electric utility steam generating units, the Amendments require two studies. The results of the first study indicated an impact from mercury emissions from such units in certain unspecified areas. The EPA has not yet stated whether or not mercury emissions limitations will be imposed. Secondly, the EPA will complete a general study in the next several years concerning the necessity of regulating hazardous air pollutant emissions from such units under the Amendments. Because APS cannot speculate as to the ultimate requirements by the EPA, APS cannot currently estimate the capital expenditures, if any, which may be required as a result of these studies.

Certain aspects of the Amendments may require related expenditures by APS, such as permit fees. APS does not expect any of these to have a material impact on its financial position or results of operations.

Superfund. The Comprehensive Environmental Response, Compensation, and Liability Act ("Superfund") establishes liability for the cleanup of hazardous substances found contaminating the soil, water, or air. Those who generated, transported, or disposed of hazardous substances at a contaminated site are among those who are potentially responsible parties ("PRPs"). PRPs may be strictly, and often jointly and severally, liable for the cost of any necessary remediation of the substances. The EPA had previously advised APS that the EPA considers APS to be a PRP in the Indian Bend Wash Superfund Site, South Area. APS' Ocotillo Power Plant is located in this area. APS is in the process of conducting an investigation to determine the extent and scope of contamination at the plant site. Based on the information to date, including available insurance coverage and an EPA estimate of cleanup costs, APS does not expect this matter to have a material impact on its financial position or results of operations.

Manufactured Gas Plant Sites. APS is currently investigating properties which APS now owns or which were at one time owned by APS or its corporate predecessor, that were at one time sites of, or sites associated with, manufactured gas plants. The purpose of this investigation is to determine if:

- waste materials are present
- such materials constitute an environmental or health risk and
- APS has any responsibility for remedial action.

Where appropriate, APS has begun remediation of certain of these sites. APS does not expect these matters to have a material adverse effect on its financial position or results of operations.

Purported Navajo Environmental Regulation

Four Corners and NGS are located on the Navajo Reservation and are held under easements granted by the federal government as well as leases from the Navajo Nation. APS is the Four Corners operating agent. APS owns a 100% interest in Four Corners Units 1, 2, and 3, and a 15% interest in Four Corners Units 4 and 5. APS owns a 14% interest in NGS Units 1, 2, and 3.

In July 1995, the Navajo Nation enacted the Navajo Nation Air Pollution Prevention and Control Act, the Navajo Nation Safe Drinking Water Act, and the Navajo Nation Pesticide Act (collectively, the "Acts"). Pursuant to the Acts, the Navajo Nation Environmental Protection Agency is authorized to promulgate regulations covering air quality, drinking water, and pesticide activities, including those that occur at Four Corners and NGS. By separate letters dated October 12 and October 13, 1995, the Four Corners participants and the NGS participants requested the United States Secretary of the Interior to resolve their dispute with the Navajo Nation regarding whether or not the Acts apply to operations of Four Corners and NGS. On October 17, 1995, the Four Corners participants and the NGS participants each filed a lawsuit in the District Court of the Navajo Nation, Window Rock District, seeking, among other things, a declaratory judgment that

- their respective leases and federal easements preclude the application of the Acts to the operations of Four Corners and NGS and

- the Navajo Nation and its agencies and courts lack adjudicatory jurisdiction to determine the enforceability of the Acts as applied to Four Corners and NGS.

On October 18, 1995, the Navajo Nation and the Four Corners and NGS participants agreed to indefinitely stay these proceedings so that the parties may attempt to resolve the dispute without litigation. The Secretary and the Court have stayed these proceedings pursuant to a request by the parties. APS cannot currently predict the outcome of this matter.

In February 1998, the EPA promulgated regulations specifying those provisions of the Clean Air Act for which it is appropriate to treat Indian tribes in the same manner as states. The EPA indicated that it believes that the Clean Air Act generally would supersede pre-existing binding agreements that may limit the scope of tribal authority over reservations. On April 10, 1998, APS filed a Petition for Review in the United States Court of Appeals for the District of Columbia. Arizona Public Service Company v. United States Environmental Protection Agency, No. 98-1196. On February 19, 1999, the EPA promulgated regulations setting forth the EPA's approach to issuing Federal operating permits to covered stationary sources on Indian reservations, pursuant to the Amendments. APS is currently evaluating the impact of these regulations.

Water Supply

Assured supplies of water are important for APS' generating plants. At the present time, APS has adequate water to meet its needs. However, conflicting claims to limited amounts of water in the southwestern United States have resulted in numerous court actions in recent years.

Both groundwater and surface water in areas important to APS' operations have been the subject of inquiries, claims, and legal proceedings which will require a number of years to resolve. APS is one of a number of parties in a proceeding before a state court in New Mexico to adjudicate rights to a stream system from which water for Four Corners is derived. (State of New Mexico, in the relation of S.E. Reynolds, State Engineer vs. United States of America, City of Farmington, Utah International, Inc., et al., San Juan County, New Mexico, District Court No. 75-184). An agreement reached with the Navajo Nation in 1985, however, provides that if Four Corners loses a portion of its rights in the adjudication, the Navajo Nation will provide, for a then-agreed upon cost, sufficient water from its allocation to offset the loss.

A summons served on APS in early 1986 required all water claimants in the Lower Gila River Watershed in Arizona to assert any claims to water on or before January 20, 1987, in an action pending in Maricopa County Superior Court. (In re The General Adjudication of All Rights to Use Water in the Gila River System and Source, Supreme Court Nos. WC-79-0001 through WC 79-0004 (Consolidated) [WC-1, WC-2, WC-3 and WC-4 (Consolidated)], Maricopa County Nos. W-1, W-2, W-3 and W-4 (Consolidated)). Palo Verde is located within the geographic area subject to the summons. APS' rights and the rights of the Palo Verde participants to the use of groundwater and effluent at Palo Verde is potentially at issue in this action. As project manager of Palo Verde, APS filed claims that dispute the court's jurisdiction over the Palo Verde participants' groundwater rights and their contractual rights to effluent relating to Palo Verde. Alternatively, APS seeks confirmation of such rights. Three of APS' less-utilized power plants are also located within the geographic area subject to the summons. APS' claims dispute the court's jurisdiction over APS' groundwater rights with respect to these plants. Alternatively, APS seeks confirmation of such rights. Issues important to the claims are pending on appeal to the Arizona Supreme Court. No trial date concerning APS' water rights claims has been set in this matter.

APS has also filed claims to water in the Little Colorado River Watershed in Arizona in an action pending in the Apache County Superior Court. (In re The General Adjudication of All Rights to Use Water in the Little

Colorado River System and Source, Supreme Court No. WC-79-0006 WC-6, Apache County No. 6417). APS' groundwater resource utilized at Cholla is within the geographic area subject to the adjudication and is therefore potentially at issue in the case. APS' claims dispute the court's jurisdiction over APS' groundwater rights. Alternatively, APS seeks confirmation of such rights. The parties are in the process of settlement negotiations with respect to this matter. No trial date concerning APS' water rights claims has been set in this matter.

Although the foregoing matters remain subject to further evaluation, APS expects that the described litigation will not have a material adverse impact on its financial position or results of operations.

BUSINESS OF SUNCOR DEVELOPMENT COMPANY

SunCor was incorporated in 1965 under the laws of the State of Arizona and is engaged primarily in the acquisition, ownership, development, operation, and sale of land and other real property, including homes and commercial buildings. The principal executive offices of SunCor are located at 3838 North Central, Suite 1500, Phoenix, Arizona 85012 (telephone 602-285-6800). SunCor and its subsidiaries, excluding SunCor Resort & Golf Management, Inc. ("Resort Management"), employ approximately 140 persons. Resort Management, which manages the Wigwam Resort and Country Club (the "Wigwam"), employs between 620 and 750 persons at the Wigwam, depending on the Wigwam's operating season. In addition, Resort Management operates three golf courses and family entertainment operations which together employ about 300 people.

Effective January 1, 1996, SunCor's homebuilding subsidiary, SunCor Homes, Inc., purchased the assets of Golden Heritage Homes. Subsequent to December 31, 1996, SunCor Homes, Inc. changed its name to Golden Heritage Homes, Inc.

SunCor's projects consist primarily of land and improvements and other real estate investments. SunCor's major asset is the Palm Valley project which consists of over 9,000 acres and is located west of Phoenix in the area of Goodyear/Litchfield Park, Arizona ("Palm Valley"). SunCor has completed the master plan for developing Palm Valley. There has been significant residential and commercial development at Palm Valley by SunCor and by other developers that have acquired land from SunCor or entered into joint ventures with SunCor. Development at Palm Valley currently includes residential communities, including a retirement community, with golf courses, hotels, restaurants, commercial and retail outlets, hospitals, and assisted-care facilities.

Other SunCor projects under development include seven master-planned communities and four commercial projects. The four commercial projects and four of the master-planned communities are located in the Phoenix area. Other master-planned communities are located near Sedona, Arizona, near St. George, Utah, and near Santa Fe, New Mexico. Several of the master-plan and commercial projects are joint ventures with other developers, financial partners, or landowners.

For the past three years, SunCor's operating revenues were about: 1998, $124.2 million; 1997, $116.5 million; and 1996, $99.5 million. For those same periods SunCor's net income was about: 1998, $44.7 million; 1997, $5.3 million; and 1996, $4.2 million. About $37.2 million of SunCor's 1998 net income represents income related to the recognition of a deferred tax asset. The deferred tax asset relates to net operating losses and book/tax basis differences. SunCor is expected to realize these benefits in subsequent periods pursuant to an intercompany tax allocation agreement. On a consolidated basis, there was no impact to consolidated net income. SunCor's capital needs consist primarily of capital expenditures for land development and home construction. On the basis of projects now under development, SunCor expects capital needs over the next three years to be: 1999, $58 million; 2000, $53 million; and 2001, $43 million.

At December 31, 1998, SunCor had total assets of about $407 million. See Note 6 of Notes to the Consolidated Financial Statements in Item 8 for information regarding SunCor's long-term debt. SunCor intends to continue its focus on real estate development in homebuilding and the development of residential, commercial, and industrial projects.

BUSINESS OF EL DORADO DEVELOPMENT COMPANY

El Dorado was incorporated in 1983 under the laws of the State of Arizona and is engaged principally in the business of making equity investments in other companies. El Dorado's short-term goal is to convert its venture capital portfolio to cash as quickly and as advantageously as possible. On a long-term basis, we may use El Dorado, when appropriate, as our subsidiary for new ventures that are strategically close to our principal business of generating, distributing, and marketing electricity. El Dorado's offices are located at 400 East Van Buren Street, Suite 750, Phoenix, Arizona 85004 (telephone 602-379-2662).

El Dorado had investments in venture capital partnerships totaling approximately $7 million at December 31, 1998. In addition to the foregoing investments, at December 31, 1998, El Dorado had direct investments of approximately $17 million in other private and public companies and partnerships. These investments include a 56% interest in NAC International, a company that specializes in nuclear spent fuel storage and transportation technology, as well as nuclear fuel cycle and international energy policy consulting.

For the past three years, El Dorado's net income was: 1998, $4.5 million; 1997, $8.2 million; and 1996, $0.4 million. At December 31, 1998, El Dorado had total assets of about $27 million.

ITEM 2. PROPERTIES

Accredited Capacity

APS' present generating facilities have an accredited capacity as follows:

	Capacity(kW)
Coal:	
Units 1, 2, and 3 at Four Corners	560,000
15% owned Units 4 and 5 at Four Corners	222,000
Units 1, 2, and 3 at Cholla Plant	615,000
14% owned Units 1, 2, and 3 at the Navajo Plant	315,000
	1,712,000
Gas or Oil:	
Two steam units at Ocotillo and two steam units at Saguaro	435,000(1)
Eleven combustion turbine units	493,000
Three combined cycle units	255,000
	1,183,000
Nuclear:	
29.1% owned or leased Units 1, 2, and 3 at Palo Verde	1,086,300
Other	5,600
Total	3,986,900

(1) West Phoenix steam units (108,300 kW) are currently mothballed.

Reserve Margin

APS' peak one-hour demand on its electric system was recorded on July 16, 1998 at 5,072,000 kW, compared to the 1997 peak of 4,608,600 kW recorded on August 22. Taking into account additional capacity then available to APS under purchase power contracts as well as APS' own generating capacity, APS' capability of meeting system demand on July 16, 1998, computed in accordance with accepted industry practices, amounted to 5,139,600 kW, for an installed reserve margin of 3.1%. The power actually available to APS from its resources fluctuates from time to time due in part to planned outages and technical problems. The available capacity from sources actually operable at the time of the 1998 peak amounted to 4,862,600 kW, for a margin of (3.9%). Firm purchases from neighboring utilities totaling 1,467,000 kW were in place at the time of the peak ensuring the ability to meet the load requirement, with an actual reserve margin of 7.4%.

Plant Sites Leased from Navajo Nation

NGS and Four Corners are located on land held under easements from the federal government and also under leases from the Navajo Nation. We do not believe that the risk with respect to enforcement of these easements and leases is material. The lease for Four Corners waives until 2001 the requirement that APS, as well as its fuel supplier, pay certain taxes to the Navajo Nation. In September 1997, a settlement agreement was finalized between the coal supplier to Four Corners, the Navajo Nation, and APS which settled certain issues in the Four Corners lease regarding the obligation of the fuel supplier to pay taxes prior to the expiration of tax waivers in 2001. Pursuant to the agreement, in 1997 APS recognized approximately $14 million of pretax earnings related to a partial refund of possessory interest taxes paid by the fuel supplier. The parties also agreed to renegotiate their business relationship before 2001 in an effort to permit the electricity generated at Four Corners to be priced competitively. APS cannot currently predict the outcome of this matter. Certain of APS' transmission lines and almost all of its contracted coal sources are also located on Indian reservations. See "Generating Fuel and Purchased Power — Coal Supply" in Item 1.

Palo Verde Nuclear Generating Station

Palo Verde Leases

See Note 10 of Notes to Consolidated Financial Statements in Item 8 for a discussion of three sale and leaseback transactions related to Palo Verde Unit 2.

Regulatory

Operation of each of the three Palo Verde units requires an operating license from the NRC. The NRC issued full power operating licenses for Unit 1 in June 1985, Unit 2 in April 1986, and Unit 3 in November 1987. The full power operating licenses, each valid for a period of approximately 40 years, authorize APS, as operating agent for Palo Verde, to operate the three Palo Verde units at full power.

Nuclear Decommissioning Costs

The NRC recently amended its rules on financial assurance requirements for the decommissioning of nuclear power plants. The amended rules became effective on November 23, 1998. The amended rules provide that a licensee may use an external sinking fund as the exclusive financial assurance mechanism if the licensee recovers estimated total decommissioning costs through cost of service rates or through a "non-bypassable charge." Other mechanisms are prescribed, including prepayment, if the requirements for exclusive reliance on the external sinking fund mechanism are not met. APS currently relies on the external sinking fund mechanism to meet the NRC financial assurance requirements for its interests in Palo Verde Units 1, 2, and 3. The decommissioning costs of Palo Verde Units 1, 2, and 3 are currently included in ACC jurisdictional rates. Proposed ACC rules regarding the introduction of retail electric competition in Arizona (see Note 3) currently provide that decommissioning costs would be recovered through a non-bypassable "system benefits" charge, which would allow APS to maintain its external sinking fund mechanism. See Note 13 of Notes to Consolidated Financial Statements in Item 8 for additional information about nuclear decommissioning costs.

Palo Verde Liability and Insurance Matters

See "Palo Verde Nuclear Generating Station" in Note 12 of Notes to Consolidated Financial Statements in Item 8 for a discussion of the insurance maintained by the Palo Verde participants, including APS, for Palo Verde.

Other Information Regarding Properties

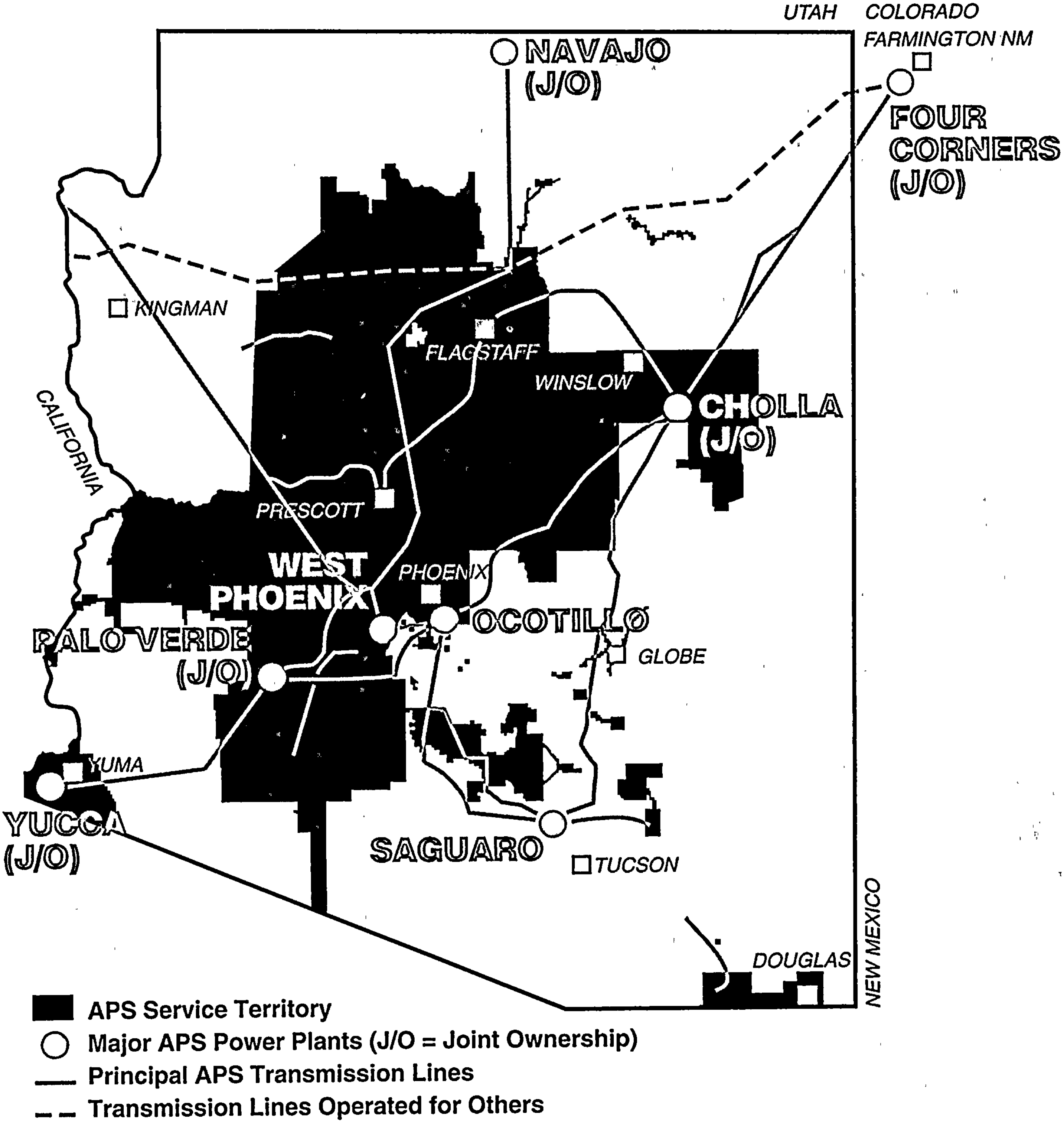
See "Environmental Matters" and "Water Supply" in Item 1 with respect to matters having possible impact on the operation of certain of APS' power plants.

See "Construction Program" in Item 1 and "Financial Review — Capital Needs and Resources" in Item 7 for a discussion of APS' construction plans.

See Notes 6, 10, and 11 of Notes to Consolidated Financial Statements in Item 8 with respect to property of the Company not held in fee or held subject to any major encumbrance.

Information Regarding SunCor's and El Dorado's Properties

See "Business of SunCor Development Company" and "Business of El Dorado Investment Company" for information regarding SunCor's and El Dorado's properties.


UTAH
COLORADO
FARMINGTON NM
NAVAJO (J/O)
FOUR CORNERS (J/O)
KINGMAN
FLAGSTAFF
WINSLOW
CHOLLA (J/O)
CALIFORNIA
PRESCOTT
WEST PHOENIX
PHOENIX
OCOTILLO
GLOBE
PALO VERDE (J/O)
YUMA
YUCCA (J/O)
SAGUARO
TUCSON
DOUGLAS
NEW MEXICO
APS Service Territory
Major APS Power Plants (J/O = Joint Ownership)
Principal APS Transmission Lines
Transmission Lines Operated for Others

ITEM 3. LEGAL PROCEEDINGS

APS

See "Environmental Matters" and "Water Supply" in Item 1 in regard to pending or threatened litigation and other disputes. See "Regulatory Matters" in Note 3 of Notes to Consolidated Financial Statements in Item 8 for a discussion of competition and the rules regarding the instruction of retail electric competition in Arizona. On February 28, 1997 and October 16, 1998, APS filed lawsuits to protect its legal rights regarding the rules and the amended rules, respectively, and in each complaint APS asked the Court for (i) a judgment vacating the retail electric competition rules, (ii) a declaratory judgment that the rules are unlawful because, among other things, they were entered into without proper legal authorization, and (iii) a permanent injunction barring the ACC from enforcing or implementing the rules and from promulgating any other regulations without lawful authority. Arizona Public Service Company v. Arizona Corporation Commission, CV 97-03753 (consolidated under CV 97-03748.) Arizona Public Service Company v. Arizona Corporation Commission, CV98-18896. On August 28, 1998, APS filed two lawsuits to protect its legal rights under the stranded cost order and in its complaints the Company asked the Court to vacate and set aside the order. Arizona Public Service Company v. Arizona Corporation Commission, CV 98-15728. Arizona Public Service Company v. Arizona Corporation Commission, 1-CA-CC-98-0008.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Not applicable.

SUPPLEMENTAL ITEM. EXECUTIVE OFFICERS OF THE REGISTRANT

Our executive officers are as follows:

Name	Age at March 1, 1999	Position(s) at March 1, 1999
Jack E. Davis	52	President, APS Energy Delivery & Sales
James L. Kunkel	61	Vice President
Michael V. Palmeri	40	Treasurer
William J. Post	48	Chief Executive Officer(1)
George A. Schreiber, Jr.	50	President and Chief Financial Officer(1)
Richard Snell	68	Chairman of the Board of Directors (1)
William L. Stewart	55	President, APS Generation
Faye Widenmann	50	Vice President of Corporate Relations and Administration and Secretary

(1) member of the Board of Directors

The executive officers of the Company are elected no less often than annually and may be removed by the Board of Directors at any time. The terms served by the named officers in their current positions and the principal occupations (in addition to those stated in the table) of such officers for the past five years have been as follows:

Mr. Davis was elected to his present position in October 1998. Prior to that time he was Executive Vice President, Commercial Operations (September 1996 - October 1998) and Vice President, Generation and Transmission (June 1993-September 1996) of APS. Mr. Davis is a director of APS.

Mr. Kunkel was elected Vice President effective December 15, 1997. Prior to December 1997, he was a partner with the accounting firm PricewaterhouseCoopers, successor to Coopers & Lybrand, in both their Los Angeles and Phoenix offices. Mr. Kunkel is also a director of Aztar Corporation.

Mr. Palmeri was elected to the position of Treasurer of both the Company and APS effective July 23, 1997. From February 1994 to July 1997, he was Assistant Treasurer of the Company. From June 1990 to February 1994, he was Manager of Finance.

Mr. Post was elected Chief Executive Officer of the Company effective February 1999. Prior to that time he was President (February 1997 - February 1999) and Executive Vice President (June 1995 - February 1997). He was also elected President and Chief Executive Officer of APS in February 1997. In October 1998, he resigned as President and maintained the position of Chief Executive Officer of APS. He has been APS' Chief Operating Officer (September 1994 - February 1997), as well as a Senior Vice President since June 1993. Mr. Post is also a director of APS.

Mr. Schreiber was elected President in February 1999 and Chief Financial Officer in February 1997. He also held the position of Executive Vice President (February 1997 - February 1999). Mr. Schreiber has also been Executive Vice President and Chief Financial Officer of APS since February 1997. From 1990 to January 1997, he was Managing Director at PaineWebber, Inc. He is also a director of APS.

Mr. Snell has been Chairman of the Board of the Company and Chairman of the Board of APS since February 1990. Until February 1999, he was also Chief Executive Officer of the Company, and until February 1997, he was President of the Company. Mr. Snell is also a director of Aztar Corporation and Central Newspapers, Inc.

Mr. Stewart was elected to his present position in October 1998. Prior to that time he was Executive Vice President, Generation (September 1996 - October 1998), Executive Vice President, Nuclear of APS (May 1994 - September 1996) and Senior Vice President — Nuclear for Virginia Power (since 1989). Mr. Stewart is a director of APS.

Ms. Widenmann was elected Secretary of the Company in 1985 and Vice President of Corporate Relations and Administration in November 1986.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON STOCK AND RELATED SECURITY HOLDER MATTERS

Our common stock is publicly held and is traded on the New York and Pacific Stock Exchanges. At the close of business on March 12, 1999, our common stock was held of record by approximately 44,968 shareholders.

The chart below sets forth the common stock price ranges on the composite tape, as reported in the Wall Street Journal for 1998 and 1997. The chart also sets forth the dividends declared and paid per share during each of the four quarters for 1998 and 1997.

Common Stock Price Ranges and Dividends

1998	High	Low	Dividend Per Share[(a)]
1st Quarter	45	39 3/8	$ .300
2nd Quarter	46 3/16	42	.600
3rd Quarter	45 9/16	40 1/16	---
4th Quarter	49 1/4	41 5/8	.325
1997			
1st Quarter	32 7/8	30 1/8	$ .275
2nd Quarter	30 3/4	27 5/8	.550
3rd Quarter	34 7/8	29 13/16	---
4th Quarter	42 3/4	33 3/16	.300

(a) Dividends for the third quarter of 1998 and 1997 were declared in June.

ITEM 6. SELECTED CONSOLIDATED FINANCIAL DATA

(Dollars in Thousands, Except Per Share Amounts)	1998	1997	1996	1995	1994
OPERATING RESULTS					
Operating revenues					
Electric	$ 2,006,398	$ 1,878,553	$ 1,718,272	$ 1,614,952	$ 1,626,168
Real estate	124,188	116,473	99,488	54,846	59,253
Income from continuing operations	$ 242,892	$ 235,856	$ 211,059(a)	$ 199,608	$ 200,619(b)
Loss from discontinued operations – net of income tax (c)	—	—	(9,539)	—	—
Extraordinary charge for early retirement of debt – net of income tax (d)	—	—	(20,340)	(11,571)	—
Net income	$ 242,892	$ 235,856	$ 181,180	$ 188,037	$ 200,619
COMMON STOCK DATA					
Book value per share – year-end	$ 25.50	$ 23.90	$ 22.51	$ 21.49	$ 20.32
Earnings (loss) per average common share outstanding					
Continuing operations – basic	$ 2.87	$ 2.76	$ 2.41(a)	$ 2.28	$ 2.30(b)
Discontinued operations	—	—	(0.11)	—	—
Extraordinary charge	—	—	(0.23)	(0.13)	—
Net income – basic	$ 2.87	$ 2.76	$ 2.07	$ 2.15	$ 2.30
Continuing operations – diluted	$ 2.85	$ 2.74	$ 2.40(a)	$ 2.27	$ 2.29(b)
Net income – diluted	$ 2.85	$ 2.74	$ 2.06	$ 2.14	$ 2.29
Dividends declared per share	$ 1.225	$ 1.125	$ 1.025	$ 0.925	$ 0.825
Indicated annual dividend rate – year-end	$ 1.30	$ 1.20	$ 1.10	$ 1.00	$ 0.90
Average common shares outstanding – basic	84,774,218	85,502,909	87,441,515	87,419,300	87,410,967
Average common shares outstanding – diluted	85,345,946	86,022,709	88,021,920	87,884,226	87,671,451
TOTAL ASSETS	$ 6,824,546	$ 6,850,417	$ 6,989,289	$ 6,997,052	$ 6,909,752
LIABILITIES AND EQUITY					
Long-term debt less current maturities	$ 2,048,961	$ 2,244,248	$ 2,372,113	$ 2,510,709	$ 2,588,525
Other liabilities	2,516,993	2,407,572	2,428,180	2,336,695	2,276,249
	4,565,954	4,651,820	4,800,293	4,847,404	4,864,774
Minority interests					
Non-redeemable preferred stock of APS	85,840	142,051	165,673	193,561	193,561
Redeemable preferred stock of APS	9,401	29,110	53,000	75,000	75,000
Common stock equity	2,163,351	2,027,436	1,970,323	1,881,087	1,776,417
Total liabilities and equity	$ 6,824,546	$ 6,850,417	$ 6,989,289	$ 6,997,052	$ 6,909,752

(a) Includes an after-tax charge of $18.9 million ($0.22 per share) for a voluntary severance program and about $12 million ($0.13 per share) of income tax benefits related to capital loss carryforwards.

(b) Includes after-tax Palo Verde Unit 3 accretion income of $20.3 million ($0.23 per share) and a non-recurring income tax benefit of $26.8 million ($0.31 per share) related to a change in tax law.

(c) Charges associated with the settlement of a legal matter related to MeraBank, A Federal Savings Bank.

(d) Charges associated with the repayment or refinancing of the parent company's high-coupon debt.

(Dollars in Thousands, Except Per Share Amounts)	1998	1997	1996	1995	1994
ELECTRIC OPERATING REVENUES					
Residential	$ 766,378	$ 746,937	$ 721,877	$ 669,762	$ 675,153
Commercial	699,016	687,988	678,130	653,425	631,212
Industrial	172,296	164,696	162,324	156,501	166,457
Irrigation	7,288	8,706	9,448	9,596	10,538
Other	10,644	11,842	13,078	12,631	12,729
Total retail	1,655,622	1,620,169	1,584,857	1,501,915	1,496,089
Sales for resale	300,698	226,828	98,560	86,510	95,158
Transmission for others	11,058	10,295	10,240	9,390	9,506
Miscellaneous services	39,020	21,261	24,615	17,137	16,107
Electric operating revenues	2,006,398	1,878,553	1,718,272	1,614,952	1,616,860
Retail rate refund reversal	—	—	—	—	9,308
Net electric operating revenues	$ 2,006,398	$ 1,878,553	$ 1,718,272	$ 1,614,952	$ 1,626,168
ELECTRIC SALES (MWh)					
Residential	8,310,689	7,970,309	7,541,440	6,848,905	6,873,300
Commercial	8,697,397	8,524,882	8,233,762	7,768,289	7,456,049
Industrial	3,279,430	3,123,283	3,039,357	2,933,459	2,926,318
Irrigation	84,640	112,363	121,775	119,580	132,340
Other	90,927	86,090	84,362	78,478	76,827
Total retail	20,463,083	19,816,927	19,020,696	17,748,711	17,464,834
Sales for resale	10,317,391	9,233,573	3,367,234	2,720,704	2,764,223
Total electric sales	30,780,474	29,050,500	22,387,930	20,469,415	20,229,057
ELECTRIC CUSTOMERS - END OF YEAR					
Residential	709,111	680,478	654,602	625,352	603,989
Commercial	84,745	81,246	78,178	75,105	72,740
Industrial	3,159	3,192	3,055	2,913	2,976
Irrigation	710	764	841	837	897
Other	895	851	828	786	762
Total retail	798,620	766,531	737,504	704,993	681,364
Sales for resale	67	50	48	39	44
Total electric customers	798,687	766,581	737,552	705,032	681,408

See "Financial Review" on pages 23-30 for a discussion of certain information in the table above.

QUARTERLY STOCK PRICES AND DIVIDENDS

Stock Symbol: PNW

1998	*High*	*Low*	*Close*	*Dividends Per Share(a)*	1997	*High*	*Low*	*Close*	*Dividends Per Share(a)*
1st Quarter	45	39 3/8	44 7/16	$ 0.300	1st Quarter	32 7/8	30 1/8	30 1/8	$ 0.275
2nd Quarter	46 3/16	42	45	$ 0.600	2nd Quarter	30 3/4	27 5/8	30 1/16	$ 0.550
3rd Quarter	45 9/16	40 1/16	44 13/16	$ —	3rd Quarter	34 7/8	29 13/16	33 5/8	$ —
4th Quarter	49 1/4	41 5/8	42 3/8	$ 0.325	4th Quarter	42 3/4	33 3/16	42 3/8	$ 0.300

(a) Dividends for the 3rd quarter of 1998 and 1997 were declared in June.

ITEM 7. FINANCIAL REVIEW

In this section, we explain the results of operations, general financial condition, and outlook for Pinnacle West and our subsidiaries: APS, SunCor, and El Dorado, including:

- the changes in our earnings from 1997 to 1998 and from 1996 to 1997
- the factors impacting our business, including competition and electric industry restructuring
- the effects of regulatory agreements on our results and outlook
- our capital needs and resources – both for APS and our non-utility operations and
- Year 2000 technology issues.

Throughout this Financial Review, we refer to specific "Notes" in the Notes to Consolidated Financial Statements that begin on page 37. These Notes add further details to the discussion.

RESULTS OF OPERATIONS

1998 Compared with 1997

Our 1998 consolidated net income was $242.9 million compared with $235.9 million in 1997 – a 3.0% increase. Net income increased by $7.0 million primarily because of increased earnings at the subsidiaries and lower financing costs as we paid down debt and took advantage of lower interest rates.

APS' 1998 earnings increased $6.9 million – a 2.9% increase – over 1997 earnings primarily because of an increase in customers, expanded power marketing and trading activities, and lower financing costs. In the comparison, these positive factors more than offset the effects of milder weather, two fuel-related settlements recorded in 1997, and two retail price reductions. See Note 3 for additional information about the price reductions.

In 1998, electric operating revenues increased $128 million primarily because of:

- increased power marketing and trading revenues ($94 million)
- increases in the number of customers and the amount of electricity used by customers ($77 million) and
- miscellaneous factors ($8 million).

As mentioned above, these positive factors were partially offset by the effects of milder weather ($33 million) and reductions in retail prices ($18 million).

Power marketing and trading activities are predominantly short-term opportunity wholesale sales. The increase in power marketing revenues resulted from higher prices, increased activity in Western bulk power markets, and increased sales to large customers in California. The increase in power marketing and trading revenues was accompanied by related increases in purchased power expenses.

The two fuel-related settlements increased 1997 pretax earnings by about $21 million. The income statement reflects these settlements as reductions in fuel expense and as other income.

Operations and maintenance expense increased $15 million because of customer growth, initiatives related to competition, and expansion of our power marketing and trading function.

Depreciation and amortization expense increased $11 million because APS had more plant in service.

APS decreased its financing costs by $9 million primarily because of lower amounts of outstanding debt and preferred stock.

Our real estate subsidiary, SunCor Development, and our investment subsidiary, El Dorado, contributed a combined $12.0 million to consolidated net income in 1998 compared with $13.5 million in 1997. SunCor's contribution increased $2.2 million as a result of an increase in land sales. El Dorado's contribution decreased $3.7 million as a result of a decrease in investment sales.

SunCor's stand-alone net income was $44.7 million, of which $37.2 million represents income related to the recognition of a deferred tax asset. The deferred tax asset relates to net operating losses and book/tax basis differences. SunCor is expected to realize these benefits in subsequent periods pursuant to an intercompany tax allocation agreement. On a consolidated basis, Pinnacle West had already recognized the income tax benefits, therefore, there was no impact on consolidated net income in 1998.

1997 Compared with 1996

Our 1997 consolidated net income was $235.9 million compared with $181.2 million in 1996. The following is a summary:

(Thousands of Dollars)	1997	1996
Income from continuing operations	$ 235,856	$ 211,059
Loss from discontinued operations – net of income tax	—	(9,539)
Extraordinary charge for early retirement of debt – net of income tax	—	(20,340)
Net income	$ 235,856	$ 181,180

Our earnings from continuing operations increased from 1996 to 1997 by $24.8 million, or 11.7%, primarily because of increased earnings at the subsidiaries and lower financing costs as we paid down debt and took advantage of lower interest rates. The 1996 loss from discontinued operations related to remnants of MeraBank legal matters.

APS' 1997 earnings increased $12.3 million – a 5.4% increase – over 1996 earnings primarily because of:

- an increase in customers
- a $32 million pretax charge in 1996 for a voluntary severance program
- two fuel-related settlements in 1997 and
- lower financing costs.

These positive factors more than offset the effects of the 1996 regulatory agreement with the Arizona Corporation Commission (ACC), which during 1997 resulted in about $60 million of additional regulatory asset amortization and a $35 million revenue decrease caused by two retail price reductions. See Note 3 and "Results of Operations – Regulatory Agreements" below for additional information. In addition, APS recognized $12 million of income tax benefits in 1996 that were not repeated in 1997.

In 1997, electric operating revenues increased $160 million primarily because of:

- increased power marketing revenues ($128 million)
- an increase in the number of customers ($58 million) and
- weather effects ($7 million).

As mentioned above, these positive factors were partially offset by a $35 million revenue decrease caused by retail price reductions. The increase in power marketing revenues resulted from increased activity in Western bulk power markets. This did not significantly affect our earnings because the increase was substantially offset by higher purchased power expenses.

Two fuel-related settlements in 1997 increased pretax earnings by about $21 million. The income statement shows these settlements as reductions in fuel expense and as other income. About $16 million of the settlements related to years prior to 1997 and $5 million related to 1997. APS expects the total annual savings from the settlements for at least the next several years to be about $10 million before income taxes. APS does not have a fuel adjustment clause as part of its retail rate structure. As a result, APS shows changes in fuel and purchased power expenses in current earnings.

APS lowered its operations and maintenance expenses in 1997 by putting in place a voluntary severance program in late 1996, with related savings reflected in 1997. These savings were partially offset by increased expenses for marketing, information technology, and power plant maintenance.

APS decreased its financing costs by $12 million during 1997 by lowering the amounts of outstanding debt and preferred stock.

SunCor Development and El Dorado contributed a combined $13.5 million to consolidated net income in 1997 compared with $4.6 million in 1996. SunCor's contribution increased as a result of increased land and home sales. El Dorado's contribution increased as a result of an increase in investment sales.

Regulatory Agreements

Regulatory agreements with the ACC affect the results of APS' operations. The following discussion focuses on two agreements: a 1996 agreement to accelerate the amortization of APS' regulatory assets and a 1994 settlement to accelerate amortization of APS' deferred investment tax credits (ITCs).

Under the 1996 agreement with the ACC, APS is recovering substantially all of its present regulatory assets through accelerated amortization. The recovery of these assets is taking place over an eight-year period that will end June 30, 2004. For more details, see Note 3. This accelerated amortization increased annual amortization expense by approximately $120 million ($72 million after taxes).

Also, as part of the 1996 regulatory agreement, APS reduced its retail prices by 3.4% effective July 1, 1996. This reduces revenue by about $48.5 million annually ($29 million after taxes). APS also agreed to share future cost savings with its customers, which resulted in the following additional retail price reductions:

- $17.6 million annually ($10.5 million after income taxes), or 1.2%, effective July 1, 1997, and
- $17 million annually ($10 million after income taxes), or 1.1%, effective July 1, 1998.

APS expects to file with the ACC for another retail price decrease of approximately $10.8 million annually ($6.5 million after income taxes) to become effective July 1, 1999. The amount and timing of the price decrease are subject to ACC approval. This will be the last price decrease under the 1996 regulatory agreement.

We discuss above, in "Results of Operations," the factors that offset the earnings impact of the accelerated regulatory asset amortization and the price decreases.

As part of the 1994 rate settlement, APS accelerated amortization of substantially all deferred investment tax credits (ITCs) over a five-year period that ends on December 31, 1999. The amortization of ITCs decreases annual consolidated income tax expense by approximately $24 million. Beginning in 2000, no further benefits will be reflected in income tax expense. See Note 4.

CAPITAL NEEDS AND RESOURCES

Pinnacle West (Parent Company)

We have reduced our debt over the last three years as follows: 1998, $113 million; 1997, $45 million; and 1996, $60 million. We have a $250 million line of credit, under which we had $42 million of borrowings outstanding at December 31, 1998. We do not have any debt repayment obligations until 2001.

During the past three years, our primary cash needs were for:

- dividends for our shareholders
- interest payments and
- optional and mandatory repayment of principal on our long-term debt.

In addition, as part of the 1996 agreement with the ACC, we invested $50 million in APS in 1998, 1997, and 1996 and will invest the same amount in 1999. This will be the last payment under the 1996 regulatory agreement. See Note 3. During 1997, we repurchased $80 million of common stock, reducing our shares outstanding at year-end by 2.7 million shares.

Our primary source of cash is from APS dividends. During 1998, APS paid $170 million in dividends. In 1998, SunCor provided cash of $30 million and El Dorado provided cash of $12 million. We expect both SunCor and El Dorado to contribute to our cash flow in 1999. Tax allocation payments from our subsidiaries, in excess of payments we made to taxing authorities, were an additional source of cash in 1998, 1997, and 1996. This is not expected to be a source of cash for Pinnacle West in the future.

APS

APS' capital requirements consist primarily of capital expenditures and optional and mandatory redemptions of long-term debt and preferred stock. APS pays for its capital requirements with:

- cash from operations
- annual cash payments from Pinnacle West of $50 million annually from 1996 through 1999 (see Note 3) and
- to the extent necessary, external financing.

During the period from 1996 through 1998, APS paid for all of its capital expenditures with cash from operations. APS expects to do so in 1999 through 2001, as well.

APS' capital expenditures in 1998 were $327 million. APS' projected capital expenditures for the next three years are: 1999, $328 million; 2000, $317 million; and 2001, $300 million. These amounts include about $30-$35 million each year for nuclear fuel. In general, most of the projected capital expenditures are for:

- expanding transmission and distribution capabilities to meet customer growth
- upgrading existing utility property and
- environmental purposes.

In addition, APS is considering expanding certain of its operations over the next several years, which may result in additional expenditures. APS currently believes that there will be opportunities to expand its investment in generating assets in the next five years. It is expected that these generating assets would be organized in a newly created non-regulated affiliate under the parent.

During 1998, APS redeemed about $145 million of long-term debt and $76 million of preferred stock, including premiums, with cash from operations and long- and short-term debt. APS' long-term debt and preferred stock redemption requirements and payment obligations on a capitalized lease for the next three years are: 1999, $260 million; 2000, $115 million; and 2001, $2 million. On March 1, 1999, APS redeemed all $95 million of its outstanding preferred stock. Based on market conditions and optional call provisions, APS may make optional redemptions of long-term debt from time to time.

As of December 31, 1998, APS had credit commitments from various banks totalling about $400 million, which were available either to support the issuance of commercial paper or to be used as bank borrowings. At the end of 1998, APS had about $179 million of commercial paper and $125 million of long-term bank borrowings outstanding.

In 1998, APS issued $100 million of unsecured long-term debt and in February 1999, APS issued $125 million of unsecured long-term debt.

Although provisions in APS' first mortgage bond indenture, articles of incorporation, and ACC financing orders establish maximum amounts of additional first mortgage bonds that APS may issue, APS does not expect any of these provisions to limit its ability to meet its capital requirements.

Non-Utility Subsidiaries

During the past three years, SunCor and El Dorado each funded all of their cash requirements with cash from operations and their own financing.

SunCor's capital needs consist primarily of capital expenditures for land development and home construction. On the basis of projects now under development, SunCor expects capital needs over the next three years to be: 1999, $58 million; 2000, $53 million; and 2001, $43 million. Capital resources to meet these requirements include funds from operations and SunCor's own external financings.

As of December 31, 1998, SunCor had a $55 million line of credit, under which $38 million of borrowings were outstanding. SunCor's debt repayment requirements for the next three years are: 1999, $4 million; 2000, $26 million; and 2001, $51 million.

COMPETITION AND INDUSTRY RESTRUCTURING

The electric industry is undergoing significant change. It is moving to a competitive, market-based structure from a highly-regulated, cost-based environment in which companies have been entitled to recover their costs and to earn fair returns on their invested capital in exchange for commitments to serve all customers within designated service territories. In December 1996, the ACC adopted rules that provide a framework for the introduction of retail electric competition in Arizona and adopted amendments to the rules in August 1998.
On January 11, 1999, the ACC issued an order which stayed the amended rules and granted waivers from compliance with the rules to all affected utilities (including APS) pending further ACC decisions. On February 5, 1999, ACC hearing officers issued recommendations for changes to the amended rules. These recommended changes were further amended by an ACC Procedural Order dated March 12, 1999. See Note 3 for additional information about these rules and other competitive developments, including an agreement with Salt River Project Agricultural Improvement and Power District (Salt River Project). We cannot currently

predict when or if the amended rules will be further modified, when the stay of the amended rules will be lifted, or when retail electric competition will be introduced in Arizona with respect to affected utilities.

The rules as recommended indicate that the ACC will allow affected utilities the opportunity to fully recover unmitigated stranded costs, but do not set forth the mechanisms for determining and recovering such costs. On June 22, 1998, the ACC issued an order on stranded cost determination and recovery and on February 5, 1999, an ACC hearing officer issued recommended changes to that order. These recommended changes were further amended by an ACC Procedural Order dated March 12, 1999. See Note 3 for additional information on proposed modifications to the stranded cost order.

An Arizona joint legislative committee studied electric utility restructuring issues in 1996 and 1997. In May 1998, a law was enacted to facilitate implementation of retail electric competition in the state. Additionally, legislation related to electric competition has been proposed in the United States Congress. See Note 3 for a discussion of legislative developments.

We believe that further ACC decisions, legislation at the Arizona and federal levels, and perhaps amendments to the Arizona Constitution will ultimately be required before significant implementation of retail electric competition can lawfully occur in Arizona. Until it has been determined how competition will be implemented in Arizona, including the manner in which stranded costs will be addressed, we cannot accurately predict the impact of full retail competition on our financial position, cash flows, or results of operations. As competition in the electric industry continues to evolve, we will continue to evaluate strategies and alternatives that will position us to compete effectively in a restructured industry.

APS prepares its financial statements in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in its financial statements. APS' existing regulatory orders and the current regulatory environment support its accounting practices related to regulatory assets, which amounted to about $900 million at December 31, 1998. Under the 1996 regulatory agreement, the ACC accelerated the amortization of substantially all of APS' regulatory assets to an eight-year period that will end June 30, 2004. If APS ceases to be cost-based regulated, it would no longer be able to apply the provisions of SFAS No. 71 to part or all of its operations, which could have a material impact on our financial statements. See Note 1 for additional information on regulatory accounting.

YEAR 2000 READINESS DISCLOSURE

Overview

As the year 2000 approaches, many companies face problems because many computer systems and equipment will not properly recognize calendar dates beginning with the year 2000. We are addressing the Year 2000 issue as described below. APS initiated a comprehensive company-wide Year 2000 program during 1997 to review and resolve all Year 2000 issues in mission critical systems (systems and equipment that are key to business function, health, and safety) in a timely manner to ensure the reliability of electric service to our customers. This included a company-wide awareness program of the Year 2000 issue.

The following chart shows Year 2000 readiness of our mission critical systems as of January 31, 1999:

	Inventory	*Assessment*	*Remediation & Testing*
APS	100%	100%	70% (1)
Pinnacle West and other subsidiaries (excluding APS)	100%	100%	80% (2)

(1) Estimated to be at 100% by June 30, 1999, except one Palo Verde unit as discussed below.
(2) Estimated to be at 100% by June 30, 1999.

Discussion

APS has been actively implementing and replacing systems and technology since 1995 for general business reasons unrelated to the Year 2000, and these actions have resulted in substantially all of its major information technology (IT) systems becoming Year 2000 ready. The major IT systems that were, and are being, implemented and replaced include the following:

- Work Management
- Materials Management
- Energy Management

- Payroll
- Financial
- Human Resources
- Trouble Call Management
- Computer and Communications Network Upgrades
- Geographic Information Management
- Customer Information System and
- Palo Verde Site Work Management.

We and our subsidiaries have made, and will continue to make, certain modifications to computer hardware and software systems and applications, including IT and non-IT systems, in an effort to ensure they are capable of handling changing business needs, including dates in the year 2000 and thereafter. In addition, other APS IT systems and non-IT systems, including embedded technology and real-time process control systems, are being analyzed for potential modifications.

Pinnacle West, APS, SunCor, and El Dorado have inventoried and assessed essentially all mission critical IT and non-IT systems and equipment. APS is 70% complete and Pinnacle West and its other subsidiaries are 80% complete with the remediation and testing of these systems. Remediation and testing is expected to be completed by June 30, 1999 for all mission critical systems, except for those items that can only be completed during maintenance outages at Palo Verde, which will be completed for the last unit, which is substantially identical to the other two units, during the last half of 1999. APS has an internal audit/quality review team that is periodically reviewing the individual Year 2000 projects and their Year 2000 readiness.

APS currently estimates that it will spend approximately $5 million relating to Year 2000 issues, about $3 million of which has been spent to date. This includes an estimated allocation of payroll costs for APS employees working on Year 2000 issues, and costs for consultants, hardware, and software. We do not separately track other internal costs. This does not include any expenditures incurred since 1995 to implement and replace systems for reasons unrelated to the Year 2000, as discussed above. Our cost to address the Year 2000 issue is charged to operating expenses as incurred and has not had, and is not expected to have, a material adverse effect on our financial position, cash flows, or results of operations. We expect to fund this cost with available cash balances and cash provided by operations.

Pinnacle West and its subsidiaries are communicating with their significant suppliers, business partners, other utilities, and large customers to determine the extent to which they may be affected by these third parties' plans to remediate their own Year 2000 issues in a timely manner. These companies have been interfacing with suppliers of systems, services, and materials in order to assess whether their schedules for analysis and remediation of Year 2000 issues are timely and to assess their ability to continue to supply required services and materials.

APS is also working with the North American Electric Reliability Council (NERC) through the Western Systems Coordinating Council (WSCC) to develop operational plans for stable grid operation that will be utilized by APS and other utilities in the western United States. These plans are expected to be completed by June 30, 1999. However, APS cannot currently predict the effect on APS if the systems of these other companies are not Year 2000 ready.

We currently expect that our most reasonably likely worst case Year 2000 scenario would be intermittent loss of power to APS customers, similar to an outage during a severe weather disturbance. In this situation, APS would restore power as soon as possible by, among other things, re-routing power flows. We do not currently expect that this scenario would have a material adverse effect on our financial position, cash flows, or results of operations.

We are working to develop our own contingency plans to handle Year 2000 issues, including the most reasonably likely worst case scenario discussed above, and we expect these plans to be completed by June 30, 1999. As discussed above, APS has also been working with NERC and WSCC to develop contingency plans related to grid operation.

ACCOUNTING MATTERS

We describe two new accounting rules in Note 2. First, the new rule on energy trading and risk management is effective in 1999. We do not expect it to have a material impact on our financial results. Secondly, the new standard on derivatives is effective for us in 2000. We are currently evaluating what impact it will have on our financial statements. Also, see Note 13 for a description of a proposed standard on accounting for certain liabilities related to closure or removal of long-lived assets.

RISK MANAGEMENT

Our operations include managing market risks related to changes in interest rates, commodity prices, and investments held by the nuclear decommissioning trust fund.

Interest Rate and Equity Risk

Our major financial market risk exposure is changing interest rates. Changing interest rates will affect interest paid on variable rate debt and interest earned by the nuclear decommissioning trust fund. Our policy is to manage interest rates through the use of a combination of fixed and floating rate debt. The nuclear decommissioning fund also has risks associated with changing market values of equity investments. Nuclear decommissioning costs are recovered in rates.

The tables below present contractual balances of our long-term and short-term debt at the expected maturity dates as well as the fair value of those instruments on December 31, 1998 and December 31, 1997. The weighted average interest rates for the various debt presented are actual as of December 31, 1998 and December 31, 1997.

Expected Maturity/Principal Repayment - December 31, 1998

(Thousands of Dollars)	*Short-Term* Interest Rates	*Short-Term* Amount	*Variable Long-Term* Interest Rates	*Variable Long-Term* Amount	*Fixed Long-Term* Interest Rates	*Fixed Long-Term* Amount
1999	6.21%	$ 178,830	7.30%	$ 3,268	7.24%	$ 164,777
2000	—	—	7.32%	25,756	5.79%	114,711
2001	—	—	6.57%	93,472	6.70%	27,488
2002	—	—	10.25%	119	8.13%	125,000
2003	—	—	5.69%	125,131	6.87%	25,000
Years thereafter	—	—	3.43%	459,803	7.75%	1,058,963
Total		$ 178,830		$ 707,549		$ 1,515,939
Fair Value		$ 178,830		$ 707,549		$ 1,577,365

Expected Maturity/Principal Repayment - December 31, 1997

(Thousands of Dollars)	*Short-Term* Interest Rates	*Short-Term* Amount	*Variable Long-Term* Interest Rates	*Variable Long-Term* Amount	*Fixed Long-Term* Interest Rates	*Fixed Long-Term* Amount
1998	6.27%	$ 130,750	7.95%	$ 3,064	7.59%	$ 105,631
1999	—	—	7.98%	28,598	7.25%	164,378
2000	—	—	7.99%	54,133	5.83%	104,711
2001	—	—	6.25%	155,079	6.70%	27,488
2002	—	—	6.25%	150,088	8.13%	125,000
Years thereafter	—	—	3.67%	443,178	7.89%	998,628
Total		$ 130,750		$ 834,140		$ 1,525,836
Fair Value		$ 130,750		$ 834,140		$ 1,556,697

Commodity Price Risk

APS utilizes a variety of derivative instruments including exchange-traded futures, options, and swaps as part of its overall risk management strategies and for trading purposes. In order to reduce the risk of adverse price fluctuations in the electricity and natural gas markets, APS enters into futures and/or option transactions to hedge certain natural gas held in storage as well as certain expected purchases and sales of natural gas and electricity. The changes in market value of such contracts have a high correlation to the price changes in the hedged commodity. Gains and losses related to derivatives that qualify as hedges of expected transactions are recognized in income when the underlying hedged physical transaction closes (deferral method). Gains and losses on derivatives utilized for trading are recognized in income on a current basis (the mark to market method).

APS has prepared a sensitivity analysis to estimate its exposure to the market risk of its derivative position for natural gas and electricity. With respect to these derivatives, a potential adverse price movement of 10% in the market price of natural gas and electricity from the December 31, 1998 levels would decrease the fair value of these instruments by approximately $1 million. This analysis does not include the favorable impact that the same hypothetical price movement would have on expected physical purchases and sales of natural gas and electricity.

APS is exposed to credit losses in the event of non-performance or non-payment by counterparties. APS uses a credit management process to assess and monitor the financial viability of its counterparties. APS does not expect counterparty defaults to materially impact its financial condition, results of operations, or net cash flows.

FORWARD-LOOKING STATEMENTS

The above discussion contains forward-looking statements that involve risks and uncertainties. Words such as "estimates," "expects," "anticipates," "plans," "believes," "projects," and similar expressions identify forward-looking statements. These risks and uncertainties include, but are not limited to, the ongoing restructuring of the electric industry; the outcome of the regulatory proceedings relating to the restructuring; regulatory, tax, and environmental legislation; the ability of APS to successfully compete outside its traditional regulated markets; regional economic conditions, which could affect customer growth; the cost of debt and equity capital; weather variations affecting customer usage; technological developments in the electric industry; Year 2000 issues; and the strength of the real estate market.

These factors and the other matters discussed above may cause future results to differ materially from historical results, or from results or outcomes we currently expect or seek.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See "Financial Review" in Item 7 for a discussion of quantitative and qualitative disclosures about market risk.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULE

See Note 14 of Notes to Financial Statements for the selected quarterly financial data required to be presented in this Item.

REPORT OF MANAGEMENT AND INDEPENDENT AUDITORS' REPORT

REPORT OF MANAGEMENT

The primary responsibility for the integrity of the Company's financial information rests with management, which has prepared the accompanying financial statements and related information. Such information was prepared in accordance with generally accepted accounting principles appropriate in the circumstances, and based on management's best estimates and judgments. Materiality was given due consideration. These financial statements have been audited by independent auditors and their report is included.

Management maintains and relies upon systems of internal accounting controls. A limiting factor in all systems of internal accounting control is that the cost of the system should not exceed the benefits to be derived. Management believes that the Company's system provides the appropriate balance between such costs and benefits.

Periodically the internal accounting control system is reviewed by both the Company's internal auditors and its independent auditors to test for compliance. Reports issued by the internal auditors are released to management, and such reports or summaries thereof are transmitted to the Audit Committee of the Board of Directors and the independent auditors on a timely basis.

The Audit Committee, composed solely of outside directors, meets periodically with the internal auditors and independent auditors (as well as management) to review the work of each. The internal auditors and independent auditors have free access to the Audit Committee, without management present, to discuss the results of their audit work.

Management believes that the Company's systems, policies and procedures provide reasonable assurance that operations are conducted in conformity with the law and with management's commitment to a high standard of business conduct.

William J. Post
Chief Executive Officer

George A. Schreiber, Jr.
President

INDEPENDENT AUDITORS' REPORT

We have audited the accompanying consolidated balance sheets of Pinnacle West Capital Corporation and its subsidiaries as of December 31, 1998 and 1997 and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1998. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Pinnacle West Capital Corporation and its subsidiaries at December 31, 1998 and 1997 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1998 in conformity with generally accepted accounting principles.

Deloitte & Touche LLP
Phoenix, Arizona
March 4, 1999

CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31, (Dollars in Thousands, Except Per Share Amounts)	1998	1997	1996
OPERATING REVENUES			
Electric	$ 2,006,398	$ 1,878,553	$ 1,718,272
Real estate	124,188	116,473	99,488
Total	2,130,586	1,995,026	1,817,760
OPERATING EXPENSES			
Fuel and purchased power	537,501	436,627	325,523
Utility operations and maintenance	414,041	399,434	430,714
Real estate operations	115,331	111,628	96,080
Depreciation and amortization (Note 1)	379,679	368,285	299,507
Taxes other than income taxes	116,906	121,546	122,077
Total	1,563,458	1,437,520	1,273,901
OPERATING INCOME	567,128	557,506	543,859
OTHER INCOME (EXPENSE)			
Allowance for equity funds used during construction	—	—	5,209
Preferred stock dividend requirements of APS	(9,703)	(12,803)	(17,092)
Net other income and expense	609	4,569	(6,748)
Total	(9,094)	(8,234)	(18,631)
INCOME BEFORE INTEREST AND INCOME TAXES	558,034	549,272	525,228
INTEREST EXPENSE			
Interest charges	169,145	182,838	198,569
Capitalized interest	(18,596)	(19,703)	(12,856)
Total	150,549	163,135	185,713
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	407,485	386,137	339,515
INCOME TAXES (NOTE 4)	164,593	150,281	128,456
INCOME FROM CONTINUING OPERATIONS	242,892	235,856	211,059
Loss from discontinued operations – net of income tax of $6,461	—	—	(9,539)
Extraordinary charge for early retirement of debt – net of income tax of $13,777	—	—	(20,340)
NET INCOME	$ 242,892	$ 235,856	$ 181,180
AVERAGE COMMON SHARES OUTSTANDING – BASIC	84,774,218	85,502,909	87,441,515
AVERAGE COMMON SHARES OUTSTANDING – DILUTED	85,345,946	86,022,709	88,021,920
EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING			
Continuing operations – basic	$ 2.87	$ 2.76	$ 2.41
Net income – basic	2.87	2.76	2.07
Continuing operations – diluted	2.85	2.74	2.40
Net income – diluted	2.85	2.74	2.06
DIVIDENDS DECLARED PER SHARE	$ 1.225	$ 1.125	$ 1.025

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

December 31, (Thousands of Dollars)	1998	1997
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 20,538	$ 27,484
Customer and other receivables – net	233,876	183,507
Accrued utility revenues	67,740	58,559
Materials and supplies (at average cost)	69,074	70,634
Fossil fuel (at average cost)	13,978	9,621
Deferred income taxes (Note 4)	3,999	57,887
Other current assets	47,594	41,408
Total current assets	456,799	449,100
INVESTMENTS AND OTHER ASSETS		
Real estate investments – net (Note 6)	331,021	365,921
Other assets (Note 13)	236,562	215,027
Total investments and other assets	567,583	580,948
UTILITY PLANT (NOTES 6, 10 AND 11)		
Electric plant in service and held for future use	7,265,604	7,009,059
Less accumulated depreciation and amortization	2,814,762	2,620,607
Total	4,450,842	4,388,452
Construction work in progress	228,643	237,492
Nuclear fuel, net of amortization of $68,569 and $66,081	51,078	51,624
Net utility plant	4,730,563	4,677,568
DEFERRED DEBITS		
Regulatory asset for income taxes (Note 4)	400,795	458,369
Rate synchronization cost deferral	303,660	358,871
Other deferred debits	365,146	325,561
Total deferred debits	1,069,601	1,142,801
TOTAL ASSETS	$ 6,824,546	$ 6,850,417

See Notes to Consolidated Financial Statements.

December 31, (Thousands of Dollars)	1998	1997
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 155,800	$ 117,429
Accrued taxes	62,520	84,610
Accrued interest	31,866	32,974
Short-term borrowings (Note 5)	178,830	130,750
Current maturities of long-term debt (Note 6)	168,045	108,695
Customer deposits	28,510	30,672
Other current liabilities	14,632	18,534
Total current liabilities	640,203	523,664
LONG-TERM DEBT LESS CURRENT MATURITIES (NOTE 6)	2,048,961	2,244,248
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	1,343,536	1,363,461
Deferred investment tax credit (Note 4)	27,345	50,861
Unamortized gain – sale of utility plant	77,787	82,363
Other	428,122	387,223
Total deferred credits and other	1,876,790	1,883,908
COMMITMENTS AND CONTINGENCIES (NOTES 3 AND 12)		
MINORITY INTERESTS (NOTE 7)		
Non-redeemable preferred stock of APS	85,840	142,051
Redeemable preferred stock of APS	9,401	29,110
COMMON STOCK EQUITY (NOTE 8)		
Common stock, no par value; authorized 150,000,000 shares; Issued and outstanding 84,824,947 at end of 1998 and 1997	1,550,643	1,553,771
Retained earnings	612,708	473,665
Total common stock equity	2,163,351	2,027,436
TOTAL LIABILITIES AND EQUITY	$ 6,824,546	$ 6,850,417

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31, (Thousands of Dollars)	1998	1997	1996
CASH FLOWS FROM OPERATING ACTIVITIES			
Income from continuing operations	$ 242,892	$ 235,856	$ 211,059
Items not requiring cash			
Depreciation and amortization	379,679	368,285	299,507
Nuclear fuel amortization	32,856	32,702	33,566
Deferred income taxes – net	41,262	24,809	13,392
Allowance for equity funds used during construction	—	—	(5,209)
Deferred investment tax credit	(23,516)	(23,518)	(23,518)
Other – net	1,190	(3,854)	1,370
Changes in current assets and liabilities			
Customer and other receivables – net	(50,369)	(14,270)	(38,106)
Accrued utility revenues	(9,181)	(3,089)	(1,951)
Materials, supplies and fossil fuel	(2,797)	7,793	11,945
Other current assets	(6,186)	(109)	(8,949)
Accounts payable	34,386	(54,882)	65,586
Accrued taxes	(22,090)	2,197	(7,088)
Accrued interest	(1,108)	(6,678)	(9,306)
Other current liabilities	(5,235)	(23,087)	1,515
Decrease in land held	33,405	33,010	19,894
Other - net	(39,350)	48,254	2,576
Net Cash Flow Provided By Operating Activities	605,838	623,419	566,283
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(319,142)	(307,876)	(258,598)
Capitalized interest	(18,596)	(19,703)	(12,856)
Other – net	(2,144)	(3,124)	(6,345)
Net Cash Flow Used For Investing Activities	(339,882)	(330,703)	(277,799)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	148,229	146,013	557,067
Short-term borrowings – net	48,080	113,850	(160,900)
Dividends paid on common stock	(103,849)	(96,160)	(89,614)
Repurchase and retirement of common stock	—	(79,997)	—
Repayment of long-term debt	(286,314)	(325,526)	(575,332)
Redemption of preferred stock	(75,517)	(47,201)	(50,360)
Extraordinary charge for early retirement of debt	—	—	(20,340)
Other – net	(3,531)	(2,897)	(1,858)
Net Cash Flow Used For Financing Activities	(272,902)	(291,918)	(341,337)
NET CASH FLOW	(6,946)	798	(52,853)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	27,484	26,686	79,539
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 20,538	$ 27,484	$ 26,686

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year Ended December 31, (Thousands of Dollars)	1998	1997	1996
Retained Earnings at Beginning of Year	$ 473,665	$ 333,969	$ 242,403
Net Income	242,892	235,856	181,180
Common Stock Dividends	(103,849)	(96,160)	(89,614)
Retained Earnings at End of Year	$ 612,708	$ 473,665	$ 333,969

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Consolidation and Nature of Operations

The consolidated financial statements include the accounts of Pinnacle West and our subsidiaries: APS, SunCor, and El Dorado.

APS, our major subsidiary and Arizona's largest electric utility, with 799,000 customers, provides wholesale or retail electric service to the entire state with the exception of Tucson and about one-half of the Phoenix area. SunCor is a developer of residential, commercial, and industrial projects on some 12,400 acres in Arizona, New Mexico, and Utah. El Dorado is a venture capital firm with a diversified portfolio.

Accounting Records

Our accounting records are maintained in accordance with generally accepted accounting principles (GAAP). The preparation of financial statements in accordance with GAAP requires the use of estimates by management. Actual results could differ from those estimates.

Regulatory Accounting

APS is regulated by the Arizona Corporation Commission (ACC) and the Federal Energy Regulatory Commission (FERC). The accompanying financial statements reflect the rate-making policies of these commissions. APS prepares its financial statements in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in its financial statements.

APS' major regulatory assets are deferred income taxes (see Note 4) and rate synchronization cost deferrals (see "Rate Synchronization Cost Deferrals" in this Note). These items, combined with miscellaneous regulatory assets and liabilities, amounted to approximately $900 million at December 31, 1998 and $1.0 billion at December 31, 1997. Most of these items are included in "Deferred Debits" on the Balance Sheets. Under the 1996 regulatory agreement (see Note 3), the ACC accelerated the amortization of substantially all of APS' regulatory assets to an eight-year period that will end June 30, 2004. APS records the accelerated portion of the regulatory asset amortization, approximately $120 million pretax in 1998 and 1997 and $60 million pretax in 1996, in depreciation and amortization expense on the Statements of Income.

During 1997, the Emerging Issues Task Force (EITF) of the Financial Accounting Standards Board (FASB) issued EITF 97-4. EITF 97-4 requires that SFAS No. 71 be discontinued no later than when legislation is passed or a rate order is issued that contains sufficient detail to determine its effect on the portion of the business being deregulated, which could result in write-downs or write-offs of physical and/or regulatory assets. Additionally, the EITF determined that regulatory assets should not be written off if they are to be recovered from a portion of the entity which continues to apply SFAS No. 71.

Although rules have been proposed for transitioning generation services to competition, there are many unresolved issues. APS continues to apply SFAS No. 71 to its generation operations. If rate recovery of regulatory assets is no longer probable, whether due to competition or regulatory action, APS would be required to write off the remaining balance as an extraordinary charge to expense.

Utility Plant and Depreciation

Utility plant is the term APS uses to describe the business property and equipment that supports electric service. APS reports utility plant at its original cost, which includes:

- material and labor
- contractor costs
- construction overhead costs (where applicable) and
- capitalized interest or an allowance for funds used during construction.

APS charges retired utility plant, plus removal costs less salvage realized, to accumulated depreciation. See Note 13 for information on a proposed accounting standard that impacts accounting for removal costs.

APS records depreciation on utility property on a straight-line basis. For the years 1996 through 1998 the rates, as prescribed by our regulators, ranged from a low of 1.51% to a high of 20%. The weighted-average rate for 1998 was 3.32%. APS depreciates non-utility property and equipment over the estimated useful lives of the related assets, ranging from 3 to 50 years.

Capitalized Interest

In 1997, APS began capitalizing interest in accordance with SFAS No. 34, "Capitalization of Interest Cost." Capitalized interest represents the cost of debt funds used to finance construction of utility plant. Plant construction costs, including capitalized interest, are recovered in authorized rates through depreciation when completed projects are placed into commercial operation. Capitalized interest does not represent current cash earnings. The rate used to calculate capitalized interest for 1998 was 6.88% and for 1997 was 7.25%.

Prior to 1997, APS accrued an allowance for funds used during construction (AFUDC). AFUDC represented the cost of debt and equity funds used to finance construction of utility plant. AFUDC did not represent current cash earnings. AFUDC has been calculated using a composite rate of 7.75% for 1996.

Revenues

APS records electric operating revenues on the accrual basis, which includes estimated amounts for service rendered but unbilled at the end of each accounting period.

Rate Synchronization Cost Deferrals

As authorized by the ACC, operating costs (excluding fuel) and financing costs of Palo Verde Units 2 and 3 were deferred from the commercial operation dates (September 1986 for Unit 2 and January 1988 for Unit 3) until the date the units were included in a rate order (April 1988 for Unit 2 and December 1991 for Unit 3). Beginning July 1, 1996, the deferrals are being amortized over an eight-year period in accordance with the 1996 regulatory agreement (see Note 3). Prior to July 1, 1996, the deferrals were amortized over thirty-five year periods. Amortization of the deferrals is included in depreciation and amortization expense on the Statements of Income.

Nuclear Fuel

APS charges nuclear fuel to fuel expense by using the unit-of-production method. The unit-of-production method is an amortization method that is based on actual physical usage. APS divides the cost of the fuel by the estimated number of thermal units that APS expects to produce with that fuel. APS then multiplies that rate by the number of thermal units that it produces within the current period. This provides APS with current period nuclear fuel expense.

APS also charges nuclear fuel expense for the permanent disposal of spent nuclear fuel. The United States Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel, and it charges APS $0.001 per kWh of nuclear generation. See Note 12 for information about spent nuclear fuel disposal. In addition, Note 13 has information on nuclear decommissioning costs.

Income Taxes

We file our federal income tax return on a consolidated basis and we file our state income tax returns on a consolidated or unitary basis. In accordance with our intercompany tax sharing agreement, federal and state income taxes are allocated to each subsidiary as though each subsidiary filed a separate income tax return. Any difference between the aforementioned allocations and the consolidated (and unitary) income tax liability is attributed to the parent company.

Reacquired Debt Costs

When APS incurs gains or losses on debt that it retires prior to maturity, APS amortizes those gains or losses over the remaining original life of the debt. In accordance with the 1996 regulatory agreement (see Note 3), the ACC accelerated APS' amortization of the regulatory asset for reacquired debt costs to an eight-year period that will end June 30, 2004. The accelerated portion of the regulatory asset amortization is included in depreciation and amortization expense in the Statements of Income.

Statements of Cash Flows

We consider temporary cash investments and marketable securities to be cash equivalents for purposes of reporting cash flows. During 1998, 1997, and 1996 we paid interest, net of amounts capitalized, income taxes, and dividends on preferred stock of APS.

Interest paid, net of amounts capitalized, was:

- $143.9 million in 1998
- $163.0 million in 1997 and
- $185.9 million in 1996.

Income taxes paid were:

- $164.9 million in 1998
- $146.2 million in 1997 and
- $121.0 million in 1996.

Dividends paid on preferred stock of APS were:

- $10.3 million in 1998
- $13.3 million in 1997 and
- $17.4 million in 1996.

Segments

APS is Pinnacle West's only reportable segment. Unless otherwise identified, APS represents substantially all of the consolidated information being reported.

Reclassifications

We have reclassified certain prior year amounts for comparison purposes with 1998.

2. ACCOUNTING MATTERS

In 1998 we adopted SFAS No. 130, "Reporting Comprehensive Income." This standard changes the reporting of certain items previously reported in the common stock equity section of the balance sheet. The effects of adopting SFAS No. 130 were not material to our financial statements.

In November 1998, the Financial Accounting Standards Board's Emerging Issues Task Force issued EITF 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," which is effective for us in 1999. EITF 98-10 requires energy trading contracts to be measured at fair value as of the balance sheet date with the gains and losses included in earnings and separately disclosed in the financial statements or footnotes. We have evaluated the impact of this rule and believe the effects are not material to our financial statements.

In June 1998, the Financial Accounting Standards Board issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," which is effective for us in 2000. SFAS No. 133 requires that entities recognize all derivatives as either assets or liabilities on the balance sheet and measure those instruments at fair value. The standard also provides specific guidance for accounting for derivatives designated as hedging instruments. We are currently evaluating what impact this standard will have on our financial statements.

3. REGULATORY MATTERS

Electric Industry Restructuring

STATE

In December 1996, the ACC adopted rules that provide a framework for the introduction of retail electric competition in Arizona. The rules, as amended, became effective on August 10, 1998, and on December 10, 1998, the ACC adopted the amended rules without any modifications that would have a significant impact on us. We believe that certain provisions of the 1996 ACC rules and the amended rules are deficient and APS has filed lawsuits to protect its legal rights regarding the 1996 rules and the amended rules. These lawsuits are pending but two related cases filed by other utilities have been partially decided in a manner adverse to those utilities' positions.

On January 11, 1999, the ACC issued an order which stayed the amended rules, granted reconsideration of the decision to make the rules permanent, and directed the hearing division of the ACC to establish a procedural order for further action on these rules. The order also granted waivers from compliance with the rules for APS, and all affected utilities.

On February 5, 1999, the ACC Hearing Division issued recommendations for changes to the amended rules. The recommended changes to the amended rules were further modified by a Procedural Order of the ACC Hearing Division dated March 12, 1999. The recommended rules include the following major provisions:

- They would apply to virtually all Arizona electric utilities regulated by the ACC, including APS.
- Each utility must make at least 20% of its 1995 retail peak demand available for competitive generation supply.
- The rules become effective when the ACC makes a final decision on each utility's stranded costs and unbundled rates (Final Decision Date) or January 1, 2001, whichever comes first.
- Subject to the 20% requirement, all utility customers with single premise loads of one megawatt or greater will be eligible for competitive electric services on the Final Decision Date. Customers with single premise loads of 40 kilowatts or greater may aggregate loads to meet this one megawatt requirement.
- When effective, residential customers will be phased in at 1-1/4% per quarter calculated beginning on January 1, 1999, subject to the 20% requirement above.
- Electric service providers that get Certificates of Convenience and Necessity (CC&Ns) from the ACC can supply only competitive services, including electric generation, but not electric transmission and distribution.
- Affected utilities must file ACC tariffs with separate pricing for electric services provided for noncompetitive services.

- ACC shall allow a reasonable opportunity for recovery of unmitigated stranded costs (see "Stranded Costs" below).
- Absent an ACC waiver, prior to January 1, 2001, each affected utility must transfer all competitive generation assets and services either to an unaffiliated party or to a separate corporate affiliate.
- Affiliate transaction rules prohibit a utility and its competitive electric affiliates from sharing certain assets, employees, and information.

If approved by the ACC, the rules would be subject to the formal rulemaking process under Arizona statute. In compliance with statutory procedural requirements, ACC oral proceedings on the matter would be scheduled no sooner than 30 days after the proposed rules are published by the Secretary of State.

We cannot currently predict when or if the amended rules will be further modified, when the stay of the amended rules will be lifted, or when retail electric competition will be introduced in Arizona.

Stranded Costs

On June 22, 1998, the ACC issued an order on stranded cost determination and recovery. APS believes that certain provisions of the stranded cost order are deficient and in August 1998, APS filed two lawsuits to protect its legal rights relating to the order.

On February 5, 1999, the ACC Hearing Division issued recommended changes to the June 1998 stranded cost order. These recommended changes were further amended by an ACC Procedural Order dated March 12, 1999. The recommended changes to the stranded cost order would be effective upon approval of the ACC. The recommended order, as amended on March 12, 1999, allows each affected utility to choose from five options for the recovery of stranded costs:

- Net Revenues Lost Methodology is the difference between generation revenues under traditional regulation and generation revenues under competition. This option provides for declining recovery percentages for stranded costs over a five-year recovery period. Regulatory assets are to be fully recovered under their presently authorized amortization schedule. In accordance with a 1996 regulatory agreement, the ACC accelerated the amortization of substantially all of APS' regulatory assets to an eight-year period that ends June 30, 2004.
- Divestiture/Auction Methodology allows a utility to divest all or substantially all of its generating assets, including regulatory assets associated with generation, in order to collect 100 percent of the difference between net sales price and book value of generating assets divested over a ten-year period, with no return on the unamortized balance.
- Financial Integrity Methodology allows a utility "sufficient revenues to meet minimum financial ratios" for a period of ten years.
- Settlement Methodology allows a settlement to be agreed upon by the ACC and a utility.
- Any combination of the above is shown to be in the best interest of all affected parties.

Legislative Initiatives

An Arizona joint legislative committee studied electric utility industry restructuring issues in 1996 and 1997. In conjunction with that study, the Arizona legislative counsel prepared memoranda in late 1997 related to the legal authority of the ACC to deregulate the Arizona electric utility industry. The memoranda raise a question as to the degree to which the ACC may, under the Arizona Constitution, deregulate any portion of the electric utility industry and allow rates to be determined by market forces. This latter issue has been subsequently decided by lower courts in favor of the ACC in four separate lawsuits, two of which are unrelated.

In May 1998, a law was enacted to facilitate implementation of retail electric competition in Arizona. The law includes the following major provisions:

- Arizona's largest government-operated electric utility (Salt River Project) and, at their option, smaller municipal electric systems must (i) make at least 20% of their 1995 retail peak demand available to electric service providers by December 31, 1998 and for all retail customers by December 31, 2000; (ii) decrease rates by at least 10% over a ten-year period beginning as early as January 1, 1991; (iii) implement procedures and public processes comparable to those already applicable to public service corporations, for establishing the terms, conditions, and pricing of electric services as well as certain other decisions affecting retail electric competition;
- describes the factors which form the basis of consideration by Salt River Project in determining stranded costs; and
- metering and meter reading services must be provided on a competitive basis during the first two years of competition only for customers having demands in excess of one megawatt (and that are eligible for competitive generation services), and thereafter for all customers receiving competitive electric generation.

In addition, the Arizona legislature will review and make recommendations for the 1999 legislature on certain competitive issues.

Agreement with Salt River Project

On April 25, 1998, APS entered into a Memorandum of Agreement with Salt River Project in anticipation of, and to facilitate, the opening of the Arizona electric industry. The Agreement contains the following major components:

- Both parties would amend the Territorial Agreement to remove any barriers to the provision of competitive electricity supply and non-distribution services.
- Both parties would amend the Power Coordination Agreement to lower the price that APS will pay Salt River Project for purchased power by approximately $17 million (pretax) during the first full year that the Agreement is effective and by lesser annual amounts during the next seven years.
- Both parties agreed on certain legislative positions regarding electric utility restructuring at the state and federal level.

Certain provisions of the Agreement (including those relating to the amendments of the Territorial Agreement and the Power Coordination Agreement) are affected by the timing of the introduction of competition. See "ACC Rules" above. On February 18, 1999, the ACC approved the Agreement.

General

We believe that further ACC decisions, legislation at the Arizona and federal levels, and perhaps amendments to the Arizona Constitution (which would require a vote of the people) will ultimately be required before significant implementation of retail electric competition can lawfully occur in Arizona. Until the manner of implementation of competition, including addressing stranded costs, is determined, we cannot accurately predict the impact of full retail competition on our financial position, cash flows, or results of operation. As competition in the electric industry continues to evolve, we will continue to evaluate strategies and alternatives that will position us to compete in the new regulatory environment.

FEDERAL

The Energy Policy Act of 1992 and recent rulemakings by FERC have promoted increased competition in the wholesale electric power markets. APS does not expect these rules to have a material impact on its financial statements.

Several electric utility reform bills have been introduced during recent congressional sessions, which as currently written would allow consumers to choose their electricity suppliers by 2000 or 2003. These bills, other bills that are expected to be introduced, and ongoing discussions at the federal level suggest a wide range of opinion that will need to be narrowed before any substantial restructuring of the electric utility industry can occur.

1996 Regulatory Agreement

In April 1996, the ACC approved a regulatory agreement between the ACC Staff and APS. The major provisions of this agreement are:

- An annual rate reduction of approximately $48.5 million ($29 million after income taxes), or 3.4% on average for all customers except certain contract customers, effective July 1, 1996.
- Recovery of substantially all of APS' present regulatory assets through accelerated amortization over an eight-year period that will end June 30, 2004, increasing annual amortization by approximately $120 million ($72 million after income taxes). See Note 1.
- A formula for sharing future cost savings between customers and shareholders (price reduction formula) referencing a return on equity (as defined) of 11.25%.
- A moratorium on filing for permanent rate changes prior to July 2, 1999, except under the price reduction formula and under certain other limited circumstances.
- Infusion of $200 million of common equity into APS by the parent company, in annual payments of $50 million starting in 1996.

Based on the price reduction formula, the ACC approved retail price decreases of approximately $17.6 million ($10.5 million after income taxes), or 1.2%, effective July 1, 1997, and approximately $17 million ($10 million after income taxes), or 1.1%, effective July 1, 1998. APS expects to file with the ACC for another retail price decrease of approximately $10.8 million annually ($6.5 million after income taxes) to become effective July 1, 1999. The amount and timing of the price decrease are subject to ACC approval. This will be the last price decrease under the 1996 regulatory agreement.

4. INCOME TAXES

Investment Tax Credit

Because of a 1994 rate settlement agreement, we are amortizing almost all of our investment tax credits (ITCs) over 5 years (1995-1999).

Income Taxes

Certain assets and liabilities are reported differently for income tax purposes than they are for financial statements. The tax effect of these differences is recorded as deferred taxes. We calculate deferred taxes using the current income tax rates.

APS has recorded a regulatory asset on its Balance Sheet in accordance with SFAS No. 71. This regulatory asset is for certain temporary differences, primarily AFUDC equity. APS amortizes this amount as the differences reverse. APS has been able to accelerate its amortization of the regulatory asset for income taxes to an eight-year period that will end June 30, 2004. This is a result of a 1996 regulatory agreement with the ACC. We are including this accelerated amortization in depreciation and amortization expense on the Statements of Income.

The components of income tax expense are:

Year Ended December 31, (Thousands of Dollars)	1998	1997	1996
Current			
Federal	$ 105,922	$ 105,818	$ 105,312
State	40,621	43,172	35,052
Total current	146,543	148,990	140,364
Deferred	41,566	28,729	23,752
Change in valuation allowance	—	(3,920)	(12,142)
ITC amortization	(23,516)	(23,518)	(23,518)
Total expense	$ 164,593	$ 150,281	$ 128,456

Multiplying income before income taxes by the statutory federal income tax rate does not equal the amount recorded as income tax expense because of the following:

Year Ended December 31, (Thousands of Dollars)	1998	1997	1996
Federal income tax expense at 35% statutory rate	$ 142,620	$ 135,148	$ 118,830
Increases (reductions) in tax expense resulting from:			
Tax under book depreciation	17,848	14,694	19,229
Preferred stock dividends of APS	3,396	4,481	5,982
ITC amortization	(23,516)	(23,518)	(23,518)
State income tax net of federal income tax benefit	22,764	24,497	19,565
Change in valuation allowance	—	(3,400)	(10,525)
Other	1,481	(1,621)	(1,107)
Income tax expense	$ 164,593	$ 150,281	$ 128,456

The components of the net deferred income tax liability were as follows:

December 31, (Thousands of Dollars)	1998	1997
Deferred tax assets		
Alternative minimum tax	$ —	$ 53,601
Deferred gain on Palo Verde Unit 2 sale/leaseback	31,285	33,257
Other	86,795	91,701
Total deferred tax assets	118,080	178,559
Deferred tax liabilities		
Plant-related	1,112,897	1,096,222
Regulatory asset for income taxes	161,836	185,084
Rate synchronization deferrals	122,130	144,908
Other	60,754	57,919
Total deferred tax liabilities	1,457,617	1,484,133
Accumulated deferred income taxes – net	$ 1,339,537	$ 1,305,574

5. LINES OF CREDIT

APS had committed lines of credit with various banks of $400 million at December 31, 1998 and 1997, which were available either to support the issuance of commercial paper or to be used for bank borrowings. The commitment fees at December 31, 1998 and 1997 for these lines of credit ranged from .07% to .15% per annum. APS had long-term bank borrowings of $125 million outstanding at December 31, 1998, and $150 million outstanding at December 31, 1997.

APS had commercial paper borrowings outstanding of $178.8 million at December 31, 1998, and $130.8 million at December 31, 1997. The weighted average interest rate on commercial paper borrowings was 6.21% on December 31, 1998, and 6.27% on December 31, 1997. By Arizona statute, APS' short-term borrowings cannot exceed 7% of its total capitalization unless approved by the ACC.

Pinnacle West had a revolving line of credit of $250 million at December 31, 1998 and 1997. The commitment fees were 0.10% in 1998 and ranged from 0.10% to 0.125% in 1997. Outstanding amounts at December 31, 1998 were $42 million and at December 31, 1997 were $155 million.

SunCor had revolving lines of credit totalling $55 million at December 31, 1998 and 1997. The commitment fees were 0.125% in 1998 and 1997. SunCor had $38.1 million outstanding at December 31, 1998, and $40.6 million outstanding at December 31,1997.

6. LONG-TERM DEBT

Borrowings under the APS mortgage bond indenture are secured by substantially all utility plant; SunCor's debt is collateralized by interests in certain real property; Pinnacle West's debt is unsecured. The following table presents the components of consolidated long-term debt:

December 31, (Thousands of Dollars)	Maturity Dates (a)	Interest Rates	1998	1997
APS				
First mortgage bonds	1998	7.625%	$ —	$ 100,000
	1999	7.625%	100,000	100,000
	2000	5.75%	100,000	100,000
	2002	8.125%	125,000	125,000
	2004	6.625%	85,000	85,000
	2020	10.25%	100,550	109,550
	2021	9.5%	45,140	45,140
	2021	9%	72,370	72,370
	2023	7.25%	91,900	97,150
	2024	8.75%	121,668	121,918
	2025	8%	88,300	88,500
	2028	5.5%	25,000	25,000
	2028	5.875%	154,000	154,000
Unamortized discount and premium			(6,482)	(7,033)
Pollution control bonds	2024-2033	Adjustable rate(b)	456,860	439,990
Collateralized loan	1999-2000	5.375%-6.125%	20,000	10,000
Unsecured note	2005	6.25%	100,000	—
Senior notes (c)	1999	6.72%	50,000	50,000
Senior notes (c)	2006	6.75%	100,000	100,000
Debentures	2025	10%	75,000	75,000
Bank loans	2003	Adjustable rate(d)	125,000	150,000
Capitalized lease obligation	1998-2001	7.48%(e)	11,612	15,645
			2,040,918	2,057,230
SunCor				
Revolving credit	2001	(f)	38,139	40,600
Bank loan	2001	(g)	42,061	45,000
Notes payable	1998-2006	(h)	3,888	5,113
			84,088	90,713
Pinnacle West				
Revolving credit	2001	(i)	42,000	155,000
Senior notes	2001-2003	(j)	50,000	50,000
			92,000	205,000
Total long-term debt			2,217,006	2,352,943
Less current maturities			168,045	108,695
Total long-term debt less current maturities			$ 2,048,961	$ 2,244,248

(a) This schedule does not reflect the timing of redemptions that may occur prior to maturity.

(b) The weighted-average rate for the year ended December 31, 1998 was 3.39% and for December 31, 1997 was 3.62%. Changes in short-term interest rates would affect the costs associated with this debt.

(c) APS has issued $150 million of first mortgage bonds ("senior note mortgage bonds") to the senior note trustee as collateral for the senior notes. The senior note mortgage bonds have the same interest rate, interest payment dates, maturity, and redemption provisions as the senior notes. APS' payments of principal, premium, and/or interest on the senior notes satisfy its corresponding payment obligations on the senior note mortgage bonds. As long as the senior note mortgage bonds secure the senior notes, the senior notes will effectively rank equally with the first mortgage bonds. On the date that APS has repaid all of its first mortgage bonds, other than those that secure senior notes, the senior note mortgage bonds will no longer secure the senior notes and will cease to be outstanding.

(d) The weighted-average rate at December 31, 1998 was 5.69% and at December 31, 1997 was 6.25%. Changes in short-term interest rates would affect the costs associated with this debt.

(e) Represents the present value of future lease payments (discounted at an interest rate of 7.48%) on a combined cycle plant that was sold and leased back (see Note 10).

(f) The weighted-average rate at December 31, 1998 was 8.21% and at December 31, 1997 was 8.60%. Interest for 1998 and 1997 was based on LIBOR plus 2% or prime plus 0.5%.

(g) The weighted-average rate at December 31, 1998 was 7.76% and at December 31, 1997 was 8.44%. Interest for 1998 and 1997 was based on LIBOR plus 2% or prime plus 0.5%.

(h) Multiple notes primarily with variable interest rates based mostly on the lenders' prime.

(i) The weighted-average rate at December 31, 1998 was 5.66% and at December 31, 1997 was 6.25%. Interest for 1998 was based on LIBOR plus 0.33% and for 1997 was LIBOR plus 0.33%-0.4%.

(j) Includes two series of notes: $25 million at 6.62% due 2001, and $25 million at 6.87% due 2003.

The following is a list of principal payments due on total long-term debt and sinking fund requirements through 2003:

- $168.0 million in 1999
- $140.4 million in 2000
- $121.0 million in 2001
- $125.1 million in 2002 and
- $150.1 million in 2003.

First mortgage bondholders share a lien on substantially all utility plant assets (other than nuclear fuel, transportation equipment, and the combined cycle plant). The mortgage bond indenture includes provisions that would restrict the payment of common stock dividends under certain conditions. These conditions did not exist at December 31, 1998.

7. PREFERRED STOCK OF APS

On March 1, 1999, APS redeemed all of its preferred stock.

Preferred stock balances of APS at December 31, 1998 and 1997 are shown below:

(Dollars in Thousands, Except Per Share Amount)	Authorized	Number of Shares Outstanding December 31, 1998	1997	Par Value Per Share	Par Value Outstanding December 31, 1998	1997	Call Price Per Share (a)
Non-Redeemable:							
$1.10 preferred	160,000	139,030	145,559	$ 25.00	$ 3,476	$ 3,639	$ 27.50
$2.50 preferred	105,000	86,440	97,252	50.00	4,322	4,863	51.00
$2.36 preferred	120,000	32,520	38,506	50.00	1,626	1,925	51.00
$4.35 preferred	150,000	62,986	68,386	100.00	6,299	6,839	102.00
Serial preferred:	1,000,000						
$2.40 Series A		200,587	234,839	50.00	10,029	11,742	50.50
$2.625 Series C		214,895	231,572	50.00	10,745	11,579	51.00
$2.275 Series D		90,691	164,101	50.00	4,534	8,205	50.50
$3.25 Series E		304,475	312,991	50.00	15,224	15,649	51.00
Serial preferred:	4,000,000(b)						
Adjustable rate Series Q		295,851	352,851	100.00	29,585	35,285	(c)
Serial preferred:	10,000,000						
$1.8125 Series W		—	1,693,016	25.00	—	42,325	
Total		1,427,475	3,339,073		$ 85,840	$ 142,051	
Redeemable:							
Serial preferred:							
$10.00 Series U		94,011	291,098	$ 100.00	$ 9,401	$ 29,110	

(a) The actual call price per share is the indicated amount plus any accrued dividends.

(b) This authorization covers all outstanding redeemable preferred stock.

(c) Dividend rate adjusted quarterly to 2% below that of certain United States Treasury securities, but in no event less than 6% or greater than 12% per annum. Redeemable at par.

APS cannot pay common stock dividends or acquire shares of common stock if preferred stock dividends or sinking fund requirements are in arrears.

Redeemable preferred stock transactions of APS during each of the three years in the period ended December 31, 1998 are as follows:

(Dollars in Thousands)	*Number of Shares*	*Par Value Amount*
Balance, December 31, 1995	750,000	$ 75,000
Retirements		
$10.00 Series U	(90,000)	(9,000)
$7.875 Series V	(130,000)	(13,000)
Balance, December 31, 1996	530,000	53,000
Retirements		
$10.00 Series U	(118,902)	(11,890)
$7.875 Series V	(120,000)	(12,000)
Balance, December 31, 1997	291,098	29,110
Retirements		
$10.00 Series U	(197,087)	(19,709)
Balance, December 31, 1998	94,011	$ 9,401

8. COMMON STOCK

Our common stock issued during each of the three years in the period ended December 31, 1998 is as follows:

(Dollars in Thousands)	*Number of Shares*	*Amount (a)*
Balance, December 31, 1995	87,515,847	$ 1,638,684
Common stock issued	—	(2,330)
Balance, December 31, 1996	87,515,847	1,636,354
Common stock issued	—	(2,586)
Common stock retired	(2,690,900)	(79,997)
Balance, December 31, 1997	84,824,947	1,553,771
Common stock issued	—	(3,128)
Balance, December 31, 1998	84,824,947	$ 1,550,643

(a) Including premiums and expenses of preferred stock issues of APS.

9. RETIREMENT PLANS AND OTHER BENEFITS

Voluntary Severance Plan

APS sponsored a voluntary severance plan in 1996. There was a pretax charge of $31.7 million in 1996 recorded mostly as operations and maintenance expense. This pretax charge included additional pension and postretirement benefit expense. Employees who participated in the plan were credited with an additional year of age and service when their pension and postretirement benefits were calculated. The additional expenses recorded in 1996 for this plan were $2.3 million for pension and $5.4 million for postretirement benefits.

Pension Plans

Pinnacle West and its subsidiaries sponsor defined benefit pension plans for their employees. A defined benefit plan specifies the amount of benefits a plan participant is to receive using information about the participant. The plan covers nearly all of our employees. Our employees do not contribute to this plan. Generally, we calculate the benefits under these plans based on age, years of service, and pay. We fund the plan by contributing at least the minimum amount required under Internal Revenue Service regulations but no more than the maximum tax-deductible amount. The assets in the plan at December 31, 1998 were mostly domestic and international common stocks and bonds and real estate. Pension expense, including administrative and severance costs, was:

- $10.5 million in 1998
- $9.3 million in 1997 and
- $15.5 million in 1996.

The following table shows the components of net pension cost before consideration of amounts capitalized or billed to others and excluding severance costs of $2.9 million in 1996:

(Thousands of Dollars)	1998	1997	1996
Service cost – benefits earned during the period	$ 24,817	$ 20,435	$ 23,397
Interest cost on projected benefit obligation	51,524	48,402	45,124
Expected return on plan assets	(54,513)	(47,959)	(42,404)
Amortization of:			
Transition asset	(3,226)	(3,226)	(3,226)
Prior service cost	2,078	2,078	1,735
Net actuarial losses	—	—	728
Net periodic pension cost	$ 20,680	$ 19,730	$ 25,354

The following table shows a reconciliation of the funded status of the plans to the amounts recognized in the balance sheets:

(Thousands of Dollars)	1998	1997
Funded status – pension plan assets less than projected benefit obligation	$ (41,034)	$ (88,732)
Unrecognized net transition asset	(23,235)	(26,462)
Unrecognized prior service cost	22,715	24,792
Unrecognized net actuarial losses/(gains)	(38,668)	16,943
Net pension amount recognized in the balance sheets	$ (80,222)	$ (73,459)

The following table sets forth the defined benefit pension plans' change in projected benefit obligation for the plan years 1998 and 1997:

(Thousands of Dollars)	1998	1997
Projected pension benefit obligation at beginning of year	$ 708,144	$ 608,675
Service cost	24,817	20,435
Interest cost	51,524	48,402
Benefit payments	(29,636)	(29,965)
Plan amendments	—	5,537
Actuarial losses/(gains)	(23,544)	55,060
Projected pension benefit obligation at end of year	$ 731,305	$ 708,144

The following table sets forth the defined benefit pension plans' change in the fair value of plan assets for the plan years 1998 and 1997:

(Thousands of Dollars)	1998	1997
Fair value of pension plan assets at beginning of year	$ 619,412	$ 539,179
Actual return on plan assets	86,527	88,620
Employer contributions	13,968	21,578
Benefit payments	(29,636)	(29,965)
Fair value of pension plan assets at end of year	$ 690,271	$ 619,412

We made the assumptions below to calculate the pension liability:

	1998	1997
Discount rate	7.00%	7.25%
Rate of increase in compensation levels	3.50%	4.50%
Expected long-term rate of return on assets	10.00%	9.00%

Employee Savings Plan Benefits

We also sponsor a defined contribution savings plan that is offered to nearly all employees. In a defined contribution plan, the benefits a participant is to receive result from regular contributions to a participant account. Under this plan, we make matching contributions to participant accounts. We recorded expenses for this plan of:

- $4.1 million in 1998
- $3.9 million in 1997 and
- $3.6 million in 1996.

Postretirement Plans

We provide medical and life insurance benefits to retired employees. Employees must retire to become eligible for these retirement benefits, which are based on years of service and age. For the medical insurance plans, retirees make contributions to cover a portion of the plan costs. For the life insurance plan, retirees do not make contributions to cover a portion of the plan costs. We retain the right to change or eliminate these benefits.

Funding is based upon actuarially determined contributions that take tax consequences into account. Plan assets consist primarily of domestic stocks and bonds. The postretirement benefit expense was:

- $9.1 million for 1998
- $9.8 million for 1997 and
- $16.2 million for 1996.

The following table shows the components of net periodic postretirement benefit costs before consideration of amounts capitalized or billed to others and excluding severance costs of $9.6 million in 1996:

(Thousands of Dollars)	1998	1997	1996
Service cost – benefits earned during the period	$ 7,890	$ 7,046	$ 8,168
Interest cost on accumulated benefit obligation	15,763	14,441	13,525
Expected return on plan assets	(12,001)	(8,706)	(6,696)
Amortization of:			
Transition obligation	7,698	7,698	8,269
Net actuarial gains	(2,952)	(2,685)	(1,345)
Net periodic postretirement benefit cost	$ 16,398	$ 17,794	$ 21,921

The following table shows a reconciliation of the funded status of the plan to the amounts recognized in the balance sheets:

(Thousands of Dollars)	1998	1997
Funded status – postretirement plan assets less than projected benefit obligation	$ (24,269)	$ (48,202)
Unrecognized net obligation at transition	107,842	115,541
Unrecognized net actuarial gains	(86,692)	(79,013)
Net postretirement amount recognized in the balance sheets	$ (3,119)	$ (11,674)

The following table sets forth the postretirement benefit plans' change in accumulated benefit obligation for the plan years 1998 and 1997:

(Thousands of Dollars)	1998	1997
Accumulated postretirement benefit obligation at beginning of year	$ 199,348	$ 181,405
Service cost	7,890	7,046
Interest cost	15,763	14,441
Benefit payments	(10,378)	(6,745)
Actuarial losses	25,056	3,201
Accumulated postretirement benefit obligation at end of year	$ 237,679	$ 199,348

The following table sets forth the postretirement benefit plans' change in the fair value of plan assets for the plan years 1998 and 1997:

(Thousands of Dollars)	1998	1997
Fair value of postretirement plan assets at beginning of year	$ 151,146	$ 109,763
Actual return on plan assets	47,284	30,846
Employer contributions	25,327	17,269
Benefit payments	(10,347)	(6,732)
Fair value of postretirement plan assets at the end of year	$ 213,410	$ 151,146

We made the assumptions below to calculate the postretirement liability:

	1998	1997
Discount rate	7.00%	7.25%
Expected long-term rate of return on assets – after tax	8.73%	7.75%
Initial health care cost trend rate – under age 65	7.50%	8.00%
Initial health care cost trend rate – age 65 and over	6.50%	7.00%
Ultimate health care cost trend rate (reached in the year 2002)	5.00%	5.00%

Assuming a 1% increase in the health care cost trend rate, the 1998 cost of postretirement benefits other than pensions would increase by approximately $4.6 million and the accumulated benefit obligation as of December 31, 1998 would increase by approximately $37.8 million.

Assuming a 1% decrease in the health care cost trend rate, the 1998 cost of postretirement benefits other than pensions would decrease by approximately $3.8 million and the accumulated benefit obligation as of December 31, 1998 would decrease by approximately $31.9 million.

10. LEASES

In 1986, APS sold about 42% of its share of Palo Verde Unit 2 and certain common facilities in three separate sale leaseback transactions. APS accounts for these leases as operating leases. The gain of approximately $140.2 million was deferred and is being amortized to operations expense over 29.5 years, the original term of the leases. There are options to renew the leases for two additional years and to purchase the property for fair market value at the end of the lease terms. Consistent with the ratemaking treatment, an amount equal to the annual lease payments is included in rent expense. A regulatory asset is recognized for the difference between lease payments and rent expense calculated on a straight-line basis.

The average amounts to be paid for the Palo Verde Unit 2 leases are as follows:

Year		(In millions)
1999	$	40.1
2000		46.3
2001-2015		49.0

In accordance with the 1996 regulatory agreement (see Note 3), the ACC accelerated APS' amortization of the regulatory asset for leases to an eight-year period that will end June 30, 2004. The accelerated amortization is included in depreciation and amortization expense on the Statements of Income. The balance of this regulatory asset at December 31, 1998 was $48.5 million. Lease expense was approximately $42 million in each of the years 1996 through 1998.

APS has a capital lease on a combined cycle plant, which it sold and leased back. The lease requires semiannual payments of $2.6 million through June 2001, and includes renewal and purchase options based on fair market value. The plant is included in plant in service at its original cost of $54.4 million; accumulated amortization at December 31, 1998 was $48.6 million.

In addition, we lease certain land, buildings, equipment, and miscellaneous other items through operating rental agreements with varying terms, provisions, and expiration dates.

Approximate miscellaneous lease expense was:

- $13.1 million in 1998
- $11.2 million in 1997 and
- $12.8 million in 1996.

Estimated future minimum lease commitments, excluding the Palo Verde and combined cycle leases, are as follows:

Year		(In millions)
1999	$	16.4
2000		16.4
2001		18.3
2002		19.3
2003		18.2
Thereafter		151.2
Total future commitments	$	239.8

11. JOINTLY-OWNED FACILITIES

APS shares ownership of some of its generation and transmission facilities with other companies. The following table shows APS' interest in those jointly-owned facilities at December 31, 1998. APS' share of operating and maintaining the facilities is included in the Income Statement in utility operations and maintenance expense.

(Dollars in Thousands)	*Percent Owned by APS*	*Plant In Service*	*Accumulated Depreciation*	*Construction Work In Progress*
Generating Facilities				
Palo Verde Nuclear Generating Station Units 1 and 3	29.1%	$ 1,821,620	$ 670,403	$ 20,152
Palo Verde Nuclear Generating Station Unit 2 (see Note 10)	17.0%	568,184	224,502	9,839
Four Corners Steam Generating Station Units 4 and 5	15.0%	150,165	69,764	312
Navajo Steam Generating Station Units 1, 2, and 3	14.0%	203,356	90,237	25,560(a)
Cholla Steam Generating Station Common Facilities (b)	62.8%(c)	67,513	37,096	267
Transmission Facilities				
ANPP 500 KV System	35.8%(c)	66,547	20,282	1,384
Navajo Southern System	31.4%(c)	26,918	17,285	21
Palo Verde – Yuma 500 KV System	23.9%(c)	11,376	4,215	—
Four Corners Switchyards	27.5%(c)	3,071	1,780	143
Phoenix – Mead System	17.1%(c)	36,324	536	—

(a) The construction costs at Navajo are primarily related to the installation of scrubbers required by environmental legislation.

(b) PacifiCorp owns Cholla Unit 4 and APS operates the unit for them. The common facilities at the Cholla Plant are jointly-owned.

(c) Weighted average of interests.

12. COMMITMENTS AND CONTINGENCIES

Litigation

We are party to various claims, legal actions, and complaints arising in the ordinary course of business. In our opinion, the ultimate resolution of these matters will not have a material adverse effect on our financial statements.

Palo Verde Nuclear Generating Station

Under the Nuclear Waste Policy Act, the Department of Energy (DOE) was to develop the facilities necessary for the storage and disposal of spent fuel and to have the first such facility in operation by 1998. That facility was to be a permanent repository, but DOE has announced that such a repository now cannot be completed before 2010. In response to lawsuits filed over DOE's obligation to accept used nuclear fuel, the United States Court of Appeals for the D.C. Circuit has ruled that DOE had an obligation to begin accepting used nuclear fuel in 1998. However, the Court refused to issue an order compelling DOE to begin moving used fuel. Instead, the Court ruled that any damages to utilities should be sought under the standard contract signed between DOE and utilities, including APS. The United States Supreme Court has refused to grant review of the D.C. Circuit's decision. In July 1998, APS filed a Petition for Review regarding DOE's obligation to begin accepting spent nuclear fuel. APS has capacity in existing fuel storage pools at Palo Verde which, with certain modifications, could accommodate all fuel expected to be discharged from normal operation of Palo Verde through 2002, and believes it could augment that wet storage with new facilities for on-site dry storage of spent fuel for an indeterminate period of operation beyond 2002, subject to obtaining any required governmental approvals. APS currently estimates that it will incur $113 million (in 1998 dollars) over the life of Palo Verde for its share of the costs related to the on-site interim storage of spent nuclear fuel. Beginning in 1999, APS will accrue these costs as a component of fuel expense, meaning the charges will be accrued as the fuel is burned. During 1998, APS recorded a liability and a regulatory asset of $35 million for on-site interim nuclear fuel storage costs related to nuclear fuel burned prior to 1999. APS currently believes that spent fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation beyond 2002.

The Palo Verde participants have insurance for public liability resulting from nuclear energy hazards to the full limit of liability under federal law. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $200 million and the balance by an industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the programs exceed the accumulated funds, APS could be assessed retrospective premium adjustments. The maximum assessment per reactor under the program for each nuclear incident is approximately $88 million, subject to an annual limit of $10 million per incident. Based upon APS' 29.1% interest in the three Palo Verde units, APS' maximum potential assessment per incident for all three units is approximately $77 million, with an annual payment limitation of approximately $9 million.

The Palo Verde participants maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.75 billion, a substantial portion of which must first be applied to stabilization and decontamination. APS has also secured insurance against portions of any increased cost of generation or purchased power and business interruption resulting from a sudden and unforeseen outage of any of the three units. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions and exclusions.

Fuel and Purchased Power Commitments

APS is a party to various fuel and purchased power contracts with terms expiring from 1999 through 2020 that include required purchase provisions. APS estimates its 1999 contract requirements to be about $132 million. However, this amount may vary significantly pursuant to certain provisions in such contracts that permit APS to decrease its required purchases under certain circumstances.

APS must reimburse certain coal providers for amounts incurred for coal mine reclamation. APS estimates its share of the total obligation to be about $103 million. The portion of the coal mine reclamation obligation related to coal already burned is about $62 million at December 31, 1998 and is included in "Deferred Credits-Other" in the Balance Sheet. A regulatory asset has been established for amounts not yet recovered from ratepayers. In accordance with the 1996 regulatory agreement (see Note 3), the ACC began accelerated amortization of APS' regulatory asset for coal mine reclamation costs over an eight-year period that will end June 30, 2004. Amortization is included in depreciation and amortization expense on the Statements of Income. The balance of the regulatory asset at December 31, 1998 was about $51 million.

Construction Program

Consolidated capital expenditures in 1999 are estimated at $386 million.

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13. NUCLEAR DECOMMISSIONING COSTS

APS recorded $11.4 million for decommissioning expense in each of the years 1998, 1997, and 1996. APS estimates it will cost about $1.8 billion ($452 million in 1998 dollars) to decommission its 29.1% share of the three Palo Verde units. The decommissioning costs are expected to be incurred over a 14-year period beginning in 2024. APS charges decomissioning costs to expense over each unit's operating license term and includes them in the accumulated depreciation balance until each unit is retired. Nuclear decommissioning costs are recovered in rates.

APS' current estimates are based on a 1998 site-specific study for Palo Verde that assumes the prompt removal/dismantlement method of decommissioning. An independent consultant prepared this study. APS is required to update the study every three years.

To fund the costs APS expects to incur to decommission the plant, APS established external decommissioning trusts in accordance with Nuclear Regulatory Commission (NRC) regulations. The trust accounts are reported in "Investments and Other Assets" on the Consolidated Balance Sheets at their market value of $145.6 million at December 31, 1998 and $124.6 million at December 31, 1997. APS invests the trust funds primarily in fixed income securities and domestic stock and classifies them as available for sale. Realized and unrealized gains and losses are reflected in accumulated depreciation.

In February 1996, the FASB issued an exposure draft, "Accounting for Certain Liabilities Related to Closure or Removal of Long-Lived Assets." This proposed standard would require the estimated present value of the cost of decommissioning and certain other removal costs to be recorded as a liability, along with an offsetting plant asset when a decommissioning or other removal obligation is incurred. The FASB has indicated that a revised exposure draft will be issued in 1999.

14. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

Consolidated quarterly financial information for 1998 and 1997 is as follows:

(Dollars in Thousands, Except per Share Amounts)

1998 Quarter Ended	March 31	June 30	September 30	December 31
Operating revenues				
Electric	$ 380,423	$ 441,715	$ 740,734	$ 443,526
Real estate	34,161	28,916	18,276	42,835
Operating income (a)	$ 90,837	$ 122,605	$ 251,838	$ 101,848
Net income	$ 31,086	$ 48,997	$ 127,281	$ 35,528
Earnings per average common share outstanding				
Net income – basic	$ 0.37	$ 0.58	$ 1.50	$ 0.42
Net income – diluted	$ 0.36	$ 0.57	$ 1.49	$ 0.42
Dividends declared per share (b)	$ 0.30	$ 0.60	$ —	$ 0.325

(Dollars in Thousands, Except per Share Amounts)

1997 Quarter Ended	March 31	June 30	September 30	December 31
Operating revenues				
Electric	$ 379,021	$ 458,751	$ 632,821	$ 407,960
Real estate	19,543	30,166	30,929	35,835
Operating income (a)	$ 82,471	$ 150,024	$ 243,454	$ 81,557
Net income	$ 25,382	$ 67,182	$ 124,340	$ 18,952
Earnings per average common share outstanding				
Net income – basic	$ 0.29	$ 0.79	$ 1.47	$ 0.21
Net income – diluted	$ 0.29	$ 0.78	$ 1.46	$ 0.21
Dividends declared per share (b)	$ 0.275	$ 0.55	$ —	$ 0.30

(a) APS' utility business is seasonal in nature, with the peak sales periods generally occurring during the summer months. Comparisons among quarters of a year may not represent overall trends and changes in operations.

(b) Dividends for the quarters ending September 30, 1998 and September 30, 1997 were declared in June.

15. FAIR VALUE OF FINANCIAL INSTRUMENTS

We believe that the carrying amounts of our cash equivalents and commercial paper are reasonable estimates of their fair values at December 31, 1998 and 1997 due to their short maturities.

We hold investments in debt and equity securities for purposes other than trading. The December 31, 1998 and 1997 fair values of such investments, which we determine by using quoted market values or by discounting cash flows at rates equal to our cost of capital, approximate their carrying amount.

The carrying value of our long-term debt (excluding a capitalized lease obligation) was $2.21 billion on December 31, 1998, with an estimated fair value of $2.28 billion. On December 31, 1997, the carrying value of our long-term debt (excluding a capitalized lease obligation) was $2.34 billion, with an estimated fair value of $2.38 billion. The fair value estimates are based on quoted market prices of the same or similar issues.

16. EARNINGS PER SHARE

In 1997 we adopted SFAS No. 128, "Earnings Per Share." This statement requires the presentation of both basic and diluted earnings per share on the financial statements. The following table presents earnings per average common share outstanding (EPS):

	1998	1997	1996
Basic EPS:			
Continuing operations	$ 2.87	$ 2.76	$ 2.41
Discontinued operations	—	—	(0.11)
Extraordinary charge	—	—	(0.23)
Net income	$ 2.87	$ 2.76	$ 2.07
Diluted EPS:			
Continuing operations	$ 2.85	$ 2.74	$ 2.40
Discontinued operations	—	—	(0.11)
Extraordinary charge	—	—	(0.23)
Net income	$ 2.85	$ 2.74	$ 2.06

Dilutive stock options increased average common shares outstanding by 571,728 shares in 1998, 519,800 shares in 1997, and 580,405 shares in 1996. Total average common shares outstanding for the purposes of calculating diluted earnings per share were 85,345,946 shares in 1998, 86,022,709 shares in 1997, and 88,021,920 shares in 1996.

Options to purchase 244,200 shares of common stock at $46.78 per share were outstanding during the last quarter of 1998 but were not included in the computation of diluted EPS because the options' exercise price was greater than the average market price of the common shares.

17. STOCK OPTIONS

We offer several stock incentive plans for our officers, APS officers, and key employees.

The plans provide for the granting of new options or awards of up to 3.5 million shares at a price per option not less than fair market value on the date the option is granted. The plans also provide for the granting of any combination of stock appreciation rights or dividend equivalents. The awards outstanding under the various incentive plans at December 31, 1998 approximate 1,497,012 non-qualified stock options, 158,121 restricted shares, and no dividend equivalent shares, incentive stock options, or stock appreciation rights.

The FASB issued SFAS No. 123, "Accounting for Stock-Based Compensation" which was effective for 1996. The statement encourages, but does not require, that a company record compensation expense based on the fair value method. We continue to recognize expense based on Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees." If we had recorded compensation expense based on the fair value method, our net income would have been reduced to the following pro forma amounts:

(Dollars in Thousands, Except per Share Amounts)	1998	1997	1996
Net income			
As reported	$ 242,892	$ 235,856	$ 181,180
Pro forma (fair value method)	$ 242,177	$ 235,446	$ 180,969
Net income per share – basic			
As reported	$ 2.87	$ 2.76	$ 2.07
Pro forma (fair value method)	$ 2.86	$ 2.75	$ 2.07

We did not consider compensation costs for stock options granted before January 1, 1995. Therefore, future reported net income may not be representative of this compensation cost calculation.

In order to present the pro forma information above, we calculated the fair value of each fixed stock option in the incentive plans using the Black-Scholes option-pricing model. The fair value was calculated based on the date the option was granted. The following weighted-average assumptions were also used in order to calculate the fair value of the stock options:

	1998	1997	1996
Risk-free interest rate	4.54%	5.66%	5.77%
Dividend yield	3.03%	4.50%	4.50%
Volatility	18.80%	15.63%	17.10%
Expected life (months)	60	60	58

The following table is a summary of the status of our stock option plans as of December 31, 1998, 1997, and 1996 and changes during the years ending on those dates:

	1998 Shares	1998 Weighted Average Exercise Price	1997 Shares	1997 Weighted Average Exercise Price	1996 Shares	1996 Weighted Average Exercise Price
Outstanding at beginning of year	1,488,131	$ 24.60	1,673,076	$ 21.59	1,807,900	$ 19.78
Granted	244,200	46.78	260,450	39.56	260,500	31.44
Exercised	(217,317)	23.09	(409,975)	21.60	(363,400)	19.41
Forfeited	(18,002)	33.42	(35,420)	27.10	(31,924)	24.35
Outstanding at end of year	1,497,012	28.34	1,488,131	24.60	1,673,076	21.59
Options exercisable at year-end	1,039,664	22.21	1,008,514	19.53	1,135,032	18.60
Weighted average fair value of options granted during the year		8.15		5.83		4.24

The following table summarizes information about our stock option plans at December 31, 1998:

Range of exercise prices per share	Outstanding	Weighted Average Remaining Contract Life	Options Exercisable
$11.25	16,500	1.90	16,500
11.50	270,000	1.10	270,000
15.75	42,500	2.90	42,500
17.68	13,275	3.10	13,275
19.00	116,537	5.90	116,537
19.56	58,500	3.90	58,500
22.13	109,584	5.00	109,584
27.44	175,090	6.90	175,090
31.44	205,292	8.00	142,230
39.75	245,534	9.00	88,665
46.78	244,200	9.90	6,783
$11.25 – $46.78	1,497,012	6.29	1,039,664

PINNACLE WEST CAPITAL CORPORATION
SCHEDULE II – VALUATION AND QUALIYING ACCOUNTS

Column A	Column B	Column C Additions		Column D	Column E
Description	Balance at beginning of period	Charged to cost and expenses	Charged to other accounts	Deductions (a)	Balance at end of Period
		(Thousands of Dollars)			
		YEAR ENDED DECEMBER 31, 1998			
Real Estate Valuation Reserves	$ 23,000	$ ---	$ ---	$ 8,000	$ 15,000
		YEAR ENDED DECEMBER 31, 1997			
Real Estate Valuation Reserves	$ 41,000	$ ---	$ ---	$ 18,000	$ 23,000
		YEAR ENDED DECEMBER 31, 1996			
Real Estate Valuation Reserves	$ 47,000	$ ---	$ ---	$ 6,000	$ 41,000

(a) Represents pro-rata allocations for sale of land.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Reference is hereby made to "Election of Directors" in the Company's Proxy Statement relating to the Annual Meeting of Shareholders to be held on May 19, 1999 (the "1999 Proxy Statement") and to the Supplemental Item --- "Executive Officers of the Registrant" in Part I of this report.

ITEM 11. EXECUTIVE COMPENSATION

Reference is hereby made to the fourth and fifth paragraphs under the heading "The Board and its Committees," to "Executive Compensation," to "Human Resources Committee Report," to "Stock Performance Comparisons" and to "Executive Benefit Plans" in the 1999 Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Reference is hereby made to "Certain Securities Ownership" in the 1999 Proxy Statement.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Reference is hereby made to "Executive Benefit Plans --- Employment and Severance Agreements" and "General-Business Relationships" in the 1999 Proxy Statement.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENTS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

Financial Statements

See the Index to Consolidated Financial Statements and Financial Statement Schedule in Part II, Item 8.

Exhibits Filed

Exhibit No.		Description
10.1[a]	—	Summary of the Pinnacle West Capital Corporation 1999 Bonus Plan
10.2[a]	—	Letter Agreement between the Company and George A. Schreiber, Jr.
21	—	Subsidiaries of the Company
23.1	—	Consent of Deloitte & Touche LLP
27.1	—	Financial Data Schedule

In addition to those Exhibits shown above, the Company hereby incorporates the following Exhibits pursuant to Exchange Act Rule 12b-32 and Regulation §229.10(d) by reference to the filings set forth below:

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
3.2	Articles of Incorporation, restated as of July 29, 1988	19.1 to the Company's September 1988 Form 10-Q Report	1-8962	11-14-88
3.3	Bylaws, amended as of February 21, 1996	3.1 to the Company's 1995 Form 10-K Report	1-8962	4-1-96
4.1	Mortgage and Deed of Trust Relating to APS' First Mortgage Bonds, together with forty-eight indentures supplemental thereto	4.1 to APS' September 1992 Form 10-Q Report	1-4473	11-9-92
4.2	Forty-ninth Supplemental Indenture	4.1 to APS' 1992 Form 10-K Report	1-4473	3-30-93
4.3	Fiftieth Supplemental Indenture	4.2 to APS' 1993 Form 10-K Report	1-4473	3-30-94
4.4	Fifty-first Supplemental Indenture	4.1 to APS' August 1, 1993 Form 8-K Report	1-4473	9-27-93
4.5	Fifty-second Supplemental Indenture	4.1 to APS' September 30, 1993 Form 10-Q Report	1-4473	11-15-93
4.6	Fifty-third Supplemental Indenture	4.5 to APS' Registration Statement No. 33-61228 by means of February 23, 1994 Form 8-K Report	1-4473	3-1-94

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
4.7	Fifty-fourth Supplemental Indenture	4.1 to APS' Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report	1-4473	11-22-96
4.8	Fifty-fifth Supplemental Indenture	4.8 to APS' Registration Statement Nos. 33-55473, 33-64455 and 333-15379 by means of April 7, 1997 Form 8-K Report	1-4473	4-9-97
4.9	Agreement, dated March 21, 1994, relating to the filing of instruments defining the rights of holders of APS long-term debt not in excess of 10% of APS' total assets	4.1 to APS' 1993 Form 10-K Report	1-4473	3-30-94
4.10	Indenture dated as of January 1, 1995 among APS and The Bank of New York, as Trustee	4.6 to APS' Registration Statement Nos. 33-61228 and 33-55473 by means of January 1, 1995 Form 8-K Report	1-4473	1-11-95
4.11	First Supplemental Indenture dated as of January 1, 1995	4.4 to APS' Registration Statement Nos. 33-61228 and 33-55473 by means of January 1, 1995 Form 8-K Report	1-4473	1-11-95
4.12	Indenture dated as of November 15, 1996 among APS and The Bank of New York, as Trustee	4.5 to APS' Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report	1-4473	11-22-96
4.13	First Supplemental Indenture	4.6 to APS' Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report	1-4473	11-22-96
4.14	Second Supplemental Indenture	4.10 to APS' Registration Statement Nos. 33-55473, 33-64455 and 333-15379 by means of April 7, 1997 Form 8-K Report	1-4473	4-9-97
4.15	Agreement of Resignation, Appointment, Acceptance and Assignment dated as of August 18, 1995 by and among APS, Bank of America National Trust and Savings Association and The Bank of New York	4.1 to APS' September 25, 1995 Form 8-K Report	1-4473	10-24-95

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
4.16	Rights Agreement, amended as of November 14, 1990, between the Company and The Valley National Bank of Arizona, as Rights Agent, which includes the Certificate of Designation of Series A Participating Preferred Stock as Exhibit A, the form of Rights Certificate as Exhibit B and the Summary of Rights as Exhibit	4.1 to the Company's 1990 Form 10-K Report	1-8962	3-28-91
4.17	Specimen Certificate of Pinnacle West Capital Corporation Common Stock, no par value	4.2 to the Company's 1988 Form 10-K Report	1-8962	3-31-89
4.18	Agreement, dated March 29, 1988, relating to the filing of instruments defining the rights of holders of long-term debt not in excess of 10% of the Company's total assets	4.1 to the Company's 1987 Form 10-K Report	1-8962	3-30-88
4.19	Indenture dated as of January 15, 1998 among APS and and Chase Manhattan Bank, as Trustee	4.10 to APS' Registration The Statement Nos. 333-15379 333-27551 by means of January 13, 1998 Form 8-K Report	1-4473	1-16-98
4.20	First Supplemental Indenture dated as of January 15, 1998	4.3 to APS' Registration Statement Nos. 333-15379 and 333-27551 by means of January 13, 1998 Form 8-K Report	1-4473	1-16-98
4.21	Second Supplemental Indenture dated as of February 15, 1999	4.3 to APS' Registration Statement Nos. 333-27551 and 333-58445 by means of February 18, 1999 Form 8-K Report	1-4473	2-22-99
10.3	Agreement, dated December 6, 1989, between the Company and the Office of Thrift Supervision, United States Department of Treasury, and related documents	4.1 to the Company's December 6, 1989 Form 8-K Report	1-8962	12-7-89

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.4	Release from the Office of Thrift Supervision, United States Department of the Treasury, to the Company, dated March 22, 1990, releasing the Company from its purported obligations under the Stipulation and under any other source of alleged obligation of the Company to infuse equity capital into MeraBank	10.1 to the Company's 1989 Form 10-K Report	1-8962	3-31-89
10.5	Release from the Federal Deposit Insurance Corporation to the Company, dated March 22, 1990, releasing the Company from its purported obligations under the Stipulation and under any other source of alleged obligation of the Company to infuse equity capital into MeraBank	10.2 to the Company's 1989 Form 10-K Report	1-8962	3-31-89
10.6	Release from the Resolution Trust Corporation (in its corporate capacity) to the Company, dated March 21, 1990, releasing the Company, from its purported obligation under the Stipulation and under any other source of alleged obligation of the Company to infuse equity capital into MeraBank	10.3 to the Company's 1989 Form 10-K Report	1-8962	3-31-89
10.7	Release from the Resolution Trust Corporation (in its capacity as Receiver of MeraBank) to the Company, dated March 21, 1990, releasing the Company from its purported obligations under the Stipulation and under any other source of alleged obligation to the Company to infuse equity capital into MeraBank	10.4 to the Company's 1989 Form 10-K Report	1-8962	3-31-89
10.8[a,d]	Form of Key Executive Employment and Severance Agreement between the Company and each of its executive officers	10.5 to the Company's 1989 Form 10-K Report	1-8962	3-31-89

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.9[a]	Employment Agreement, effective as of February 5, 1990, between Richard Snell and the Company	10.1 to the Company's 1990 Form 10-K Report	2-96386	3-28-91
10.10	Two separate Decommissioning Trust Agreements (relating to PVNGS Units 1 and 3, respectively), each dated July 1, 1991, between APS and Mellon Bank, N.A., as Decommissioning Trustee	10.2 to APS' September 1991 Form 10-Q Report	1-4473	11-14-91
10.11	Amendment No. 1 to Decommissioning Trust Agreement (PVNGS Unit 1), dated as of December 1, 1994	10.1 to APS' 1994 Form 10-K Report	1-4473	3-30-95
10.12	Amendment No. 1 to Decommissioning Trust Agreement (PVNGS Unit 3), dated as of December 1, 1994	10.2 to APS' 1994 Form 10-K Report	1-4473	3-30-95
10.13	Amendment No. 2 to APS Decommissioning Trust Agreement (PVNGS Unit 1) dated as of July 1, 1991	10.4 to APS' 1996 Form 10-K Report	1-4473	3-28-97
10.14	Amendment No. 2 to APS Decommissioning Trust Agreement (PVNGS Unit 3) dated as of July 1, 1991	10.6 to APS' 1996 Form 10-K Report	1-4473	3-28-97
10.15	Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of January 31, 1992, among APS, Mellon Bank, N.A., as Decommissioning Trustee, and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee under two separate Trust Agreements, each with a separate Equity Participant, and as Lessor under two separate Facility Leases, each relating to an undivided interest in PVNGS Unit 2	10.1 to the Company's 1991 Form 10-K Report	1-8962	3-26-92
10.16	First Amendment to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of November 1, 1992	10.2 to APS' 1992 Form 10-K Report	1-4473	3-30-93

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.17	Amendment No. 2 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of November 1, 1994	10.2 to APS' 1994 Form 10-K Report	1-4473	3-30-95
10.18	Amendment No. 3 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of November 1, 1994	10.1 to APS' June 1996 Form 10-Q Report	1-4473	8-9-96
10.19	Amendment No. 4 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of January 31, 1992	APS 10.5 to APS' 1996 Form 10-K Report	1-4473	3-28-97
10.20	Asset Purchase and Power Exchange Agreement dated September 21, 1990 between APS and PacifiCorp, as amended as of October 11, 1990 and as of July 18, 1991	10.1 to APS' June 1991 Form 10-Q Report	1-4473	8-8-91
10.21	Long-Term Power Transaction Agreement dated September 21, 1990 between APS and PacifiCorp, as amended as of October 11, 1990, and as of July 8, 1991	10.2 to APS' June 1991 Form 10-Q Report	1-4473	8-8-91
10.22	Amendment No. 1 dated April 5, 1995 to the Long-Term Power Transaction Agreement and Asset Purchase and Power Exchange Agreement between PacifiCorp and APS	10.3 to APS' 1995 Form 10-K Report	1-4473	3-29-96
10.23	Restated Transmission Agreement between PacifiCorp and APS dated April 5, 1995	10.4 to APS' 1995 Form 10-K Report	1-4473	3-29-96
10.24	Contract among PacifiCorp, APS and United States Department of Energy Western Area Power Administration, Salt Lake Area Integrated Projects for Firm Transmission Service dated May 5, 1995	10.5 to APS' 1995 Form 10-K Report	1-4473	3-29-96
10.25	Reciprocal Transmission Service Agreement between APS and PacifiCorp dated as of March 2, 1994	10.6 to APS' 1995 Form 10-K Report	1-4473	3-29-86

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.26	Contract, dated July 21, 1984, with DOE providing for the disposal of nuclear fuel and/or high-level radioactive waste, ANPP	10.31 to the Company's Form S-14 Registration Statement	2-96386	3-13-85
10.27	Indenture of Lease with Navajo Tribe of Indians, Four Corners Plant	5.01 to APS' Form S-7 Registration Statement	2-59644	9-1-77
10.28	Supplemental and Additional Indenture of Lease, including amendments and supplements to original lease with Navajo Tribe of Indians, Four Corners Plant	5.02 to APS' Form S-7 Registration Statement	2-59644	9-1-77
10.29	Amendment and Supplement No. 1 to Supplemental and Additional Indenture of Lease Four Corners, dated April 25, 1985	10.36 to the Company's Registration Statement on Form 8-B Report	1-8962	7-25-85
10.30	Application and Grant of 10.31 multi-party rights-of-way and easements, Four Corners Plant Site	5.04 to APS' Form S-7 Registration Statement	2-59644	9-1-77
10.31	Application and Amendment No. 1 to Grant of multi-party rights-of-way and easements, Four Corners Power Plant Site dated April 25, 1985	10.37 to the Company's Registration Statement on Form 8-B	1-8962	7-25-85
10.32	Application and Grant of Arizona Public Service Company rights-of-way and easements, Four Corners Plant Site	5.05 to APS' Form S-7 Registration Statement	2-59644	9-1-77
10.33	Application and Amendment No. 1 to Grant of Arizona Public Service Company rights-of-way and easements, Four Corners Power Plant Site dated April 25, 1985	10.38 to the Company's Registration Statement on Form 8-B	1-8962	7-25-85
10.34	Indenture of Lease, Navajo Units 1, 2, and 3	5(g) to APS' Form S-7 Registration Statement	2-36505	3-23-70
10.35	Application and Grant of rights-of-way and easements, Navajo Plant	5(h) to APS' Form S-7 Registration Statement	2-36505	3-23-70
10.36	Water Service Contract Assignment with the United States Department of Interior, Bureau of Reclamation, Navajo Plant	5(1) to APS' Form S-7 Registration Statement	2-394442	3-16-71

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.37	Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, among APS Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles, and amendments 1-12 thereto	10. 1 to APS' 1988 Form 10-K	1-4473	3-8-89
10.38	Amendment No. 13, dated as of April 22, 1991, to Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, among APS, Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles	10.1 to APS' March 1991 Form 10-Q	1-4473	5-15-91
10.39[c]	Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee	4.3 to APS' Form S-3 Registration Statement	33-9480	10-24-86
10.40[c]	Amendment No. 1, dated as of November 1, 1986, to Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee	10.5 to APS' September 1986 Form 10-Q Report by means of Amendment No. on December 3, 1986 Form 8	1-4473	12-4-86

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.41[c]	Amendment No. 2 dated as of June 1, 1987 to Facility Lease dated as of August 1, 1986 between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.3 to APS' 1988 Form 10-K Report	1-4473	3-8-89
10.42[c]	Amendment No. 3, dated as of March 17, 1993, to Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.3 to APS' 1992 Form 10-K Report	1-4473	3-30-93
10.43	Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and APS, as Lessee	10.1 to APS' November 18 1986 Form 8-K Report	1-4473	1-20-87
10.44	Amendment No. 1, dated as of August 1, 1987, to Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	4.13 to APS' Form S-3 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report	1-4473	8-24-87
10.45	Amendment No. 2, dated as of March 17, 1993, to Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.4 to APS' 1992 Form 10-K Report	1-4473	3-30-93
10.46[a]	Directors' Deferred Compensation Plan, as restated, effective January 1, 1986	10.1 to APS' June 1986 Form 10-Q Report	1-4473	8-13-86
10.47[a]	Second Amendment to the Arizona Public Service Company Deferred Compensation Plan, effective as of January 1, 1993	10.2 to APS' 1993 Form 10-K Report	1-4473	3-30-94

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.48[a]	Third Amendment to the Arizona Public Service Company Directors' Deferred Compensation Plan, effective as of May 1, 1993	10.1 to APS' September 1994 Form 10-Q	1-4473	11-10-94
10.49[a]	Arizona Public Service Company Deferred Compensation Plan, as restated, effective January 1, 1984, and the second and third amendments thereto, dated December 22, 1986, and December 23, 1987 respectively	10.4 to APS' 1988 Form 10-K Report	1-4473	3-8-89
10.50	Third Amendment to the Arizona Public Service Company Deferred Compensation Plan, effective as of January 1, 1993	10.3 to APS' 1993 Form 10-K Report	1-4473	3-30-94
10.51[a]	Fourth Amendment to the Arizona Public Service Company Deferred Compensation Plan effective as of May 1, 1993	10.2 to APS' September 1994 Form 10-Q Report	1-4473	11-10-94
10.52[a]	Fifth Amendment to the Arizona Public Service Company Deferred Compensation Plan	10.3 to APS' 1996 Form 10-K Report	1-4473	3-28-97
10.53[a]	1999 APS Management Variable Pay Plan	10.1 to APS' 1998 Form 10-K Report	1-4473	3-31-99
10.54[a]	1999 APS Senior Management Variable Pay Plan	10.2 to APS' 1998 Form 10-K Report	1-4473	3-31-99
10.55[a]	1999 APS Officers Variable Pay Plan	10.3 to APS' 1998 Form 10-K Report	1-4473	3-31-99
10.56[a]	Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan as amended and restated effective January 1, 1996	10.10 to APS' 1995 Form 10-K Report	1-4473	3-29-86

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.57[a]	Arizona Public Service Company Supplemental Excess Benefit Retirement Plan as amended and restated on December 20, 1995	10.11 to APS' 1995 Form 10-K Report	1-4473	3-29-86
10.58[a]	Pinnacle West Capital Corporation and Arizona Public Service Company Directors' Retirement Plan, effective as of January 1, 1995	10.7 to APS' 1994 Form 10-K Report	1-4473	3-30-95
10.59[a]	Letter Agreement dated December 21, 1993, between APS and William L. Stewart	10.7 to APS' 1994 Form 10-K Report	1-4473	3-30-96
10.60[a]	Letter Agreement, dated April 3, 1978, between APS and O. Mark DeMichele, regarding certain retirement benefits granted to Mr. DeMichele	10.7 to APS' 1988 Form 10-K Report	1-4473	3-8-89
10.61[a]	Letter Agreement dated as of January 1, 1996 between APS and Robert G. Matlock & Associates, Inc. for consulting services	10.8 to APS' 1995 Form 10-K Report	1-4473	3-29-96
10.62	Letter Agreement dated August 16, 1996 between APS and William L. Stewart	10.8 to APS' 1996 Form 10-K Report	1-4473	3-28-97
10.63	Letter Agreement between APS and William L. Stewart	10.2 to APS' September 1997 Form 10-Q Report	1-4473	11-12-97
10.64	Letter Agreement dated November 27, 1996 between APS and George A. Schreiber, Jr.	10.9 to APS' 1996 Form 10-K Report	1-4473	3-28-97
10.65[ad]	Key Executive Employment and Severance Agreement between APS and certain executive of officers of APS	10.3 to APS' 1989 Form 10-K Report	1-4473	3-8-90
10.66[ad]	Revised form of Key Executive' Employment and Severance Agreement between APS and certain executive officers of APS	10.5 to APS' 1993 Form 10-K Report	1-4473	3-30-94
10.67[ad]	Second revised form of Key Executive Employment and Severance Agreement between APS and certain executive officers of APS	10.9 to APS' 1994 Form 10-K Report	1-4473	3-30-95

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.68[d]	Key Executive Employment and Severance Agreement between APS and certain managers of APS	10.4 to APS' 1989 Form 10-K Report	1-4473	3-8-90
10.69[ad]	Revised form of Key Executive Employment and Severance Agreement between APS and certain key employees of APS	10.4 to APS' 1993 Form 10-K Report	1-4473	3-30-94
10.70[ad]	Second revised Form of Key Executive Employment and Severance Agreement between APS and certain key employees of APS	10.8 to APS' 1994 Form 10-K Report	1-4473	3-30-95
10.71[a]	Pinnacle West Capital Corporation Stock Option and Incentive Plan	10.1 to APS' 1992 Form 10-K Report	1-4473	3-30-93
10.72[a]	Pinnacle West Capital Corporation 1994 Long-Term Incentive Plan, effective as of March 23, 1994	A to the Proxy Statement for the Plan Report for the Company's 1994 Annual Meeting of Shareholders	1-8962	4-16-94
10.73[a]	Pinnacle West Capital Corporation Director Equity Participation Plan	B to the Proxy Statement for the Plan Report for the Company's 1994 Annual Meeting of Shareholders	1-8962	4-16-94
10.74	Agreement No. 13904 (Option and Purchase of Effluent) with Cities of Phoenix, Glendale, Mesa, Scottsdale, Tempe, Town of Youngtown, and Salt River Project Agricultural Improvement and Power District, dated April 23, 1973	10.3 to APS' 1991 Form 10-K Report	1-4473	3-19-92
10.75	Agreement for the Sale and purchase of Wastewater Effluent with City of Tolleson and Salt River Agricultural Improvement and Power District, dated June 12, 1981, including Amendment No. 1 dated as of November 12, 1981 and Amendment No. 2 dated as of June 4, 1986	10.4 to A PS' 1991 Form 10-K Report	1-4473	3-19-92
10.76[a]	First Amendment to Employment Agreement, effective March 31, 1995, between Richard Snell and the Company	10.2 to the Company's 1995 Form 10-K Report	1-8962	4-1-96

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.77[a]	Second Amendment to Employment Agreement, effective February 5, 1997, between Richard Snell and the Company	10.2 to the Company's 1996 Form 10-K Report	1-8962	3-31-97
10.78[a]	APS Director Equity Plan	10.1 to September 1997 Form 10-Q Report	1-4473	11-12-97
10.79	Territorial Agreement between the Company and Salt River Project	10.1 to APS' March 1998 Form 10-Q Report	1-4473	5-15-98
10.80	Power Coordination Agreement between the Company and Salt River Project	10.2 to APS' March 1998 Form 10-Q Report	1-4473	5-15-98
10.81	Memorandum of Agreement between the Company and Salt River Project	10.3 to APS' March 1998 Form 10-Q Report	1-4473	5-15-98
10.82	Addendum to Memorandum of Agreement between APS and Salt River Project dated as of May 19, 1998	10.2 to APS' May 19, 1998 Form 8-K Report	1-4473	6-26-98
99.1	Collateral Trust Indenture among PVNGS II Funding Corp., Inc., APS and Chemical Bank, as Trustee	4.2 to APS' 1992 Form 10 K Report	1-4473	3-30-93
99.2	Supplemental Indenture to Collateral Trust Indenture among PVNGS II Funding Corp., Inc., APS and Chemical Bank, as Trustee	4.3 to APS' 1992 Form 10 K Report	1-4473	3-30-93
99.3[c]	Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	28.1 to APS' September 1992 Form 10-Q Report	1-4473	11-9-92

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.4[c]	Amendment No. 1 dated as of November 1, 1986, to Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	10.8 to APS' September 1986 Form 10-Q Report by means of Amendment No. 1, on December 3, 1986 Form 8	1-4473	12-4-86
99.5[c]	Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., PVNGS II Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Equity Participant named therein	28.4 to APS' 1992 Form 10-K Report	1-4473	3-30-93
99.6[c]	Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.5 to APS' Form S-3 Registration Statement	33-9480	10-24-86
99.7[c]	Supplemental Indenture No. 1, dated as of November 1, 1986 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	10.6 to APS' September 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8	1-4473	12-4-86

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.8[c]	Supplemental Indenture No. 2 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Lease Indenture Trustee	28.14 to APS' 1992 Form 10-K Report	1-4473	3-30-93
99.9[c]	Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.3 to APS' Form S-3 Registration Statement	33-9480	10-24-86
99.10[c]	Amendment No. 1, dated as of November 1, 1986, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	10.10 to APS' September 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8	1-4473	12-4-86
99.11[c]	Amendment No. 2, dated as of March 17, 1993, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.6 to APS' 1992 Form 10-K Report	1-4473	3-30-93
99.12	Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Report Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee under a Trust Indenture, APS, and the Owner Participant named therein	28.2 to APS' September 1992 Form 10-Q Report	1-4473	11-9-92

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.13	Amendment No. 1, dated as of August 1, 1987, to Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc. as Funding Corporation, State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, Chemical Bank, as Indenture Trustee, APS, and the Owner Participant named therein	28.20 to APS' Form S-3 Registration Statement No. 33-9480 by means of a November 6, 1986 Form 8-K Report	1-4473	8-10-87
99.14	Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc., PVNGS II Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, APS, and the Owner Participant named therein	28.5 to APS' 1992 Form 10-K Report	1-4473	3-30-93
99.15	Trust Indenture, Mortgage Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	10.2 to APS' November 18, 1986 Form 10-K Report	1-4473	1-20-87
99.16	Supplemental Indenture No. 1, dated as of August 1, 1987, to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.13 to APS' Form S-3 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report	1-4473	8-24-87

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.17	Supplemental Indenture No. 2 to Trust Indenture Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Lease Indenture Trustee	4.5 to APS' 1992 Form 10-K Report	1-4473	3-30-93
99.18	Assignment, Assumption and Further Agreement, dated as of December 15, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	10.5 to APS' November 18, 1986 Form 8-K Report	1-4473	1-20-87
99.19	Amendment No. 1, dated as of March 17, 1993, to Assignment, Assumption and Further Agreement, dated as of December 15, 1986, between APS and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.7 to APS' 1992 Form 10-K Report	1-4473	3-30-93
99.20[c]	Indemnity Agreement dated as of March 17, 1993 by APS	28.3 to APS' 1992 Form 10-K Report	1-4473	3-30-93
99.21	Extension Letter, dated as of August 13, 1987, from the signatories of the Participation Agreement to Chemical Bank	28.20 to APS' Form S-3 Registration Statement No. 33-9480 by means of a November 6, 1986 Form 8-K Report	1-4473	8-10-87
99.22	Arizona Corporation Commission Order dated December 6, 1991	28.1 to APS' 1991 Form 10-K Report	1-4473	3-19-92
99.23	Arizona Corporation Commission Order dated June 1, 1994	10.1 to APS' June 1994 form 10-Q Report	1-4473	8-12-94
99.24	Rate Reduction Agreement dated December 4, 1995 between APS and the ACC Staff	10.1 to APS' December 4, 1995 8-K Report	1-4473	12-14-95
99.25	ACC Order dated April 24, 1996	10.1 to APS' March 1996 Form	1-4473 10-Q Report	5-14-96

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.26	Arizona Corporation Commission Order, Decision No. 59943, dated December 26, 1996, including the Rules regarding the introduction of retail competition in Arizona	99.1 to APS' 1996 Form 10-K Report	1-4473	3-28-97
99.27	Retail Electric Competition Rules	10.1 to APS' June 1998 Form 10-Q Report	1-4473	8-14-98

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[a]Management contract or compensatory plan or arrangement to be filed as an exhibit pursuant to Item 14(c) of Form 10-K.

[b]Reports filed under File No. 1-4473 and 1-8962 were filed in the office of the Securities and Exchange Commission located in Washington, D.C.

[c]An additional document, substantially identical in all material respects to this Exhibit, has been entered into, relating to an additional Equity Participant. Although such additional document may differ in other respects (such as dollar amounts, percentages, tax indemnity matters, and dates of execution), there are no material details in which such document differs from this Exhibit.

[d]Additional agreements, substantially identical in all material respects to this Exhibit have been entered into with additional persons. Although such additional documents may differ in other respects (such as dollar amounts and dates of execution), there are no material details in which such agreements differ from this Exhibit.

Reports on Form 8-K

During the quarter ended December 31, 1998, and the period ended March 30, 1999, the Company filed the following Reports on Form 8-K.

Report dated December 1, 1998 relating to an order by the Arizona Supreme Court staying ACC hearings regarding APS' settlement agreement with the ACC Staff.

Report dated December 9, 1998 relating to (1) a Notice of Withdrawal of Settlement filed by the ACC Staff, (2) terms of expiration of a memorandum of understanding, (3) ACC adoption of the amended rules, and (4) issues affecting the agreement between APS and Salt River Project.

Report dated January 11, 1999 relating to (i) the ACC hearing officers' recommended changes to the amended rules regarding the introduction of retail electric competition in Arizona and to the June 1998 stranded cost order and (ii) action by the Arizona Supreme Court vacating its order staying ACC hearings on the proposed settlement agreement and dismissing the Attorney General's action.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PINNACLE WEST CAPITAL CORPORATION
(Registrant)

Date: March 30, 1999

/s/ William J. Post

(William J. Post, Chief Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	*Title*	*Date*
/s/ William J. Post (William J. Post, Chief Executive Officer)	Principal Executive Officer and Director	March 30, 1999
/s/ George A. Schreiber, Jr. (George A. Schreiber, Jr., President and Chief Financial Officer)	Principal Financial Officer, Principal Accounting Officer, and Director	March 30, 1999
/s/ Richard Snell (Richard Snell, Chairman of the Board of Directors)	Director	March 30, 1999
/s/ Pamela Grant (Pamela Grant)	Director	March 30, 1999
/s/ Roy A. Herberger, Jr. (Roy A. Herberger, Jr.)	Director	March 30, 1999
/s/ Martha O. Hesse (Martha O. Hesse)	Director	March 30, 1999
/s/ William S. Jamieson, Jr. (William S. Jamieson, Jr.)	Director	March 30, 1999
/s/ Humberto S. Lopez (Humberto S. Lopez)	Director	March 30, 1999

Signature	***Title***	***Date***
/s/ John R. Norton, III (John R. Norton, III)	Director	March 30, 1999
/s/ Douglas J. Wall (Douglas J. Wall)	Director	March 30, 1999

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 1998

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ______ to ______

Commission File Number 1-4473

Arizona Public Service Company
(Exact name of registrant as specified in its charter)

ARIZONA (State or other jurisdiction of incorporation or organization)	86-0011170 (I.R.S. Employer Identification No.)
400 North Fifth Street, P.O. Box 53999 Phoenix, Arizona 85072-3999 (Address of principal executive offices, including zip code)	(602) 250-1000 (Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
10% Junior Subordinated Deferrable Interest Debentures, Series A, Due 2025	New York Stock Exchange

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in any amendment to this Form 10-K. [X]

As of March 30, 1999, there were issued and outstanding 71,264,947 shares of the registrant's common stock, $2.50 par value, all of which were held beneficially and of record by Pinnacle West Capital Corporation.

The registrant meets the conditions set forth in General Instruction I1(a) and (b) and is therefore filing this document with the reduced disclosure format.

TABLE OF CONTENTS

GLOSSARY

ACC — Arizona Corporation Commission

ACC Staff — Staff of the Arizona Corporation Commission

AFUDC — Allowance for Funds Used During Construction

Amendments — Clean Air Act Amendments of 1990

ANPP — Arizona Nuclear Power Project, also known as Palo Verde

APS — Arizona Public Service Company

CC&N — Certificate of convenience and necessity

Cholla — Cholla Power Plant

Cholla 4 — Unit 4 of the Cholla Power Plant

Company — Arizona Public Service Company

CUC — Citizens Utilities Company

DOE — United States Department of Energy

EITF — Emerging Issues Task Force

EITF 97-4 — Emerging Issues Task Force Issue No. 97-4, "Deregulation of the Pricing of Electricity — Issues Related to the Applications of FASB Statements No. 71, Accounting for the Effects of Certain Types of Regulation, and No. 101, Regulated Enterprises — Accounting for the Discontinuation of Application of FASB Statement No. 71"

EITF 98-10 — Emerging Issues Task Force Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities"

Energy Act — National Energy Policy Act of 1992

EPA — United States Environmental Protection Agency

FASB — Financial Accounting Standards Board

FERC — Federal Energy Regulatory Commission

Four Corners — Four Corners Power Plant

GAAP — Generally accepted accounting principles

ITC — Investment tax credit

kW — Kilowatt, one thousand watts

kWh — Kilowatt-hour, one thousand watts per hour

Mortgage — Mortgage and Deed of Trust, dated as of July 1, 1946, as supplemented and amended

MW — Megawatt, one million watts

MWh — Megawatt hours, one million watts per hour

1935 Act — Public Utility Holding Company Act of 1935

NGS — Navajo Generating Station

NRC — Nuclear Regulatory Commission

PacifiCorp — An Oregon-based utility company

Palo Verde — Palo Verde Nuclear Generating Station

Pinnacle West — Pinnacle West Capital Corporation, an Arizona corporation, the Company's parent

SEC — Securities and Exchange Commission

SFAS No. 34 — Statement of Financial Accounting Standards No. 34, "Capitalization of Interest Cost"

SFAS No. 71 — Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation"

SFAS No. 123 — Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation"

SFAS No. 130 — Statement of Financial Accounting Standards No. 130, "Reporting Comprehensive Income"

SFAS No. 133 — Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities"

Salt River Project — Salt River Project Agricultural Improvement and Power District

USEC — United States Enrichment Corporation

Waste Act — Nuclear Waste Policy Act of 1982, as amended

PART I

ITEM 1. BUSINESS

The Company

We were incorporated in 1920 under the laws of Arizona and are engaged principally in serving electricity in the State of Arizona. Our principal executive offices are located at 400 North Fifth Street, Phoenix, Arizona 85004 (telephone 602-250-1000). Pinnacle West owns all of the outstanding shares of our common stock.

We are Arizona's largest electric utility, with 799,000 customers. We provide wholesale or retail electric service to the entire state of Arizona, with the exception of Tucson and about one-half of the Phoenix area. During 1998, no single purchaser or user of energy accounted for more than 2% of total electric revenues. At December 31, 1998, we employed 6,075 people, which includes employees assigned to joint projects where we are project manager.

This document contains forward-looking statements that involve risks and uncertainties. Words such as "estimates," "expects," "anticipates," "plans," "believes," "projects," and similar expressions identify forward-looking statements. These risks and uncertainties include, but are not limited to, the ongoing restructuring of the electric industry; the outcome of the regulatory proceedings relating to the restructuring; regulatory, tax, and environmental legislation; our ability to successfully compete outside our traditional regulated markets; regional economic conditions, which could affect customer growth; the cost of debt and equity capital; weather variations affecting customer usage; technological developments in the electric industry; and Year 2000 issues. See "Competition" in this Item for a discussion of some of these factors.

Competition

Retail

General. Under current law, we are not in direct competition with any other regulated electric utility for electric service in our retail service territory. Nevertheless, we are subject to varying degrees of competition in certain territories adjacent to or within areas that we serve that are also currently served by other utilities in our region (such as Tucson Electric Power Company, Southwest Gas Corporation, and Citizens Utility Company) as well as cooperatives, municipalities, electrical districts, and similar types of governmental organizations (principally Salt River Project).

We face competitive challenges from low-cost hydroelectric power and natural gas fuel, as well as the access of some utilities to preferential low-priced federal power and other subsidies. In addition, some customers, particularly industrial and large commercial, may own and operate facilities to generate their own electric energy requirements. Such facilities may be operated by the customers themselves or by other entities engaged for such purpose.

Arizona Electric Industry Restructuring. See Note 3 of Notes to Financial Statements in Item 8 for a discussion of the electric industry restructuring in Arizona, including ACC rules for the introduction of retail electric competition; stranded cost recovery; and Arizona legislative initiatives. See also "Financial Review - Competition and Industry Restructuring" in Item 7.

Wholesale

General. We compete with other utilities, power marketers, and independent power producers in the sale of electric capacity and energy in the wholesale market. We expect that competition to sell capacity will remain vigorous. Our rates for wholesale power sales and transmission services are subject to regulation by the FERC. During 1998, approximately 16% of our electric operating revenues resulted from such sales and charges.

The National Energy Policy Act of 1992 (the "Energy Act") has promoted increased competition in the wholesale electric power markets. The Energy Act reformed provisions of the Public Utility Holding Company Act of 1935 (the "1935 Act") and the Federal Power Act to remove certain barriers to competition for the supply of electricity. For example, the Energy Act permits the FERC to order transmission access for third parties to transmission facilities owned by another entity so that independent suppliers and other third parties can sell at wholesale to customers wherever located. The Energy Act does not, however, permit the FERC to issue an order requiring transmission access to retail customers.

Effective July 9, 1996, a FERC decision requires all electric utilities subject to the FERC's jurisdiction to file transmission tariffs which provide competitors with access to transmission facilities comparable to the transmission owners' access for wholesale transactions, establishes information requirements, and provides for recovery of certain wholesale stranded costs. Retail stranded costs resulting from a state-authorized retail direct-access program are the responsibility of the states, unless a state lacks authority to impose rates to recover such costs, in which case FERC will consider doing so. We have filed a revised open access tariff in accordance with this decision. We do not believe that this decision will have a material adverse impact on our results of operations or financial position.

Regulatory Assets

Our major regulatory assets are deferred income taxes and rate synchronization cost deferrals. These items, combined with miscellaneous regulatory assets and liabilities, amounted to approximately $900 million at December 31, 1998. Under a 1996 regulatory agreement, the ACC accelerated the amortization of substantially all of our regulatory assets to an eight-year period that will end June 30, 2004. Our existing regulatory orders and the current regulatory environment support our accounting practices related to regulatory assets. If rate recovery of these assets is no longer probable, whether due to competition or regulatory action, we would be required to write off the remaining balance as an extraordinary charge to expense. This could have a material impact on our financial statements. See Notes 1, 3, and 10 of Notes to Financial Statements in Item 8 for additional information.

Competitive Strategies

We are pursuing strategies to maintain and enhance our competitive position. These strategies include (i) cost management, with an emphasis on the reduction of variable costs (fuel, operations, and maintenance expenses) and on increased productivity through technological efficiencies; (ii) a focus on our core business through customer service, distribution system reliability, business segmentation, and the anticipation of market opportunities; (iii) an emphasis on good regulatory relationships; (iv) asset maximization (e.g., higher capacity factors and lower forced outage rates); (v) expanding our generation asset base to support growth in the competitive power marketing arena; (vi) strengthening our capital structure and financial condition; (vii) leveraging core competencies into related areas, such as energy management products and services; and (viii) establishing a trading floor and implementing a risk management program to provide for more stability of prices and the ability to retain or grow incremental margin through more competitive pricing and risk management. Underpinning our competitive strategies are the strong growth characteristics of our service territory. As competition in the electric utility industry continues to evolve, we will continue to evaluate strategies and alternatives that will position us to compete effectively in a more competitive, restructured industry.

Generating Fuel and Purchased Power

1998 Energy Mix

Our sources of energy during 1998 were: coal – 36.2%; nuclear – 27.5%; purchased power - 32.3%; and other – 4.0%.

Coal Supply

We believe that Cholla has sufficient reserves of low sulfur coal committed to the plant through 2005. In 1998, the current supplier agreed to allow Cholla to test burn coal from other sources, which led to coal purchases on the spot market. The current supplier is expected to continue to provide substantially all of Cholla's low sulfur coal requirements. We believe there are sufficient reserves of low sulfur coal available to allow the continued operation of Cholla for its useful life. We also believe that Four Corners and NGS have sufficient reserves of low sulfur coal available for use by those plants to continue operating them for their useful lives.

The current sulfur content of coal being used at Four Corners, NGS, and Cholla is approximately 0.77%, 0.54%, and 0.44%, respectively. In 1998, average prices paid for coal supplied from the reserves dedicated under existing contracts were slightly lower, but still comparable to 1997. Escalation components of existing long-term coal contracts impact future coal prices. In addition, major price adjustments can occur from time to time as a result of contract renegotiation.

NGS and Four Corners are located on the Navajo Reservation and held under easements granted by the federal government as well as leases from the Navajo Nation. See "Properties- Plant Sites Leased from the Navajo Nation" in Item 2. We purchase all of the coal which fuels Four Corners from a coal supplier with a long-term lease of coal reserves owned by the Navajo Nation and for NGS from a coal supplier with a long-term lease with the Navajo Nation and the Hopi Tribe. Coal is supplied to Cholla from a coal supplier who mines all of the coal under a long-term lease of coal reserves owned by the Navajo Nation, the federal government, and private landholders. See Note 12 of Notes to Financial Statements in Item 8 for information regarding our obligation for coal mine reclamation.

Natural Gas Supply

We are a party to contracts with a number of natural gas operators and marketers which allow us to purchase natural gas in the method we determine to be most economic. Currently, we are purchasing the majority of our natural gas requirements from 25 companies pursuant to contracts. Our natural gas supply is transported pursuant to a firm transportation service contract with El Paso Natural Gas Company. We continue to analyze the market to determine the most favorable source and method of meeting our natural gas requirements.

Nuclear Fuel Supply

The fuel cycle for Palo Verde is comprised of the following stages:

- the mining and milling of uranium ore to produce uranium concentrates,
- the conversion of uranium concentrates to uranium hexafluoride,
- the enrichment of uranium hexafluoride,
- the fabrication of fuel assemblies,
- the utilization of fuel assemblies in reactors and
- the storage of spent fuel and the disposal thereof.

The Palo Verde participants have made contractual arrangements to obtain quantities of uranium concentrates anticipated to be sufficient to meet operational requirements through 2001. Existing contracts and options could be utilized to meet approximately 93% of requirements in 2002, 62% of requirements in 2003, 51% of requirements in 2004, and 44% of requirements from 2005 through 2007. Spot purchases on the uranium market will be made, as appropriate, in lieu of any uranium that might be obtained through contractual options.

The Palo Verde participants have contracted for 85% of conversion services required through 2002. The Palo Verde participants have an enrichment services contract and an enriched uranium product contract that furnish enrichment services required for the operation of the three Palo Verde units through 2003. In addition, existing contracts will provide fuel assembly fabrication services until at least 2003 for each Palo Verde unit, and through contract options, approximately fifteen additional years are available.

Spent Nuclear Fuel and Waste Disposal. Pursuant to the Nuclear Waste Policy Act of 1982, as amended in 1987 (the "Waste Act"), DOE is obligated to accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by all domestic power reactors. The NRC, pursuant to the Waste Act, requires operators of nuclear power reactors to enter into spent fuel disposal contracts with DOE. We have done so on our behalf and on behalf of the other Palo Verde participants. Under the Waste Act, DOE was to develop the facilities necessary for the storage and disposal of spent nuclear fuel and to have the first such facility in operation by 1998. That facility was to be a permanent repository. DOE has announced that such a repository now cannot be completed before 2010. In July 1996, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) ruled that the DOE has an obligation to start disposing of spent nuclear fuel no later than January 31, 1998. By way of letter dated December 17, 1996, DOE informed us and other contract holders that DOE anticipates that it will be unable to begin acceptance of spent nuclear fuel for disposal in a repository or interim storage facility by January 31, 1998. In November 1997, the D.C. Circuit issued a Writ of Mandamus precluding DOE from excusing its own delay on the grounds that DOE has not yet prepared a permanent repository or interim storage facility. On May 5, 1998, the D.C. Circuit issued a ruling refusing to order DOE to begin moving spent nuclear fuel. On July 24, 1998, we filed a Petition for Review regarding DOE's obligation to begin accepting spent nuclear fuel. Arizona Public Service Company v. Department of Energy and United States of America, No. 98-1346 (D.C. Cir.). See "Palo Verde Nuclear Generating Station" in Note 12 of Notes to Financial Statements in Item 8 for a discussion of interim spent fuel storage costs.

Several bills have been introduced in Congress contemplating the construction of a central interim storage facility; however, there is resistance to certain features of these bills both in Congress and the Administration.

Facility funding is a further complication. While all nuclear utilities pay into a so-called nuclear waste fund an amount calculated on the basis of the output of their respective plants, the annual Congressional appropriations for the permanent repository have been for amounts less than the amounts paid into the waste fund (the balance of which is being used for other purposes). According to DOE spokespersons, the fund may now be at a level less than needed to achieve a 2010 operational date for a permanent repository. No funding will be available for a central interim facility until one is authorized by Congress.

We have storage capacity in existing fuel storage pools at Palo Verde which, with certain modifications, could accommodate all fuel expected to be discharged from normal operation of Palo Verde through about 2002. We also believe we could augment that wet storage with new facilities for on-site dry storage of spent fuel for an indeterminate period of operation beyond 2002, subject to obtaining any required governmental approvals. One way or another, we currently believe that spent fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation beyond 2002.

A new low-level waste facility was built in 1995 on-site which could store an amount of waste equivalent to ten years of normal operation at Palo Verde. Although some low-level waste has been stored on-site, we are currently shipping low-level waste to off-site facilities. We currently believe that interim low-level waste storage methods are or will be available for use by Palo Verde to allow its continued operation and to safely store low-level waste until a permanent disposal facility is available.

We believe that scientific and financial aspects of the issues of spent fuel and low-level waste storage and disposal can be resolved satisfactorily. However, we also acknowledge that their ultimate resolution in a timely fashion will require political resolve and action on national and regional scales which we are less able to predict.

Purchased Power Agreements

In addition to that available from its own generating capacity (see "Properties" in Item 2), we purchase electricity from other utilities under various arrangements. One of the most important of these is a long-term contract with Salt River Project. This contract may be canceled by Salt River Project on three years' notice and requires Salt River Project to make available, and us to pay for, certain amounts of electricity. The amount of electricity is based in large part on customer demand within certain areas now served by us pursuant to a related territorial agreement. The generating capacity available to us pursuant to the contract was 292 MW January through May 1998, and starting June 1998 increased to 316 MW. In 1998, we received approximately 943,354 MWh of energy under the contract and paid about $43 million for capacity availability and energy received. See Note 3 of Notes to Financial Statements for a discussion of amendments to agreements with Salt River Project.

In September 1990, we entered into certain agreements with PacifiCorp relating principally to sales and purchases of electric power and electric utility assets. In July 1991 we sold Cholla 4 to PacifiCorp. As part of the transaction, PacifiCorp agreed to make a firm system sale to us for thirty years during our summer peak season. The amount of the sale for the first seven years was 175 MW and it increases after that at our option, up to a maximum amount of 380 MW. We converted the firm system sales to one-for-one seasonal capacity exchanges with PacifiCorp on October 31, 1997. On January 1, 1999 our agreements with PacifiCorp provide for 275 MW capacity exchange and beginning in May 1999, an additional 205 MW capacity exchange begins. In 1998, we had 275 MW of generating capacity available from PacifiCorp. We received approximately 281,217 MWh of energy under the exchange.

During 1996, we entered into an agreement with Citizens Utilities Company to build, own, operate, and maintain a combustion turbine in northwest Arizona. CUC terminated the combustion turbine project in February 1999. We have notified CUC that we will retain the rights to the combustion turbine project.

Construction Program

During the years 1996 through 1998, we incurred approximately $899 million in capitalized expenditures. Utility capitalized expenditures for the years 1999 through 2001 are expected to be primarily for expanding transmission and distribution capabilities to meet customer growth, upgrading existing facilities, and for environmental purposes. Capitalized expenditures, including expenditures for environmental control facilities, for the years 1999 through 2001 have been estimated as follows:

(Millions of Dollars)

By Year		By Major Facilities	
1999	$328	Production	$236
2000	317	Transmission and Distribution	564
2001	300	General	113
Total	$945	Other Projects	32
		Total	$945

The amounts for 1999 through 2001 exclude capitalized interest costs and include capitalized property taxes and about $30-$35 million each year for nuclear fuel. We conduct a continuing review of our construction program. We are considering expanding certain of our operations over the next several years, which may result in additional expenditures. We currently believe that there will be opportunities to expand our investment in generating assets in the next five years. It is expected that these generating assets would be organized in a newly-created, non-regulated affiliate under Pinnacle West.

Mortgage Replacement Fund Requirements

So long as any of our first mortgage bonds are outstanding, we are required for each calendar year to deposit with the trustee under our Mortgage cash in a formularized amount related to net additions to our mortgaged utility plant. We may satisfy all or any part of this "replacement fund" requirement by utilizing redeemed or retired bonds, net property additions, or property retirements. For 1998, the replacement fund requirement amounted to approximately $138 million. Certain of the bonds we have issued under the Mortgage that are callable prior to maturity are redeemable at their par value plus accrued interest with cash we deposit in the replacement fund. This is subject in many cases to a period of time after the original issuance of the bonds during which they may not be so redeemed.

Environmental Matters

EPA Environmental Regulation

Clean Air Act. We are subject to a number of requirements under the Clean Air Act. Pursuant to the 1977 amendments to the Clean Air Act, the EPA adopted regulations that address visibility impairment in certain federally-protected areas which can be reasonably attributed to specific sources. In September 1991, the EPA issued a final rule that limited sulfur dioxide emissions at NGS. One NGS unit had to comply with this rule in 1997, one in 1998, and the last unit in 1999. Salt River Project is the NGS operating agent. Salt River Project estimates a capital cost of $430 million and annual operations and maintenance costs of approximately $14 million for all three units, for NGS to meet these requirements. We are required to fund 14% of these expenditures. Approximately 93% of these capital costs have been incurred through 1998.

The Clean Air Act Amendments of 1990 (the "Amendments") address, among other things:

- "acid rain,"
- visibility in certain specified areas,
- hazardous air pollutants and
- areas that have not attained national ambient air quality standards.

With respect to "acid rain," the Amendments establish a system of sulfur dioxide emissions "allowances." Each existing utility unit is granted a certain number of "allowances." For Phase II plants, which include our plants, allowances will be required beginning in the year 2000 to operate the plants. On March 5, 1993, the EPA promulgated rules listing allowance allocations applicable to our plants. Based on those allocations, we will have sufficient allowances to permit continued operation of our plants at current levels without installing additional equipment.

In addition, the Amendments require the EPA to set nitrogen oxides emissions limitations. These limitations require certain plants to install additional pollution control equipment. In December 1996, the EPA issued rules for nitrogen oxides emissions limitations that may require us to install additional pollution control equipment at Four Corners by January 1, 2000. On February 14, 1997, we filed a Petition for Review in the United States Court of Appeals for the District of Columbia. We alleged that the EPA improperly classified Four Corners Unit 4 in these rules, thereby subjecting Unit 4 to a more stringent emission limitation. Arizona Public Service Company v. United States Environmental Protection Agency, No. 97-1091. In February 1998, the Court vacated the Unit 4 emission limitation and remanded the issue to EPA for reconsideration. We cannot currently predict how the EPA will respond. However, based on our initial evaluation, we currently estimate our capital cost of complying with the rules may be approximately $4 million.

With respect to protection of visibility in certain specified areas, the Amendments require the EPA to conduct a study concerning visibility impairment in those areas and to identify sources contributing to such impairment.

Interim findings of this study indicate that any beneficial effect on visibility as a result of the Amendments would be offset by expected population and industry growth. The Amendments also require EPA to establish a "Grand Canyon Visibility Transport Commission" to complete a study on visibility impairment in the "Golden Circle of National Parks" in the Colorado Plateau. NGS, Cholla, and Four Corners are located near the Golden Circle of National Parks. The Commission completed its study and on June 10, 1996 submitted its final recommendations to the EPA. The Commission recommended that, beginning in 2000 and every 5 years thereafter, if actual sulfur dioxide emissions from all stationary sources in an eight-state region (including Arizona, New Mexico, Utah, Nevada, and California) exceed the projected emissions, which are projected to decline under the current regulatory scheme, the projected total emissions will be changed to a "regional emissions cap" and an emissions trading program would be implemented to limit total sulfur dioxide emissions in the region. The EPA will consider these recommendations before promulgating final requirements on a regional haze regulatory program which the EPA proposed in July 1997 and which is expected to be finalized by mid-1999.

Under EPA's proposed regional haze program, states would be required to submit plans to meet "presumptive reasonable progress targets" for achieving perceptible improvements in visibility conditions in Federal Class I areas (e.g., national parks) every 10-15 years. The proposal also calls for states to conduct three year "best available retrofit technology" ("BART") reviews on point sources which became operational between 1962 and 1977 and which may normally be anticipated to contribute to regional haze visibility impairment.

Also, in July 1997, EPA promulgated final National Ambient Air Quality Standards for ozone and particulate matter. Pursuant to the rules, the ozone standard is more stringent and a new ambient standard for very fine particles has been established. Congress has enacted legislation that could delay the implementation of regional haze requirements and the particulate matter ambient standard. Because the actual level of emissions controls, if any, for any unit cannot be determined at this time, we currently cannot estimate the capital expenditures, if any, which would result from the final rules. However, we do not currently expect these rules to have a material adverse effect on our financial position or results of operations.

With respect to hazardous air pollutants emitted by electric utility steam generating units, the Amendments require two studies. The results of the first study indicated an impact from mercury emissions from such units in certain unspecified areas. The EPA has not yet stated whether or not mercury emissions limitations will be imposed. Secondly, the EPA will complete a general study in the next several years concerning the necessity of regulating hazardous air pollutant emissions from such units under the Amendments. Because we cannot speculate as to the ultimate requirements by the EPA, we cannot currently estimate the capital expenditures, if any, which may be required as a result of these studies.

Certain aspects of the Amendments may require us to make related expenditures, such as permit fees. We do not expect any of these to have a material impact on our financial position or results of operations.

Superfund. The Comprehensive Environmental Response, Compensation, and Liability Act ("Superfund") establishes liability for the cleanup of hazardous substances found contaminating the soil, water, or air. Those who generated, transported, or disposed of hazardous substances at a contaminated site are among those who are potentially responsible parties ("PRPs"). PRPs may be strictly, and often jointly and severally, liable for the cost of any necessary remediation of the substances. The EPA had previously advised us that the EPA considers us to be a PRP in the Indian Bend Wash Superfund Site, South Area. Our Ocotillo Power Plant is located in this area. We are in the process of conducting an investigation to determine the extent and scope of contamination at the plant site. Based on the information to date, including available insurance coverage and an EPA estimate of cleanup costs, we do not expect this matter to have a material impact on our financial position or results of operations.

Manufactured Gas Plant Sites. We are currently investigating properties which we now own or which were at one time owned by us or our corporate predecessor, that were at one time sites of, or sites associated with, manufactured gas plants. The purpose of this investigation is to determine if:

- waste materials are present
- such materials constitute an environmental or health risk and
- we have any responsibility for remedial action.

Where appropriate, we have begun remediation of certain of these sites. We do not expect these matters to have a material adverse effect on our financial position or results of operations.

Purported Navajo Environmental Regulation

Four Corners and NGS are located on the Navajo Reservation and are held under easements granted by the federal government as well as leases from the Navajo Nation. We are the Four Corners operating agent. We own a 100% interest in Four Corners Units 1, 2, and 3, and a 15% interest in Four Corners Units 4 and 5. We own a 14% interest in NGS Units 1, 2, and 3.

In July 1995, the Navajo Nation enacted the Navajo Nation Air Pollution Prevention and Control Act, the Navajo Nation Safe Drinking Water Act, and the Navajo Nation Pesticide Act (collectively, the "Acts"). Pursuant to the Acts, the Navajo Nation Environmental Protection Agency is authorized to promulgate regulations covering air quality, drinking water, and pesticide activities, including those that occur at Four Corners and NGS. By separate letters dated October 12 and October 13, 1995, the Four Corners participants and the NGS participants requested the United States Secretary of the Interior to resolve their dispute with the Navajo Nation regarding whether or not the Acts apply to operations of Four Corners and NGS. On October 17, 1995, the Four Corners participants and the NGS participants each filed a lawsuit in the District Court of the Navajo Nation, Window Rock District, seeking, among other things, a declaratory judgment that

- their respective leases and federal easements preclude the application of the Acts to the operations of Four Corners and NGS and

- the Navajo Nation and its agencies and courts lack adjudicatory jurisdiction to determine the enforceability of the Acts as applied to Four Corners and NGS.

On October 18, 1995, the Navajo Nation and the Four Corners and NGS participants agreed to indefinitely stay these proceedings so that the parties may attempt to resolve the dispute without litigation. The Secretary and the Court have stayed these proceedings pursuant to a request by the parties. We cannot currently predict the outcome of this matter.

In February 1998, the EPA promulgated regulations specifying those provisions of the Clean Air Act for which it is appropriate to treat Indian tribes in the same manner as states. The EPA indicated that it believes that the Clean Air Act generally would supersede pre-existing binding agreements that may limit the scope of tribal authority over reservations. On April 10, 1998, we filed a Petition for Review in the United States Court of Appeals for the District of Columbia. Arizona Public Service Company v. United States Environmental Protection Agency, No. 98-1196. On February 19, 1999, the EPA promulgated regulations setting forth the EPA's approach to issuing Federal operating permits to covered stationary sources on Indian reservations, pursuant to the Amendments. We are currently evaluating the impact of these regulations.

Water Supply

Assured supplies of water are important for our generating plants. At the present time, we have adequate water to meet our needs. However, conflicting claims to limited amounts of water in the southwestern United States have resulted in numerous court actions in recent years.

Both groundwater and surface water in areas important to our operations have been the subject of inquiries, claims, and legal proceedings which will require a number of years to resolve. We are one of a number of parties in a proceeding before a state court in New Mexico to adjudicate rights to a stream system from which water for Four Corners is derived. (State of New Mexico, in the relation of S.E. Reynolds, State Engineer vs. United States of America, City of Farmington, Utah International, Inc., et al., San Juan County, New Mexico, District Court No. 75-184). An agreement reached with the Navajo Nation in 1985, however, provides that if Four Corners loses a portion of its rights in the adjudication, the Navajo Nation will provide, for a then-agreed upon cost, sufficient water from its allocation to offset the loss.

A summons served on us in early 1986 required all water claimants in the Lower Gila River Watershed in Arizona to assert any claims to water on or before January 20, 1987, in an action pending in Maricopa County Superior Court. (In re The General Adjudication of All Rights to Use Water in the Gila River System and Source, Supreme Court Nos. WC-79-0001 through WC 79-0004 (Consolidated) [WC-1, WC-2, WC-3 and WC-4 (Consolidated)], Maricopa County Nos. W-1, W-2, W-3 and W-4 (Consolidated)). Palo Verde is located within the geographic area subject to the summons. Our rights and the rights of the Palo Verde participants to the use of groundwater and effluent at Palo Verde is potentially at issue in this action. As project manager of Palo Verde, we filed claims that dispute the court's jurisdiction over the Palo Verde participants' groundwater rights and their contractual rights to effluent relating to Palo Verde. Alternatively, we seek confirmation of such rights. Three of our less-utilized power plants are also located within the geographic area subject to the summons. Our claims dispute the court's jurisdiction over our groundwater rights with respect to these plants. Alternatively, we seek confirmation of such rights. Issues important to the claims are pending on appeal to the Arizona Supreme Court. No trial date concerning our water rights claims has been set in this matter.

We have also filed claims to water in the Little Colorado River Watershed in Arizona in an action pending in the Apache County Superior Court. (In re The General Adjudication of All Rights to Use Water in the Little Colorado River System and Source, Supreme Court No. WC-79-0006 WC-6, Apache County No. 6417). Our groundwater resource utilized at Cholla is within the geographic area subject to the adjudication and is therefore potentially at issue in the case. Our claims dispute the court's jurisdiction over our groundwater rights. Alternatively, we seek confirmation of such rights. The parties are in the process of settlement negotiations with respect to this matter. No trial date concerning our water rights claims has been set in this matter.

Although the foregoing matters remain subject to further evaluation, we expect that the described litigation will not have a material adverse impact on our financial position or results of operations.

ITEM 2. PROPERTIES

Accredited Capacity

Our present generating facilities have an accredited capacity as follows:

	Capacity(kW)
Coal:	
Units 1, 2, and 3 at Four Corners	560,000
15% owned Units 4 and 5 at Four Corners	222,000
Units 1, 2, and 3 at Cholla Plant	615,000
14% owned Units 1, 2, and 3 at the Navajo Plant	315,000
	1,712,000
Gas or Oil:	
Two steam units at Ocotillo and two steam units at Saguaro	435,000(1)
Eleven combustion turbine units	493,000
Three combined cycle units	255,000
	1,183,000
Nuclear:	
29.1% owned or leased Units 1, 2, and 3 at Palo Verde	1,086,300
Other	5,600
Total	3,986,900

(1) West Phoenix steam units (108,300 kW) are currently mothballed.

Reserve Margin

Our peak one-hour demand on our electric system was recorded on July 16, 1998 at 5,072,000 kW, compared to the 1997 peak of 4,608,600 kW recorded on August 22. Taking into account additional capacity then available to us under purchase power contracts as well as our own generating capacity, our capability of meeting system demand on July 16, 1998, computed in accordance with accepted industry practices, amounted to 5,139,600 kW, for an installed reserve margin of 3.1%. The power actually available to us from our resources fluctuates from time to time due in part to planned outages and technical problems. The available capacity from sources actually operable at the time of the 1998 peak amounted to 4,862,600 kW, for a margin of (3.9%). Firm purchases from neighboring utilities totaling 1,467,000 kW were in place at the time of the peak ensuring the ability to meet the load requirement, with an actual reserve margin of 7.4%.

Plant Sites Leased from Navajo Nation

NGS and Four Corners are located on land held under easements from the federal government and also under leases from the Navajo Nation. We do not believe that the risk with respect to enforcement of these easements and leases is material. The lease for Four Corners waives until 2001 the requirement that we, as well as our fuel supplier, pay certain taxes to the Navajo Nation. In September 1997, a settlement agreement was finalized between the coal supplier to Four Corners, the Navajo Nation, and us which settled certain issues in the Four Corners lease regarding the obligation of the fuel supplier to pay taxes prior to the expiration of tax waivers in 2001. Pursuant to the agreement, in 1997 we recognized approximately $14 million of pretax earnings related to a partial refund of possessory interest taxes paid by the fuel supplier. The parties also agreed to renegotiate their business relationship before 2001 in an effort to permit the electricity generated at Four Corners to be priced competitively. We cannot currently predict the outcome of this matter. Certain of our transmission lines and almost all of its contracted coal sources are also located on Indian reservations. See "Generating Fuel and Purchased Power — Coal Supply" in Item 1.

Palo Verde Nuclear Generating Station

Palo Verde Leases

See Note 9 of Notes to Financial Statements in Item 8 for a discussion of three sale and leaseback transactions related to Palo Verde Unit 2.

Regulatory

Operation of each of the three Palo Verde units requires an operating license from the NRC. The NRC issued full power operating licenses for Unit 1 in June 1985, Unit 2 in April 1986, and Unit 3 in November 1987. The full power operating licenses, each valid for a period of approximately 40 years, authorize us, as operating agent for Palo Verde, to operate the three Palo Verde units at full power.

Nuclear Decommissioning Costs

The NRC recently amended its rules on financial assurance requirements for the decommissioning of nuclear power plants. The amended rules became effective on November 23, 1998. The amended rules provide that a licensee may use an external sinking fund as the exclusive financial assurance mechanism if the licensee recovers estimated total decommissioning costs through cost of service rates or through a "non-bypassable charge." Other mechanisms are prescribed, including prepayment, if the requirements for exclusive reliance on the external sinking fund mechanism are not met. We currently rely on the external sinking fund mechanism to meet the NRC financial assurance requirements for our interests in Palo Verde Units 1, 2, and 3. The decommissioning costs of Palo Verde Units 1, 2, and 3 are currently included in ACC jurisdictional rates. Proposed ACC rules regarding the introduction of retail electric competition in Arizona (see Note 3) currently provide that decommissioning costs would be recovered through a non-bypassable "system benefits" charge, which would allow us to maintain our external sinking fund mechanism. See Note 13 of Notes to Financial Statements in Item 8 for additional information about our nuclear decommissioning costs.

Palo Verde Liability and Insurance Matters

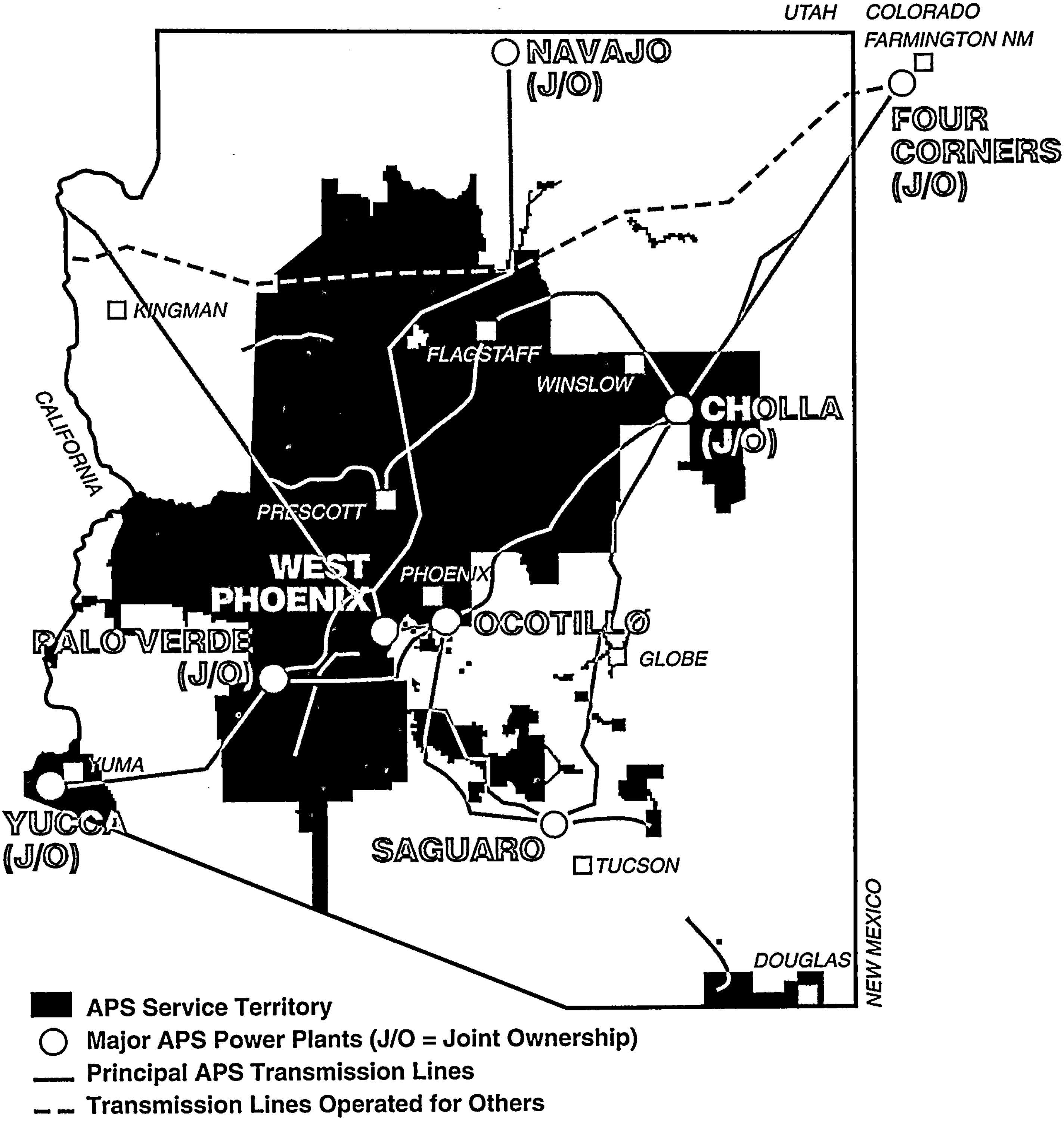
See "Palo Verde Nuclear Generating Station" in Note 12 of Notes to Financial Statements in Item 8 for a discussion of the insurance maintained by the Palo Verde participants, including us, for Palo Verde.

Other Information Regarding Our Properties

See "Environmental Matters" and "Water Supply" in Item 1 with respect to matters having possible impact on the operation of certain of our power plants.

See "Construction Program" in Item 1 and "Financial Review — Capital Needs and Resources" in Item 7 for a discussion of our construction plans.

See Notes 5, 8, and 9 of Notes to Financial Statements in Item 8 with respect to our property not held in fee or held subject to any major encumbrance.


UTAH
COLORADO
FARMINGTON NM
NAVAJO (J/O)
FOUR CORNERS (J/O)
KINGMAN
FLAGSTAFF
WINSLOW
CHOLLA (J/O)
CALIFORNIA
PRESCOTT
WEST PHOENIX
PHOENIX
OCOTILLO
GLOBE
PALO VERDE (J/O)
YUMA
YUCCA (J/O)
SAGUARO
TUCSON
DOUGLAS
NEW MEXICO
APS Service Territory
Major APS Power Plants (J/O = Joint Ownership)
Principal APS Transmission Lines
Transmission Lines Operated for Others

ITEM 3. LEGAL PROCEEDINGS

See "Environmental Matters" and "Water Supply" in Item 1 in regard to pending or threatened litigation and other disputes. See "Regulatory Matters" in Note 3 of Notes to Financial Statements in Item 8 for a discussion of competition and the rules regarding the introduction of retail electric competition in Arizona. On February 28, 1997 and October 16, 1998, we filed lawsuits to protect our legal rights regarding the rules and the amended rules, respectively, and in each complaint we asked the Court for (i) a judgment vacating the retail electric competition rules, (ii) a declaratory judgment that the rules are unlawful because, among other things, they were entered into without proper legal authorization, and (iii) a permanent injunction barring the ACC from enforcing or implementing the rules and from promulgating any other regulations without lawful authority. Arizona Public Service Company v. Arizona Corporation Commission, CV 97-03753 (consolidated under CV 97-03748.) Arizona Public Service Company v. Arizona Corporation Commission, CV 98-18896. On August 28, 1998, we filed two lawsuits to protect our legal rights under the stranded cost order and in its complaints the Company asked the Court to vacate and set aside the order. Arizona Public Service Company v. Arizona Corporation Commission, CV 98-15728. Arizona Public Service Company v. Arizona Corporation Commission, 1-CA-CC-98-0008.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Not applicable.

SUPPLEMENTAL ITEM. EXECUTIVE OFFICERS OF THE REGISTRANT

The Company's executive officers are as follows:

Name	Age At March 1, 1999	Position(s) At March 1, 1999
Richard Snell	68	Chairman of the Board of Directors(1)
William J. Post	48	Chief Executive Officer(1)
Jack E. Davis	52	President, Energy Delivery and Sales(1)
William L. Stewart	55	President, Generation(1)
George A. Schreiber, Jr.	50	Executive Vice President and Chief Financial Officer(1)
Armando B. Flores	55	Executive Vice President, Corporate Business Services
James M. Levine	49	Senior Vice President, Nuclear Generation
Jan H. Bennett	51	Vice President, Distribution
John G. Bohon	53	Vice President, Corporate Services and Human Resources
John R. Denman	56	Vice President, Fossil Generation
Edward Z. Fox	45	Vice President, Environmental/Health/Safety and New Technology Ventures
William E. Ide	52	Vice President, Nuclear Engineering
Nancy C. Loftin	45	Vice President, Chief Legal Counsel and Secretary
Gregg R. Overbeck	52	Vice President, Nuclear Production
Chris N. Froggatt	41	Controller
Michael V. Palmeri	40	Treasurer

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(1) Member of the Board of Directors.

Our executive officers are elected no less often than annually and may be removed by the Board of Directors at any time. The terms served by the named officers in their current positions and the principal occupations (in addition to those stated in the table) of such officers for the past five years have been as follows:

Mr. Snell was elected to his present position as of February 1990. He was also elected Chairman of the Board, President and Chief Executive Officer of Pinnacle West at that time. He retired as President in February 1997 and as Chief Executive Officer in February 1999. Mr. Snell is also a director of Pinnacle West, Aztar Corporation, and Central Newspapers, Inc.

Mr. Post was elected President and Chief Executive Officer in February 1997. In October 1998, he resigned as President and maintained the position of Chief Executive Officer. Prior to that time he was Senior Vice President and Chief Operating Officer (September 1994 - February 1997) and Senior Vice President, Planning, Information and Financial Services (June 1993 - September 1994). Mr. Post was President of Pinnacle West (February 1997 - February 1999) and in February 1999, he became Chief Executive Officer of Pinnacle West. Mr. Post is also a director of Pinnacle West.

Mr. Davis was elected to his present position in October 1998. Prior to that time he was Executive Vice President, Commercial Operations (September 1996 - October 1998) and Vice President, Generation and Transmission (June 1993-September 1996).

Mr. Stewart was elected to his present position in October 1998. Prior to that time he was Executive Vice President, Generation (September 1996 - October 1998), Executive Vice President, Nuclear (May 1994 - September 1996) and Senior Vice President — Nuclear for Virginia Power (since 1989).

Mr. Schreiber was elected to his present position in February 1997. Prior to that time he was Managing Director at PaineWebber, Inc. (since February 1990). Mr. Schreiber was Executive Vice President of Pinnacle West (February 1997 - February 1999), and he is currently President (since February 1999) and Chief Financial Officer (since February 1997) of Pinnacle West. Mr. Schreiber is also a director of Pinnacle West.

Mr. Flores was elected to his present position in October 1998. Prior to that time, he was Senior Vice President, Corporate Business Services (September 1996 - October 1998) and Vice President, Human Resources (1991-1996). Mr. Flores is a director of Harris Trust Bank.

Mr. Levine was elected to his present position in September 1996. Prior to that time he was Vice President, Nuclear Production (since September 1989).

Mr. Bennett was elected to his present position in May 1991.

Mr. Bohon was elected to his present position in October 1998. Prior to that time he was Vice President, Procurement (April 1997 - October 1998) and Director, Corporate Services (December 1989-April 1997).

Mr. Denman was elected to his present position in April 1997. Prior to that time he was Director of Fossil Generation (since 1990).

Mr. Fox was elected to his present position in October 1995. Prior to that time he was Director, Arizona Department of Environmental Quality and Chairman, Wastewater Management Authority of Arizona (July 1991-September 1995).

Mr. Ide was elected to his present position in September 1996. Prior to that time he was Director, Palo Verde Operations (1994-1996) and Palo Verde Unit 1 Plant Manager (1988-1994).

Ms. Loftin was elected to the positions of Vice President and Chief Legal Counsel in September 1996 and has been Secretary since April 1987. Prior to that time, in addition to Secretary, she was Corporate Counsel (since February 1989).

Mr. Overbeck was elected to his current position in July 1995. Prior to that time he was Assistant to Vice President of the Company (January 1994-July 1995).

Mr. Froggatt was elected to his present position in July 1997. Prior to that time he was Director, Accounting Services (since December 1992) of the Company.

Mr. Palmeri was elected to his present position in July 1997. Prior to that time he was Assistant Treasurer (February 1994-July 1997) and Manager of Finance (June 1990-February 1994) of Pinnacle West. He also became Treasurer of Pinnacle West in July 1997.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON STOCK AND RELATED SECURITY HOLDER MATTERS

The Company's common stock is wholly-owned by Pinnacle West and is not listed for trading on any stock exchange. As a result, there is no established public trading market for the Company's common stock.

The chart below sets forth the dividends declared on the Company's common stock for each of the four quarters for 1998 and 1997.

Common Stock Dividends
(Thousands of Dollars)

Quarter	1998	1997
1st Quarter	$42,500	$42,500
2nd Quarter	42,500	42,500
3rd Quarter	42,500	42,500
4th Quarter	42,500	42,500

After payment or setting aside for payment of cumulative dividends and mandatory sinking fund requirements, where applicable, on all outstanding issues of preferred stock, the holders of common stock are entitled to dividends when and as declared out of funds legally available therefor. See Notes 4 and 5 of Notes to Financial Statements in Item 8 for restrictions on retained earnings available for the payment of common stock dividends.

ITEM 6. SELECTED FINANCIAL DATA

	1998	1997	1996	1995	1994
	(Thousands of Dollars)				
Electric Operating Revenues	$2,006,398	$1,878,553	$1,718,272	$1,614,952	$1,626,168
Fuel and Purchased Power	537,501	436,627	325,523	269,798	300,689
Operating Expenses	1,098,086	1,070,101	1,027,541	963,400	957,046
Operating Income	370,811	371,825	365,208	381,754	368,433
Other Income	20,448	21,586	35,217	25,548	44,510
Interest Deductions — Net	136,012	141,918	156,954	167,732	169,457
Net Income	255,247	251,493	243,471	239,570	243,486
Preferred Dividends	9,703	12,803	17,092	19,134	25,274
Earnings for Common Stock	$ 245,544	$ 238,690	$ 226,379	$ 220,436	$ 218,212
Total Assets	$6,393,299	$6,331,142	$6,423,222	$6;418,262	$6,348,261
Capital Structure:					
Common Stock Equity	$1,975,755	$1,849,324	$1,729,390	$1,621,555	$1,571,120
Non-Redeemable Preferred Stock	85,840	142,051	165,673	193,561	193,561
Redeemable Preferred Stock	9,401	29,110	53,000	75,000	75,000
Long-Term Debt Less Current Maturities	1,876,540	1,953,162	2,029,482	2,132,021	2,181,832
Total Capitalization	3,947,536	3,973,647	3,977,545	4,022,137	4,021,513
Current Maturities of Long-Term Debt	164,378	104,068	153,780	3,512	3,428
Commercial Paper	178,830	130,750	16,900	177,800	131,500
Total	$4,290,744	$4,208,465	$4,148,225	$4,203,449	$4,156,441

See "Financial Review" in Item 7 for a discussion of certain information in the foregoing table.

ITEM 7. FINANCIAL REVIEW

In this section, we explain our results of operations, general financial condition, and outlook, including:

- the changes in our earnings from 1997 to 1998 and from 1996 to 1997
- the factors impacting our business, including competition and electric industry restructuring
- the effects of regulatory agreements on our results
- our capital needs and resources and
- Year 2000 technology issues.

Throughout this Financial Review, we refer to specific "Notes" in the Notes to Financial Statements that begin on page 35. These Notes add further details to the discussion.

Results of Operations

1998 Compared with 1997 Our 1998 earnings increased $6.9 million – a 2.9% increase - over 1997 earnings primarily because of an increase in customers, expanded power marketing and trading activities, and lower financing costs. In the comparison, these positive factors more than offset the effects of milder weather, two fuel-related settlements recorded in 1997, and two retail price reductions. See Note 3 for additional information about the price reductions.

In 1998, electric operating revenues increased $128 million primarily because of:

- increased power marketing and trading revenues ($94 million)
- increases in the number of customers and the amount of electricity used by customers ($77 million) and
- miscellaneous factors ($8 million).

As mentioned above, these positive factors were partially offset by the effects of milder weather ($33 million) and reductions in retail prices ($18 million).

Power marketing and trading activities are predominantly short-term opportunity wholesale sales. The increase in power marketing revenues resulted from higher prices, increased activity in Western bulk power markets, and increased sales to large customers in California. The increase in power marketing and trading revenues was accompanied by related increases in purchased power expenses.

The two fuel-related settlements increased 1997 pretax earnings by about $21 million. The income statement reflects these settlements as reductions in fuel expense and as other income.

Operations and maintenance expense increased $15 million because of customer growth, initiatives related to competition, and expansion of our power marketing and trading function.

Depreciation and amortization expense increased $11 million because we had more plant in service.

Financing costs decreased by $9 million primarily because of lower amounts of outstanding debt and preferred stock.

1997 Compared with 1996 Our 1997 earnings increased $12.3 million – a 5.4% increase - over 1996 earnings primarily because of:

- an increase in customers
- a $32 million pretax charge in 1996 for a voluntary severance program
- two fuel-related settlements in 1997 and
- lower financing costs.

These positive factors more than offset the effects of our 1996 regulatory agreement with the Arizona Corporation Commission (ACC), which during 1997 resulted in about $60 million of additional regulatory asset amortization and a $35 million revenue decrease caused by two retail price reductions. See Note 3 and "Results of Operations — Regulatory Agreements" below for additional information. In addition, we recognized $12 million of income tax benefits in 1996 that were not repeated in 1997.

In 1997, electric operating revenues increased $160 million primarily because of:

- increased power marketing revenues ($128 million)
- an increase in the number of customers ($58 million) and
- weather effects ($7 million).

As mentioned above, these positive factors were partially offset by a $35 million revenue decrease caused by retail price reductions. The increase in power marketing revenues resulted from increased activity in Western bulk power markets. This did not significantly affect our earnings because the increase was substantially offset by higher purchased power expenses.

Two fuel-related settlements in 1997 increased pretax earnings by about $21 million. The income statement shows these settlements as reductions in fuel expense and as other income. About $16 million of the settlements related to years prior to 1997 and $5 million related to 1997. We expect the total annual savings from the settlements for at least the next several years to be about $10 million before income taxes. We do not have a fuel adjustment clause as part of our retail rate structure. As a result, we show changes in fuel and purchased power expenses in current earnings.

We lowered our operations and maintenance expenses in 1997 by putting in place a voluntary severance program in late 1996, with related savings reflected in 1997. These savings were partially offset by increased expenses for marketing, information technology, and power plant maintenance.

We decreased our financing costs by $12 million during 1997 by lowering the amounts of outstanding debt and preferred stock.

Regulatory Agreements Regulatory agreements with the ACC affect the results of our operations. The following discussion focuses on two agreements: a 1996 agreement to accelerate the amortization of our regulatory assets and a 1994 settlement to accelerate amortization of our deferred investment tax credits (ITCs).

Under the 1996 agreement with the ACC, we are recovering substantially all of our present regulatory assets through accelerated amortization. The recovery of these assets is taking place over an eight-year period that will end June 30, 2004. For more details, see Note 3. This accelerated amortization increased annual amortization expense by about $120 million ($72 million after taxes).

Also, as part of the 1996 regulatory agreement, we reduced our retail prices by 3.4% effective July 1, 1996. This reduces revenue by about $48.5 million annually ($29 million after taxes). We also agreed to share future cost savings with our customers, which resulted in the following additional retail price reductions:

- $17.6 million annually ($10.5 million after income taxes), or 1.2%, effective July 1, 1997, and

- $17 million annually ($10 million after income taxes), or 1.1%, effective July 1, 1998.

We expect to file with the ACC for another retail price decrease of approximately $10.8 million annually ($6.5 million after income taxes) to become effective July 1, 1999. The amount and timing of the price decrease are subject to ACC approval. This will be the last price decrease under the 1996 regulatory agreement.

We discuss above, in "Results of Operations," the factors that offset the earnings impact of the accelerated regulatory asset amortization and the price decreases.

As part of the 1994 rate settlement, we accelerated amortization of substantially all deferred ITCs over a five-year period that ends on December 31, 1999. The amortization of ITCs is shown on our income statement as Other Income — Income Taxes. It decreases annual income tax expense by about $28 million. Beginning in 2000, no further benefits will be reflected in income tax expense. See Note 10.

Capital Needs and Resources

Our capital requirements consist primarily of capital expenditures and optional and mandatory redemptions of long-term debt and preferred stock. We pay for our capital requirements with:

- cash from our operations
- annual cash payments from Pinnacle West of $50 million from 1996 through 1999 (see Note 3) and
- to the extent necessary, external financing.

During the period from 1996 through 1998, we paid for all of our capital expenditures with cash from our operations. We expect to do so in 1999 through 2001 as well.

Our capital expenditures in 1998 were $327 million. Our projected capital expenditures for the next three years are: 1999, $328 million; 2000, $317 million; and 2001, $300 million. These amounts include about $30-$35 million each year for nuclear fuel. In general, most of the projected capital expenditures are for:

- expanding transmission and distribution capabilities to meet customer growth
- upgrading existing utility property and
- environmental purposes.

In addition, we are considering expanding certain of our operations over the next several years, which may result in additional expenditures. We currently believe that there will be opportunities to expand our investment in generating assets in the next five years. It is expected that these generating assets would be organized in a newly created non-regulated affiliate under Pinnacle West.

During 1998, we redeemed about $145 million of long-term debt and $76 million of preferred stock, including premiums, with cash from operations and long- and short-term debt. Our long-term debt and preferred stock redemption requirements and payment obligations on a capitalized lease for the next three years are: 1999, $260 million; 2000, $115 million; and 2001, $2 million. On March 1, 1999, we redeemed all $95 million of our outstanding preferred stock. Based on market conditions and optional call provisions, we may make optional redemptions of long-term debt from time to time.

As of December 31, 1998, we had credit commitments from various banks totaling about $400 million, which were available either to support the issuance of commercial paper or to be used as bank borrowings. At the end of 1998, we had about $179 million of commercial paper and $125 million of long-term bank borrowings outstanding.

In 1998, we issued $100 million of unsecured long-term debt and in February 1999, we issued $125 million of unsecured long-term debt.

Although provisions in our first mortgage bond indenture, articles of incorporation, and ACC financing orders establish maximum amounts of additional first mortgage bonds that we may issue, we do not expect any of these provisions to limit our ability to meet our capital requirements.

Competition and Industry Restructuring

The electric industry is undergoing significant change. It is moving to a competitive, market-based structure from a highly-regulated, cost-based environment in which companies have been entitled to recover their costs and to earn fair returns on their invested capital in exchange for commitments to serve all customers within designated service territories. In December 1996, the ACC adopted rules that provide a framework for the introduction of retail electric competition in Arizona and adopted amendments to the rules in August 1998. On January 11, 1999, the ACC issued an order which stayed the amended rules and granted waivers from compliance with the rules to all affected utilities (including us) pending further ACC decisions. On February 5, 1999, ACC hearing officers issued recommendations for changes to the amended rules. These recommended changes were further amended by an ACC Procedural Order dated March 12, 1999. See Note 3 for additional information about these rules and other competitive developments, including an agreement with Salt River Project Agricultural Improvement and Power District (Salt River Project). We cannot currently predict when or if the amended rules will be further modified, when the stay of the amended rules will be lifted, or when retail electric competition will be introduced in Arizona with respect to affected utilities.

The rules as recommended indicate that the ACC will allow affected utilities the opportunity to fully recover unmitigated stranded costs, but do not set forth the mechanisms for determining and recovering such costs. On June 22, 1998, the ACC issued an order on stranded cost determination and recovery and on February 5, 1999, an ACC hearing officer issued recommended changes to that order. These recommended changes were further amended by an ACC Procedural Order dated March 12, 1999. See Note 3 for additional information on proposed modifications to the stranded cost order.

An Arizona joint legislative committee studied electric utility restructuring issues in 1996 and 1997. In May 1998, a law was enacted to facilitate implementation of retail electric competition in the state. Additionally, legislation related to electric competition has been proposed in the United States Congress. See Note 3 for a discussion of legislative developments.

We believe that further ACC decisions, legislation at the Arizona and federal levels, and perhaps amendments to the Arizona Constitution will ultimately be required before significant implementation of retail electric competition can lawfully occur in Arizona. Until it has been determined how competition will be implemented in Arizona, including the manner in which stranded costs will be addressed, we cannot accurately predict the impact of full retail competition on our financial position, cash flows, or results of operations. As competition in the electric industry continues to evolve, we will continue to evaluate strategies and alternatives that will position us to compete effectively in a restructured industry.

We prepare our financial statements in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in its financial statements. Our existing regulatory orders and the current regulatory environment support our accounting practices related to regulatory assets, which amounted to about $900 million at December 31, 1998. Under the 1996 regulatory agreement, the ACC accelerated the amortization of substantially all of our regulatory assets to an eight-year period that will end June 30, 2004. If we cease to be cost-based regulated, we would no longer be able to apply the provisions of SFAS No. 71 to part or all of our operations, which could have a material impact on our financial statements. See Note 1 for additional information on regulatory accounting.

Year 2000 Readiness Disclosure

Overview As the year 2000 approaches, many companies face problems because many computer systems and equipment will not properly recognize calendar dates beginning with the year 2000. We are addressing the Year 2000 issue as described below. We initiated a comprehensive company-wide Year 2000 program during 1997 to review and resolve all Year 2000 issues in mission critical systems (systems and equipment that are key to business function, health, and safety) in a timely manner to ensure the reliability of electric service to our customers. This included a company-wide awareness program of the Year 2000 issue.

The following chart shows Year 2000 readiness of our mission critical systems as of January 31, 1999:

Inventory	Assessment	Remediation & Testing
100%	100%	70%*

* Estimated to be at 100% by June 30, 1999, except one Palo Verde unit as discussed below.

Discussion We have been actively implementing and replacing systems and technology since 1995 for general business reasons unrelated to the Year 2000, and these actions have resulted in substantially all of our major information technology (IT) systems becoming Year 2000 ready. The major IT systems that were, and are being, implemented and replaced include the following:

- Work Management
- Materials Management
- Energy Management
- Payroll
- Financial
- Human Resources
- Trouble Call Management
- Computer and Communications Network Upgrades
- Geographic Information Management
- Customer Information System and
- Palo Verde Site Work Management.

We have made, and will continue to make, certain modifications to computer hardware and software systems and applications, including IT and non-IT systems, in an effort to ensure they are capable of handling changing business needs, including dates in the year 2000 and thereafter. In addition, we are analyzing other IT systems and non-IT systems, including embedded technology and real-time process control systems, for potential modifications.

We have inventoried and assessed essentially all mission critical IT and non-IT systems and equipment. We are 70% complete with the remediation and testing of these systems. Remediation and testing is expected to be completed by June 30, 1999, for all mission critical systems, except for those items that can only be completed during maintenance outages at Palo Verde, which will be completed for the last unit, which is substantially identical to the other two units, during the last half of 1999. We have an internal audit/quality review team that is periodically reviewing the individual Year 2000 projects and their Year 2000 readiness.

We currently estimate that we will spend about $5 million relating to Year 2000 issues, about $3 million of which has been spent to date. This includes an estimated allocation of payroll costs for our employees working on Year 2000 issues, and costs for consultants, hardware, and software. We do not separately track other internal costs. This does not include costs incurred since 1995 to implement and replace systems for reasons unrelated to the Year 2000, as discussed above. Our cost to address the Year 2000 issue is charged to operating expenses as incurred and has not had, and is not expected to have, a material adverse effect on our financial position, cash flows, or results of operations. We expect to fund this cost with available cash balances and cash provided by operations.

We are communicating with our significant suppliers, business partners, other utilities, and large customers to determine the extent to which we may be affected by these third parties' plans to remediate their own Year 2000 issues in a timely manner. We have been interfacing with suppliers of systems, services, and materials in order to assess whether their schedules for analysis and remediation of Year 2000 issues are timely and to assess their ability to continue to supply required services and materials.

We are also working with the North American Electric Reliability Council (NERC) through the Western Systems Coordinating Council (WSCC) to develop operational plans for stable grid operation that will be used by other utilities and us in the western United States. These plans are expected to be completed by June 30, 1999. However, we cannot currently predict the effect on us if the systems of these other companies are not Year 2000 ready.

We currently expect that our most reasonably likely worst case Year 2000 scenario would be intermittent loss of power to customers, similar to an outage during a severe weather disturbance. In this situation, we would restore power as soon as possible by, among other things, re-routing power flows. We do not currently expect that this scenario would have a material adverse effect on our financial position, cash flows, or results of operations.

We are working to develop our own contingency plans to handle Year 2000 issues, including the most reasonably likely worst case scenario, discussed above, and we expect these plans to be completed by June 30, 1999. As discussed above, we have also been working with NERC and WSCC to develop contingency plans related to grid operation.

Accounting Matters

We describe two new accounting rules in Note 2. First, the new rule on energy trading and risk management is effective in 1999. We do not expect it to have a material impact on our financial results. Secondly, the new standard on derivatives is effective for us in 2000. We are currently evaluating what impact it will have on our financial statements. Also, see Note 13 for a description of a proposed standard on accounting for certain liabilities related to closure or removal of long-lived assets.

Risk Management

Our operations include managing market risks related to changes in interest rates, commodity prices, and investments held by the nuclear decommissioning trust fund.

Interest Rate and Equity Risk Our major financial market risk exposure is changing interest rates. Changing interest rates will affect interest paid on variable rate debt and interest earned by the nuclear decommissioning trust fund. Our policy is to manage interest rates through the use of a combination of fixed and floating rate debt. The nuclear decommissioning fund also has risks associated with changing market values of equity investments. Nuclear decommissioning costs are recovered in rates.

The tables below present contractual balances of our long-term debt and commercial paper at the expected maturity dates as well as the fair value of those instruments on December 31, 1998 and December 31, 1997. The weighted average interest rates for the various debt presented are actual as of December 31, 1998 and December 31, 1997.

Expected Maturity/Principal Repayment
December 31, 1998
(Thousands of Dollars)

	Short-Term		Variable Long-Term		Fixed Long-Term	
	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
1999	6.21%	$ 178,830	-	$ -	7.24%	$ 164,378
2000	-	-	-	-	5.79%	114,711
2001	-	-	-	-	7.48%	2,488
2002	-	-	-	-	8.13%	125,000
2003	-	-	5.69%	125,000	-	-
Years thereafter	-	-	3.39%	456,860	7.75%	1,058,963
Total		$ 178,830		$ 581,860		$ 1,465,540
Fair Value		$ 178,830		$ 581,860		$ 1,525,900

Expected Maturity/Principal Repayment
December 31, 1997
(Thousands of Dollars)

	Short-Term		Variable Long-Term		Fixed Long-Term	
	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
1998	6.27%	$ 130,750	-	$ -	7.62%	$ 104,068
1999	-	-	-	-	7.25%	164,378
2000	-	-	-	-	5.83%	104,711
2001	-	-	-	-	7.48%	2,488
2002	-	-	6.25%	150,000	8.13%	125,000
Years thereafter	-	-	3.62%	439,990	7.92%	973,628
Total		$ 130,750		$ 589,990		$ 1,474,273
Fair Value		$ 130,750		$ 589,990		$ 1,504,417

Commodity Price Risk We utilize a variety of derivative instruments including exchange-traded futures, options, and swaps as part of our overall risk management strategies and for trading purposes. In order to reduce the risk of adverse price fluctuations in the electricity and natural gas markets, we enter into futures and/or option transactions to hedge certain natural gas held in storage as well as certain expected purchases and sales of natural gas and electricity. The changes in market value of such contracts have a high correlation to the price changes in the hedged commodity. Gains and losses related to derivatives that qualify as hedges of expected transactions are recognized in income when the underlying hedged physical transaction closes (deferral method). Gains and losses on derivatives utilized for trading are recognized in income on a current basis (the mark to market method).

We have prepared a sensitivity analysis to estimate our exposure to the market risk of our derivative position for natural gas and electricity. With respect to these derivatives, a potential adverse price movement of 10% in the market price of natural gas and electricity from the December 31, 1998 levels would decrease the fair value of these instruments by approximately $1 million. This analysis does not include the favorable impact that the same hypothetical price movement would have on expected physical purchases and sales of natural gas and electricity.

We are exposed to credit losses in the event of non-performance or non-payment by counterparties. We use a credit management process to assess and monitor the financial viability of counterparties. We do not expect counterparty defaults to materially impact our financial condition, results of operations, or net cash flows.

Forward-Looking Statements

The above discussion contains forward-looking statements that involve risks and uncertainties. Words such as "estimates," "expects," "anticipates," "plans," "believes," "projects," and similar expressions identify forward-looking statements. These risks and uncertainties include, but are not limited to, the ongoing restructuring of the electric industry; the outcome of the regulatory proceedings relating to the restructuring; regulatory, tax, and environmental legislation; our ability to successfully compete outside our traditional regulated markets; regional economic conditions, which could affect customer growth; the cost of debt and equity capital; weather variations affecting customer usage; technological developments in the electric industry; and Year 2000 issues.

These factors and the other matters discussed above may cause future results to differ materially from historical results, or from results or outcomes we currently expect or seek.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

See "Financial Review" in Item 7 for a discussion of quantitative and qualitative disclosures about market risk.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS

See Note 14 of Notes to Financial Statements for the selected quarterly financial data required to be presented in this Item.

REPORT OF MANAGEMENT

The primary responsibility for the integrity of the Company's financial information rests with management, which has prepared the accompanying financial statements and related information. Such information was prepared in accordance with generally accepted accounting principles appropriate in the circumstances and based on management's best estimates and judgments. Materiality was given due consideration. These financial statements have been audited by independent auditors and their report is included.

Management maintains and relies upon systems of internal accounting controls. A limiting factor in all systems of internal accounting control is that the cost of the system should not exceed the benefits to be derived. Management believes that the Company's system provides the appropriate balance between such costs and benefits.

Periodically the internal accounting control system is reviewed by both the Company's internal auditors and its independent auditors to test for compliance. Reports issued by the internal auditors are released to management, and such reports or summaries thereof are transmitted to the Audit Review Committee of the Board of Directors and the independent auditors on a timely basis.

The Audit Review Committee, composed solely of outside directors, meets periodically with the internal auditors and independent auditors (as well as management) to review the work of each. The internal auditors and independent auditors have free access to the Audit Review Committee, without management present, to discuss the results of their audit work.

Management believes that the Company's systems, policies, and procedures provide reasonable assurance that operations are conducted in conformity with the law and with management's commitment to a high standard of business conduct.

William J. Post
Chief Executive Officer

George A. Schreiber, Jr.
Executive Vice President
and Chief Financial Officer

INDEPENDENT AUDITORS' REPORT

We have audited the accompanying balance sheets of Arizona Public Service Company as of December 31, 1998 and 1997 and the related statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1998. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of the Company at December 31, 1998 and 1997 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1998 in conformity with generally accepted accounting principles.

Deloitte & Touche LLP

Deloitte & Touche LLP
Phoenix, Arizona
March 4, 1999

ARIZONA PUBLIC SERVICE COMPANY
STATEMENTS OF INCOME

	Year Ended December 31,		
	1998	1997	1996
		(Thousands of Dollars)	
Electric Operating Revenues	$ 2,006,398	$ 1,878,553	$ 1,718,272
Fuel Expenses:			
Fuel for electric generation	231,967	201,341	230,393
Purchased power	305,534	235,286	95,130
Total	537,501	436,627	325,523
Operating Revenues Less Fuel Expenses	1,468,897	1,441,926	1,392,749
Other Operating Expenses:			
Operations and maintenance excluding fuel expenses	414,041	399,434	430,714
Depreciation and amortization (Note 1)	376,574	365,671	297,210
Income taxes (Note 10)	192,207	184,737	178;513
Other taxes	115,264	120,259	121,104
Total	1,098,086	1,070,101	1,027,541
Operating Income	370,811	371,825	365,208
Other Income (Deductions):			
Allowance for equity funds used during construction	—	—	5,209
Income taxes (Note 10)	32,751	31,413	45,552
Other — net	(12,303)	(9,827)	(15,544)
Total	20,448	21,586	35,217
Income Before Interest Deductions	391,259	393,411	400,425
Interest Deductions:			
Interest on long-term debt	137,214	140,931	147,666
Interest on short-term borrowings	7,481	9,404	10,621
Debt discount, premium and expense	7,580	7,791	8,176
Capitalized interest	(16,263)	(16,208)	(9,509)
Total	136,012	141,918	156,954
Net Income	255,247	251,493	243,471
Preferred Stock Dividend Requirements	9,703	12,803	17,092
Earnings for Common Stock	$ 245,544	$ 238,690	$ 226,379

See Notes to Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
BALANCE SHEETS
ASSETS

	December 31, 1998	December 31, 1997
	(Thousands of Dollars)	
Utility Plant (Notes 5, 8 and 9):		
Electric plant in service and held for future use	$ 7,265,604	$ 7,009,059
Less accumulated depreciation and amortization	2,814,762	2,620,607
Total	4,450,842	4,388,452
Construction work in progress	228,643	237,492
Nuclear fuel, net of amortization of $68,569 and $66,081	51,078	51,624
Utility Plant — net	4,730,563	4,677,568
Investments and Other Assets (Note 13)	183,549	164,906
Current Assets:		
Cash and cash equivalents	5,558	12,552
Accounts receivable:		
Service customers	205,999	141,022
Other	23,213	31,313
Allowance for doubtful accounts	(1,725)	(1,338)
Accrued utility revenues	67,740	58,559
Materials and supplies (at average cost)	69,074	70,634
Fossil fuel (at average cost)	13,978	9,621
Deferred income taxes (Note 10)	3,999	3,496
Other	26,695	24,529
Total Current Assets	414,531	350,388
Deferred Debits:		
Regulatory asset for income taxes (Note 10)	400,795	458,369
Rate synchronization cost deferral	303,660	358,871
Unamortized costs of reacquired debt	53,744	63,501
Unamortized debt issue costs	14,916	15,303
Other	291,541	242,236
Total Deferred Debits	1,064,656	1,138,280
Total	$ 6,393,299	$ 6,331,142

See Notes to Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
BALANCE SHEETS
LIABILITIES

	December 31, 1998	December 31, 1997
	(Thousands of Dollars)	
Capitalization (Notes 4 and 5):		
Common stock	$ 178,162	$ 178,162
Additional paid - in capital	1,195,625	1,142,364
Retained earnings	601,968	528,798
Common stock equity	1,975,755	1,849,324
Non-redeemable preferred stock	85,840	142,051
Redeemable preferred stock	9,401	29,110
Long-term debt less current maturities	1,876,540	1,953,162
Total Capitalization	3,947,536	3,973,647
Current Liabilities:		
Commercial paper (Note 6)	178,830	130,750
Current maturities of long-term debt (Note 5)	164,378	104,068
Accounts payable	145,139	107,423
Accrued taxes	59,827	85,886
Accrued interest	31,218	31,660
Customer deposits	26,815	29,116
Other	16,755	19,588
Total Current Liabilities	622,962	508,491
Deferred Credits and Other:		
Deferred income taxes (Note 10)	1,312,007	1,345,177
Deferred investment tax credit (Note 10)	32,465	60,093
Unamortized gain — sale of utility plant (Note 9)	77,787	82,363
Customer advances for construction	31,451	29,294
Other	369,091	332,077
Total Deferred Credits and Other	1,822,801	1,849,004
Commitments and Contingencies (Note 12)		
Total	$ 6,393,299	$ 6,331,142

ARIZONA PUBLIC SERVICE COMPANY
STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	1998	1997	1996
	(Thousands of Dollars)		
Cash Flows from Operations:			
Net income	$ 255,247	$ 251,493	$ 243,471
Items not requiring cash:			
Depreciation and amortization	376,574	365,671	297,210
Nuclear fuel amortization	32,856	32,702	33,566
Allowance for equity funds used during construction	—	—	(5,209)
Deferred income taxes — net	(26,374)	(55,278)	(12,717)
Deferred investment tax credit — net	(27,628)	(27,630)	(27,630)
Changes in certain current assets and liabilities:			
Accounts receivable — net	(56,490)	(11,069)	(33,044)
Accrued utility revenues	(9,181)	(3,089)	(1,951)
Materials, supplies and fossil fuel	(2,797)	7,793	11,945
Other current assets	(2,166)	(1,762)	(4,928)
Accounts payable	33,731	(56,710)	68,788
Accrued taxes	(26,059)	(441)	3,500
Accrued interest	(442)	(7,455)	(2,565)
Other current liabilities	(4,654)	(3,997)	(522)
Other — net	(29,641)	46,625	7,616
Net cash provided	512,976	536,853	577,530
Cash Flows from Investing:			
Capital expenditures	(319,142)	(307,876)	(258,598)
Capitalized interest	(16,263)	(16,208)	(9,509)
Other	(8,593)	(15,982)	(102)
Net cash used	(343,998)	(340,066)	(268,209)
Cash Flows from Financing:			
Long-term debt	126,245	109,906	205,830
Short-term borrowings — net	48,080	113,850	(160,900)
Common equity infusion from parent	50,000	50,000	50,000
Dividends paid on common stock	(170,000)	(170,000)	(170,000)
Dividends paid on preferred stock	(10,279)	(13,307)	(17,416)
Repayment of preferred stock	(75,517)	(47,201)	(50,360)
Repayment and reacquisition of long-term debt	(144,501)	(240,004)	(172,343)
Net cash used	(175,972)	(196,756)	(315,189)
Net increase (decrease) in cash and cash equivalents	(6,994)	31	(5,868)
Cash and cash equivalents at beginning of year	12,552	12,521	18,389
Cash and cash equivalents at end of year	$ 5,558	$ 12,552	$ 12,521
Supplemental Disclosure of Cash Flow Information:			
Cash paid during the year for:			
Interest (excluding capitalized interest)	$128,627	$ 141,991	$ 150,603
Income taxes	$235,475	$ 236,676	$ 158,553

See Notes to Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
STATEMENTS OF RETAINED EARNINGS

	Year Ended December 31,		
	1998	1997	1996
	(Thousands of Dollars)		
Retained earnings at beginning of year	$ 528,798	$ 460,106	$ 403,843
Add: Net income	255,247	251,493	243,471
Total	784,045	711,599	647,314
Deduct:			
Dividends:			
Common stock (Notes 4 and 5)	170,000	170,000	170,000
Preferred stock (at required rates) (Note 4)	9,703	12,801	17,092
Other	2,374	—	116
Total deductions	182,077	182,801	187,208
Retained earnings at end of year	$ 601,968	$ 528,798	$ 460,106

See Notes to Financial Statements.

APS
NOTES TO FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Nature of Operations We are Arizona's largest electric utility, with 799,000 customers. We provide wholesale or retail electric service to the entire state of Arizona, with the exception of Tucson and about one-half of the Phoenix area.

Accounting Records Our accounting records are maintained in accordance with generally accepted accounting principles (GAAP). The preparation of financial statements in accordance with GAAP requires the use of estimates by management. Actual results could differ from those estimates.

Regulatory Accounting We are regulated by the Arizona Corporation Commission (ACC) and the Federal Energy Regulatory Commission (FERC). The accompanying financial statements reflect the rate-making policies of these commissions. We prepare our financial statements in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in its financial statements.

Our major regulatory assets are deferred income taxes (see Note 10) and rate synchronization cost deferrals (see "Rate Synchronization Cost Deferrals" in this Note). These items, combined with miscellaneous regulatory assets and liabilities, amounted to approximately $900 million at December 31, 1998 and $1.0 billion at December 31, 1997. Most of these items are included in "Deferred Debits" on the Balance Sheets. Under the 1996 regulatory agreement (see Note 3), the ACC accelerated the amortization of substantially all of our regulatory assets to an eight-year period that will end June 30, 2004. We record the accelerated portion of the regulatory asset amortization, approximately $120 million pretax in 1998 and 1997 and $60 million pretax in 1996, in depreciation and amortization expense on the Statements of Income.

During 1997, the Emerging Issues Task Force (EITF) of the Financial Accounting Standards Board (FASB) issued EITF 97-4. EITF 97-4 requires that SFAS No. 71 be discontinued no later than when legislation is passed or a rate order is issued that contains sufficient detail to determine its effect on the portion of the business being deregulated, which could result in write-downs or write-offs of physical and/or regulatory assets. Additionally, the EITF determined that regulatory assets should not be written off if they are to be recovered from a portion of the entity which continues to apply SFAS No. 71.

Although rules have been proposed for transitioning generation services to competition, there are many unresolved issues. We continue to apply SFAS No. 71 to our generation operations. If rate recovery of regulatory assets is no longer probable, whether due to competition or regulatory action, we would be required to write off the remaining balance as an extraordinary charge to expense.

Common Stock All of the outstanding shares of our common stock are owned by Pinnacle West. See Note 4.

Utility Plant and Depreciation Utility plant is the term we use to describe the business property and equipment that supports electric service. We report utility plant at its original cost, which includes:

- material and labor
- contractor costs
- construction overhead costs (where applicable) and
- capitalized interest or an allowance for funds used during construction.

We charge retired utility plant, plus removal costs less salvage realized, to accumulated depreciation. See Note 13 for information on a proposed accounting standard that impacts accounting for removal costs.

We record depreciation on utility property on a straight-line basis. For the years 1996 through 1998 the rates, as prescribed by our regulators, ranged from a low of 1.51% to a high of 20%. The weighted-average rate for 1998 was 3.32%. We depreciate non-utility property and equipment over the estimated useful lives of the related assets, ranging from 3 to 50 years.

Capitalized Interest In 1997 we began capitalizing interest in accordance with SFAS No. 34, "Capitalization of Interest Cost." Capitalized interest represents the cost of debt funds used to finance construction of utility plant. Plant construction costs, including capitalized interest, are recovered in authorized rates through depreciation when completed projects are placed into commercial operation. Capitalized interest does not represent current cash earnings. The rate used to calculate capitalized interest for 1998 was 6.88% and for 1997 was 7.25%.

Prior to 1997 we accrued an allowance for funds used during construction (AFUDC). AFUDC represented the cost of debt and equity funds used to finance construction of utility plant. AFUDC did not represent current cash earnings. AFUDC has been calculated using a composite rate of 7.75% for 1996.

Revenues We record electric operating revenues on the accrual basis, which includes estimated amounts for service rendered but unbilled at the end of each accounting period.

Rate Synchronization Cost Deferrals As authorized by the ACC, operating costs (excluding fuel) and financing costs of Palo Verde Units 2 and 3 were deferred from the commercial operation dates (September 1986 for Unit 2 and January 1988 for Unit 3) until the date the units were included in a rate order (April 1988 for Unit 2 and December 1991 for Unit 3). Beginning July 1, 1996, the deferrals are being amortized over an eight-year period in accordance with the 1996 regulatory agreement (see Note 3). Prior to July 1, 1996, the deferrals were amortized over thirty-five year periods. Amortization of the deferrals is included in depreciation and amortization expense on the Statements of Income.

Nuclear Fuel We charge nuclear fuel to fuel expense by using the unit-of-production method. The unit-of-production method is an amortization method that is based on actual physical usage. We divide the cost of the fuel by the estimated number of thermal units that we expect to produce with that fuel. We then multiply that rate by the number of thermal units that we produce within the current period. This provides us with current period nuclear fuel expense.

We also charge nuclear fuel expense for the permanent disposal of spent nuclear fuel. The United States Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel, and it charges us $0.001 per kWh of nuclear generation. See Note 12 for information about spent nuclear fuel disposal. In addition, Note 13 has information on nuclear decommissioning costs.

Reacquired Debt Costs When we incur gains or losses on debt that we retire prior to maturity, we amortize those gains and losses over the remaining original life of the debt. In accordance with the 1996 regulatory agreement (see Note 3), the ACC accelerated our amortization of the regulatory asset for reacquired debt costs to an eight-year period that will end June 30, 2004. The accelerated portion of the regulatory asset amortization is included in depreciation and amortization expense in the Statements of Income.

Cash and Cash Equivalents For purposes of reporting cash flows, we define cash equivalents as highly liquid debt instruments that will mature in three months or less.

Reclassifications We have reclassified certain prior year amounts for comparison purposes with 1998.

2. Accounting Matters

In 1998 we adopted SFAS No. 130, "Reporting Comprehensive Income." This standard changes the reporting of certain items previously reported in the common stock equity section of the balance sheet. The effects of adopting SFAS No. 130 were not material to our financial statements.

In November 1998, the Financial Accounting Standards Board's Emerging Issues Task Force issued EITF 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," which is effective for us in 1999. EITF 98-10 requires energy trading contracts to be measured at fair value as of the balance sheet date with the gains and losses included in earnings and separately disclosed in the financial statements or footnotes. We have evaluated the impact of this rule and believe the effects are not material to our financial statements.

In June 1998, the Financial Accounting Standards Board issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," which is effective for us in 2000. SFAS No. 133 requires that entities recognize all derivatives as either assets or liabilities on the balance sheet and measure those instruments at fair value. The standard also provides specific guidance for accounting for derivatives designated as hedging instruments. We are currently evaluating what impact this standard will have on our financial statements.

3. Regulatory Matters

Electric Industry Restructuring

State In December 1996, the ACC adopted rules that provide a framework for the introduction of retail electric competition in Arizona. The rules, as amended, became effective on August 10, 1998, and on December 10, 1998, the ACC adopted the amended rules without any modifications that would have a significant impact on us. We believe that certain provisions of the 1996 ACC rules and the amended rules are deficient and we have filed lawsuits to protect our legal rights regarding the 1996 rules and the amended rules. These lawsuits are pending but two related cases filed by other utilities have been partially decided in a manner adverse to those utilities' positions.

On January 11, 1999, the ACC issued an order which stayed the amended rules, granted reconsideration of the decision to make the rules permanent, and directed the hearing division of the ACC to establish a procedural order for further action on these rules. The order also granted waivers from compliance with the rules for us, and all affected utilities.

On February 5, 1999, the ACC Hearing Division issued recommendations for changes to the amended rules. The recommended changes to the amended rules were further modified by a Procedural Order of the ACC Hearing Division dated March 12, 1999. The recommended rules include the following major provisions:

- They would apply to virtually all Arizona electric utilities regulated by the ACC, including APS.
- Each utility must make at least 20% of its 1995 retail peak demand available for competitive generation supply.
- The rules become effective when the ACC makes a final decision on each utility's stranded costs and unbundled rates (Final Decision Date) or January 1, 2001, whichever comes first.
- Subject to the 20% requirement, all utility customers with single premise loads of one megawatt or greater will be eligible for competitive electric services on the Final Decision Date. Customers with single premise loads of 40 kilowatts or greater may aggregate loads to meet this one megawatt requirement.
- When effective, residential customers will be phased in at 1¼% per quarter calculated beginning on January 1, 1999, subject to the 20% requirement above.
- Electric service providers that get Certificates of Convenience and Necessity (CC&Ns) from the ACC can supply only competitive services, including electric generation, but not electric transmission and distribution.
- Affected utilities must file ACC tariffs with separate pricing for electric services provided for noncompetitive services.
- ACC shall allow a reasonable opportunity for recovery of unmitigated stranded costs (see "Stranded Costs" below).

- Absent an ACC waiver, prior to January 1, 2001, each affected utility must transfer all competitive generation assets and services either to an unaffiliated party or to a separate corporate affiliate.

- Affiliate transaction rules prohibit a utility and its competitive electric affiliates from sharing certain assets, employees, and information.

If approved by the ACC, the rules would be subject to the formal rulemaking process under Arizona statute. In compliance with statutory procedural requirements, ACC oral proceedings on the matter would be scheduled no sooner than 30 days after the proposed rules are published by the Secretary of State.

We cannot currently predict when or if the amended rules will be further modified, when the stay of the amended rules will be lifted, or when retail electric competition will be introduced in Arizona.

Stranded Costs On June 22, 1998, the ACC issued an Order on stranded cost determination and recovery. We believe that certain provisions of the stranded cost order are deficient and in August 1998, we filed two lawsuits to protect our legal rights relating to the order.

On February 5, 1999, the ACC Hearing Division issued recommended changes to the June 1998 stranded cost order. These recommended changes were further amended by an ACC Procedural Order dated March 12, 1999. The recommended changes to the stranded cost order would be effective upon approval of the ACC. The recommended order, as amended on March 12, 1999, allows each affected utility to choose from five options for the recovery of stranded costs:

- Net Revenues Lost Methodology is the difference between generation revenues under traditional regulation and generation revenues under competition. This option provides for declining recovery percentages for stranded costs over a five-year recovery period. Regulatory assets are to be fully recovered under their presently authorized amortization schedule. In accordance with a 1996 regulatory agreement, the ACC accelerated the amortization of substantially all of our regulatory assets to an eight-year period that ends June 30, 2004.

- Divestiture/Auction Methodology allows a utility to divest all or substantially all of its generating assets, including regulatory assets associated with generation, in order to collect 100 percent of the difference between net sales price and book value of generating assets divested over a ten-year period, with no return on the unamortized balance.

- Financial Integrity Methodology allows a utility "sufficient revenues to meet minimum financial ratios" for a period of ten years.

- Settlement Methodology allows a settlement to be agreed upon by the ACC and a utility.

- Any combination of the above if shown to be in the best interests of all affected parties.

Legislative Initiatives An Arizona joint legislative committee studied electric utility industry restructuring issues in 1996 and 1997. In conjunction with that study, the Arizona legislative counsel prepared memoranda in late 1997 related to the legal authority of the ACC to deregulate the Arizona electric utility industry. The memoranda raise a question as to the degree to which the ACC may, under the Arizona Constitution, deregulate any portion of the electric utility industry and allow rates to be determined by market forces. This latter issue has been subsequently decided by lower courts in favor of the ACC in four separate lawsuits, two of which are unrelated.

In May 1998, a law was enacted to facilitate implementation of retail electric competition in Arizona. The law includes the following major provisions:

- Arizona's largest government-operated electric utility (Salt River Project) and, at their option, smaller municipal electric systems must (i) make at least 20% of their 1995 retail peak demand available to electric service providers by December 31, 1998 and for all retail customers by December 31, 2000; (ii) decrease rates by at least 10% over a ten-year period beginning as early as January 1, 1991; (iii) implement procedures and public processes comparable to those already applicable to public service corporations for establishing the terms, conditions, and pricing of electric services as well as certain other decisions affecting retail electric competition;

- describes the factors which form the basis of consideration by Salt River Project in determining stranded costs; and

- metering and meter reading services must be provided on a competitive basis during the first two years of competition only for customers having demands in excess of one megawatt (and that are eligible for competitive generation services), and thereafter for all customers receiving competitive electric generation.

In addition, the Arizona legislature will review and make recommendations for the 1999 legislature on certain competitive issues.

Agreement with Salt River Project On April 25, 1998, we entered into a Memorandum of Agreement with Salt River Project in anticipation of, and to facilitate, the opening of the Arizona electric industry. The Agreement contains the following major components:

- Both parties would amend the Territorial Agreement to remove any barriers to the provision of competitive electricity supply and non-distribution services.

- Both parties would amend the Power Coordination Agreement to lower the price that we will pay Salt River Project for purchased power by approximately $17 million (pretax) during the first full year that the Agreement is effective and by lesser annual amounts during the next seven years.

- Both parties agreed on certain legislative positions regarding electric utility restructuring at the state and federal level.

Certain provisions of the Agreement (including those relating to the amendments of the Territorial Agreement and the Power Coordination Agreement) are affected by the timing of the introduction of competition. See "ACC Rules" above. On February 18, 1999, the ACC approved the Agreement.

General We believe that further ACC decisions, legislation at the Arizona and federal levels, and perhaps amendments to the Arizona Constitution (which would require a vote of the people) will ultimately be required before significant implementation of retail electric competition can lawfully occur in Arizona. Until the manner of implementation of competition, including addressing stranded costs, is determined, we cannot accurately predict the impact of full retail competition on our financial position, cash flows, or results of operation.

As competition in the electric industry continues to evolve, we will continue to evaluate strategies and alternatives that will position us to compete in the new regulatory environment.

Federal The Energy Policy Act of 1992 and recent rulemakings by FERC have promoted increased competition in the wholesale electric power markets. We do not expect these rules to have a material impact on our financial statements.

Several electric utility reform bills have been introduced during recent congressional sessions, which as currently written would allow consumers to choose their electricity suppliers by 2000 or 2003. These bills, other bills that are expected to be introduced, and ongoing discussions at the federal level suggest a wide range of opinion that will need to be narrowed before any substantial restructuring of the electric utility industry can occur.

1996 Regulatory Agreement

In April 1996, the ACC approved a regulatory agreement between the ACC Staff and us. The major provisions of this agreement are:

- An annual rate reduction of approximately $48.5 million ($29 million after income taxes), or 3.4% on average for all customers except certain contract customers, effective July 1, 1996.

- Recovery of substantially all of our present regulatory assets through accelerated amortization over an eight-year period that will end June 30, 2004, increasing annual amortization by approximately $120 million ($72 million after income taxes). See Note 1.

- A formula for sharing future cost savings between customers and shareholders (price reduction formula), referencing a return on equity (as defined) of 11.25%.

- A moratorium on filing for permanent rate changes prior to July 2, 1999, except under the price reduction formula and under certain other limited circumstances.

- Infusion of $200 million of common equity into us by Pinnacle West, in annual payments of $50 million starting in 1996.

Based on the price reduction formula, the ACC approved retail price decreases of approximately $17.6 million ($10.5 million after income taxes), or 1.2%, effective July 1, 1997, and approximately $17 million ($10 million after income taxes), or 1.1%, effective July 1, 1998. We expect to file with the ACC for another retail price decrease of approximately $10.8 million annually ($6.5 million after income taxes) to become effective July 1, 1999. The amount and timing of the price decrease are subject to ACC approval. This will be the last price decrease under the 1996 regulatory agreement.

4. Common and Preferred Stocks

On March 1, 1999, we redeemed all of our preferred stock. Common and preferred stock balances at December 31, 1998 and 1997 are shown below:

	Authorized	Number of Shares Outstanding 1998	Number of Shares Outstanding 1997	Par Value Per Share	Par Value Outstanding 1998 (Thousands of Dollars)	Par Value Outstanding 1997 (Thousands of Dollars)	Call Price Per Share(a)
Common Stock	100,000,000	71,264,947	71,264,947	$ 2.50	$178,162	$178,162	—
Preferred Stock:							
Non-Redeemable:							
$1.10	160,000	139,030	145,559	$ 25.00	$3,476	$ 3,639	$ 27.50
$2.50	105,000	86,440	97,252	50.00	4,322	4,863	51.00
$2.36	120,000	32,520	38,506	50.00	1,626	1,925	51.00
$4.35	150,000	62,986	68,386	100.00	6,299	6,839	102.00
Serial preferred	1,000,000						
$2.40 Series A		200,587	234,839	50.00	10,029	11,742	50.50
$2.625 Series C		214,895	231,572	50.00	10,745	11,579	51.00
$2.275 Series D		90,691	164,101	50.00	4,534	8,205	50.50
$3.25 Series E		304,475	312,991	50.00	15,224	15,649	51.00
Serial preferred	4,000,000(b)						
Adjustable rate — Series Q		295,851	352,851	100.00	29,585	35,285	(c)
Serial preferred	10,000,000						
$1.8125 Series W		—	1,693,016	25.00	—	42,325	
Total		1,427,475	3,339,073		$ 85,840	$142,051	
Redeemable:							
Serial preferred:							
$10.00 Series U		94,011	291,098	$100.00	$ 9,401	$ 29,110	

(a) The actual call price per share is the indicated amount plus any accrued dividends.

(b) This authorization also covers all outstanding redeemable preferred stock.

(c) Dividend rate adjusted quarterly to 2% below that of certain United States Treasury securities, but in no event less than 6% or greater than 12% per annum. Redeemable at par.

We cannot pay common stock dividends or acquire shares of common stock if preferred stock dividends or sinking fund requirements are in arrears.

Redeemable preferred stock transactions during each of the three years in the period ended December 31, 1998 are as follows:

	Number of Shares Outstanding			Par Value Outstanding (Thousands of Dollars)		
Description	1998	1997	1996	1998	1997	1996
Balance, January 1	291,098	530,000	750,000	$29,110	$53,000	$75,000
Retirements:						
$10.00 Series U	(197,087)	(118,902)	(90,000)	(19,709)	(11,890)	(9,000)
$7.875 Series V	---	(120,000)	(130,000)	---	(12,000)	(13,000)
Balance, December 31	94,011	291,098	530,000	$ 9,401	$29,110	$53,000

APS
NOTES TO FINANCIAL STATEMENTS

5. Long-Term Debt

The following table presents long-term debt outstanding:

	Maturity Dates (a)	Interest Rates	December 31 1998 (Thousands	1997 of Dollars)
First mortgage bonds	1998	7.625%	$ -	$100,000
	1999	7.625%	100,000	100,000
	2000	5.75%	100,000	100,000
	2002	8.125%	125,000	125,000
	2004	6.625%	85,000	85,000
	2020	10.25%	100,550	109,550
	2021	9.5%	45,140	45,140
	2021	9%	72,370	72,370
	2023	7.25%	91,900	97,150
	2024	8.75%	121,668	121,918
	2025	8%	88,300	88,500
	2028	5.5%	25,000	25,000
	2028	5.875%	154,000	154,000
Unamortized discount and premium			(6,482)	(7,033)
Pollution control bonds	2024-2033	Adjustable rate (b)	456,860	439,990
Collateralized loan	1999-2000	5.375% - 6.125%	20,000	10,000
Unsecured note	2005	6.25%	100,000	-
Senior notes(c)	1999	6.72%	50,000	50,000
Senior notes(c)	2006	6.75%	100,000	100,000
Debentures	2025	10%	75,000	75,000
Bank loans	2003	Adjustable rate (d)	125,000	150,000
Capitalized lease obligation	1998-2001	7.48% (e)	11,612	15,645
Total long-term debt			2,040,918	2,057,230
Less current maturities			164,378	104,068
Total long-term debt less current maturities			$1,876,540	$1,953,162

(a) This schedule does not reflect the timing of redemptions that may occur prior to maturity.

(b) The weighted-average rate for the years ended December 31, 1998 was 3.39% and for December 31, 1997 was 3.62%. Changes in short-term interest rates would affect the costs associated with this debt.

(c) *We issued $150 million of first mortgage bonds ("senior note mortgage bonds") to the senior note trustee as collateral for the senior notes. The senior note mortgage bonds have the same interest rate, interest payment dates, maturity, and redemption provisions as the senior notes. Our payments of principal, premium, and/or interest on the senior notes satisfy our corresponding payment obligations on the senior note mortgage bonds. As long as the senior note mortgage bonds secure the senior notes, the senior notes will effectively rank equally with the first mortgage bonds. When we repay all of our first mortgage bonds, other than those that secure senior notes, the senior note mortgage bonds will no longer secure the senior notes and will cease to be outstanding.*

(d) *The weighted-average rate at December 31, 1998 was 5.69% and at December 31, 1997 was 6.25%. Changes in short-term interest rates would affect the costs associated with this debt.*

(e) *Represents the present value of future lease payments (discounted at an interest rate of 7.48%) on a combined cycle plant that was sold and leased back (see Note 9).*

Principal payments due on total long-term debt and sinking fund requirements over the next five years are:

- $164.4 million in 1999
- $114.7 million in 2000
- $2.5 million in 2001
- $125 million in 2002 and
- $125 million in 2003.

First mortgage bondholders have a lien on substantially all utility plant assets (other than nuclear fuel, transportation equipment, and the combined cycle plant). The mortgage bond indenture restricts the payment of common stock dividends under certain conditions. These conditions did not exist at December 31, 1998.

6. Lines of Credit

We had committed lines of credit with various banks of $400 million at December 31, 1998 and 1997, which were available either to support the issuance of commercial paper or to be used for bank borrowings. The commitment fees at December 31, 1998 and 1997 for these lines of credit ranged from .07% to .15% per annum. We had long-term bank borrowings of $125 million outstanding at December 31, 1998, and $150 million outstanding at December 31, 1997.

Our commercial paper borrowings outstanding were $178.8 million at December 31, 1998, and $130.8 million at December 31, 1997. The weighted average interest rate on commercial paper borrowings was 6.21% on December 31, 1998 and 6.27% on December 31, 1997. By Arizona statute, our short-term borrowings cannot exceed 7% of our total capitalization unless approved by the ACC.

7. Fair Value of Financial Instruments

We believe that the carrying amounts of our cash equivalents and commercial paper are reasonable estimates of their fair values at December 31, 1998 and 1997 due to their short maturities. We hold investments in debt and equity securities for purposes other than trading. The December 31, 1998 and 1997 fair values of these investments, which we determine by using quoted market values or by discounting cash flows at rates equal to our cost of capital, approximate their carrying amounts.

The carrying value of our long-term debt (excluding a capitalized lease obligation) was $2.03 billion on December 31, 1998, with an estimated fair value of $2.11 billion. On December 31, 1997, the carrying value of our long-term debt (excluding a capitalized lease obligation) was $2.04 billion, with an estimated fair value of $2.08 billion. The fair value estimates are based on quoted market prices of the same or similar issues.

8. Jointly-Owned Facilities

We share ownership of some of our generating and transmission facilities with other companies. The following table shows our interest in those jointly-owned facilities at December 31, 1998. Our share of operating and maintaining these facilities is included in the income statement in operations and maintenance expense.

	Percent Owned by Company	Plant in Service	Accumulated Depreciation	Construction Work in Progress
		(Thousands of Dollars)		
Generating Facilities:				
Palo Verde Nuclear Generating Station Units 1 and 3	29.1%	$1,821,620	$670,403	$20,152
Palo Verde Nuclear Generating Station Unit 2 (see Note 9)	17.0%	568,184	224,502	9,839
Four Corners Steam Generating Station Units 4 and 5	15.0%	150,165	69,764	312
Navajo Steam Generating Station Units 1, 2, and 3	14.0%	203,356	90,237	25,560(a)
Cholla Steam Generating Station Common Facilities (b)	62.8%(c)	67,513	37,096	267
Transmission Facilities:				
ANPP 500KV System	35.8%(c)	66,547	20,282	1,384
Navajo Southern System	31.4%(c)	26,918	17,285	21
Palo Verde-Yuma 500KV System	23.9%(c)	11,376	4,215	-
Four Corners Switchyards	27.5%(c)	3,071	1,780	143
Phoenix-Mead System	17.1%(c)	36,324	536	-

(a) The construction costs at Navajo are primarily related to the installation of scrubbers required by environmental legislation.

(b) PacifiCorp owns Cholla Unit 4 and we operate the unit for them. The common facilities at the Cholla Plant are jointly-owned.

(c) Weighted average of interests.

9. Leases

In 1986, we sold about 42% of our share of Palo Verde Unit 2 and certain common facilities in three separate sale leaseback transactions. We account for these leases as operating leases. The gain of approximately $140.2 million was deferred and is being amortized to operations expense over 29.5 years, the original term of the leases. There are options to renew the leases for two additional years and to purchase the property for fair market value at the end of the lease terms. Consistent with the ratemaking treatment, an amount equal to the annual lease payments is included in rent expense. A regulatory asset is recognized for the difference between lease payments and rent expense calculated on a straight-line basis.

The average amounts to be paid for the Palo Verde Unit 2 leases are as follows:

Year	(In millions)
1999	$ 40.1
2000	46.3
2001-2015	49.0

In accordance with the 1996 regulatory agreement (see Note 3), the ACC accelerated our amortization of the regulatory asset for leases to an eight-year period that will end June 30, 2004. The accelerated amortization is included in depreciation and amortization expense on the Statements of Income. The balance of this regulatory asset at December 31, 1998 was $48.5 million. Lease expense was approximately $42 million in each of the years 1996 through 1998.

We have a capital lease on a combined cycle plant, which we sold and leased back. The lease requires semiannual payments of $2.6 million through June 2001, and includes renewal and purchase options based on fair market value. The plant is included in plant in service at its original cost of $54.4 million; accumulated amortization at December 31, 1998 was $48.6 million.

In addition, we lease certain land, buildings, equipment, and miscellaneous other items through operating rental agreements with varying terms, provisions, and expiration dates.

Approximate miscellaneous lease expense was:

- $9.6 million in 1998
- $7.8 million in 1997 and
- $9.7 million in 1996.

Estimated future minimum lease commitments, excluding the Palo Verde and combined cycle leases, are as follows:

Year	(In millions)
1999	$ 13
2000	13
2001	14
2002	14
2003	13
Thereafter	91
Total future commitments	$ 158

10. Income Taxes

We are included in Pinnacle West's consolidated tax return. However, when Pinnacle West allocates income taxes to us, it does so based on our taxable income or loss alone. Because of a 1994 rate settlement agreement, we are amortizing almost all of our investment tax credits (ITCs) over 5 years (1995-1999).

Certain assets and liabilities are reported differently for income tax purposes than they are for financial statements. The tax effect of these differences is recorded as deferred taxes. We calculate deferred taxes using the current income tax rates.

We have recorded a regulatory asset on our Balance Sheet in accordance with SFAS No. 71. This regulatory asset is for certain temporary differences, primarily AFUDC equity. We amortize this amount as the differences reverse. We have been able to accelerate the amortization of the regulatory asset for income taxes to an eight-year period that will end June 30, 2004. This is a result of a 1996 regulatory agreement with the ACC. We are including this accelerated amortization in depreciation and amortization expense on the Statements of Income.

The components of income tax expense are as follows:

	Year Ended December 31,		
	1998	1997	1996
	(Thousands of Dollars)		
Current:			
Federal	$170,806	$187,701	$137,531
State	42,652	48,531	35,777
Total current	213,458	236,232	173,308
Deferred	(26,374)	(55,278)	(869)
Change in valuation allowance	—	—	(11,848)
Investment tax credit amortization	(27,628)	(27,630)	(27,630)
Total expense	$159,456	$153,324	$132,961

Multiplying income before income taxes by the statutory federal income tax rate does not equal the amount recorded as income tax expense because of the following:

	Year Ended December 31,		
	1998	1997	1996
	(Thousands of Dollars)		
Federal income tax expense at 35% statutory rate	$145,146	$141,686	$131,751
Increases (reductions) in tax expense resulting from:			
Tax under book depreciation	17,848	14,694	19,229
Investment tax credit amortization	(27,628)	(27,630)	(27,630)
State income tax — net of federal income tax benefit	23,024	23,160	20,790
Change in valuation allowance	—	—	(10,269)
Other	1,066	1,414	(910)
Income tax expense	$159,456	$153,324	$132,961

The components of the net deferred income tax liability were as follows:

	December 31,	
	1998	1997
	(Thousands of Dollars)	
Deferred tax assets:		
Deferred gain on Palo Verde Unit 2 sale/leaseback	$ 31,285	$ 33,257
Other	74,292	77,412
Total deferred tax assets	105,577	110,669
Deferred tax liabilities:		
Plant related	1,112,897	1,096,222
Regulatory asset for income taxes	161,836	185,084
Rate synchronization deferrals	122,130	144,908
Other	16,722	26,136
Total deferred tax liabilities	1,413,585	1,452,350
Deferred income taxes — net	$1,308,008	$1,341,681

11. Retirement Plans and Other Benefits

Voluntary Severance Plan We sponsored a voluntary severance plan in 1996. There was a pretax charge of $31.7 million in 1996 recorded mostly as operations and maintenance expense. This pretax charge included additional pension and postretirement benefit expense. Employees who participated in the plan were credited with an additional year of age and service when their pension and postretirement benefits were calculated. The additional expenses recorded in 1996 for this plan were $2.3 million for pension and $5.4 million for postretirement benefits.

Pension Plan We sponsor a defined benefit pension plan for our employees. A defined benefit plan specifies the amount of benefits a plan participant is to receive using information about the participant. The plan covers nearly all APS employees. Our employees do not contribute to this plan. Generally, we calculate the benefits under this plan based on age, years of service, and pay. We fund the plan by contributing at least the minimum amount required under Internal Revenue Service regulations but no more than the maximum tax-deductible amount. The assets in the plan at December 31, 1998 were mostly domestic and international common stocks and bonds and real estate. Pension expense, including administrative and severance costs, was:

- $9.8 million in 1998
- $8.7 million in 1997 and
- $14.9 million in 1996.

The following table shows the components of net pension cost before consideration of amounts capitalized or billed to others and excluding severance costs of $2.9 million in 1996:

	1998	1997	1996
		(Thousands of Dollars)	
Service cost — benefits earned during the period	$24,126	$19,881	$22,861
Interest cost on projected benefit obligation	50,863	47,824	44,602
Expected return on plan assets	(53,883)	(47,422)	(41,958)
Amortization of:			
Transition asset	(3,216)	(3,216)	(3,216)
Prior service cost	2,063	2,063	1,727
Net actuarial losses	---	---	721
Net periodic pension cost	$19,953	$19,130	$24,737

The following table shows a reconciliation of the funded status of the plan to the amounts recognized in the balance sheets:

	1998	1997
	(Thousands of Dollars)	
Funded status — Pension plan assets less than projected benefit obligation	$(38,957)	$(87,208)
Unrecognized net transition asset	(23,159)	(26,376)
Unrecognized prior service cost	22,562	24,625
Unrecognized net actuarial losses/(gains)	(38,916)	16,989
Net pension amount recognized in the balance sheets	$(78,470)	$(71,970)

The following table sets forth the defined benefit pension plan's change in projected benefit obligation for the plan years 1998 and 1997:

	1998	1997
	(Thousands of Dollars)	
Projected pension benefit obligation at beginning of year	$699,600	$601,094
Service cost	24,126	19,881
Interest cost	50,863	47,824
Benefit payments	(29,384)	(29,741)
Plan amendments	---	5,537
Actuarial losses/(gains)	(23,976)	55,005
Projected pension benefit obligation at end of year	$721,229	$699,600

The following table sets forth the defined benefit pension plan's change in the fair value of plan assets for the plan years 1998 and 1997:

	1998	1997
	(Thousands of Dollars)	
Fair value of pension plan assets at beginning of year	$612,392	$533,444
Actual return on plan assets	85,764	87,583
Employer contributions	13,500	21,106
Benefit payments	(29,384)	(29,741)
Fair value of pension plan assets at end of year	$682,272	$612,392

We made the assumptions below to calculate the pension liability:		
Discount rate	7.00%	7.25%
Rate of increase in compensation levels	3.50%	4.50%
Expected long-term rate of return on assets	10.00%	9.00%

Employee Savings Plan Benefits We also sponsor a defined contribution savings plan that is offered to nearly all APS employees. In a defined contribution plan, the benefits a participant is to receive result from regular contributions to a participant account. Under this plan, we make matching contributions to participant accounts. We recorded expenses for this plan of:

- $3.9 million in 1998
- $3.7 million in 1997 and
- $3.4 million in 1996.

Postretirement Plans We provide medical and life insurance benefits to retired employees. Employees must retire to become eligible for these retirement benefits, which are based on years of service and age. For the medical insurance plans, retirees make contributions to cover a portion of the plan costs. For the life insurance plan, retirees do not make contributions to cover a portion of the plan costs. We retain the right to change or eliminate these benefits.

Funding is based upon actuarially determined contributions that take tax consequences into account. Plan assets consist primarily of domestic stocks and bonds. The postretirement benefit expense was:

- $8.7 million for 1998
- $9.4 million for 1997 and
- $15.8 million for 1996.

The following table shows the components of net periodic postretirement benefit costs before consideration of amounts capitalized or billed to others and excluding severance costs of $9.6 million in 1996:

	1998	1997	1996
	(Thousands of Dollars)		
Service cost — benefits earned during the period	$ 7,676	$ 6,865	$ 7,974
Interest cost on accumulated benefit obligation	15,610	14,315	13,395
Expected return on plan assets	(12,001)	(8,706)	(6,696)
Amortization of:			
Transition obligation	7,652	7,652	8,223
Net actuarial gains	(2,927)	(2,647)	(1,344)
Net periodic postretirement benefit cost	$16,010	$17,479	$21,552

The following table shows a reconciliation of the funded status of the plan to the amounts recognized in the balance sheets:

	1998	1997
	(Thousands of Dollars)	
Funded status — postretirement plan assets less than accumulated benefit obligation	$(21,912)	$(46,435)
Unrecognized net obligation at transition	107,134	114,787
Unrecognized net actuarial gains	(86,131)	(78,209)
Net postretirement amount recognized in the balance sheets	$ (909)	$ (9,857)

The following table sets forth the postretirement benefit plan's change in accumulated benefit obligation for the plan years 1998 and 1997:

	1998	1997
	(Thousands of Dollars)	
Accumulated postretirement benefit obligation at beginning of year	$197,581	$179,550
Service cost	7,676	6,865
Interest cost	15,610	14,315
Benefit payments	(10,347)	(6,732)
Actuarial losses	24,802	3,583
Accumulated postretirement benefit obligation at end of year	$235,322	$197,581

The following table sets forth the postretirement benefit plan's change in the fair value of plan assets for the plan years 1998 and 1997:

	1998	1997
	(Thousands of Dollars)	
Fair value of postretirement plan assets at beginning of year	$151,146	$109,763
Actual return on plan assets	47,284	30,846
Employer contributions	25,327	17,269
Benefit payments	(10,347)	(6,732)
Fair value of postretirement plan assets at end of year	$213,410	$151,146

We made the assumptions below to calculate the postretirement liability:		
Discount rate	7.00%	7.25%
Expected long-term rate of return on assets-after tax	8.73%	7.75%
Initial health care cost trend rate - under age 65	7.50%	8.00%
Initial health care cost trend rate - age 65 and over	6.50%	7.00%
Ultimate health care cost trend rate (reached in the year 2002)	5.00%	5.00%

Assuming a 1% increase in the health care cost trend rate, the 1998 cost of postretirement benefits other than pensions would increase by approximately $5 million and the accumulated benefit obligation as of December 31, 1998 would increase by approximately $37 million.

Assuming a 1% decrease in the health care cost trend rate, the 1998 cost of postretirement benefits other than pensions would decrease by approximately $4 million and the accumulated benefit obligations as of December 31, 1998 would decrease by approximately $32 million.

12. Commitments and Contingencies

Litigation We are a party to various claims, legal actions, and complaints arising in the ordinary course of business. In our opinion, the ultimate resolution of these matters will not have a material adverse effect on our financial statements.

Palo Verde Nuclear Generating Station Under the Nuclear Waste Policy Act, DOE was to develop the facilities necessary for the storage and disposal of spent fuel and to have the first such facility in operation by 1998. That facility was to be a permanent repository, but DOE has announced that such a repository now cannot be completed before 2010. In response to lawsuits filed over DOE's obligation to accept used nuclear fuel, the United States Court of Appeals for the D.C. Circuit has ruled that DOE had an obligation to begin accepting used nuclear fuel in 1998. However, the Court refused to issue an order compelling DOE to begin moving used fuel. Instead, the Court ruled that any damages to utilities should be sought under the standard contract signed between DOE and utilities, including APS. The United States Supreme Court has refused to grant review of the D.C. Circuit's decision. In July 1998, we filed a Petition for Review regarding DOE's obligation to begin accepting spent nuclear fuel.

We have capacity in existing fuel storage pools at Palo Verde which, with certain modifications, could accommodate all fuel expected to be discharged from normal operation of Palo Verde through about 2002, and believe we could augment that wet storage with new facilities for on-site dry storage of spent fuel for an indeterminate period of operation beyond 2002, subject to obtaining any required governmental approvals. We currently estimate that we will incur $113 million (in 1998 dollars) over the life of Palo Verde for our share of the costs related to the on-site interim storage of spent nuclear fuel. Beginning in 1999, we will accrue these costs as a component of fuel expense, meaning the charges will be accrued as the fuel is burned. During 1998, we recorded a liability and a regulatory asset of $35 million for on-site interim nuclear fuel storage costs related to nuclear fuel burned prior to 1999. We currently believe that spent fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation beyond 2002.

The Palo Verde participants have insurance for public liability resulting from nuclear energy hazards to the full limit of liability under federal law. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $200 million and the balance by an industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the programs exceed the accumulated funds, we could be assessed retrospective premium adjustments. The maximum assessment per reactor under the program for each nuclear incident is approximately $88 million, subject to an annual limit of $10 million per incident. Based upon our 29.1% interest in the three Palo Verde units, our maximum potential assessment per incident for all three units is approximately $77 million, with an annual payment limitation of approximately $9 million.

The Palo Verde participants maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.75 billion, a substantial portion of which must first be applied to stabilization and decontamination. We have also secured insurance against portions of any increased cost of generation or purchased power and business interruption resulting from a sudden and unforeseen outage of any of the three units. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions and exclusions.

Fuel and Purchased Power Commitments We are a party to various fuel and purchased power contracts with terms expiring from 1999 through 2020 that include required purchase provisions. We estimate our 1999 contract requirements to be about $132 million. However, this amount may vary significantly pursuant to certain provisions in such contracts that permit us to decrease our required purchases under certain circumstances.

We must reimburse certain coal providers for amounts incurred for coal mine reclamation. We estimate our share of the total obligation to be about $103 million. The portion of the coal mine reclamation obligation related to coal already burned is about $62 million at December 31, 1998 and is included in "Deferred Credits — Other" in the Balance Sheet. A regulatory asset has been established for amounts not yet recovered from ratepayers. In accordance with the 1996 regulatory agreement (see Note 3), the ACC began accelerated amortization of our regulatory asset for coal mine reclamation costs over an eight-year period that will end June 30, 2004. Amortization is included in depreciation and amortization expense on the Statements of Income. The balance of the regulatory asset at December 31, 1998 was about $51 million.

Construction Program Total capital expenditures in 1999 are estimated at $328 million.

13. Nuclear Decommissioning Costs

We recorded $11.4 million for decommissioning expense in each of the years 1998, 1997, and 1996. We estimate it will cost about $1.8 billion ($452 million in 1998 dollars) to decommission our 29.1% share of the three Palo Verde units. The decommissioning costs are expected to be incurred over a 14-year period beginning in 2024. We charge decommissioning costs to expense over each unit's operating license term and include them in the accumulated depreciation balance until each unit is retired. Nuclear decommissioning costs are recovered in rates.

Our current estimates are based on a 1998 site-specific study for Palo Verde that assumes the prompt removal/dismantlement method of decommissioning. An independent consultant prepared this study for us. We are required to update the study every three years.

To fund the costs we expect to incur to decommission the plant, we established external trusts in accordance with Nuclear Regulatory Commission (NRC) regulations. The trust accounts are reported in "Investments and Other Assets" in our Balance Sheets at their market value of $145.6 million at December 31, 1998 and $124.6 million at December 31, 1997. We invest the trust funds primarily in fixed-income securities and domestic stock and classify them as available for sale. Realized and unrealized gains and losses are reflected in accumulated depreciation.

In February 1996, the FASB issued an exposure draft, "Accounting for Certain Liabilities Related to Closure or Removal of Long-Lived Assets." This proposed standard would require the estimated present value of the cost of decommissioning and certain other removal costs to be recorded as a liability, along with an offsetting plant asset when a decommissioning or other removal obligation is incurred. The FASB has indicated that a revised exposure draft will be issued in 1999.

APS
NOTES TO FINANCIAL STATEMENTS

14. Selected Quarterly Financial Data (Unaudited)

Quarterly financial information for 1998 and 1997 is as follows:

Quarter Ended	Electric Operating Revenues	Operating Income(a)	Net Income	Earnings for Common Stock
		(Thousands of Dollars)		
1998				
March 31	$380,423	$ 63,541	$ 31,935	$ 29,057
June 30	441,715	81,299	52,184	49,749
September 30	740,734	155,079	133,193	130,846
December 31	443,526	70,892	37,935	35,892
1997				
March 31	$379,021	$61,439	$28,645	$25,019
June 30	458,751	99,706	69,493	66,298
September 30	632,821	150,892	129,699	126,715
December 31	407,960	59,788	23,656	20,658

(a) Our utility business is seasonal in nature, with the peak sales periods generally occurring during the summer months. Comparisons among quarters of a year may not represent overall trends and changes in operations.

15. Stock Options

Our parent company, Pinnacle West Capital Corporation, offers several stock incentive plans for our officers, our parent company's officers, and key employees.

The plans provide for the granting of new options or awards of up to 3.5 million shares at a price per option not less than fair market value on the date the option is granted. The plans also provide for the granting of any combination of stock appreciation rights or dividend equivalents. The awards outstanding under the various incentive plans at December 31, 1998 approximate 1,497,012 non-qualified stock options, 158,121 restricted shares, and no dividend equivalent shares, incentive stock options, or stock appreciation rights.

The FASB issued SFAS No. 123, "Accounting for Stock-Based Compensation," which was effective beginning in 1996. This statement encourages, but does not require, that a company record compensation expense based on the fair value method. We continue to recognize expense based on Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees." If we had recorded compensation expense based on the fair value method, our net income would have been reduced to the following pro forma amounts:

	1998	1997	1996
	(Thousands of Dollars)		
Net income			
As reported	$255,247	$251,493	$243,471
Pro forma (fair value method)	$254,640	$251,142	$243,291

We did not consider compensation costs for stock options granted before January 1, 1995. Therefore, future reported net income may not be representative of this compensation cost calculation.

In order to present the pro forma information above, we calculated the fair value of each fixed stock option in the incentive plans using the Black-Scholes option-pricing model. The fair value was calculated based on the date the option was granted. The following weighted-average assumptions were also used in order to calculate the fair value of the stock options:

	1998	1997	1996
Risk-free interest rate	4.54%	5.66%	5.77%
Dividend growth	3.03%	4.50%	4.50%
Volatility	18.80%	15.63%	17.10%
Expected life (months)	60	60	58

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Not applicable.

ITEM 11. EXECUTIVE COMPENSATION

Not applicable.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Not applicable.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Not applicable.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENTS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

Financial Statements

See the Index to Financial Statements in Part II, Item 8 on page 28.

Exhibits Filed

Exhibit No.		*Description*
10.1[a]	—	1999 Management Variable Incentive Plan
10.2[a]	—	1999 Senior Management Variable Incentive Plan
10.3[a]	—	1999 Officers Variable Incentive Plan
23.1	—	Consent of Deloitte & Touche LLP
27.1	—	Financial Data Schedule

In addition to those Exhibits shown above, the Company hereby incorporates the following Exhibits pursuant to Exchange Act Rule 12b-32 and Regulation §229.10(d) by reference to the filings set forth below:

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
3.1	Bylaws, amended as of February 20, 1996	3.1 to 1995 Form 10-K Report	1-4473	3-29-96
3.2	Resolution of Board of Directors temporarily suspending Bylaws in part	3.2 to 1994 Form 10-K Report	1-4473	3-30-95
3.3	Articles of Incorporation, restated as of May 25, 1988	4.2 to Form S-3 Registration Nos. 33-33910 and 33-55248 by means of September 24, 1993 Form 8-K Report	1-4473	9-29-93
3.4	Certificates pursuant to Sections 10-152.01 and 10-016, Arizona Revised Statutes, establishing Series A through V of the Company's Serial Preferred Stock	4.3 to Form S-3 Registration Nos. 33-33910 and 33-55248 by means of September 24, 1993 Form 8-K Report	1-4473	9-29-93

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
3.5	Certificate pursuant to Section 10-016, Arizona Revised Statutes, establishing Series W of the Company's Serial Preferred Stock	4.4 to Form S-3 Registration Nos. 33-33910 and 33-55248 by means of September 24, 1993 Form 8-K Report	1-4473	9-29-93
4.1	Mortgage and Deed of Trust Relating to the Company's First Mortgage Bonds, together with forty-eight indentures supplemental thereto	4.1 to September 1992 Form 10-Q Report	1-4473	11-9-92
4.2	Forty-ninth Supplemental Indenture	4.1 to 1992 Form 10-K Report	1-4473	3-30-93
4.3	Fiftieth Supplemental Indenture	4.2 to 1993 Form 10-K Report	1-4473	3-30-94
4.4	Fifty-first Supplemental Indenture	4.1 to August 1, 1993 Form 8-K Report	1-4473	9-27-93
4.5	Fifty-second Supplemental Indenture	4.1 to September 30, 1993 Form 10-Q Report	1-4473	11-15-93
4.6	Fifty-third Supplemental Indenture	4.5 to Registration Statement No. 33-61228 by means of February 23, 1994 Form 8-K Report	1-4473	3-1-94
4.7	Fifty-fourth Supplemental Indenture	4.1 to Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report	1-4473	11-22-96
4.8	Fifty-fifth Supplemental Indenture	4.8 to Registration Statement Nos. 33-55473, 33-64455 and 333-15379 by means of April 7, 1997 Form 8-K Report	1-4473	4-9-97
4.9	Agreement, dated March 21, 1994, relating to the filing of instruments defining the rights of holders of long-term debt not in excess of 10% of the Company's total assets	4.1 to 1993 Form 10-K Report	1-4473	3-30-94

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
4.10	Indenture dated as of January 1, 1995 among the Company and The Bank of New York, as Trustee	4.6 to Registration Statement Nos. 33-61228 and 33-55473 by means of January 1, 1995 Form 8-K Report	1-4473	1-11-95
4.11	First Supplemental Indenture dated as of January 1, 1995	4.4 to Registration Statement Nos. 33-61228 and 33-55473 by means of January 1, 1995 Form 8-K Report	1-4473	1-11-95
4.12	Indenture dated as of November 15, 1996 among the Company and The Bank of New York, as Trustee	4.5 to Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report	1-4473	11-22-96
4.13	First Supplemental Indenture	4.6 to Registration Statements Nos. 33-61228, 33-55473, 33-64455 and 333-15379 by means of November 19, 1996 Form 8-K Report	1-4473	11-22-96
4.14	Second Supplemental Indenture dated as of April 1, 1997	4.10 to Registration Statement Nos. 33-55473, 33-64455 and 333-15379 by means of April 7, 1997 Form 8-K Report	1-4473	4-9-97
4.15	Indenture dated as of January 15, 1998 among the Company and The Chase Manhattan Bank, as Trustee	4.10 to Registration Statement Nos. 333-15379 and 333-27551 by means of January 13, 1998 Form 8-K Report	1-4473	1-16-98
4.16	First Supplemental Indenture dated as of January 15, 1998	4.3 to Registration Statement Nos. 333-15379 and 333-27551 by means of January 13, 1998 Form 8-K Report	1-4473	1-16-98
4.17	Second Supplemental Indenture dated as of February 15, 1999	4.3 to Registration Statement Nos. 333-27551 and 333-58445 by means of February 18, 1999 Form 8-K Report	1-4473	2-22-99

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
4.18	Agreement of Resignation, Appointment, Acceptance and Assignment dated as of August 18, 1995 by and among the Company, Bank of America National Trust and Savings Association and The Bank of New York	4.1 to September 25, 1995 Form 8-K Report	1-4473	10-24-95
10.4	Two separate Decommissioning Trust Agreements (relating to PVNGS Units 1 and 3, respectively), each dated July 1, 1991, between the Company and Mellon Bank, N.A., as Decommissioning Trustee	10.2 to September 1991 Form 10-Q	1-4473	11-14-91
10.5	Amendment No. 1 to Decommissioning Trust Agreement (PVNGS Unit 1) dated as of December 1, 1994	10.1 to 1994 Form 10-K Report	1-4473	3-30-95
10.6	Amendment No. 2 to Decommissioning Trust Agreement (PVNGS Unit 1) dated as of July 1, 1991	10.4 to 1996 Form 10-K Report	1-4473	3-28-97
10.7	Amendment No. 1 to Decommissioning Trust Agreement (PVNGS Unit 3) dated as of December 1, 1994	10.2 to 1994 Form 10-K Report	1-4473	3-30-95
10.8	Amendment No. 2 to Decommissioning Trust Agreement (PVNGS Unit 3) dated as of July 1, 1991	10.6 to 1996 Form 10-K Report	1-4473	3-28-97

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.9	Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of January 31, 1992, among the Company, Mellon Bank, N.A., as Decommissioning Trustee, and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee under two separate Trust Agreements, each with a separate Equity Participant, and as Lessor under two separate Facility Leases, each relating to an undivided interest in PVNGS Unit 2	10.1 to Pinnacle West 1991 Form 10-K Report	1-8962	3-26-92
10.10	First Amendment to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2), dated as of November 1, 1992	10.2 to 1992 Form 10-K Report	1-4473	3-30-93
10.11	Amendment No. 2 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of November 1, 1994	10.3 to 1994 Form 10-K Report	1-4473	3-30-95
10.12	Amendment No. 3 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of January 31, 1992	10.1 to June 1996 Form 10-Q Report	1-4473	8-9-96
10.13	Amendment No. 4 to Amended and Restated Decommissioning Trust Agreement (PVNGS Unit 2) dated as of January 31, 1992	10.5 to 1996 Form 10-K Report	1-4473	3-28-97
10.14	Asset Purchase and Power Exchange Agreement dated September 21, 1990 between the Company and PacifiCorp, as amended as of October 11, 1990 and as of July 18, 1991	10.1 to June 1991 Form 10-Q Report	1-4473	8-8-91

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.15	Long-Term Power Transactions Agreement dated September 21, 1990 between the Company and PacifiCorp, as amended as of October 11, 1990 and as of July 8, 1991	10.2 to June 1991 Form 10-Q Report	1-4473	8-8-91
10.16	Contract, dated July 21, 1984, with DOE providing for the disposal of nuclear fuel and/or high-level radioactive waste, ANPP	10.31 to Pinnacle West's Form S-14 Registration Statement	2-96386	3-13-85
10.17	Amendment No. 1 dated April 5, 1995 to the Long-Term Power Transactions Agreement and Asset Purchase and Power Exchange Agreement between PacifiCorp and the Company	10.3 to 1995 Form 10-K Report	1-4473	3-29-96
10.18	Restated Transmission Agreement between PacifiCorp and the Company dated April 5, 1995	10.4 to 1995 Form 10-K Report	1-4473	3-29-96
10.19	Contract among PacifiCorp, the Company and United States Department of Energy Western Area Power Administration, Salt Lake Area Integrated Projects for Firm Transmission Service dated May 5, 1995	10.5 to 1995 Form 10-K Report	1-4473	3-29-96
10.20	Reciprocal Transmission Service Agreement between the Company and PacifiCorp dated as of March 2, 1994	10.6 to 1995 Form 10-K Report	1-4473	3-29-96
10.21	Indenture of Lease with Navajo Tribe of Indians, Four Corners Plant	5.01 to Form S-7 Registration Statement	2-59644	9-1-77
10.22	Supplemental and Additional Indenture of Lease, including amendments and supplements to original lease with Navajo Tribe of Indians, Four Corners Plant	5.02 to Form S-7 Registration Statement	2-59644	9-1-77

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.23	Amendment and Supplement No. 1 to Supplemental and Additional Indenture of Lease, Four Corners, dated April 25, 1985	10.36 to Registration Statement on Form 8-B of Pinnacle West	1-8962	7-25-85
10.24	Application and Grant of multi-party rights-of-way and easements, Four Corners Plant Site	5.04 to Form S-7 Registration Statement	2-59644	9-1-77
10.25	Application and Amendment No. 1 to Grant of multi-party rights-of-way and easements, Four Corners Power Plant Site, dated April 25, 1985	10.37 to Registration Statement on Form 8-B of Pinnacle West	1-8962	7-25-85
10.26	Application and Grant of Arizona Public Service Company rights-of-way and easements, Four Corners Plant Site	5.05 to Form S-7 Registration Statement	2-59644	9-1-77
10.27	Application and Amendment No. 1 to Grant of Arizona Public Service Company rights-of-way and easements, Four Corners Power Plant Site, dated April 25, 1985	10.38 to Registration Statement on Form 8-B of Pinnacle West	1-8962	7-25-85
10.28	Indenture of Lease, Navajo Units 1, 2, and 3	5(g) to Form S-7 Registration Statement	2-36505	3-23-70
10.29	Application and Grant of rights-of-way and easements, Navajo Plant	5(h) to Form S-7 Registration Statement	2-36505	3-23-70
10.30	Water Service Contract Assignment with the United States Department of Interior, Bureau of Reclamation, Navajo Plant	5(l) to Form S-7 Registration Statement	2-39442	3-16-71

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.31	Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, among the Company, Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles, and amendments 1-12 thereto	10.1 to 1988 Form 10-K Report	1-4473	3-8-89
10.32	Amendment No. 13 dated as of April 22, 1991, to Arizona Nuclear Power Project Participation Agreement, dated August 23, 1973, among the Company, Salt River Project Agricultural Improvement and Power District, Southern California Edison Company, Public Service Company of New Mexico, El Paso Electric Company, Southern California Public Power Authority, and Department of Water and Power of the City of Los Angeles	10.1 to March 1991 Form 10-Q Report	1-4473	5-15-91
10.33[c]	Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and the Company, as Lessee	4.3 to Form S-3 Registration Statement	33-9480	10-24-86

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.34[c]	Amendment No. 1, dated as of November 1, 1986, to Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and the Company, as Lessee	10.5 to September 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8	1-4473	12-4-86
10.35[c]	Amendment No. 2 dated as of June 1, 1987 to Facility Lease dated as of August 1, 1986 between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and APS, as Lessee	10.3 to 1988 Form 10-K Report	1-4473	3-8-89
10.36[c]	Amendment No. 3, dated as of March 17, 1993, to Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and the Company, as Lessee	10.3 to 1992 Form 10-K Report	1-4473	3-30-93
10.37	Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its capacity as Owner Trustee, as Lessor, and the Company, as Lessee	10.1 to November 18, 1986 Form 8-K Report	1-4473	1-20-87
10.38	Amendment No. 1, dated as of August 1, 1987, to Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and the Company, as Lessee	4.13 to Form S-3 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report	1-4473	8-24-87

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.39	Amendment No. 2, dated as of March 17, 1993, to Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Lessor, and the Company, as Lessee	10.4 to 1992 Form 10-K Report	1-4473	3-30-93
10.40[a]	Directors' Deferred Compensation Plan, as restated, effective January 1, 1986	10.1 to June 1986 Form 10-Q Report	1-4473	8-13-86
10.41[a]	Second Amendment to the Arizona Public Service Company Directors' Deferred Compensation Plan, effective as of January 1, 1993	10.2 to 1993 Form 10-K Report	1-4473	3-30-94
10.42[a]	Third Amendment to the Arizona Public Service Company Directors' Deferred Compensation Plan effective as of May 1, 1993	10.1 to September 1994 Form 10-Q	1-4473	11-10-94
10.43[a]	Arizona Public Service Company Deferred Compensation Plan, as restated, effective January 1, 1984, and the second and third amendments thereto, dated December 22, 1986, and December 23, 1987, respectively	10.4 to 1988 Form 10-K Report	1-4473	3-8-89
10.44[a]	Third Amendment to the Arizona Public Service Company Deferred Compensation Plan, effective as of January 1, 1993	10.3 to 1993 Form 10-K Report	1-4473	3-30-94
10.45[a]	Fourth Amendment to the Arizona Public Service Company Deferred Compensation Plan effective as of May 1, 1993	10.2 to September 1994 Form 10-Q Report	1-4473	11-10-94

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.46[a]	Fifth Amendment to the Arizona Public Service Company Deferred Compensation Plan	10.3 to 1997 Form 10-K Report	1-4473	3-28-97
10.47[a]	Pinnacle West Capital Corporation, Arizona Public Service Company, SunCor Development Company and El Dorado Investment Company Deferred Compensation Plan as amended and restated effective January 1, 1996	10.10 to 1995 Form 10-K Report	1-4473	3-29-96
10.48[a]	Arizona Public Service Company Supplemental Excess Benefit Retirement Plan as amended and restated on December 20, 1995	10.11 to 1995 Form 10-K Report	1-4473	3-29-96
10.49[a]	Pinnacle West Capital Corporation and Arizona Public Service Company Directors' Retirement Plan effective as of January 1, 1995	10.7 to 1994 Form 10-K Report	1-4473	3-30-95
10.50[a]	Arizona Public Service Company Director Equity Plan	10.1 to September 1997 Form 10-K Report	1-4473	11-12-97
10.51[a]	Letter Agreement dated December 21, 1993, between the Company and William L. Stewart	10.6 to 1994 Form 10-K Report	1-4473	3-30-95
10.52[a]	Letter Agreement dated August 16, 1996 between the Company and William L. Stewart	10.8 to 1996 Form 10-K Report	1-4473	3-28-97
10.53[a]	Letter Agreement between the Company and William L. Stewart	10.2 to September 1997 Form 10-Q Report	1-4473	11-12-97

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.54[a]	Letter Agreement, dated April 3, 1978, between the Company and O. Mark DeMichele, regarding certain retirement benefits granted to Mr. DeMichele	10.7 to 1988 Form 10-K Report	1-4473	3-8-89
10.55[a]	Letter Agreement dated November 27, 1996 between the Company and George A. Schreiber, Jr.	10.9 to 1996 Form 10-K Report	1-4473	3-28-97
10.56[a]	Letter Agreement dated as of January 1, 1996 between the Company and Robert G. Matlock & Associates, Inc. for consulting services	10.8 to 1995 Form 10-K Report	1-4473	3-29-96
10.57[ad]	Key Executive Employment and Severance Agreement between the Company and certain executive officers of the Company	10.3 to 1989 Form 10-K Report	1-4473	3-8-90
10.58[ad]	Revised form of Key Executive Employment and Severance Agreement between the Company and certain executive officers of the Company	10.5 to 1993 Form 10-K Report	1-4473	3-30-94
10.59[ad]	Second revised form of Key Executive Employment and Severance Agreement between the Company and certain executive officers of the Company	10.9 to 1994 Form 10-K Report	1-4473	3-30-95
10.60[ad]	Key Executive Employment and Severance Agreement between the Company and certain managers of the Company	10.4 to 1989 Form 10-K Report	1-4473	3-8-90

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
10.61[ad]	Revised form of Key Executive Employment and Severance Agreement between the Company and certain key employees of the Company	10.4 to 1993 Form 10-K Report	1-4473	3-30-94
10.62[ad]	Second revised form of Key Executive Employment and Severance Agreement between the Company and certain key employees of the Company	10.8 to 1994 Form 10-K Report	1-4473	3-30-95
10.63[a]	Pinnacle West Capital Corporation Stock Option and Incentive Plan	10.1 to 1992 Form 10-K Report	1-4473	3-30-93
10.64[a]	Pinnacle West Capital Corporation 1994 Long-Term Incentive Plan effective as of March 23, 1994	A to the Proxy Statement for the Plan Report Pinnacle West 1994 Annual Meeting of Shareholders	1-8962	4-16-94
10.65	Agreement No. 13904 (Option and Purchase of Effluent) with Cities of Phoenix, Glendale, Mesa, Scottsdale, Tempe, Town of Youngtown, and Salt River Project Agricultural Improvement and Power District, dated April 23, 1973	10.3 to 1991 Form 10-K Report	1-4473	3-19-92
10.66	Agreement for the Sale and Purchase of Wastewater Effluent with City of Tolleson and Salt River Agricultural Improvement and Power District, dated June 12, 1981, including Amendment No. 1 dated as of November 12, 1981 and Amendment No. 2 dated as of June 4, 1986	10.4 to 1991 Form 10-K Report	1-4473	3-19-92
10.67	Territorial Agreement between the Company and Salt River Project	10.1 to March 1998 Form 10-Q Report	1-4473	5-15-98

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
10.68	Power Coordination Agreement between the Company and Salt River Project	10.2 to March 1998 Form 10-Q Report	1-4473	5-15-98
10.69	Memorandum of Agreement between the Company and Salt River Project	10.3 to March 1998 Form 10-Q Report	1-4473	5-15-98
10.70	Addendum to Memorandum of Agreement between the Company and Salt River Project dated as of May 19, 1998	10.2 to May 19, 1998 Form 8-K Report	1-4473	6-26-98
99.1	Collateral Trust Indenture among PVNGS II Funding Corp., Inc., the Company and Chemical Bank, as Trustee	4.2 to 1992 Form 10-K Report	1-4473	3-30-93
99.2	Supplemental Indenture to Collateral Trust Indenture among PVNGS II Funding Corp., Inc., the Company and Chemical Bank, as Trustee	4.3 to 1992 Form 10-K Report	1-4473	3-30-93
99.3[c]	Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, the Company, and the Equity Participant named therein	28.1 to September 1992 Form 10-Q Report	1-4473	11-9-92

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.4[c]	Amendment No. 1 dated as of November 1, 1986, to Participation Agreement, dated as of August 1,1986, among PVNGS Funding Corp., Inc., Bank of America National Trust and Savings Association, State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, the Company, and the Equity Participant named therein	10.8 to September 1986 Form 10-Q Report by means of Amendment No. 1, on December 3, 1986 Form 8	1-4473	12-4-86
99.5[c]	Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of August 1, 1986, among PVNGS Funding Corp., Inc., PVNGS II Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, the Company, and the Equity Participant named therein	28.4 to 1992 Form 10-K Report	1-4473	3-30-93
99.6[c]	Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.5 to Form S-3 Registration Statement	33-9480	10-24-86

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
99.7[c]	Supplemental Indenture No. 1, dated as of November 1, 1986 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	10.6 to September 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8	1-4473	12-4-86
99.8[c]	Supplemental Indenture No. 2 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of August 1, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.4 to 1992 Form 10-K Report	1-4473	3-30-93
99.9[c]	Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between the Company and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.3 to Form S-3 Registration Statement	33-9480	10-24-86
99.10[c]	Amendment No. 1, dated as of November 1, 1986, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between the Company and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	10.10 to September 1986 Form 10-Q Report by means of Amendment No. 1 on December 3, 1986 Form 8	1-4473	12-4-86

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.11[c]	Amendment No. 2, dated as of March 17, 1993, to Assignment, Assumption and Further Agreement, dated as of August 1, 1986, between the Company and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.6 to 1992 Form 10-K Report	1-4473	3-30-93
99.12	Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee under a Trust Indenture, the Company, and the Owner Participant named therein	28.2 to September 1992 Form 10-Q Report	1-4473	11-9-92
99.13	Amendment No. 1, dated as of August 1, 1987, to Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc. as Funding Corporation, State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, Chemical Bank, as Indenture Trustee, the Company, and the Owner Participant named therein	28.20 to Form S-3 Registration Statement No. 33-9480 by means of a November 6, 1986 Form 8-K Report	1-4473	8-10-87

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.14	Amendment No. 2, dated as of March 17, 1993, to Participation Agreement, dated as of December 15, 1986, among PVNGS Funding Corp., Inc., PVNGS II Funding Corp., Inc., State Street Bank and Trust Company, as successor to The First National Bank of Boston, in its individual capacity and as Owner Trustee, Chemical Bank, in its individual capacity and as Indenture Trustee, the Company, and the Owner Participant named therein	28.5 to 1992 Form 10-K Report	1-4473	3-30-93
99.15	Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	10.2 to November 18, 1986 Form 8-K Report	1-4473	1-20-87
99.16	Supplemental Indenture No. 1, dated as of August 1, 1987, to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.13 to Form S-3 Registration Statement No. 33-9480 by means of August 1, 1987 Form 8-K Report	1-4473	8-24-87

Exhibit No.	Description	Originally Filed as Exhibit:	File No.[b]	Date Effective
99.17	Supplemental Indenture No. 2 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease, dated as of December 15, 1986, between State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee, and Chemical Bank, as Indenture Trustee	4.5 to 1992 Form 10-K Report	1-4473	3-30-93
99.18	Assignment, Assumption and Further Agreement, dated as of December 15, 1986, between the Company and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	10.5 to November 18, 1986 Form 8-K Report	1-4473	1-20-87
99.19	Amendment No. 1, dated as of March 17, 1993, to Assignment, Assumption and Further Agreement, dated as of December 15, 1986, between the Company and State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee	28.7 to 1992 Form 10-K Report	1-4473	3-30-93
99.20[c]	Indemnity Agreement dated as of March 17, 1993 by the Company	28.3 to 1992 Form 10-K Report	1-4473	3-30-93
99.21	Extension Letter, dated as of August 13, 1987, from the signatories of the Participation Agreement to Chemical Bank	28.20 to Form S-3 Registration Statement No. 33-9480 by means of a November 6, 1986 Form 8-K Report	1-4473	8-10-87
99.22	Arizona Corporation Commission Order dated December 6, 1991	28.1 to 1991 Form 10-K Report	1-4473	3-19-92
99.23	Arizona Corporation Commission Order dated June 1, 1994	10.1 to June Form 10-Q Report	1-4473	8-12-94

Exhibit No.	*Description*	*Originally Filed as Exhibit:*	*File No.*[b]	*Date Effective*
99.24	Rate Reduction Agreement dated December 4, 1995 between the Company and the ACC Staff	10.1 to December 4, 1995 Form 8-K Report	1-4473	12-14-95
99.25	Arizona Corporation Commission Order dated April 24, 1996	10.1 to March 1996 Form 10-Q Report	1-4473	5-14-96
99.26	Arizona Corporation Commission Order, Decision No. 59943, dated December 26, 1996, including the Rules regarding the introduction of retail competition in Arizona	99.1 to 1996 Form 10-K Report	1-4473	3-28-97
99.27	Retail Electric Competition Rules	10.1 to June 1998 Form 10-Q Report	1-4473	8-14-98

[a]Management contract or compensatory plan or arrangement to be filed as an exhibit pursuant to Item 14(c) of Form 10-K.

[b]Reports filed under File No. 1-4473 were filed in the office of the Securities and Exchange Commission located in Washington, D.C.

[c]An additional document, substantially identical in all material respects to this Exhibit, has been entered into, relating to an additional Equity Participant. Although such additional document may differ in other respects (such as dollar amounts, percentages, tax indemnity matters, and dates of execution), there are no material details in which such document differs from this Exhibit.

[d]Additional agreements, substantially identical in all material respects to this Exhibit have been entered into with additional officers and key employees of the Company. Although such additional documents may differ in other respects (such as dollar amounts and dates of execution), there are no material details in which such agreements differ from this Exhibit.

Reports on Form 8-K

During the quarter ended December 31, 1998 and the period ended March 30, 1999, the Company filed the following Report on Form 8-K:

Report dated December 1, 1998 relating to an order by the Arizona Supreme Court staying ACC hearings regarding our settlement agreement with the ACC Staff.

Report dated December 9, 1998 relating to (1) a Notice of Withdrawal of Settlement filed by the ACC Staff, (2) terms of expiration of a memorandum of understanding, (3) ACC adoption of the amended rules, and (4) issues affecting the agreement with Salt River Project.

Report dated January 11, 1999 relating to (i) the ACC hearing officers' recommended changes to the amended rules regarding the introduction of retail electric competition in Arizona and to the June 1998 stranded cost order and (ii) action by the Arizona Supreme Court vacating its order staying ACC hearings on the proposed settlement agreement and dismissing the Attorney General's action.

Report dated February 18, 1999 comprised of Exhibits to the Company's Registration Statements (Registration Nos. 333-27551 and 333-58445) relating to the Company's offering of $125 million of Notes.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ARIZONA PUBLIC SERVICE COMPANY
(Registrant)

Date: March 30, 1999

/s/ WILLIAM J. POST
(William J. Post, Chief Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	*Title*	*Date*
/s/ WILLIAM J. POST (William J. Post, Chief Executive Officer)	Principal Executive Officer and Director	March 30, 1999
/s/ GEORGE A SCHREIBER, JR. (George A. Schreiber, Jr.)	Principal Accounting Officer, Principal Financial Officer and Director	March 30, 1999
/s/ JACK E. DAVIS (Jack E. Davis)	President and Director	March 30, 1999
/s/ O. MARK DEMICHELE (O. Mark DeMichele)	Director	March 30, 1999
/s/ MICHAEL L. GALLAGHER (Michael L. Gallagher)	Director	March 30, 1999
/s/ MARTHA O. HESSE (Martha O. Hesse)	Director	March 30, 1999
/s/ MARIANNE M. JENNINGS (Marianne M. Jennings)	Director	March 30, 1999
/s/ ROBERT E. KEEVER (Robert E. Keever)	Director	March 30, 1999

/s/ ROBERT G. MATLOCK (Robert G. Matlock)	Director	March 30, 1999
/s/ BRUCE J. NORDSTROM (Bruce J. Nordstrom)	Director	March 30, 1999
/s/ JOHN R. NORTON III (John R. Norton III)	Director	March 30, 1999
/s/ DONALD M. RILEY (Donald M. Riley)	Director	March 30, 1999
/s/ QUENTIN P. SMITH, JR. (Quentin P. Smith, Jr.)	Director	March 30, 1999
/s/ WILLIAM L. STEWART (William L. Stewart)	President and Director	March 30, 1999
/s/ RICHARD SNELL (Richard Snell)	Director	March 30, 1999
/s/ DIANNE C. WALKER (Dianne C. Walker)	Director	March 30, 1999
/s/ BEN F. WILLIAMS JR. (Ben F. Williams, Jr.)	Director	March 30, 1999

-NOTICE-

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Southern California Edison (SCE) is the nation's second largest investor-owned electric utility. Headquartered in Rosemead, California, SCE is a subsidiary of Edison International, which is primarily an energy-services company.

SCE, a 113-year old electric utility, serves 4.3 million customers and more than 11 million people within a 50,000-square-mile area of central, coastal and Southern California.

Contents

SOUTHERN CALIFORNIA
EDISON

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

Results of Operations

Earnings

Southern California Edison Company's (SCE) 1998 earnings were $490 million, compared with $576 million in 1997 and $621 million in 1996. SCE's 1996 earnings included special charges of $18 million for workforce management costs and reserves. The $86 million earnings decline in 1998 was primarily due to lower authorized revenue, which resulted from reduced authorized returns on generating assets and a lower earning asset base resulting from the accelerated recovery of investments and divestiture of gas- and oil-fueled generation assets, partially offset by superior operating performance at the San Onofre Nuclear Generating Station. Before special charges, 1997 earnings declined $63 million compared to the prior year, mainly due to the extended outage and lower return at San Onofre. The decline was partially offset by higher sales and lower non-nuclear operating expenses.

Operating Revenue

Since April 1, 1998, SCE has been required to sell all of its generated power to the power exchange (PX). For more details, see Competitive Environment. Excluding the sales to the PX, operating revenue decreased 6% from 1997. The decrease reflects lower average residential rates (mandated by legislation enacted in September 1996), partially offset by an increase in other revenue resulting from maintenance work SCE is providing for the new owners of the divested gas- and oil-fueled plants, as required by the restructuring legislation. Operating revenue increased 5% in 1997 over 1996, due to an increase in sales volume and customer refunds in 1996. There were no comparable refunds in 1997. The increase in volume is mainly attributable to the overall increase in retail sales among residential and commercial customers due to unusually warm weather during the third quarter of 1997. In 1998, over 99% of operating revenue (excluding sales to the PX) was from retail sales. Retail rates are regulated by the California Public Utilities Commission (CPUC) and wholesale rates are regulated by the Federal Energy Regulatory Commission (FERC).

Due to warmer weather during the summer months, operating revenue (excluding sales to the PX) during the third quarter of each year is significantly higher than other quarters.

The changes in operating revenue (excluding sales to the PX) resulted from:

In millions Year ended December 31,	1998	1997	1996
Operating revenue —			
Rate changes (including refunds)	$(527)	$173	$(522)
Sales volume changes	(44)	193	206
Other	117	4	26
Total	$(454)	$370	$(290)

Legislation enacted in September 1996 provided for, among other things, a 10% rate reduction (financed through the issuance of rate reduction notes) for residential and small commercial customers in 1998 and other rates to remain frozen at June 1996 levels (system average of 10.1¢ per kilowatt-hour). See discussion in Competitive Environment.

Operating Expenses

Fuel expense decreased 63% in 1998, primarily due to the sale of the gas- and oil-fueled generation plants, as well as significantly lower gas prices in the first quarter of 1998. Fuel expense increased 40% in 1997 over 1996. The increase was due to a $174 million gas contract termination payment during the third quarter of 1997, combined with higher gas prices and the extended refueling outages at San Onofre. San Onofre Unit 2 was shut down during the entire first quarter of 1997, Unit 3 was shut down 80 days of the second quarter and both units had a combined outage time of 30 days during the third quarter, which resulted in an overall increase in gas-powered generation for 1997. There were no comparable outages in 1996.

Since April 1, 1998, SCE has been required to purchase all of its power from the PX for distribution to its retail customers. SCE is continuing to purchase power from certain nonutility generators (known as qualifying facilities) and under existing inter-utility contracts. This purchased power is sold to the PX. Excluding the power purchased from the PX, purchased-power expense decreased slightly in 1998, while increasing slightly in 1997. SCE is required under federal law to purchase power from certain qualifying facilities even though energy prices under these contracts are generally higher than other sources. In 1998, SCE paid about $1.5 billion (including energy and capacity payments) more for these power purchases than the cost of power available from other sources. The CPUC has mandated the prices for these contracts.

Provisions for regulatory adjustment clauses decreased in 1998, mainly due to the rate-making treatment of the rate reduction notes. This rate-making treatment has allowed for the deferral of the collection of a portion of the transition-related revenue, from a four-year period to a 10-year period. This decrease was almost completely offset by overcollections resulting from the gain on sales of the gas- and oil-fueled generation plants during 1998 and other transition costs, as well as overcollections related to the administration of public-purpose funds. The provisions for regulatory adjustment clauses decreased substantially in 1997, due to undercollections in the energy cost balancing account as actual energy costs (including the gas termination payment discussed above) exceeded CPUC-authorized fuel and purchased-power cost estimates. In addition, there were undercollections associated with SCE's direct access activities (see discussion in Competitive Environment), research and development activities, and San Onofre. These undercollections were offset by overcollections related to actual base-rate revenue from kilowatt-hour sales exceeding CPUC-authorized estimates and the final settlement of SCE's Canadian supply and transportation contracts.

Other operating expenses increased 22% in 1998, primarily due to must-run reliability services, direct access activities, and PX and independent system operator (ISO) costs incurred by SCE. Also, storm damage expense resulting from the harsh winter in 1998 contributed to the increase.

Maintenance expense increased 23% in 1997, due to higher maintenance costs at the transmission and distribution operating facilities, and the scheduled refueling outages at the San Onofre units.

Depreciation, decommissioning and amortization expense increased 25% in 1998, primarily due to the further acceleration of recovery of San Onofre Units 2 and 3 and the Palo Verde Nuclear Generating Station units, accelerated recovery of the gas- and oil-fueled generation plants, and the amortization of the loss on plant sales. The amortization of the loss on plant sales, as well as the accelerated recoveries implemented in 1998 are part of the competition transition charge (CTC) mechanism. Depreciation, decommissioning and amortization expense increased 17% in 1997, mainly due to increases in plant assets and the accelerated recovery of the Palo Verde units, effective January 1997.

Income taxes decreased 23% in 1998, primarily due to lower pre-tax income, as well as additional amortization related to the CTC mechanism.

Property and other taxes decreased 32% in 1997, due to a reclassification of payroll taxes to operation and maintenance expense.

Gain on sale of utility plant represents the net result from the sale of the gas- and oil-fueled generation plants in 1998. Gains on sales of the gas- and oil-fueled plants were used to reduce stranded costs. Losses on sales will be recovered from customers over the transition period.

Other Income and Deductions

The provision for rate phase-in plan reflected a CPUC-authorized, 10-year rate phase-in plan, which deferred the collection of revenue during the first four years of operation for the Palo Verde units. The deferred revenue (including interest) was collected evenly over the final six years of each unit's plan.

The plan ended in February 1996, September 1996 and January 1998 for Units 1, 2 and 3, respectively. The provision was a non-cash offset to the collection of deferred revenue.

Interest and dividend income increased 49% in 1998, reflecting higher investment balances due to the sale of the gas- and oil-fueled generation plants, as well as increases in interest earned on higher balancing account undercollections. In 1997, interest and dividend income increased 18% due to increases in interest earned on balancing accounts and increases in dividend income from equity investments.

Other nonoperating income increased 81% in 1998, when compared to 1997, primarily due to the additional accruals in 1997 for regulatory matters. These accruals caused a substantial decrease in other nonoperating income in 1997, when compared to 1996.

Interest Expense

Interest on long-term debt increased 22% in 1998, mainly due to the issuance of the rate reduction notes in December 1997. In 1997, interest on long-term debt decreased due to the early retirement of $400 million of first and refunding mortgage bonds in July 1997, partially offset by the additional interest expense associated with the rate reduction notes issued in December 1997. Interest on the rate reduction notes was $148 million in 1998 and $9 million in 1997.

Other interest expense decreased substantially in 1998, mostly due to lower overall short-term debt balances, particularly short-term debt used to finance fuel inventories. These fuel inventories are no longer needed because of the divestiture of the gas- and oil-fueled plants. Other interest expense increased substantially in 1997, due to higher levels of short-term debt used to retire first and refunding mortgage bonds.

Financial Condition

SCE's liquidity is primarily affected by debt maturities, dividend payments and capital expenditures. Capital resources include cash from operations and external financings.

Edison International's board of directors has authorized the repurchase of up to $2.8 billion (increased from $2.3 billion in July 1998) of its outstanding shares of common stock. Edison International repurchased 100.4 million shares ($2.4 billion) between January 1995 and February 4, 1999, funded by dividends from its subsidiaries and the issuance of rate reduction notes.

SCE's cash flow coverage of dividends was 0.9 times for both 1998 and 1997 and 2.2 times in 1996. The 1998 decrease reflects the $680 million special dividend SCE paid to Edison International in 1998 from the gas- and oil-fueled plant sales proceeds, as well as the rate-making treatment of the gains on sales of the gas- and oil-fueled plants. The 1997 decrease reflects the $1.2 billion special dividend SCE paid to Edison International in December 1997 from rate reduction note proceeds.

Cash Flows from Operating Activities

Net cash provided by operating activities totaled $1.0 billion in 1998, $1.7 billion in 1997 and $1.8 billion in 1996. Cash from operations exceed capital requirements for all years presented.

Cash Flows from Financing Activities

At December 31, 1998, SCE had available lines of $1.3 billion, with $800 million for general purpose, short-term debt and $500 million for the long-term refinancing of its variable-rate pollution-control bonds. These unsecured lines of credit are at negotiated or bank index rates and expire in 2002.

Short-term debt is used to finance fuel inventories and general cash requirements. Long-term debt is used mainly to finance capital expenditures. External financings are influenced by market conditions and other factors, including limitations imposed by SCE's articles of incorporation and trust indenture. As of December 31, 1998, SCE could issue approximately $13.9 billion of additional first and refunding mortgage bonds and $4.4 billion of preferred stock at current interest and dividend rates.

California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates. Additionally, the CPUC regulates SCE's capital structure, limiting the dividends it may pay Edison International. At December 31, 1998, SCE had the capacity to pay $794 million in additional dividends and continue to maintain its authorized capital structure.

In December 1997, SCE Funding LLC, a special purpose entity (SPE), of which SCE is the sole member, issued approximately $2.5 billion of rate reduction notes to Bankers Trust Company of California, as certificate trustee for the California Infrastructure and Economic Development Bank Special Purpose Trust SCE-1 (Trust), which is a special purpose entity established by the State of California. The terms of the rate reduction notes generally mirror the terms of the pass-through certificates issued by the Trust, which are known as rate reduction certificates. The proceeds of the rate reduction notes were used by the SPE to purchase from SCE an enforceable right known as transition property. Transition property is a current property right created pursuant to the restructuring legislation and a financing order of the CPUC, and consists generally of the right to be paid a specified amount from a non-bypassable tariff levied on residential and small commercial customers. Notwithstanding the legal sale of the transition property by SCE to the SPE, the amounts reflected as assets on SCE's balance sheet have not been reduced by the amount of the transition property sold to the SPE, and the liabilities of the SPE for the rate reduction notes are for accounting purposes reflected as long-term liabilities on the consolidated balance sheet of SCE. SCE used the proceeds from the sale of the transition property to retire debt and equity securities.

The rate reduction notes have maturities ranging from one to nine years, and bear interest at rates ranging from 6.14% to 6.42%. The rate reduction notes are secured solely by the transition property and certain other assets of the SPE, and there is no recourse to SCE or Edison International.

Although the SPE is consolidated with SCE in the financial statements, as required by generally accepted accounting principles, the SPE is legally separate from SCE, the assets of the SPE are not available to creditors of SCE or Edison International, and the transition property is legally not an asset of SCE or Edison International.

Cash Flows from Investing Activities

Cash flows from investing activities are affected by additions to property and plant, proceeds from the sale of plant (see discussion in Competitive Environment) and funding of nuclear decommissioning trusts. Decommissioning costs are accrued and recovered in rates over the term of each nuclear generating facility's operating license through charges to depreciation expense. SCE estimates that it will spend approximately $8.6 billion between 2000—2070 to decommission its nuclear facilities. This estimate is based on SCE's current-dollar decommissioning costs ($1.9 billion), escalated at rates averaging 5.6% annually. These costs are expected to be funded from independent decommissioning trusts, which currently receive SCE contributions of approximately $100 million per year. However, SCE has requested the CPUC to authorize a reduction in the annual contributions to the decommissioning trusts beginning January 1, 2000. The plan to decommission San Onofre Unit 1 beginning in 2000, which is pending CPUC approval, is not expected to affect SCE's annual contributions to the decommissioning trusts.

Market Risk Exposures

SCE's primary market risk exposures arise from fluctuations in energy prices and interest rates. SCE's risk management policy allows the use of derivative financial instruments to manage its financial exposures, but prohibits the use of these instruments for speculative or trading purposes.

As a result of the rate freeze established in the restructuring legislation, SCE's transition costs are recovered as the residual component of rates once the costs for distribution, transmission, public purpose programs, nuclear decommissioning and the cost of supplying power to its customers through the PX and ISO have already been recovered. Accordingly, more revenue will be available to cover transition costs when market prices in the PX and ISO are low than when PX and ISO prices are high. The PX and ISO market prices to date have generally been reasonable, although some irregular price spikes have occurred. The ISO has responded to price spikes in the market for reliability services (referred to as ancillary services) by imposing a price cap of $250/MW on the market for such services until certain actions have been completed to improve the functioning of those markets. Similarly, the ISO currently maintains a cap of $250/MWh on its market for imbalance energy while a software problem affecting the efficient operation of that market persists. The caps in these markets mitigate the risk of costly price spikes that would reduce the revenue available to SCE to pay transition costs. During the upcoming year, the ISO will be considering removing these price caps, which could increase the risk of high market prices. SCE has entered into hedges against high natural gas prices, since increases in natural gas prices tend to raise the price of electricity purchased from the PX.

A 10% increase in market interest rates would result in a $7 million increase in the fair value of SCE's interest rate hedge agreements. A 10% decrease in market interest rates would result in a $7 million decline in the fair market value of interest rate hedge agreements. A 10% increase in natural gas prices would result in a $21 million increase in the fair market value of gas call options. A 10% decrease in natural gas prices would result in a $14 million decline in the fair market value of gas call options. A 10% change in market rates is expected to have an immaterial effect on SCE's other financial instruments.

Projected Capital Requirements

SCE's projected construction expenditures for the next five years are: 1999 — $922 million; 2000 — $831 million; 2001 — $726 million; 2002 — $699 million; and 2003 — $689 million.

Long-term debt maturities and sinking fund requirements for the next five years are: 1999 — $401 million; 2000 — $571 million; 2001 — $646 million; 2002 — $446 million; and 2003 — $371 million.

Preferred stock redemption requirements for next five years are: 1999 through 2001 — zero; 2002 — $105 million; and 2003 — $9 million.

Regulatory Matters

Legislation enacted in September 1996 provided for, among other things, a 10% rate reduction for residential and small commercial customers in 1998 and other rates to remain frozen at June 1996 levels (system average of 10.1¢ per kilowatt-hour).

In 1999, revenue will be determined by various mechanisms depending on the utility operation. Revenue related to distribution operations will be determined through a performance-based rate-making mechanism (PBR) and the distribution assets will have the opportunity to earn a CPUC-authorized 9.49% return. The distribution-only PBR will extend through December 2001. Transmission revenue will be determined through FERC-authorized rates and transmission assets will earn a 9.43% return. These rates are subject to refund. Key elements of PBR include: transmission and distribution (T&D) rates indexed for inflation based on the Consumer Price Index less a productivity factor; adjustments for cost changes that are not within SCE's control; a cost-of-capital trigger mechanism based on changes in a bond index; standards for service reliability and safety; and a net revenue-sharing mechanism that determines how customers and shareholders will share gains and losses from T&D operations.

Revenue from generation-related operations will be determined through the competitive market and the CTC mechanism, which now includes the nuclear rate-making agreements. Revenue related to fossil and hydroelectric generation operations is recovered from two sources. The portion that is made uneconomic by electric industry restructuring is recovered through the CTC mechanism. The portion that is economic is recovered through the market. In 1999, fossil and hydroelectric generation assets will earn a 7.22% return.

In 1996 and 1997, the CPUC authorized revised rate-making plans for SCE's nuclear facilities, which call for the accelerated recovery of the nuclear investments in exchange for a lower authorized rate of return. SCE's nuclear assets are earning an annual rate of return of 7.35%. In addition, the San Onofre plan authorizes a fixed rate of approximately 4¢ per kilowatt-hour generated for operating costs including incremental capital costs, and nuclear fuel and nuclear fuel financing costs. The San Onofre plan commenced in April 1996, and ends in December 2001 for the accelerated recovery portion and in December 2003 for the incentive-pricing portion. Palo Verde's operating costs, including incremental capital costs, and nuclear fuel and nuclear fuel financing costs, are subject to balancing account treatment. The Palo Verde plan commenced in January 1997 and ends in December 2001. Beginning January 1, 1998, both the San Onofre and Palo Verde rate-making plans became part of the CTC mechanism.

The changes in revenue from the regulatory mechanisms discussed above, excluding the effects of other rate actions, are expected to have an approximately $20 million negative impact on 1999 earnings.

The CPUC is considering unbundling SCE's cost of capital based on major utility function. In May 1998, SCE filed an application on this issue and hearings were completed in October 1998. A CPUC decision is expected in early to mid-1999.

Competitive Environment

SCE currently operates in a highly regulated environment in which it has an obligation to deliver electric service to customers in return for an exclusive franchise within its service territory. This regulatory environment is changing. The generation sector has experienced competition from nonutility power producers and regulators are restructuring California's electric utility industry.

California Electric Utility Industry Restructuring

Restructuring Decision and Statute — The CPUC's December 1995 decision on restructuring California's electric utility industry started the transition to a new market structure involving competition and customer choice. The State of California enacted legislation in 1996 to provide a transition to a competitive market structure. The Statute substantially adopted the CPUC's restructuring decision by addressing stranded-cost recovery for utilities and providing a certain cost-recovery time period for the transition costs associated with utility-owned generation-related assets. Transition costs related to power-purchase contracts are being recovered through the terms of their contracts while most of the remaining transition costs will be recovered through 2001. The Statute also included provisions to finance a portion of the stranded costs that residential and small commercial customers would have paid between 1998 and 2001, which allowed SCE to reduce rates by at least 10% to these customers, effective January 1, 1998. The Statute included a rate freeze for all other customers, including large commercial and industrial customers, as well as provisions for continued funding for energy conservation, low-income programs and renewable resources. Despite the rate freeze, SCE expects to be able to recover its revenue requirement during the 1998—2001 transition period. In addition, the Statute mandated the implementation of the CTC that provides utilities the opportunity to recover costs made uneconomic by electric utility restructuring. Finally, the Statute contained provisions for the recovery (through 2006) of reasonable employee-related transition costs, incurred and projected, for retraining, severance, early retirement, outplacement and related expenses. The new market structure and customer choice began on April 1, 1998.

1998 Activities — During 1998, SCE implemented changes to comply with restructuring elements required by the CPUC and the Statute. Beginning January 1, 1998:

- SCE's rates were unbundled into separate charges for energy, transmission, distribution, the CTC, public benefit programs and nuclear decommissioning. The transmission component is being collected through FERC-approved rates, subject to refund.

- SCE's costs associated with its hydroelectric plants are being recovered through a performance-based mechanism. The mechanism sets the hydroelectric revenue requirement and establishes a formula for extending it through the duration of the electric industry restructuring transition period, or until market valuation of the hydroelectric facilities, whichever occurs first. The mechanism provides that power sales revenue from hydroelectric facilities in excess of the hydroelectric revenue requirement be credited against the costs to transition to a competitive market.

- SCE transition costs are being recovered through a non-bypassable CTC. This charge applies to all customers who were using or began using utility services on or after the CPUC's December 1995 restructuring decision date. SCE has estimated its transition costs to be approximately $10.6 billion (1998 net present value) from 1998 through 2030. This estimate was based on incurred costs, forecasts of future costs and assumed market prices. However, changes in the assumed market prices could materially affect these estimates. The potential transition costs are comprised of $6.4 billion from SCE's qualifying facilities contracts, which are the direct result of prior legislative and regulatory mandates, and $4.2 billion (which reflects the sale of SCE's gas- and oil-fueled generation plants) from costs pertaining to certain generating assets and regulatory commitments consisting of costs incurred (whose recovery has been deferred by the CPUC) to provide service to customers. Such commitments include the recovery of income tax benefits previously flowed through to customers, postretirement benefit transition costs; accelerated recovery of San Onofre Units 2 and 3 and the Palo Verde units (as discussed in Regulatory Matters), and certain other costs.

- Residential and small commercial customers who began receiving a 10% rate reduction are repaying the rate reduction notes issued in December 1997 (see further discussion in Cash Flows from Financing Activities) through non-bypassable charges based on electricity consumption.

Effective April 1, 1998:

- The ISO assumed operational control of the transmission system after the ISO and PX had begun accepting bids and schedules for electricity purchases on March 31, 1998. The restructuring implementation costs related to the start-up and development of the PX, which are paid by the utilities, will be recovered from all retail customers over the four-year transition period. SCE's share of the charge is $45 million, plus interest and fees. SCE's share of the ISO's start-up and development costs (approximately $16 million per year) will be paid over a 10-year period.

- Customers can choose to remain utility customers with either bundled electric service or an hourly PX pricing option from SCE (which is purchasing its power through the PX), or choose direct access, which means the customer can contract directly with either independent power producers or energy service providers (ESPs) such as power brokers, marketers and aggregators. Electric utilities are continuing to provide the core distribution service of delivering energy through their distribution system regardless of a customer's choice of electricity supplier. The CPUC is continuing to regulate the prices and service obligations related to distribution services. As of December 31, 1998, approximately 47,000 of SCE's 4.3 million customers have requested the direct access option.

- Customers have options regarding metering, billing and related services (referred to as revenue cycle services) that have been provided by California's investor-owned utilities. ESPs can provide their customers with one consolidated bill for their services and the utility's services, request the utility to provide such a consolidated bill to the customer or elect to have both the ESP and the utility bill the customer for their respective charges. Customers with maximum demand above 20 kW (primarily industrial and medium and large commercial) can choose SCE or any other supplier to provide their metering service. Beginning in January 1999, all customers can make these choices. In September 1998, the CPUC issued a decision regarding the credits that would be provided to customers if they elect to obtain revenue cycle services from someone other than SCE. Although the decision adopted SCE's recommendation of using the net avoided cost, it also adopted a methodology which results in higher credits to customers but requires

ESPs to pay service fees to SCE for the costs that SCE incurs as a result of dealing with the ESP. SCE may experience a reduction in revenue security as a result of this unbundling.

During 1998, SCE sold all of its gas- and oil-fueled generation plants. The total sales price of the 12 plants was $1.2 billion, over $500 million more than the combined book value. Net proceeds of the sales were used to reduce stranded costs, which otherwise were expected to be collected through the CTC mechanism.

Accounting for Generation-Related Assets — If the CPUC's electric industry restructuring plan continues as described above, SCE would be allowed to recover its transition costs through non-bypassable charges to its distribution customers (although its investment in certain generation assets would be subject to a lower authorized rate of return). In 1997, SCE discontinued application of accounting principles for rate-regulated enterprises for its investment in generation facilities based on new accounting guidance. The financial reporting effect of this discontinuance was to segregate these assets on the balance sheet; the new guidance did not require SCE to write off any of its generation-related assets, including related regulatory assets. However, the new guidance did not specifically address the application of asset impairment standards to these assets. SCE has retained these assets on its balance sheet because the Statute and restructuring plan referred to above make probable their recovery through a non-bypassable CTC to distribution customers. The regulatory assets relate primarily to the recovery of accelerated income tax benefits previously flowed through to customers, purchased power contract termination payments and unamortized losses on reacquired debt. The new accounting guidance also permits the recording of new generation-related regulatory assets during the transition period that are probable of recovery through the CTC mechanism.

During the second quarter of 1998, additional guidance was developed related to the application of asset impairment standards to these assets. Using this guidance resulted in SCE reducing its remaining nuclear plant investment by $2.6 billion (as of June 30, 1998) and recording a regulatory asset on its balance sheet for the same amount. For this impairment assessment, the fair value of the investment was calculated by discounting future net cash flows. This reclassification had no effect on SCE's results of operations.

If during the transition period events were to occur that made the recovery of these generation-related regulatory assets no longer probable, SCE would be required to write off the remaining balance of such assets (approximately $2.4 billion, after tax, at December 31, 1998) as a one-time, non-cash charge against earnings.

If events occur during the restructuring process that result in all or a portion of the transition costs being improbable of recovery, SCE could have additional write-offs associated with these costs if they are not recovered through another regulatory mechanism. At this time, SCE cannot predict what other revisions will ultimately be made during the restructuring process in subsequent proceedings or the effect, after the transition period, that competition will have on its results of operations or financial position.

Environmental Protection

SCE is subject to numerous environmental laws and regulations, which require it to incur substantial costs to operate existing facilities, construct and operate new facilities, and mitigate or remove the effect of past operations on the environment.

As further discussed in Note 10 to the Consolidated Financial Statements, SCE records its environmental liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. SCE reviews its sites and measures the liability quarterly, by assessing a range of reasonably likely costs for each identified site. Unless there is a probable amount, SCE records the lower end of this likely range of costs.

SCE's recorded estimated minimum liability to remediate its 49 identified sites is $171 million. One of SCE's sites, a former pole-treating facility, is considered a federal Superfund site and represents 41% of its recorded liability. The ultimate costs to clean up SCE's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process. SCE believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $247 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes. SCE has sold all of its gas- and oil-fueled power plants and has retained some liability associated with the divested properties.

The CPUC allows SCE to recover environmental-cleanup costs at 41 of its sites, representing $88 million of its recorded liability, through an incentive mechanism. Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. Costs incurred at SCE's remaining sites are expected to be recovered through customer rates. SCE has recorded a regulatory asset of $141 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

SCE's identified sites include several sites for which there is a lack of currently available information, including the nature and magnitude of contamination, and the extent, if any, that SCE may be held responsible for contributing to any costs incurred for remediating these sites. Thus, no reasonable estimate of cleanup costs can be made for these sites.

SCE expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $4 million to $10 million. Recorded costs for 1998 were $7 million.

Based on currently available information, SCE believes it is unlikely that it will incur amounts in excess of the upper limit of the estimated range and, based upon the CPUC's regulatory treatment of environmental-cleanup costs, SCE believes that costs ultimately recorded will not materially affect its results of operations or financial position. There can be no assurance, however, that future developments, including additional information about existing sites or the identification of new sites, will not require material revisions to such estimates.

The 1990 federal Clean Air Act requires power producers to have emissions allowances to emit sulfur dioxide. Power companies receive emissions allowances from the federal government and may bank or sell excess allowances. SCE expects to have excess allowances under Phase II of the Clean Air Act (2000 and later). The act also calls for a study to determine if additional regulations are needed to reduce regional haze in the southwestern U.S. In addition, another study is in progress to determine the specific impact of air contaminant emissions from the Mohave Coal Generating Station on visibility in Grand Canyon National Park. The potential effect of these studies on sulfur dioxide emissions regulations for Mohave is unknown.

SCE's projected environmental capital expenditures are $900 million for the 1999—2003 period, mainly for aesthetics treatment, including undergrounding certain transmission and distribution lines.

The possibility that exposure to electric and magnetic fields (EMF) emanating from power lines, household appliances and other electric sources may result in adverse health effects has been the subject of scientific research. After many years of research, scientists have not found that exposure to EMF causes disease in humans. Research on this topic is continuing. However, the CPUC has issued a decision, which provides for a rate-recoverable research and public education program conducted by California electric utilities, and authorizes these utilities to take no-cost or low-cost steps to reduce EMF in new electric facilities. SCE is unable to predict when or if the scientific community will be able to reach a consensus on any health effects of EMF, or the effect that such a consensus, if reached, could have on future electric operations.

San Onofre Steam Generator Tubes

The San Onofre Units 2 and 3 steam generators have performed relatively well through the first 15 years of operation, with low rates of ongoing steam generator tube degradation. However, during the Unit 2 scheduled refueling and inspection outage in 1997, an increased rate of tube degradation was identified, which resulted in the removal of more tubes from service than had been expected. The steam generator design allows for the removal of up to 10% of the tubes before the rated capacity of the unit must be reduced. As a result of the increased degradation, a mid-cycle inspection outage was conducted in early 1998 for Unit 2. Continued degradation was found during this inspection. A favorable or decreasing trend in degradation was observed during inspection in the scheduled refueling outage in January 1999. The results of the January 1999 inspection are being analyzed to determine if there is a need for a mid-cycle inspection outage in early 2000. With the results from the January 1999 outage, 7.5% of the tubes have now been removed from service. In September 1998, San Onofre Unit 2 experienced a small amount of leakage from a steam generator tube plug, which required an 11-day outage to repair.

During Unit 3's refueling outage, which was completed in July 1997, inspections of structural supports for steam generator tubes identified several areas where the thickness of the supports had been reduced, apparently by erosion during normal plant operation. A follow-up mid-cycle inspection indicated that the erosion had been stabilized. Additional monitoring inspections are planned during the next scheduled refueling outage in 1999. To date, 5% of Unit 3's tubes have been removed from service.

During Unit 2's February 1998 mid-cycle outage, similar tube supports showed no significant levels of such erosion.

New Accounting Rules

A recently issued accounting rule requires that costs related to start-up activities be expensed as incurred, effective January 1, 1999. SCE does not expect this new accounting rule to materially affect its results of operations or financial position.

In June 1997, a new accounting standard for reporting operating segment information was issued. The new standard, which became effective for financial reports issued after December 15, 1998, requires that operating segment information be disclosed in the Notes to the Consolidated Financial Statements. Since, in management's view, SCE currently operates as one segment, this standard is not expected to affect SCE's consolidated financial statements and the accompanying notes to the consolidated financial statements.

In June 1998, a new accounting standard for derivative instruments and hedging activities was issued. The new standard, which will be effective January 1, 2000, requires all derivatives to be recognized on the balance sheet at fair value. Gains or losses from changes in fair value would be recognized in earnings in the period of change unless the derivative is designated as a hedging instrument. Gains or losses from hedges of a forecasted transaction or foreign currency exposure would be reflected in other comprehensive income. Gains or losses from hedges of a recognized asset or liability or a firm commitment would be reflected in earnings for the ineffective portion of the hedge. SCE anticipates that most of its derivatives under the new standard would qualify for hedge accounting. SCE expects to recover in rates any market price changes from its derivatives that could potentially affect earnings. Accordingly, implementation of this new standard is not expected to affect earnings.

Year 2000 Issue

Many of SCE's existing computer systems were originally programmed to represent any date by using six digits (e.g., 12/31/99) rather than eight digits (e.g., 12/31/1999). Accordingly, such programs, if not appropriately addressed, could fail or create erroneous results when attempting to process information containing dates after December 31, 1999. This situation has been referred to generally as the Year 2000 Issue.

SCE has a comprehensive program in place to address potential Year 2000 impacts. Edison International provides overall coordination of this effort, working with SCE and its business units. SCE divides Year 2000 activities into five phases: inventory, impact assessment, remediation, testing and implementation. SCE's objective for the Year 2000 readiness of critical systems is to be 100% complete by July 1999. A critical system is defined as those applications and systems, including embedded processor technology, which if not appropriately remediated, may have a significant impact on customers, the health and safety of the public and/or personnel, the revenue stream, or regulatory compliance. SCE was 80% complete at year-end 1998 (the goal was 75%) and is on track to meets its July 1999 goal.

A system, application or physical asset is deemed to be Year 2000-ready if it is determined by SCE to be suitable for continued use through the year 2028 (or through the last year of the anticipated life of the asset, whichever occurs first), even though it is not fully Year 2000-compliant. A system, application, or physical asset is Year 2000-compliant if it accurately processes date/time data.

SCE has structured the scope of the program to focus on three principal categories: mainframe computing, distributed computing and physical assets (also known as embedded processors). The mainframe and distributed computing assets consist of computer application systems (software). Physical assets include information technology infrastructure (hardware, operating system software) and embedded processor technology in generation, transmission, distribution, and facilities components.

Year 2000-readiness preparations for SCE's mainframe financial systems were completed in the fourth quarter of 1997, and preparations for SCE's material management system were completed in the second quarter of 1998. SCE's customer information and billing system is in the process of being replaced with a system designed to be Year 2000-ready and final conversion activities are expected to be completed during the first quarter of 1999. SCE's distributed computing assets include operations and business information systems. SCE's critical operations information systems include outage management, power management, and plant monitoring and access retrieval systems. SCE's business information systems include a data acquisition system for billing, the computer call center support system, credit support and maintenance management.

Ongoing efforts in 1999 will continue to focus on guarding against reintroduction of components that are not Year 2000-ready into Year 2000-ready systems.

The other essential component of the SCE Year 2000-readiness program is to identify and assess vendor products and business partners for Year 2000 readiness, as these external parties may have the potential to impact SCE's Year 2000 readiness. SCE has implemented a process to identify and contact vendors and business partners to determine their Year 2000 status, and is evaluating the responses. As of January 31, 1999, Edison International has contacted over 4,300 critical vendors and business partners (the largest percentage of which are SCE's vendors and business partners). SCE's general policy requires that all newly purchased products and services be Year 2000-ready or otherwise designed to allow SCE to determine whether such products and services present Year 2000 issues. SCE is also working to address Year 2000 issues related to all ISO and PX interfaces, as well as joint ownership facilities. SCE exchanges Year 2000-readiness information (including, but not limited to, test results and related data) with certain of its affiliates and other external parties as part of its Year 2000-readiness efforts.

SCE's current estimate of the costs to complete these modifications, including the cost of new hardware and software application modification, is $72 million, about 40% of which is expected to be capital costs. SCE's Year 2000 costs expended through December 31, 1998, were $35 million. SCE expects current rate levels for providing electric service to be sufficient to provide funding for utility-related modifications.

Although SCE expects that its critical systems will be fully Year 2000-ready prior to year-end 1999, there can be no assurance that the systems of other companies on which the systems and operations of SCE rely will be converted on a timely basis. SCE believes that prudent business practices call for the development of contingency plans. Such contingency plans shall include developing strategies for dealing with the most reasonably likely worst case scenario concerning Year 2000-related processing failures or malfunctions caused by SCE's internal systems or from external parties. As noted above, SCE has, in many cases, completed its Year 2000-readiness work and is currently in the remediation and testing phases for certain of their other internal systems as well as assessing risks posed by external parties. SCE is working with industry groups in an effort to help define a reasonably likely worst case scenario and in the development of contingency plans. SCE's contingency plans, which will include scheduling of key personnel, are expected to be completed by March 1999. As of January 31, 1999, draft component and system contingency plans were completed and being evaluated, draft plans were in progress for generating units, and a draft of the grid operations plan had been submitted to the Western Systems Coordinating Council. However, contingency plans will continue to be revised and enhanced as 2000 approaches. SCE also plans to test these contingency plans by conducting or participating in exercises during 1999. Also, SCE is scheduled to participate in industry-wide drills during 1999.

SCE does not expect the Year 2000 Issue to have a material adverse effect on its results of operation or financial position; however, if not effectively remediated, negative effects from Year 2000 issues, including those related to internal systems, vendors, business partners, the ISO, the PX or customers, could cause results to differ.

Forward-looking Information

In the preceding Management's Discussion and Analysis of Results of Operations and Financial Condition and elsewhere in this annual report, the words estimates, expects, anticipates, believes, and other similar expressions are intended to identify forward-looking information that involves risks and uncertainties. Actual results or outcomes could differ materially as a result of such important factors as further actions by state and federal regulatory bodies setting rates and implementing the restructuring of the electric utility industry; the effects of new laws and regulations relating to restructuring and other matters; the effects of increased competition in the electric utility business, including direct customer access to retail energy suppliers and the unbundling of revenue cycle services such as metering and billing; changes in prices of electricity and fuel costs; changes in market interest rates; new or increased environmental liabilities; the effects of the Year 2000 Issue; and other unforeseen events.

Consolidated Statements of Income

In thousands Year ended December 31,	1998	1997	1996
Sales to ultimate consumers	$7,104,800	$7,639,417	$7,272,919
Sales to power exchange	1,347,579	—	—
Other	394,719	313,969	310,463
Operating revenue	8,847,098	7,953,386	7,583,382
Fuel	323,716	881,471	630,512
Purchased power — contracts	2,625,900	2,854,002	2,705,880
Purchased power — power exchange	1,983,922	—	—
Provisions for regulatory adjustment clauses — net	(472,519)	(410,935)	(225,908)
Other operating expenses	1,480,644	1,216,317	1,181,641
Maintenance	410,566	405,545	329,371
Depreciation, decommissioning and amortization	1,545,735	1,239,878	1,063,505
Income taxes	445,642	582,031	578,329
Property and other taxes	128,402	129,038	190,284
Net gains on sale of utility plant	(542,608)	(3,849)	(3,325)
Total operating expenses	7,929,400	6,893,498	6,450,289
Operating income	917,698	1,059,888	1,133,093
Provision for rate phase-in plan	—	(48,486)	(84,288)
Allowance for equity funds used during construction	11,826	7,651	15,579
Interest and dividend income	66,725	44,636	37,855
Other nonoperating income (deductions) — net	(4,385)	(23,036)	(3,623)
Total other income (deductions) — net	74,166	(19,235)	(34,477)
Income before interest expense	991,864	1,040,653	1,098,616
Interest on long-term debt	421,857	345,592	380,812
Other interest expense	64,225	101,078	73,914
Allowance for borrowed funds used during construction	(8,046)	(9,213)	(9,794)
Capitalized interest	(1,294)	(2,398)	(1,711)
Total interest expense — net	476,742	435,059	443,221
Net income	515,122	605,594	655,395
Dividends on preferred stock	24,632	29,488	34,395
Earnings available for common stock	$ 490,490	$ 576,106	$ 621,000

Consolidated Statements of Comprehensive Income

In thousands Year ended December 31,	1998	1997	1996
Net income	$515,122	$605,594	$655,395
Unrealized gain on securities – net	9,275	14,641	14,900
Reclassification adjustment for gains included in net income	(17,836)	—	—
Comprehensive income	$506,561	$620,235	$670,295

The accompanying notes are integral part of these financial statements.

Consolidated Balance Sheets

In thousands December 31,	1998	1997
ASSETS		
Transmission and distribution:		
Utility plant, at original cost, subject to cost-based rate regulation	$11,771,678	$11,213,352
Accumulated provision for depreciation	(6,062,562)	(5,573,742)
Construction work in progress	455,233	492,614
	6,164,349	6,132,224
Generation:		
Utility plant, at original cost, not subject to cost-based rate regulation	1,689,469	9,522,127
Accumulated provision for depreciation, decommissioning and amortization	(833,917)	(4,970,137)
Construction work in progress	61,431	100,283
Nuclear fuel, at amortized cost	172,250	154,757
	1,089,233	4,807,030
Total utility plant	7,253,582	10,939,254
Nonutility property — less accumulated provision for depreciation of $25,682 and $24,730 at respective dates	56,681	67,869
Nuclear decommissioning trusts	2,239,929	1,831,460
Other investments	179,480	171,399
Total other property and investments	2,476,090	2,070,728
Cash and equivalents	81,500	962,272
Receivables, including unbilled revenue, less allowances of $22,230 and $26,453 for uncollectible accounts at respective dates	1,112,630	906,388
Fuel inventory	51,299	58,059
Materials and supplies, at average cost	116,259	132,980
Accumulated deferred income taxes — net	274,833	123,146
Regulatory balancing accounts — net	648,781	193,311
Prepayments and other current assets	91,992	93,098
Total current assets	2,377,294	2,469,254
Regulatory asset — unamortized nuclear investment — net	2,161,998	—
Regulatory asset — income tax-related deferred charges	1,463,256	1,543,380
Unamortized debt issuance and reacquisition expense	348,816	359,304
Other deferred charges	865,892	677,378
Total deferred charges	4,839,962	2,580,062
Total assets	$16,946,928	$18,059,298

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

In thousands, except share amounts December 31,	Southern California Edison Company 1998	1997
CAPITALIZATION AND LIABILITIES		
Common shareholder's equity:		
Common stock (434,888,104 shares outstanding at each date)	$ 2,168,054	$ 2,168,054
Additional paid-in capital	334,031	334,031
Accumulated other comprehensive income	39,462	48,023
Retained earnings	793,625	1,407,834
	3,335,172	3,957,942
Preferred stock:		
Not subject to mandatory redemption	128,755	183,755
Subject to mandatory redemption	255,700	275,000
Long-term debt	5,446,638	6,144,597
Total capitalization	9,166,265	10,561,294
Other long-term liabilities	467,109	479,637
Current portion of long-term debt	400,810	692,875
Short-term debt	469,565	322,028
Accounts payable	447,484	406,704
Accrued taxes	678,955	509,270
Accrued interest	89,828	85,406
Dividends payable	91,742	95,146
Deferred unbilled revenue and other current liabilities	1,096,332	931,856
Total current liabilities	3,274,716	3,043,285
Accumulated deferred income taxes — net	2,993,142	2,939,471
Accumulated deferred investment tax credits	250,116	326,728
Customer advances and other deferred credits	795,266	708,745
Total deferred credits	4,038,524	3,974,944
Minority interest	314	138
Commitments and contingencies (Notes 2, 8, 9 and 10)		
Total capitalization and liabilities	$16,946,928	$18,059,298

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

Consolidated Statements of Cash Flows

In thousands Year ended December 31,	1998	1997	1996
Cash flows from operating activities:			
Net income	$ 515,122	$ 605,594	$ 655,395
Adjustments for non-cash items:			
Depreciation, decommissioning and amortization	1,545,735	1,239,878	1,063,505
Other amortization	163,063	81,363	90,931
Deferred income taxes and investment tax credits	(94,504)	63,379	46,122
Regulatory asset related to the sale of oil and gas plant	(220,232)	—	—
Net gains on sale of oil and gas plant	(564,623)	—	—
Other — net	(78,668)	(105,986)	5,710
Changes in working capital:			
Receivables	(206,242)	14,695	(9,120)
Regulatory balancing accounts	(455,470)	(374,799)	(156,379)
Fuel inventory, materials and supplies	23,481	35,707	38,791
Prepayments and other current assets	1,106	12,039	9,152
Accrued interest and taxes	174,107	16,625	(58,827)
Accounts payable and other current liabilities	205,256	120,464	93,362
Net cash provided by operating activities	1,008,131	1,708,959	1,778,642
Cash flows from financing activities:			
Long-term debt issued	—	—	396,309
Long-term debt repaid	(776,030)	(916,145)	(403,957)
Rate reduction notes issued	—	2,449,289	—
Rate reduction notes repaid	(251,591)	—	—
Preferred stock redeemed	(74,300)	(100,000)	—
Nuclear fuel financing — net	16,244	(20,140)	41,803
Short-term debt financing — net	147,537	91,879	(129,359)
Capital transferred	—	153,000	—
Dividends paid	(1,129,812)	(1,871,944)	(799,593)
Net cash used by financing activities	(2,067,952)	(214,061)	(894,797)
Cash flows from investing activities:			
Additions to property and plant	(860,837)	(685,320)	(616,427)
Proceeds from sale of oil and gas plant	1,203,039	—	—
Funding of nuclear decommissioning trusts	(162,925)	(153,756)	(148,158)
Unrealized gain (loss) in equity investments — net	(8,561)	14,641	14,900
Other — net	8,333	(28,133)	(75,985)
Net cash provided (used) by investing activities	179,049	(852,568)	(825,670)
Net increase (decrease) in cash and equivalents	(880,772)	642,330	58,175
Cash and equivalents, beginning of year	962,272	319,942	261,767
Cash and equivalents, end of year	$ 81,500	$ 962,272	$ 319,942

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

Note 1. Summary of Significant Accounting Policies

Accounting Principles

Southern California Edison Company's (SCE) accounting policies conform with generally accepted accounting principles, including the accounting principles for rate-regulated enterprises which reflect the rate-making policies of the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC). As a result of industry restructuring legislation enacted by the State of California and a related change in the application of accounting principles for rate-regulated enterprises adopted by the Financial Accounting Standards Board's Emerging Issues Task Force, during the third quarter of 1997, SCE began accounting for its investment in generation facilities in accordance with accounting principles applicable to enterprises in general and SCE's balance sheets display a separate caption for its investment in generation. Application of such accounting principles to SCE's generation assets did not result in any adjustment of their carrying value; however, SCE's nuclear investments were reclassified as a regulatory asset in second quarter 1998.

Competition Transition Charge (CTC)

Beginning January 1, 1998, a non-bypassable charge is being billed to all customers, which provides SCE the opportunity to recover its costs to transition to a competitive market.

Consolidation Policy

The consolidated financial statements include SCE and its subsidiaries. Intercompany transactions have been eliminated.

Estimates

Financial statements prepared in compliance with generally accepted accounting principles require management to make estimates and assumptions that affect the amounts reported in the financial statements and disclosure of contingencies. Actual results could differ from those estimates. Certain significant estimates related to electric utility restructuring, decommissioning and contingencies are further discussed in Notes 2, 9 and 10 to the Consolidated Financial Statements, respectively.

Fuel Inventory

Fuel inventory is valued under the last-in, first-out method for fuel oil and natural gas, and under the first-in, first-out method for coal.

Nature of Operations

SCE is a rate-regulated public utility, which produces and supplies electric energy for its 4.3 million customers in central, coastal and Southern California. SCE operates in a highly regulated environment in which it has an obligation to deliver electric service to customers in return for an exclusive franchise within its service territory. This regulatory environment is changing, as further discussed in Note 2 to the Consolidated Financial Statements. As a result of these changes, effective April 1, 1998, SCE sells all electric energy produced to the power exchange (PX), as mandated by state legislation and purchases electric energy from the PX to supply to its customers. SCE's outstanding common stock is owned entirely by its parent company, Edison International.

Nuclear

CPUC-authorized rate phase-in plans, which deferred collection of revenue for each unit at the Palo Verde Nuclear Generating Station during the first four years of operation, ended in February 1996, September 1996 and January 1998 for Units 1, 2 and 3, respectively.

Under federal law, SCE is liable for its share of the estimated costs to decommission three federal nuclear enrichment facilities (based on purchases). These costs, which will be paid over 15 years, are recorded as a fuel cost and recovered through non-bypassable customer rates.

In 1996 and 1997, the CPUC authorized acceleration of the recovery of SCE's remaining investment of $2.6 billion in San Onofre Nuclear Generation Station Units 2 and 3 and $1.2 billion in Palo Verde Units 1, 2 and 3, respectively. The accelerated recovery will continue through December 2001, earning a 7.35% fixed rate of return. San Onofre's operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures are recovered through an incentive pricing plan which allows SCE to receive about 4¢ per kilowatt-hour through 2003. Any differences between these costs and the incentive price will flow through to the shareholders. Palo Verde's accelerated plant recovery, as well as operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, are subject to balancing account treatment through 2001.

Beginning January 1, 1998, San Onofre's incentive pricing plan and accelerated plant recovery and the Palo Verde balancing account became part of the CTC mechanism. SCE will be required to share equally with ratepayers the net benefits received from operation of Palo Verde, beginning in 2002, and from the operation of the San Onofre units in 2004. Palo Verde's existing nuclear unit incentive procedure will continue only for purposes of calculating a reward for performance of any unit above an 80% capacity factor for a fuel cycle.

Reclassifications

Certain prior-year amounts were reclassified to conform to the December 31, 1998, financial statement presentation.

Regulatory Balancing Accounts

Prior to January 1, 1998, the differences between CPUC-authorized and actual base-rate revenue from kilowatt-hour sales and CPUC-authorized and actual energy costs were accumulated in balancing accounts until they were refunded to, or recovered from, customers through authorized rate adjustments (with interest). On January 1, 1998, the balances in these balancing accounts were transferred to a transition cost balancing account. Also, beginning January 1, 1998, the difference between generation-related revenue and generation-related costs is being accumulated in the transition cost balancing account, effectively eliminating all other balancing accounts except those used to assist in the administration of public purpose funds. Additionally, gains resulting from the divestiture of the gas- and oil-fueled generation plants were credited to the transition cost balancing account; the losses are being amortized over the remaining transition period and accumulated in the transition cost balancing account. These transition costs are being recovered from utility customers (with interest) through the CTC. For further details, see discussion under California Electric Utility Industry Restructuring in Note 2 to the Consolidated Financial Statements. Income tax effects on all balancing account changes are deferred.

In January 1997, in compliance with the restructuring legislation, overcollections in the kilowatt-hour sales and energy cost balancing accounts at December 31, 1996, were transferred to an interim balancing account and were subsequently credited to the transition cost balancing account in January 1998.

Research, Development and Demonstration (RD&D)

SCE capitalizes RD&D costs that are expected to result in plant construction. If construction does not occur, these costs are charged to expense. RD&D expenses were $2 million in 1998, $39 million in 1997 and $21 million in 1996.

Revenue

Operating revenue includes amounts for services rendered but unbilled at the end of each year. Beginning April 1, 1998, operating revenue also includes amounts for sales to the PX.

Supplemental Cash Flows Information

SCE's supplemental cash flows information was:

In millions Year ended December 31,	1998	1997	1996
Payments for interest and taxes:			
Interest — net of amounts capitalized	$ 264	$ 342	$ 347
Taxes	405	438	546

Utility Plant

Plant additions, including replacements and betterments, are capitalized. Such costs include direct material and labor, construction overhead and an allowance for funds used during construction (AFUDC). AFUDC represents the estimated cost of debt and equity funds that finance utility-plant construction. AFUDC is capitalized during plant construction and reported in current earnings. AFUDC is recovered in rates through depreciation expense over the useful life of the related asset. Depreciation of utility plant is computed on a straight-line, remaining-life basis.

Replaced or retired property and removal costs less salvage are charged to the accumulated provision for depreciation. Depreciation expense stated as a percent of average original cost of depreciable utility plant was 4.2% for 1998, 5.2% for 1997 and 4.2% for 1996.

During the third quarter of 1997, SCE discontinued accounting for its investment in generation facilities using accounting principles applicable to rate-regulated enterprises and began accounting for such investment using accounting principles applicable to enterprises in general. The carrying value of such investment was unaffected by this change. However, the nuclear investments were reclassified as a regulatory asset in second quarter 1998.

Note 2. Regulatory Matters

California Electric Utility Industry Restructuring

Restructuring Decision and Statute — The CPUC's December 1995 decision on restructuring California's electric utility industry started the transition to a new market structure involving competition and customer choice. The State of California enacted legislation in 1996 to provide a transition to a competitive market structure. The Statute substantially adopted the CPUC's restructuring decision by addressing stranded-cost recovery for utilities and providing a certain cost-recovery time period for the transition costs associated with utility-owned generation-related assets. Transition costs related to power-purchase contracts are being recovered through the terms of their contracts while most of the remaining transition costs will be recovered through 2001. The Statute also included provisions to finance a portion of the stranded costs that residential and small commercial customers would have paid between 1998 and 2001, which allowed SCE to reduce rates by at least 10% to these customers, effective January 1, 1998. The Statute included a rate freeze for all other customers, including large commercial and industrial customers, as well as provisions for continued funding for energy conservation, low-income programs and renewable resources. Despite the rate freeze, SCE expects to be able to recover its revenue requirement during the 1998–2001 transition period. In addition, the Statute mandated the implementation of the CTC that provides utilities the opportunity to recover costs made uneconomic by electric utility restructuring. Finally, the Statute contained provisions for the recovery (through 2006) of reasonable employee-related transition costs, incurred and projected, for retraining, severance, early retirement, outplacement and related expenses. The new market structure and customer choice began on April 1, 1998.

1998 Activities — During 1998, SCE implemented changes to comply with restructuring elements required by the CPUC and the Statute. Beginning January 1, 1998:

- SCE's rates were unbundled into separate charges for energy, transmission, distribution, the CTC, public benefit programs and nuclear decommissioning. The transmission component is being collected through FERC-approved rates, subject to refund.

- SCE's costs associated with its hydroelectric plants are being recovered through a performance-based mechanism. The mechanism sets the hydroelectric revenue requirement and establishes a formula for extending it through the duration of the electric industry restructuring transition period, or until market valuation of the hydroelectric facilities, whichever occurs first. The mechanism provides that power sales revenue from hydroelectric facilities in excess of the hydroelectric revenue requirement be credited against the costs to transition to a competitive market.

- SCE's transition costs are being recovered through a non-bypassable CTC. This charge applies to all customers who were using or began using utility services on or after the CPUC's December 1995 restructuring decision date. SCE has estimated its transition costs to be approximately $10.6 billion (1998 net present value) from 1998 through 2030. This estimate was based on incurred costs, forecasts of future costs and assumed market prices. However, changes in the assumed market prices could materially affect these estimates. The potential transition costs are comprised of $6.4 billion from SCE's qualifying facilities contracts, which are the direct result of prior legislative and regulatory mandates, and $4.2 billion (which reflects the sale of SCE's gas- and oil- fueled generation plants) from costs pertaining to certain generating assets and regulatory commitments consisting of costs incurred (whose recovery has been deferred by the CPUC) to provide service to customers. Such commitments include the recovery of income tax benefits previously flowed through to customers, postretirement benefit transition costs, accelerated recovery of San Onofre Units 2 and 3 and the Palo Verde units, and certain other costs.

- Residential and small commercial customers who began receiving a 10% rate reduction are repaying the rate reduction notes issued in December 1997 (see further discussion in Note 3 to the Consolidated Financial Statements) through non-bypassable charges based on electricity consumption.

Effective April 1, 1998:

- The ISO assumed operational control of the transmission system after the ISO and PX had begun accepting bids and schedules for electricity purchases on March 31, 1998. The restructuring implementation costs related to the start-up and development of the PX, which are paid by the utilities, will be recovered from all retail customers over the four-year transition period. SCE's share of the charge is $45 million, plus interest and fees. SCE's share of the ISO's start-up and development costs (approximately $16 million per year) will be paid over a 10-year period.

- Customers can choose to remain utility customers with either bundled electric service or an hourly PX pricing option from SCE (which is purchasing its power through the PX), or choose direct access, which means the customer can contract directly with either independent power producers or energy service providers (ESPs) such as power brokers, marketers and aggregators. Electric utilities are continuing to provide the core distribution service of delivering energy through their distribution system regardless of a customer's choice of electricity supplier. The CPUC is continuing to regulate the prices and service obligations related to distribution services.

- Customers have options regarding metering, billing and related services (referred to as revenue cycle services) that have been provided by California's investor-owned utilities. ESPs can provide their customers with one consolidated bill for their services and the utility's services, request the utility to provide such a consolidated bill to the customer or elect to have both the ESP and the utility bill the customer for their respective charges. Customers with maximum demand above 20kW (primarily industrial and medium and large commercial) can choose SCE or any other supplier to provide their metering service. Beginning in January 1999, all customers can make these choices. In September 1998, the CPUC issued a decision regarding the credits that would be provided to customers if they elect to obtain revenue cycle services from someone other than SCE. Although the decision adopted SCE's recommendation of using the net avoided cost, it also adopted a methodology which results in higher credits to customers but requires ESPs to pay service fees to SCE for the costs that SCE incurs as a result of dealing with the ESP.

During 1998, SCE sold all of its gas- and oil-fueled generation plants. The total sales price of the 12 plants was $1.2 billion, over $500 million more than the combined book value. Net proceeds of the sales were used to reduce stranded costs, which otherwise were expected to be collected through the CTC mechanism.

Accounting for Generation-Related Assets — If the CPUC's electric industry restructuring plan continues as described above, SCE would be allowed to recover its transition costs through non-bypassable charges to its distribution customers (although its investment in certain generation assets would be subject to a lower authorized rate of return). In 1997, SCE discontinued application of accounting principles for rate-regulated enterprises for its investment in generation facilities based on new accounting guidance. The financial reporting effect of this discontinuance was to segregate these assets on the balance sheet; the new guidance did not require SCE to write off any of its generation-related assets, including related regulatory assets. However, the new guidance did not specifically address the application of asset impairment standards to these assets. SCE has retained these assets on its balance sheet because the Statute and restructuring plan referred to above make probable their recovery through a non-bypassable CTC to distribution customers. The regulatory assets relate primarily to the recovery of accelerated income tax benefits previously flowed through to customers, purchased power contract termination payments and unamortized losses on reacquired debt. The new accounting guidance also permits the recording of new generation-related regulatory assets during the transition period that are probable of recovery through the CTC mechanism.

During the second quarter of 1998, additional guidance was developed related to the application of asset impairment standards to these assets. Using this guidance resulted in SCE reducing its remaining nuclear plant investment by $2.6 billion (as of June 30, 1998) and recording a regulatory asset on its balance sheet for the same amount. For this impairment assessment, the fair value of the investment was calculated by discounting future net cash flows. This reclassification had no effect on SCE's results of operations.

If during the transition period events were to occur that made the recovery of these generation-related regulatory assets no longer probable, SCE would be required to write off the remaining balance of such assets (approximately $2.4 billion, after tax, at December 31, 1998) as a one-time, non-cash charge against earnings.

If events occur during the restructuring process that result in all or a portion of the transition costs being improbable of recovery, SCE could have additional write-offs associated with these costs if they are not recovered through another regulatory mechanism. At this time, SCE cannot predict what other revisions will ultimately be made during the restructuring process in subsequent proceedings or the effect, after the transition period, that competition will have on its results of operations or financial position.

Note 3. Financial Instruments

Cash Equivalents

Cash and equivalents include tax-exempt investments ($78 million at December 31, 1998, and $936 million at December 31, 1997), and time deposits and other investments ($4 million at December 31, 1998, and $26 million at December 31, 1997) with maturities of three months or less.

Derivative Financial Instruments

SCE's risk management policy allows the use of derivative financial instruments to manage financial exposure on its investments and fluctuations in interest rates, but prohibits the use of these instruments for speculative or trading purposes.

SCE uses the hedge accounting method to record its derivative financial instruments, except for gas call options. Hedge accounting requires an assessment that the transaction reduces risk, that the derivative be designated as a hedge at the inception of the derivative contract, and that the changes in the market value of a hedge move in an inverse direction to the item being hedged. Under hedge accounting, the derivative itself is not recorded on SCE's balance sheet. Mark-to-market accounting would be used if the hedge accounting criteria were not met. Interest rate differentials and amortization of premiums for interest rate caps are recorded as adjustments to interest expense. If the derivatives were terminated before the maturity of the corresponding debt issuance, the realized gain or loss on the transaction would be amortized over the remaining term of the debt.

SCE has gas call options that mitigate its exposure to increases in natural gas prices. Increases in natural gas prices tend to increase the price of electricity purchased from the PX. The options cover various periods from 1998 through 2001.

SCE uses the mark-to-market accounting method for its gas call options. Gains and losses from monthly changes in market prices are recorded as income or expense. However, the costs of the options and the market price changes are included in the transition cost balancing account. As a result, the mark-to-market gains or losses have no effect on earnings.

Interest rate swaps are used to reduce the potential impact of interest rate fluctuations on floating-rate long-term debt. At the balance sheet dates of December 31, 1998, and December 31, 1997, SCE had an interest rate swap agreement which fixed the interest rate at 5.585% for $196 million of debt due 2008; it expires February 28, 2008. The interest rate swap agreement requires the parties to pledge collateral according to bond rating and market interest rate changes. At December 31, 1998, SCE had pledged $25 million as collateral due to a decline in market interest rates. SCE is exposed to credit loss in the event of nonperformance by the counterparty to the agreement, but does not expect the counterparty to fail to meet its obligation.

Fair Value of Financial Instruments

Fair values of financial instruments were:

In millions December 31,	1998		1997	
	Cost Basis	Fair Value	Cost Basis	Fair Value
Financial assets:				
Decommissioning trusts	$1,534	$2,240	$1,371	$1,831
Equity investments	7	72	9	90
Gas call options	39	31	34	34
Financial liabilities:				
DOE decommissioning and decontamination fees	45	40	50	43
Interest rate hedges	—	28	—	24
Long-term debt	5,447	5,699	6,145	6,456
Preferred stock subject to mandatory redemption	256	274	275	293

Financial assets are carried at their fair value based on quoted market prices for decommissioning trusts and equity investments and on financial models for gas call options. Financial liabilities are recorded at cost. Financial liabilities' fair values are based on: termination costs for the interest rate swap; brokers' quotes for long-term debt and preferred stock; and discounted future cash flows for U.S. Department of Energy (DOE) decommissioning and decontamination fees. Due to their short maturities, amounts reported for cash equivalents and short-term debt approximate fair value.

Gross unrealized holding gains (losses) on financial assets were:

In millions December 31,	1998	1997
Decommissioning trusts:		
Municipal bonds	$196	$131
Stocks	365	190
U.S. government issues	115	91
Short-term and other	30	48
	706	460
Equity investments	65	81
Gas call options	(8)	—
Total	$763	$541

There were no unrealized holding losses on financial assets for the years presented, other than the unrealized holding loss on the gas call options in 1998.

In June 1998, a new accounting standard for derivative instruments and hedging activities was issued. The new standard, which will be effective January 1, 2000, requires all derivatives to be recognized on the balance sheet at fair value. Gains or losses from changes in fair value would be recognized in earnings in the period of change unless the derivative is designated as a hedging instrument. Gains or losses from hedges of a forecasted transaction or foreign currency exposure would be reflected in other comprehensive income. Gains or losses from hedges of a recognized asset or liability or a firm commitment would be reflected in earnings for the ineffective portion of the hedge. SCE anticipates that most of its derivatives under the new standard would qualify for hedge accounting. SCE expects to recover in rates any market price changes from its derivatives that could potentially affect earnings. Accordingly, implementation of this new standard is not expected to affect earnings.

Investments

Net unrealized gains (losses) on equity investments are recorded as a separate component of shareholder's equity under the caption: Accumulated other comprehensive income. Unrealized gains and losses on decommissioning trust funds are recorded in the accumulated provision for decommissioning.

All investments are classified as available-for-sale.

Long-Term Debt

California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates.

Almost all SCE properties are subject to a trust indenture lien. SCE has pledged first and refunding mortgage bonds as security for borrowed funds obtained from pollution-control bonds issued by government agencies. SCE uses these proceeds to finance construction of pollution-control facilities. Bondholders have limited discretion in redeeming certain pollution-control bonds, and SCE has arranged with securities dealers to remarket or purchase them if necessary.

Debt premium, discount and issuance expenses are amortized over the life of each issue. Under CPUC rate-making procedures, debt reacquisition expenses are amortized over the remaining life of the reacquired debt or, if refinanced, the life of the new debt.

Commercial paper intended to be refinanced for a period exceeding one year and used to finance nuclear fuel scheduled to be used more than one year after the balance sheet date is classified as long-term debt.

Long-term debt maturities and sinking-fund requirements for the five years are: 1999 — $401 million; 2000 — $571 million; 2001 — $646 million; 2002 — $446 million; and 2003 — $371 million.

In December 1997, SCE Funding LLC, a special purpose entity (SPE), of which SCE is the sole member, issued approximately $2.5 billion of rate reduction notes to Bankers Trust Company of California, as certificate trustee for the California Infrastructure and Economic Development Bank Special Purpose Trust SCE-1 (Trust), which is a special purpose entity established by the State of California. The terms of the rate reduction notes generally mirror the terms of the pass-through certificates issued by the Trust, which are known as rate reduction certificates. The proceeds of the rate reduction notes were used by the SPE to purchase from SCE an enforceable right known as transition property. Transition property is a current property right created pursuant to the restructuring legislation and a financing order of the CPUC and consists generally of the right to be paid a specified amount from a non-bypassable tariff levied on residential and small commercial customers. Notwithstanding the legal sale of the transition property by SCE to the SPE, the amounts reflected as assets on SCE's balance sheet have not been reduced by the amount of the transition property sold to the SPE, and the liabilities of the SPE for the rate reduction notes are for accounting purposes reflected as long-term liabilities on the consolidated balance sheet of SCE. SCE used the proceeds from the sale of the transition property to retire debt and equity securities. The rate reduction notes are secured solely by the transition property and certain other assets of the SPE, and there is no recourse to SCE or Edison International.

Although the SPE is consolidated with SCE in the financial statements, as required by generally accepted accounting principles, the SPE is legally separate from SCE, the assets of the SPE are not available to creditors of SCE or Edison International, and the transition property is legally not an asset of SCE or Edison International.

Long-term debt consisted of:

In millions	December 31,	1998	1997
First and refunding mortgage bonds:			
1999 - 2026 (5.625% to 7.5%)		$1,550	$1,825
Rate reduction notes:			
1999 - 2007 (6.14% to 6.42%)		2,217	2,463
Pollution-control bonds:			
1999 - 2027 (5.4% to 7.2% and variable)		1,201	1,202
Funds held by trustees		(2)	(2)
Debentures and notes:			
1999 - 2006 (5.6% to 8.25%)		700	1,195
Subordinated debentures:			
2044 (8.375%)		100	100
Commercial paper for nuclear fuel		108	92
Long-term debt due within one year		(401)	(693)
Unamortized debt discount — net		(26)	(37)
Total		$5,447	$6,145

Short-Term Debt

SCE has lines of credit it can use at negotiated or bank index rates. At December 31, 1998, these lines totaled $1.3 billion, with $800 million available for short-term debt and $500 million available for the long-term refinancing of certain variable-rate pollution-control debt.

Short-term debt consisted of commercial paper used to finance fuel inventories and general cash requirements. Commercial paper outstanding at December 31, 1998, and December 31, 1997, was $581 million and $415 million, respectively. Commercial paper intended to finance nuclear fuel scheduled to be used more than one year after the balance sheet date is classified as long-term debt in connection with refinancing terms under five-year term lines of credit with commercial banks. Weighted-average interest rates were 5.3% and 6.0% at December 31, 1998, and December 31, 1997, respectively.

Note 4. Equity

The CPUC regulates SCE's capital structure, limiting the dividends it may pay Edison International. At December 31, 1998, SCE had the capacity to pay $794 million in additional dividends and continue to maintain its authorized capital structure.

In 1998, SCE implemented a recently issued accounting standard that requires companies to report comprehensive income. Implementation of the new standard had no effect on SCE's results of operations or financial position.

Changes in SCE's common shareholder's equity were as follows:

In millions	Common Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income	Retained Earnings	Total Common Shareholder's Equity
Balance at December 31, 1995	$ 2,168	$ 178	$ 18	$2,780	$5,144
Net income				655	655
Unrealized gain on securities			25		25
Tax effect			(10)		(10)
Dividends declared on common stock				(735)	(735)
Dividends declared on preferred stock				(34)	(34)
Balance at December 31, 1996	2,168	178	33	2,666	5,045
Net income				606	606
Unrealized gain on securities			24		24
Tax effect			(9)		(9)
Dividends declared on common stock				(1,829)	(1,829)
Dividends declared on preferred stock				(30)	(30)
Reacquired capital stock expense				(5)	(5)
Additional investment from parent company		156			156
Balance at December 31, 1997	2,168	334	48	1,408	3,958
Net income				515	515
Unrealized gain on securities			14		14
Tax effect			(5)		(5)
Reclassified adjustment for gain included in net income			(30)		(30)
Tax effect			12		12
Dividends declared on common stock				(1,101)	(1,101)
Dividends declared on preferred stock				(24)	(24)
Stock option appreciation				(4)	(4)
Balance at December 31, 1998	$ 2,168	$ 334	$ 39	$ 794	$3,335

Authorized common stock is 560 million shares with no par value. Authorized shares of preferred and preference stock are: $25 cumulative preferred — 24 million; $100 cumulative preferred — 12 million; and preference — 50 million. All cumulative preferred stocks are redeemable. Mandatorily redeemable preferred stocks are subject to sinking-fund provisions. When preferred shares are redeemed, the premiums paid are charged to common equity.

Preferred stock redemption requirements for the next five years are: 1999 through 2001 — zero; 2002 — $105 million; and 2003 — $9 million.

Cumulative preferred stock consisted of:

Dollars in millions, except per share amounts	December 31, 1998 Shares Outstanding	December 31, 1998 Redemption Price	1998	1997
Not subject to mandatory redemption:				
$25 par value:				
4.08% Series	1,000,000	$25.50	$ 25	$ 25
4.24	1,200,000	25.80	30	30
4.32	1,653,429	28.75	41	41
4.78	1,296,769	25.80	33	33
5.80	—	—	—	55
Total			$129	$184
Subject to mandatory redemption:				
$100 par value:				
6.05% Series	750,000	$100.00	$ 75	$ 75
6.45	1,000,000	100.00	100	100
7.23	807,000	100.00	81	100
Total			$256	$275

In 1998, 193,000 shares of Series 7.23% and 2.2 million shares of Series 5.8% preferred stock were redeemed. In 1997, 4 million shares of Series 7.36% preferred stock were redeemed. There were no preferred stock issuances for the years presented.

Note 5. Income Taxes

SCE and its subsidiaries will be included in Edison International's consolidated federal income tax and combined state franchise tax returns. Under income tax allocation agreements, each subsidiary calculates its own tax liability.

Income tax expense includes the current tax liability from operations and the change in deferred income taxes during the year. Investment tax credits are amortized over the lives of the related properties.

The components of the net accumulated deferred income tax liability were:

In millions December 31,	1998	1997
Deferred tax assets:		
Property-related	$ 197	$ 227
Unrealized gains or losses	387	273
Investment tax credits	152	192
Regulatory balancing accounts	96	180
Decommissioning-related	126	114
Fixed costs	188	109
Other	285	226
Total	$1,431	$1,321
Deferred tax liabilities:		
Property-related	$3,005	$3,272
Capitalized software costs	196	127
Regulatory balancing accounts	162	202
Other	786	536
Total	$4,149	$4,137
Accumulated deferred income taxes — net	$2,718	$2,816
Classification of accumulated deferred income taxes:		
Included in deferred credits	$2,993	$2,939
Included in current assets	275	123

The current and deferred components of income tax expense were:

In millions Year ended December 31,	1998	1997	1996
Current:			
Federal	$450	$375	$386
State	101	100	129
	551	475	515
Deferred—federal and state:			
Accrued charges	(43)	(33)	(14)
Property related	(106)	(47)	(14)
Investment and energy tax credits — net	(74)	(20)	(24)
Pension reserve	(3)	(5)	45
Rate phase-in plan	—	(19)	(32)
Regulatory balancing accounts	177	141	34
Unbilled revenue	(67)	6	—
Other	7	22	1
	(109)	45	(4)
Total income tax expense	$442	$520	$511
Classification of income taxes:			
Included in operating income	$446	$582	$578
Included in other income	(4)	(62)	(67)

The composite federal and state statutory income tax rate was 40.551% for 1998 and 1997, and 41.045% for 1996.

The federal statutory income tax rate is reconciled to the effective tax rate below:

Year ended December 31,	1998	1997	1996
Federal statutory rate	35.0%	35.0%	35.0%
Capitalized software	(0.7)	(0.9)	(0.8)
Property related and other	11.4	6.9	4.5
Investment and energy tax credits	(6.8)	(1.8)	(2.0)
State tax — net of federal deduction	6.9	7.0	7.1
Effective tax rate	45.8%	46.2%	43.8%

Note 6. Employee Compensation and Benefit Plans

Stock Option Plans

In April 1998, Edison International shareholders approved the Edison International Equity Compensation Plan. The plan replaces the Long-Term Incentive Compensation Program, consisting of officer, director, and management plans, which was adopted by Edison International shareholders in 1992. No new awards will be made under the prior program; however, it will remain in effect as long as any awards remain outstanding under the prior program.

The prior program participated in the use of 8.2 million shares of parent company common stock reserved for potential issuance under various stock compensation programs to directors, officers and senior managers of Edison International and its affiliates. Under these programs, options on 3.0 million shares of Edison International common stock are currently outstanding to officers and senior managers of SCE.

The new plan authorizes the annual issuance of shares equal to one percent of the issued and outstanding shares of Edison International common stock as of December 31 of the prior year. This authorization is cumulative so that to the extent shares are not needed to meet new plan requirements in any year, the excess authorized shares will carry over to subsequent years until plan termination. One percent of the issued and outstanding Edison International common stock on December 31, 1997, was 3.8 million shares. Under the new plan, options on 1.4 million shares of Edison International common stock are currently outstanding to officers and senior managers of SCE.

Each option may be exercised to purchase one share of Edison International common stock, and is exercisable at a price equivalent to the fair market value of the underlying stock at the date of grant. Edison International stock options include a dividend equivalent feature. Generally, for options issued before 1994, amounts equal to dividends accrue on the options at the same time and at the same rate as would be payable on the number of shares of Edison International common stock covered by the options. The amounts accumulate without interest. For Edison International stock options issued after 1993, dividend equivalents are subject to reduction unless certain shareholder return performance criteria are met.

The new plan's stock options have a 10-year term with one-fourth of the total award vesting after each of the first four years of the award term. The prior program's stock options have a 10-year term with one-third of the total award vesting after each of the first three years of the award term. If an optionee retires, dies or is permanently and totally disabled during the vesting period, the unvested options will vest and be exercisable to the extent of 1/36 (prior program) or 1/48 (the new plan) of the grant for each full month of service during the vesting period.

Unvested options of any person who has served in the past on the Edison International or SCE Management Committee (which was dissolved in 1993) will vest and be exercisable upon the member's retirement, death or permanent and total disability. Upon retirement, death or permanent and total disability, the vested options may continue to be exercised within their original terms by the recipient or beneficiary. If an optionee is terminated other than by retirement, death or permanent and total disability, options which had vested as of the prior anniversary date of the grant are forfeited unless exercised within 180 days of the date of termination. All unvested options are forfeited on the date of termination.

SCE measures compensation expense related to stock-based compensation by the intrinsic value method. Compensation expense recorded under the stock-compensation program was $8 million, $5 million and $8 million for the years 1998, 1997 and 1996, respectively.

Stock-based compensation expense under the fair-value method of accounting would have resulted in pro forma earnings of $516 million, $602 million and $653 million for the years 1998, 1997 and 1996, respectively.

The weighted-average fair value of options granted during 1998 and 1997 was $6.44 per share option and $7.62 per share option, respectively. The weighted-average remaining life of options outstanding as of December 31, 1998, and December 31, 1997, was 7 years.

The fair value for each option granted, reflecting the basis for the above pro forma disclosures, was determined on the date of grant using the Black-Scholes option-pricing model. The following assumptions were used in determining fair value through the model:

	1998	1997
Expected life	7 years	7 years
Risk-free interest rate	4.7% - 5.6%	6.3% - 6.8%
Expected volatility	17%	17%

The application of fair-value accounting to calculate the pro forma disclosures above is not an indication of future income statement effects. The pro forma disclosures do not reflect the effect of fair-value accounting on stock-based compensation awards granted prior to 1995.

Pension Plan

SCE has a noncontributory, defined-benefit pension plan that covers employees meeting minimum service requirements. SCE recognizes pension expense as calculated by the actuarial method used for ratemaking. In 1996, SCE recorded pension gains from a special voluntary early retirement program. In 1998, SCE adopted a new accounting standard that revises the disclosure requirements for pension plans. Prior periods have been restated.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	1998	1997
Change in benefit obligation		
Benefit obligation at beginning of year	$2,094	$2,002
Service cost	59	44
Interest cost	141	138
Actuarial loss	90	192
Benefits paid	(133)	(282)
Benefit obligation at end of year	$2,251	$2,094
Change in plan assets		
Fair value of plan assets at beginning of year	$2,298	$2,158
Actual return on plan assets	334	369
Employer contributions	53	53
Benefits paid	(133)	(282)
Fair value of plan assets at end of year	$2,552	$2,298
Funded status	$ 301	$ 204
Unrecognized net gain	(372)	(304)
Unrecognized net obligation (17-year amortization)	33	38
Unrecognized prior service cost	168	184
Pension asset (liability)	$ 130	$ 122
Discount rate	6.75%	7.0%
Rate of compensation increase	5.0%	5.0%
Expected return on plan assets	7.5%	8.0%

The components of pension expense were:

In millions Year ended December 31,	1998	1997	1996
Service cost	$ 59	$ 44	$ 49
Interest cost	141	138	178
Expected return on plan assets	(170)	(160)	(203)
Net amortization and deferral	14	13	5
Pension expense under accounting standards	44	35	29
Regulatory adjustment — deferred	11	17	22
Net pension expense recognized	55	52	51
Settlement gain	—	—	(121)
Total expense (gain)	$ 55	$ 52	$ (70)

Postretirement Benefits Other Than Pensions

Employees retiring at or after age 55 with at least 10 years of service (or those eligible under a 1996 special voluntary early retirement program), are eligible for postretirement health and dental care, life insurance and other benefits. In 1996, SCE recorded special termination expenses from a special voluntary early retirement program. In 1998, SCE adopted a new accounting standard that revises the disclosure requirements for postretirement benefit plans. Prior periods have been restated.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	1998	1997
Change in benefit obligation		
Benefit obligation at beginning of year	$1,533	$1,349
Service cost	41	30
Interest cost	99	99
Actuarial loss (gain)	(74)	114
Benefits paid	(54)	(59)
Benefit obligation at end of year	$1,545	$1,533
Change in plan assets		
Fair value of plan assets at beginning of year	$ 815	$ 617
Actual return on plan assets	147	147
Employer contributions	121	110
Benefits paid	(54)	(59)
Fair value of plan assets at end of year	$1,029	$ 815
Funded status	$ (516)	$ (718)
Unrecognized net loss	84	244
Unrecognized transition obligation (20-year amortization)	376	403
Recorded asset (liability)	$ (56)	$ (71)
Discount rate	6.75%	7.0%
Expected return on plan assets	7.5%	8.0%

The components of postretirement benefits other than pension expense were:

In millions Year ended December 31,	1998	1997	1996
Service cost	$ 41	$ 30	$ 31
Interest cost	99	99	90
Expected return on plan assets	(62)	(50)	(43)
Amortization of loss	1	4	6
Amortization of transition obligation	27	27	27
Net expense	106	110	111
Special termination expense	—	—	72
Total expense	$ 106	$ 110	$ 183

The assumed rate of future increases in the per-capita cost of health care benefits is 8.25% for 1999, gradually decreasing to 5.0% for 2009 and beyond. Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 1998, by $264 million and annual aggregate service and interest costs by $31 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 1998, by $211 million and annual aggregate service and interest costs by $24 million.

Employee Savings Plan

SCE has a 401(k) defined contribution savings plan designed to supplement employees' retirement income. The plan received employer contributions of $17 million in 1998, $15 million in 1997 and $24 in 1996.

Note 7. Jointly Owned Utility Projects

SCE owns interests in several generating stations and transmission systems for which each participant provides its own financing. SCE's share of expenses for each project is included in the consolidated statements of income.

The investment in each project, as included in the consolidated balance sheet as of December 31, 1998, was:

In millions	Original Cost of Facility	Accumulated Depreciation and Amortization	Under Construction	Ownership Interest
Transmission systems:				
Eldorado	$ 31	$ 6	$ 2	60%
Pacific Intertie	239	78	5	50
Generating stations:				
Four Corners Units 4 and 5 (coal)	459	288	2	48
Mohave (coal)	315	183	6	56
Palo Verde (nuclear)[1]	1,605	908	12	16
San Onofre (nuclear)[1]	4,217	2,762	63	75
Total	$6,866	$4,225	$90	

[1] Reported as "Regulatory asset — unamortized nuclear investment — net."

Note 8. Leases

SCE has operating leases, primarily for vehicles, with varying terms, provisions and expiration dates.

Estimated remaining commitments for noncancellable leases at December 31, 1998, were:

Year ended December 31,	In millions
1999	$ 13
2000	11
2001	8
2002	5
2003	3
Thereafter	5
Total	$45

Note 9. Commitments

Nuclear Decommissioning

Decommissioning is estimated to cost $1.9 billion in current-year dollars, based on site-specific studies performed in 1998 for San Onofre and Palo Verde. Changes in the estimated costs, timing of decommissioning, or the assumptions underlying these estimates could cause material revisions to the estimated total cost to decommission in the near term. SCE plans to decommission its nuclear generating facilities by a prompt removal method authorized by the Nuclear Regulatory Commission. Decommissioning is scheduled to begin in 2013 for San Onofre Units 2 and 3, and 2025 at Palo Verde. In December 1998, SCE requested the CPUC's approval to access its nuclear decommissioning trust funds to commence decommissioning of San Onofre Unit 1 in 2000.

Decommissioning costs, which are accrued and recovered through non-bypassable customer rates over the term of each nuclear facility's operating license, are recorded as a component of depreciation expense.

Decommissioning expense was $164 million in 1998, $154 million in 1997 and $148 million in 1996. The accumulated provision for decommissioning, excluding San Onofre Unit 1, was $1.2 billion at December 31, 1998, and $1.1 billion at December 31, 1997. The estimated costs to decommission San Onofre Unit 1 ($368 million) are recorded as a liability.

Decommissioning funds collected in rates are placed in independent trusts, which, together with accumulated earnings, will be utilized solely for decommissioning.

Trust investments include:

In millions	Maturity Dates	December 31, 1998	1997
Municipal bonds	2000—2029	$ 547	$ 459
Stocks	—	550	392
U.S. government issues	1999—2029	355	357
Short-term and other	1999—2028	82	163
Trust fund balance (at cost)		$1,534	$1,371

Trust fund earnings (based on specific identification) increase the trust fund balance and the accumulated provision for decommissioning. Net earnings were $63 million in 1998, $54 million in 1997 and $49 million in 1996. Proceeds from sales of securities (which are reinvested) were $1.2 billion in 1998, $595 million in 1997 and $1.0 billion in 1996. Approximately 89% of the trust fund contributions were tax-deductible.

Other Commitments

SCE has fuel supply contracts which require payment only if the fuel is made available for purchase.

SCE has power-purchase contracts with certain qualifying facilities (cogenerators and small power producers) and other utilities. These contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE. There are no requirements to make debt-service payments.

SCE has unconditional purchase obligations for part of a power plant's generating output, as well as firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the provider, whether or not the plant or transmission line is operable. The purchased-power contract is not expected to provide more than 5% of current or estimated future operating capacity. SCE's minimum commitment under both contracts is approximately $172 million through 2017.

Certain commitments for the years 1999 through 2003 are estimated below:

In millions	1999	2000	2001	2002	2003
Projected construction expenditures	$922	$831	$726	$699	$689
Fuel supply contracts	167	136	123	139	117
Purchased-power capacity payments	744	786	797	704	689
Unconditional purchase obligations	9	10	10	9	10

Note 10. Contingencies

In addition to the matters disclosed in these notes, SCE is involved in other legal, tax and regulatory proceedings before various courts and governmental agencies regarding matters arising in the ordinary course of business. SCE believes the outcome of these other proceedings will not materially affect its results of operations or liquidity.

Environmental Protection

SCE is subject to numerous environmental laws and regulations, which require it to incur substantial costs to operate existing facilities, construct and operate new facilities, and mitigate or remove the effect of past operations on the environment.

SCE records its environmental liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. SCE reviews its sites and measures the liability quarterly, by assessing a range of reasonably likely costs for each identified site using currently available information, including existing technology, presently enacted laws and regulations, experience gained at similar sites, and the probable level of involvement and financial condition of other potentially responsible parties. These estimates include costs for site investigations, remediation, operations and maintenance, monitoring and site closure. Unless there is a probable amount, SCE records the lower end of this reasonably likely range of costs (classified as other long-term liabilities at undiscounted amounts).

SCE's recorded estimated minimum liability to remediate its 49 identified sites is $171 million. The ultimate costs to clean up SCE's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. SCE believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $247 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes. SCE has sold all of its gas- and oil-fueled generation plants and has retained some liability associated with the divested properties.

The CPUC allows SCE to recover environmental-cleanup costs at 41 of its sites, representing $88 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. Costs incurred at SCE's remaining sites are expected to be recovered through customer rates. SCE has recorded a regulatory asset of $141 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

SCE's identified sites include several sites for which there is a lack of currently available information, including the nature and magnitude of contamination, and the extent, if any, that SCE may be held responsible for contributing to any costs incurred for remediating these sites. Thus, no reasonable estimate of cleanup costs can now be made for these sites.

SCE expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $4 million to $10 million. Recorded costs for 1998 were $7 million.

Based on currently available information, SCE believes it is unlikely that it will incur amounts in excess of the upper limit of the estimated range and, based upon the CPUC's regulatory treatment of environmental-cleanup costs, SCE believes that costs ultimately recorded will not materially affect its results of operations or financial position. There can be no assurance, however, that future developments, including additional information about existing sites or the identification of new sites, will not require material revisions to such estimates.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to $9.6 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($200 million). The balance is covered by the industry's retrospective rating plan that uses deferred premium charges to every reactor licensee if a nuclear incident at any licensed reactor in the U.S. results in claims and/or costs which exceed the primary insurance at that plant site. Federal regulations require this secondary level of financial protection. The Nuclear Regulatory Commission exempted San Onofre Unit 1 from this secondary level, effective June 1994. The maximum deferred premium for each nuclear incident is $88 million per reactor, but not more than $10 million per reactor may be charged in any one year for each incident. Based on its ownership interests, SCE could be required to pay a maximum of $175 million per nuclear incident. However, it would have to pay no more than $20 million per incident in any one year. Such amounts include a 5% surcharge if additional funds are needed to satisfy public liability claims and are subject to adjustment for inflation. If the public liability limit above is insufficient, federal regulations may impose further revenue-raising measures to pay claims, including a possible additional assessment on all licensed reactor operators.

Property damage insurance covers losses up to $500 million, including decontamination costs, at San Onofre and Palo Verde. Decontamination liability and property damage coverage exceeding the primary $500 million also has been purchased in amounts greater than federal requirements. Additional insurance covers part of replacement power expenses during an accident-related nuclear unit outage. These policies are issued primarily by 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 for these insurance programs, SCE could be assessed retrospective premium adjustments of up to $22 million per year. Insurance premiums are charged to operating expense.

Spent Nuclear Fuel

Under the Nuclear Waste Policy Act of 1982, the DOE is responsible for the selection and development of repositories for, and the disposal of, spent nuclear fuel and high-level radioactive waste. The Act requires that the DOE provide for the disposal of spent nuclear fuel and high-level radioactive waste from nuclear generation stations beginning January 31, 1998. However, the DOE did not meet its obligations. It is not certain when the DOE will begin accepting spent nuclear fuel from San Onofre or from other nuclear power plants.

SCE has paid the DOE the required one-time fee applicable to nuclear generation at San Onofre through April 6, 1983 (approximately $24 million, plus interest). SCE is also paying the required quarterly fee equal to one mill per kilowatt-hour of nuclear-generated electricity sold after April 6, 1983.

SCE has primary responsibility for the interim storage of its spent nuclear fuel at San Onofre. Current capability to store spent fuel is estimated to be adequate through 2005. Meeting spent fuel storage requirements beyond that period could require new and separate interim storage facilities, the costs for which have not been determined. Extended delays by the DOE can lead to consideration of costly alternatives involving siting and environmental issues.

Palo Verde on-site spent fuel storage capacity will accommodate needs until 2002 for Units 1 and 2, and until 2003 for Unit 3. Arizona Public Services, operating agent for Palo Verde, has commenced construction of an interim fuel storage facility and projects completion in 2002.

SCE and other owners of nuclear power plants may be able to recover interim storage costs arising from DOE delays in the acceptance of utility spent nuclear fuel by pursuing relief under the terms of the contracts, as directed by the courts, through other court actions.

Quarterly Financial Data

	1998					1997				
In millions	Total	Fourth	Third	Second	First	Total	Fourth	Third	Second	First
Operating revenue[1]	$8,847	$2,245	$3,057	$1,922	$1,623	$7,953	$1,980	$2,434	$1,844	$1,695
Operating income	918	241	237	212	228	1,060	248	349	229	234
Net income	515	121	169	120	105	606	123	233	129	121
Earnings available for common stock	490	115	163	114	98	576	116	226	122	112
Common dividends declared	1,101	141	422	442	96	1,829	1,266	217	171	175

(1) Effective second quarter 1998, operating revenue includes sales to the PX.

Responsibility for Financial Reporting

The management of Southern California Edison Company (SCE) is responsible for the integrity and objectivity of the accompanying financial statements. The statements have been prepared in accordance with generally accepted accounting principles applied on a consistent basis and are based, in part, on management estimates and judgment.

SCE maintains systems of internal control to provide reasonable, but not absolute, assurance that assets are safeguarded, transactions are executed in accordance with management's authorization and the accounting records may be relied upon for the preparation of the financial statements. There are limits inherent in all systems of internal control, the design of which involves management's judgment and the recognition that the costs of such systems should not exceed the benefits to be derived. SCE believes its systems of internal control achieve this appropriate balance. These systems are augmented by internal audit programs through which the adequacy and effectiveness of internal controls and policies and procedures are monitored, evaluated and reported to management. Actions are taken to correct deficiencies as they are identified.

SCE's independent public accountants, Arthur Andersen LLP, are engaged to audit the financial statements in accordance with generally accepted auditing standards and to express an informed opinion on the fairness, in all material respects, of SCE's reported results of operations, cash flows and financial position.

As a further measure to assure the ongoing objectivity of financial information, the audit committee of the board of directors, which is composed of outside directors, meets periodically, both jointly and separately, with management, the independent public accountants and internal auditors, who have unrestricted access to the committee. The committee recommends annually to the board of directors the appointment of a firm of independent public accountants to conduct audits of its financial statements; considers the independence of such firm and the overall adequacy of the audit scope and SCE's systems of internal control; reviews financial reporting issues; and is advised of management's actions regarding financial reporting and internal control matters.

SCE maintains high standards in selecting, training and developing personnel to assure that its operations are conducted in conformity with applicable laws and is committed to maintaining the highest standards of personal and corporate conduct. Management maintains programs to encourage and assess compliance with these standards.

Richard K. Bushey
Vice President
and Controller

John E. Bryson
Chairman of the Board
and Chief Executive Officer

February 4, 1999

To the Shareholders and the Board of Directors,
Southern California Edison Company:

We have audited the accompanying consolidated balance sheets of Southern California Edison Company (SCE, a California corporation) and its subsidiaries as of December 31, 1998, and 1997, and the related consolidated statements of income, comprehensive income and cash flows for each of the three years in the period ended December 31, 1998. These financial statements are the responsibility of SCE's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position o SCE and its subsidiaries as of December 31, 1998, and 1997, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1998, in conformity with generally accepted accounting principles.

Arthur Andersen LLP

ARTHUR ANDERSEN LLP

Los Angeles, California
February 4, 1999

Selected Financial and Operating Data: 1994-1998

Southern California Edison Company

Dollars in millions	1998	1997	1996	1995	1994
Income statement data:					
Operating revenue[1]	$ 8,847	$ 7,953	$ 7,583	$ 7,873	$ 7,799
Operating expenses[2]	7,929	6,893	6,450	6,724	6,705
Fuel and purchased power expenses[2]	4,934	3,735	3,336	3,197	3,403
Income tax from operations	446	582	578	560	508
Allowance for funds used during construction	20	17	25	34	29
Interest expense — net	485	444	453	464	443
Net income	515	606	655	680	639
Earnings available for common stock	490	576	621	643	599
Ratio of earnings to fixed charges	2.95	3.49	3.54	3.52	3.43
Balance sheet data:					
Assets	$16,947	$18,059	$17,737	$18,155	$18,076
Gross utility plant	14,150	21,483	21,134	20,717	20,127
Accumulated provision for depreciation and decommissioning	6,896	10,544	9,431	8,569	7,710
Common shareholder's equity	3,335	3,958	5,045	5,144	5,039
Preferred stock:					
Not subject to mandatory redemption	129	184	284	284	359
Subject to mandatory redemption	256	275	275	275	275
Long-term debt	5,447	6,145	4,779	5,215	4,988
Capital structure:					
Common shareholder's equity	36.4%	37.5%	48.6%	47.1%	47.3%
Preferred stock:					
Not subject to mandatory redemption	1.4%	1.7%	2.7%	2.6%	3.3%
Subject to mandatory redemption	2.8%	2.6%	2.7%	2.5%	2.6%
Long-term debt	59.4%	58.2%	46.0%	47.8%	46.8%
Operating data:					
Peak demand in megawatts (MW)	19,935	19,118	18,207	17,548	18,044
Generation capacity at peak (MW)	10,546	21,511	21,602	21,603	20,615
Kilowatt-hour sales (kWh) (in millions)	76,595	77,234	75,572	74,296	77,986
Total energy requirement (kWh) (in millions)[3]	80,289	86,849	84,236	81,924	85,011
Energy mix:					
Thermal	38.8%	44.6%	47.6%	51.6%	59.5%
Hydro	7.4%	6.5%	6.9%	7.7%	3.9%
Purchased power and other sources	53.8%	48.9%	45.5%	40.7%	36.6%
Customers (in millions)	4.27	4.25	4.22	4.18	4.15
Full-time employees	13,177	12,642	12,057	14,886	16,351

(1) 1998 includes $1.3 billion from sales to the power exchange (PX).
(2) 1998 includes $2.0 billion for purchases from the PX.
(3) 1998 excludes direct access and resale customer requirements.

Board of Directors

John E. Bryson
Chairman of the Board and CEO,
Edison International and SCE

Winston H. Chen
Chairman of the Paramitas Foundation
and Chairman of Paramitas
Investment Corporation,
Santa Clara, California

Warren Christopher
Senior Partner,
O'Melveny & Myers,
Los Angeles, California

Stephen E. Frank
President and Chief Operating
Officer, SCE

Joan C. Hanley
Former General Partner,
Miramonte Vineyards,
Rancho Palos Verdes, California

Carl F. Huntsinger
General Partner,
DAE Limited Partnership Ltd.,
Ojai, California

Charles D. Miller
Chairman of the Board,
Avery Dennison Corporation,
Pasadena, California

Luis G. Nogales
President,
Nogales Partners,
Los Angeles, California

Ronald L. Olson
Senior Partner,
Munger, Tolles and Olson,
Los Angeles, California

James M. Rosser
President,
California State University, Los Angeles,
Los Angeles, California

E. L. Shannon, Jr.*
Retired Chairman of the Board,
Santa Fe International Corporation,
Alhambra, California

Robert H. Smith
Managing Director,
Smith and Crowley Incorporated,
Pasadena, California

Thomas C. Sutton
Chairman of the Board and CEO,
Pacific Life Insurance Company,
Newport Beach, California

Daniel M. Tellep
Retired Chairman of the Board,
Lockheed Martin Corporation,
Bethesda, Maryland

James D. Watkins*
Admiral USN, Retired,
President, Joint Oceanographic
Institutions, Inc., and
President, Consortium for
Oceanographic Research and Education,
Washington, D.C.

Edward Zapanta, M.D.
Physician and Neurosurgeon,
Torrance, California

* Retiring on April 15, 1999

Management Team

John E. Bryson
Chairman of the Board and CEO

Stephen E. Frank
President and Chief Operating Officer

Bryant C. Danner
Executive Vice President and
General Counsel

Alan J. Fohrer
Executive Vice President and
Chief Financial Officer

Harold B. Ray
Executive Vice President,
Generation Business Unit

Pamela A. Bass
Senior Vice President,
Customer Service Business Unit

Theodore F. Craver, Jr.
Senior Vice President and Treasurer

John R. Fielder
Senior Vice President,
Regulatory Policy and Affairs

Robert G. Foster
Senior Vice President,
Public Affairs

Lillian R. Gorman
Senior Vice President, Human Resources

Richard M. Rosenblum
Senior Vice President,
T&D Business Unit

Emiko Banfield
Vice President, Shared Services

Richard K. Bushey**
Vice President and Controller

Bruce C. Foster
Vice President,
San Francisco Regulatory Affairs

Lawrence D. Hamlin
Vice President, Power Production

Thomas J. Higgins
Vice President,
Corporate Communications

R. W. Krieger
Vice President, Nuclear Generation

J. Michael Mendez
Vice President, Labor Relations

Thomas M. Noonan***
Vice President and Controller

Dwight E. Nunn
Vice President, Nuclear Engineering
and Technical Services

Frank J. Quevedo
Vice President, Equal Opportunity

Anthony L. Smith***
Vice President, Tax

Mahvash Yazdi
Vice President and Chief
Information Officer

Beverly P. Ryder
Corporate Secretary

** Resigned March 1, 1999
*** Effective March 1, 1999

Annual Meeting of Shareholders

Thursday, April 15, 1999
10:00 a.m.
The Industry Hills Sheraton Resort and Conference Center
One Industry Hills Parkway
City of Industry, California

Stock Listing and Trading Information

SCE Preferred Stock

The American and Pacific stock exchanges use the ticker symbol SCE. Previous day's closing prices, when traded, are listed in the daily newspapers in the American Stock Exchange table under the symbol SoCalEd. The 6.05%, 6.45% and 7.23% series are not listed.

Where to Buy and Sell Stock

The listed preferred stocks may be purchased through any brokerage firm. Firms handling unlisted series can be located through your broker.

Transfer Agent and Registrar

Southern California Edison Company maintains shareholder records and is transfer agent and registrar for SCE preferred stock. Shareholders may call Shareholder Services, (800) 347-8625, between 8:00 a.m. and 4:00 p.m. (Pacific time) every business day, regarding:

- stock transfer and name-change requirements;
- address changes, including dividend addresses;
- electronic deposit of dividends;
- taxpayer identification number submission or changes;
- duplicate 1099 forms and W-9 forms;
- notices of and replacement of lost or destroyed stock certificates;
- dividend checks;
- requests to eliminate multiple annual report mailings; and
- request access to online account information via Edison International's Internet Home Page, www.edisoninvestor.com

The address of Shareholder Services is:

P.O. Box 400, Rosemead, California 91770-0400
FAX: (626) 302-4815

-NOTICE-

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