

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

YEAR ENDED DECEMBER 31,

| (dollars in thousands) | <i>2000</i> | <i>1999</i> | <i>1998</i> |
|---|-------------------|-------------------|-------------------|
| Retained earnings at beginning of year | \$ 668,284 | \$ 612,708 | \$ 473,665 |
| Net income | 302,332 | 167,887 | 242,892 |
| Common stock dividends | (120,733) | (112,311) | (103,849) |
| Retained earnings at end of year | \$ 849,883 | \$ 668,284 | \$ 612,708 |

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, Pinnacle West Energy, APS Energy Services, SunCor, and El Dorado. Significant intercompany accounts and transactions between the consolidated companies have been eliminated.

APS, our major subsidiary and Arizona's largest electric utility, provides retail and wholesale electric service to the entire state with the exception of Tucson and about one-half of the Phoenix area. APS also generates and, directly or through our power marketing division, sells and delivers electricity to wholesale customers in the western United States. Pinnacle West Energy, which was formed in 1999, is the subsidiary through which we intend to conduct our unregulated generation operations. APS Energy Services was formed in 1998 and sells energy and energy-related products and services in competitive retail markets in the western United States. SunCor is a developer of residential, commercial, and industrial real estate projects in Arizona, New Mexico, and Utah. El Dorado is primarily a venture capital and investment firm.

Accounting Records

Our accounting records are maintained in accordance with accounting principles generally accepted in the United States of America (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 ACC and the FERC. The accompanying financial statements reflect the rate-making policies of these commissions. For regulated operations, we prepare our financial statements in accordance with 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 our financial statements.

During 1997, the EITF of the 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.

The 1999 Settlement Agreement was approved by the ACC in September 1999 (see Note 3 for a discussion of the agreement). Consequently, we have discontinued the application of SFAS No. 71 for our generation operations. As a result, we tested the generation assets for impairment and determined that the generation assets were not impaired. Pursuant to the 1999 Settlement Agreement, a regulatory disallowance removed \$234 million pre-tax (\$183 million net present value) from ongoing regulatory cash flows and was recorded as a net reduction of regulatory assets. This reduction (\$140 million after income taxes) was reported as an extraordinary charge on the income statement during the third quarter of 1999. Prior to the 1999 Settlement Agreement, 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 would have ended June 30, 2004.

The regulatory assets to be recovered under the 1999 Settlement Agreement are now being amortized as follows:

(dollars in millions)

| 1999 | 2000 | 2001 | 2002 | 2003 | 1/1-6/30 2004 | Total |
|-------|-------|-------|-------|------|------------------|-------|
| \$164 | \$158 | \$145 | \$115 | \$86 | \$18 | \$686 |

The majority of our remaining regulatory assets relate to deferred income taxes (see Note 4) and rate synchronization cost deferrals (see "Rate Synchronization Cost Deferrals" in this Note).

The balance sheets include the amounts listed below for generation assets not subject to SFAS No. 71 (for additional generation information see Note 18):

| DECEMBER 31, | | |
|---|--------------|--------------|
| (dollars in thousands) | <i>2000</i> | <i>1999</i> |
| Electric plant in service and held for future use | \$ 3,856,600 | \$ 3,817,919 |
| Accumulated depreciation and amortization | (1,693,079) | (1,664,782) |
| Construction work in progress | 304,992 | 87,819 |
| Nuclear fuel, net of amortization | 47,389 | 49,114 |

Utility Plant and Depreciation

Utility plant is the term we use to describe the business property and equipment that supports electric service, consisting primarily of generation, transmission, and distribution facilities. 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 2 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 1998 through 2000 the rates, as prescribed by our regulators, ranged from a low of 3.33% to a high of 20%. The weighted-average rate was 3.40% for 2000, 3.34% for 1999, and 3.32% for 1998. We depreciate non-utility property and equipment over the estimated useful lives of the related assets, ranging from 3 to 30 years.

El Dorado Investments

Net other income consists primarily of El Dorado's share in the earnings of a venture capital partnership. The partnership adjusts the value of its investments at the end of each fiscal quarter. The value of El Dorado's investment in the partnership is determined by various factors beyond our control, including equity market conditions. Most of the partnership's investments are in technology-related companies whose share prices are highly volatile.

Prior to June 2000, we recorded our share of the earnings from the partnership, as the partnership adjusted the value of its investment, on a one-quarter lag. This procedure was followed due to time constraints in obtaining and analyzing such results for inclusion in our consolidated financial statements on a current basis. In the second quarter of 2000, we requested a distribution of our share of the investments held by the

partnership, and we adjusted our investment to reflect the current market value.

An amendment to the partnership agreement resulted in El Dorado receiving a distribution, subject to certain sales restrictions, of securities representing substantially all of El Dorado's investment in the partnership. We began accounting for the securities as available for sale with changes in fair value recorded in other comprehensive income. Gains and losses from the ultimate sale of such securities will be reflected in our net earnings.

The book value of El Dorado's investment in the partnership was approximately \$7 million at December 31, 2000 and \$21 million at December 31, 1999.

Capitalized Interest

Capitalized interest represents the cost of debt funds used to finance construction of utility plants. Plant construction costs, including capitalized interest, are expensed 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 was a composite rate of 6.62% for 2000, 6.65% for 1999, and 6.88% for 1998.

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). In accordance with the 1999 Settlement Agreement, we are continuing to accelerate the amortization of the deferrals over an eight-year period that will end June 30, 2004. 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 it 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 calculation determines the 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 and Note 13 for 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

For debt related to the regulated portion of APS' business, APS amortizes those gains and losses incurred upon early retirement over the remaining life of the debt. In accordance with the 1999 Settlement Agreement, APS is continuing to accelerate reacquired debt costs over 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.

Derivative Instruments

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal, and emissions allowances. We employ established procedures to manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange-traded futures and options and over-the-counter forwards, options, and swaps. As part of our overall risk management program, we enter into derivative transactions to hedge purchases and sales of electricity, fuels, and emissions allowances/credits. The changes in market value of such contracts have a high correlation to price changes in the hedged commodity. In addition, subject to specified risk parameters established by the Board of Directors and monitored by the ERM, we engage in trading activities intended to profit from market price movements.

Gains and losses related to derivatives that qualify as hedges of expected transactions are recognized in revenue or fuel and purchased power expense as an offset to the related item being hedged when the underlying hedged physical transaction closes (deferral method).

Net gains and losses on derivatives utilized for trading are recognized in wholesale revenues on a current basis (the mark to market method). Trading positions are measured at fair value as of the balance sheet date. The net gain was \$9 million for 2000 and \$1 million for 1999.

Statements of Cash Flows

We consider temporary cash investments and marketable securities, with original maturities of less than 90 days, to be cash equivalents for purposes of reporting cash flows. During 2000, 1999, and 1998, we paid interest, net of amounts capitalized, income taxes, and dividends on preferred stock of APS as follows:

| | YEARS ENDED DECEMBER 31, | | |
|--|--------------------------|--------|--------|
| (dollars in millions) | 2000 | 1999 | 1998 |
| Interest paid | \$ 132 | \$ 141 | \$ 144 |
| Income taxes paid | 219 | 200 | 165 |
| Dividends paid on preferred stock of APS | — | 1 | 10 |

2. ACCOUNTING MATTERS

Effective January 1, 2001, we adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." 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. Changes in the fair value of derivative financial instruments are either recognized periodically in income or shareholder's equity (as a component of other comprehensive income), depending on whether or not the derivative meets specific hedge accounting criteria. Hedge effectiveness is measured based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in the fair value resulting from ineffectiveness, as defined by SFAS No. 133, is recognized immediately in net income. This new standard may result in additional volatility in our net income and comprehensive income.

As a result of adopting SFAS No. 133, we recognized \$118 million of derivative assets and \$16 million of derivative liabilities in our balance sheet as of January 1, 2001. We recorded a \$3 million after-tax loss in net income as a cumulative effect of change in accounting principles and a \$64 million after-tax gain in equity (as a component of other comprehensive income). The gain resulted from unrealized gains on cash flow hedges.

In December 2000, the FASB's Derivatives Implementation Group (DIG) discussed whether contracts in the electric industry that have some of the characteristics of purchased and written options should qualify for the "normal purchases and sales" scope exception. The DIG did not reach a conclusion on this issue. We account for electricity contracts with characteristics of options as normal purchases and sales if it is probable that the contract will not be settled in cash and will result in the physical delivery of electricity. The DIG also discussed but did not determine whether electricity contracts subject to "bookout" should qualify for the normal exception. A bookout occurs when one party appears more than once in a contract path for the sale and purchase of energy. In that instance, the counterparties may agree that they will not schedule or deliver physical energy that originates and ends with the same counterparty, but rather will settle in cash the amounts due to or from each counterparty. We account for our non-trading electricity transactions that bookout as gross settlement with physical delivery (and eligible for the normal scope exception) if title transfers, gross cash payment is made, and the transaction retains both performance and credit risk. Trading contracts are measured at fair value (mark to market) as discussed in Note 1.

Our accounting is reflective of the non-storability of our product and the lack of predictability of the demand for electricity at any point in time. If the FASB or DIG ultimately provides us with contrary guidance, we may be required to mark our non-trading electricity contracts to their fair market values each reporting period, which could have a material impact on our financial statements and add significant net income and comprehensive income volatility that would not be reflective of the nature of our business. If these agreements are required to be treated as derivative instruments, a cumulative effect of a change in accounting principles would be applied in the quarter following final resolution of the issues.

In 1999 we adopted EITF 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." 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. The effects of adopting EITF 98-10 were not material to our 1999 financial statements.

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 issued a revised exposure draft in February 2000 and we are evaluating the impacts.

3. REGULATORY MATTERS

Electric Industry Restructuring State

1999 SETTLEMENT AGREEMENT. On May 14, 1999, APS entered into a comprehensive Settlement Agreement with various parties, including representatives of major consumer groups, related to the implementation of retail electric competition. On September 23, 1999, the ACC voted to approve the 1999 Settlement Agreement, with some modifications. On December 13, 1999, two parties filed lawsuits challenging the ACC's approval of the 1999 Settlement Agreement. Each party bringing the lawsuits appealed the ACC's order approving the APS 1999 Settlement Agreement directly to the Arizona Court of Appeals, as provided by Arizona law. In one of the appeals, on December 26, 2000, the Arizona Court of Appeals affirmed the ACC's approval of the 1999 Settlement Agreement. A decision is still pending on the other appeal, which raises a number of different issues.

The following are the major provisions of the 1999 Settlement Agreement, as approved:

- APS has reduced, and will reduce, rates for standard offer service for customers with loads less than three MW in a

series of annual retail electric price reductions of 1.5% beginning July 1, 1999 through July 1, 2003, for a total of 7.5%. The first reduction of approximately \$24 million (\$14 million after income taxes) included the July 1, 1999 retail price decrease of approximately \$11 million (\$7 million after income taxes) related to the 1996 regulatory agreement. See "1996 Regulatory Agreement" below. Based on the price reduction authorized in the 1999 Settlement Agreement, there was a retail price decrease of approximately \$28 million (\$17 million after taxes), or 1.5%, effective July 1, 2000. For customers having loads three MW or greater, standard offer rates will be reduced in varying annual increments that total 5% in the years 1999 through 2002.

- Unbundled rates being charged by APS for competitive direct access service (for example, distribution services) became effective upon approval of the 1999 Settlement Agreement, retroactive to July 1, 1999, and also became subject to annual reductions beginning January 1, 2000, that vary by rate class, through January 1, 2004.
- There will be a moratorium on retail price changes for standard offer and unbundled competitive direct access services until July 1, 2004, except for the price reductions described above and certain other limited circumstances. Neither the ACC nor APS will be prevented from seeking or authorizing rate changes prior to July 1, 2004 in the event of conditions or circumstances that constitute an emergency, such as an inability to finance on reasonable terms, or material changes in APS' cost of service for ACC-regulated services resulting from federal, tribal, state or local laws, regulatory requirements, judicial decisions, actions or orders.
- APS will be permitted to defer for later recovery prudent and reasonable costs of complying with the ACC electric competition rules, system benefits costs in excess of the levels included in current rates, and costs associated with the "provider of last resort" and standard offer obligations for service after July 1, 2004. These costs are to be recovered through an adjustment clause or clauses commencing on July 1, 2004.
- APS' distribution system opened for retail access effective September 24, 1999. Customers were eligible for retail access in accordance with the phase-in adopted by the ACC under the electric competition rules (see "Retail Electric Competition Rules" below), including an additional 140 MW being made available to eligible non-residential customers. APS opened its distribution system to retail access for all customers on January 1, 2001.
- Prior to the 1999 Settlement Agreement, APS was recovering substantially all of its regulatory assets through July 1, 2004, pursuant to the 1996 regulatory agreement. In addition, the 1999 Settlement Agreement states that APS has demonstrated that its allowable stranded costs, after

mitigation and exclusive of regulatory assets, are at least \$533 million net present value. APS will not be allowed to recover \$183 million net present value of the above amounts. The 1999 Settlement Agreement provides that APS will have the opportunity to recover \$350 million net present value through a competitive transition charge (CTC) that will remain in effect through December 31, 2004, at which time it will terminate. Any over/under-recovery due to sales volume variances will be credited/debited against the costs subject to recovery under the adjustment clause described above.

- APS will form a separate corporate affiliate or affiliates and transfer to such affiliate(s) its generating assets and competitive services at book value as of the date of transfer, which transfer shall take place no later than December 31, 2002. Accordingly, APS plans to complete the move of such assets and services from APS to the parent company or to Pinnacle West Energy by the end of 2002, as required. APS will be allowed to defer and later collect, beginning July 1, 2004, sixty-seven percent of its costs to accomplish the required transfer of generation assets to an affiliate.
- When the 1999 Settlement Agreement approved by the ACC is no longer subject to judicial review, APS will move to dismiss all of its litigation pending against the ACC as of the date APS entered into the 1999 Settlement Agreement. To protect its rights, APS has several lawsuits pending on ACC orders relating to stranded cost recovery and the adoption and amendment of the ACC's electric competition rules, which would be voluntarily dismissed at the appropriate time under this provision.

As discussed in Note 1 above, we have discontinued the application of SFAS No. 71 for our generation operations.

RETAIL ELECTRIC COMPETITION RULES. On September 21, 1999, the ACC voted to approve the rules that provide a framework for the introduction of retail electric competition in Arizona. Under the 1999 Settlement Agreement, the Rules are to be interpreted and applied, to the greatest extent possible, in a manner consistent with the 1999 Settlement Agreement. If the two cannot be reconciled, APS must seek, and the other parties to the 1999 Settlement Agreement must support, a waiver of the Rules in favor of the 1999 Settlement Agreement. On December 8, 1999, APS filed a lawsuit to protect its legal rights regarding the Rules. This lawsuit is pending, along with several other lawsuits on ACC orders relating to stranded cost recovery, the adoption or amendment of the Rules, and the certification of competitive electric service providers.

On November 27, 2000, a Maricopa County, Arizona, Superior Court judge issued a final judgment holding that the Rules are unconstitutional and unlawful in their entirety due to failure to establish a fair value rate base for competitive electric service providers and because certain of the Rules were not submitted to the Arizona Attorney General for certification.

The judgment also invalidates all ACC orders authorizing competitive electric service providers, including APS Energy Services, in Arizona. We do not believe the ruling affects the 1999 Settlement Agreement. The 1999 Settlement Agreement was not at issue in the consolidated cases before the judge. Further, the ACC made findings related to the fair value of APS' property in the order approving the 1999 Settlement Agreement. The ACC and other parties aligned with the ACC have appealed the ruling to the Court of Appeals, as a result of which the ruling is automatically stayed pending further judicial review. The Rules approved by the ACC include the following major provisions:

- They apply to virtually all Arizona electric utilities regulated by the ACC, including APS.
- Effective January 1, 2001, retail access was available to all APS retail customers.
- Electric service providers that get Certificates of Convenience and Necessity from the ACC can supply only competitive services, including electric generation, but not electric transmission and distribution.
- Affected utilities must file ACC tariffs that unbundle rates for non-competitive services.
- The ACC shall allow a reasonable opportunity for recovery of unmitigated stranded costs.
- Absent an ACC waiver, prior to January 1, 2001, each affected utility (except certain electric cooperatives) must transfer all competitive generation assets and services either to an unaffiliated party or to a separate corporate affiliate. Under the 1999 Settlement Agreement, APS received a waiver to allow transfer of its generation and other competitive assets and services to affiliates no later than December 31, 2002. See "1999 Settlement Agreement" above for a discussion of the planned timing of the transfer.

1996 REGULATORY AGREEMENT. In April 1996, the ACC approved a regulatory agreement between the ACC Staff and APS. Based on the price reduction formula authorized in the agreement, the ACC approved retail price decreases (approximate) as follows:

(dollars in millions)

| Annual Electric Revenue Decrease | Percentage Decrease | Effective Date |
|----------------------------------|---------------------|-----------------|
| \$49 | 3.4% | July 1, 1996 |
| \$18 | 1.2% | July 1, 1997 |
| \$17 | 1.1% | July 1, 1998 |
| \$11 | 0.7% | July 1, 1999(a) |

(a) Included in the first rate reduction under the 1999 Settlement Agreement (see above).

The regulatory agreement also required that we infuse \$200 million of common equity into APS in annual payments of \$50 million from 1996 through 1999. All of these equity infusions were made by December 31, 1999.

LEGISLATION. 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 MW

(and that are eligible for competitive generation services), and thereafter for all customers receiving competitive electric generation.

General

APS cannot accurately predict the impact of full retail competition on its financial position, cash flows, results of operations, or liquidity. As competition in the electric industry continues to evolve, APS will continue to evaluate strategies and alternatives that will position it to compete in the new regulatory environment.

Federal

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

Several electric utility industry restructuring bills will undoubtedly be introduced during the current congressional session. Several of these bills are written to allow consumers to choose their electricity suppliers beginning in 2001 and beyond. These bills and other bills 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 comprehensive restructuring of the electric utility industry can occur.

4. 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 related to income taxes on its Balance Sheet in accordance with SFAS No. 71. This regulatory asset is for certain temporary differences, primarily the allowance for equity funds used during construction. APS

amortizes this amount as the differences reverse. In accordance with the 1999 Settlement Agreement, APS is continuing to accelerate its amortization of the regulatory asset for income taxes over an eight-year period that will end June 30, 2004 (see Note 1). We are including this accelerated amortization in depreciation and amortization expense on the Statements of Income. The components of income tax expense for continuing operations are:

YEAR ENDED DECEMBER 31,

| (dollars in thousands) | <i>2000</i> | <i>1999</i> | <i>1998</i> |
|------------------------|-------------|-------------|-------------|
| Current | | | |
| Federal | \$ 189,779 | \$ 171,491 | \$ 105,922 |
| State | 42,306 | 37,501 | 40,621 |
| Total current | 232,085 | 208,992 | 146,543 |
| Deferred | (8,973) | (17,413) | 41,566 |
| ITC amortization | 740 | (23,514) | (23,516) |
| Total expense | \$ 223,852 | \$ 168,065 | \$ 164,593 |

The following chart compares pretax income at the 35% federal income tax rate to income tax expense:

| (dollars in thousands) | YEAR ENDED DECEMBER 31, | | |
|---|-------------------------|-------------------|-------------------|
| | 2000 | 1999 | 1998 |
| Federal income tax expense at 35% statutory rate | \$ 184,164 | \$ 153,243 | \$ 142,620 |
| Increases (reductions) in tax expense resulting from: | | | |
| Tax under book depreciation | 12,328 | 14,575 | 17,848 |
| Preferred stock dividends of APS | — | 356 | 3,396 |
| ITC amortization | 740 | (23,514) | (23,516) |
| State income tax net of federal income tax benefit | 23,555 | 23,030 | 22,764 |
| Other | 3,065 | 375 | 1,481 |
| Income tax expense | \$ 223,852 | \$ 168,065 | \$ 164,593 |

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

| (dollars in thousands) | YEAR ENDED DECEMBER 31, | |
|---|-------------------------|---------------------|
| | 2000 | 1999 |
| DEFERRED TAX ASSETS | | |
| Deferred gain on Palo Verde Unit 2 sale/leaseback | \$ 27,056 | \$ 29,446 |
| Other | 89,416 | 133,748 |
| Total deferred tax assets | 116,472 | 163,194 |
| DEFERRED TAX LIABILITIES | | |
| Plant-related | 1,081,637 | 1,104,769 |
| Regulatory asset for income taxes | 172,082 | 234,117 |
| Total deferred tax liabilities | 1,253,719 | 1,338,886 |
| Accumulated deferred income taxes – net | \$ 1,137,247 | \$ 1,175,692 |

Investment Tax Credit

Because of a 1994 rate settlement agreement, we accelerated amortization of substantially all of our ITCs over a five-year period (1995-1999).

Income Tax Benefit From Discontinued Operations

In 1999, the income tax benefit from discontinued operations for \$38 million resulted from resolution of tax issues related to a former subsidiary, MeraBank, A Federal Savings Bank.

5. LINES OF CREDIT

APS had committed lines of credit with various banks of \$250 million at December 31, 2000 and \$350 million at December 31, 1999, which were available either to support the issuance of commercial paper or to be used for bank borrowings. The commitment fees at December 31, 2000 and 1999 for these lines of credit ranged from 0.09% to 0.125% per annum. APS had no long-term bank borrowings at December 31, 2000 and \$50 million outstanding at December 31, 1999.

APS' commercial paper borrowings outstanding were \$82 million at December 31, 2000 and \$38 million at December 31, 1999. The weighted average interest rate on commercial paper borrowings was 6.64% for the year ended December 31, 2000 and 5.33% for the year ended December 31, 1999.

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, 2000 and 1999. The commitment fees were 0.15% in 2000 and 0.10% in 1999. Outstanding amounts at December 31, 2000 were \$188 million and at December 31, 1999 were \$56 million.

SunCor had revolving lines of credit totalling \$120 million at December 31, 2000 and \$100 million at December 31, 1999. The commitment fees were 0.125% in 2000 and 1999. SunCor had \$110 million outstanding at December 31, 2000 and \$94 million outstanding at December 31, 1999.

6. LONG-TERM DEBT

Borrowings under the APS mortgage bond indenture are secured by substantially all utility plants; APS also has unsecured debt; 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 outstanding at December 31, 2000 and December 31, 1999:

| | | YEAR ENDED DECEMBER 31, | | |
|--|-----------------------|-------------------------|--------------------|--------------------|
| (dollars in thousands) | Maturity Dates (a) | Interest Rates | <i>2000</i> | <i>1999</i> |
| APS | | | | |
| First mortgage bonds | 2000 | 5.75% | \$ — | \$ 100,000 |
| | 2002 | 8.125% | 125,000 | 125,000 |
| | 2004 | 6.625% | 80,000 | 80,000 |
| | 2020 | 10.25% | — | 100,550 |
| | 2021 | 9.5% | 45,140 | 45,140 |
| | 2021 | 9% | 72,370 | 72,370 |
| | 2023 | 7.25% | 70,650 | 70,650 |
| | 2024 | 8.75% | 121,668 | 121,668 |
| | 2025 | 8% | 33,075 | 47,075 |
| | 2028 | 5.5% | 25,000 | 25,000 |
| | 2028 | 5.875% | 154,000 | 154,000 |
| Unamortized discount and premium | | | (5,993) | (5,860) |
| Pollution control bonds | 2024-2034 | Adjustable rate(b) | 476,860 | 476,860 |
| Funds held in trust account for certain pollution control bonds | | | — | (1,236) |
| Collateralized loan | 2000 | 5.375%-6.125% | — | 10,000 |
| Unsecured notes | 2004 | 5.875% | 125,000 | 125,000 |
| Unsecured notes | 2005 | 6.25% | 100,000 | 100,000 |
| Unsecured notes | 2005 | 7.625% | 300,000 | — |
| Floating rate notes | 2001 | Adjustable rate(c) | 250,000 | 250,000 |
| Senior notes (d) | 2006 | 6.75% | 83,695 | 83,695 |
| Debentures | 2025 | 10% | — | 75,000 |
| Bank loans | 2003 | Adjustable rate(e) | — | 50,000 |
| Capitalized lease obligation | 2000 | 7.48%(f) | — | 7,199 |
| Capitalized lease obligation | 2001-2003 | 7.75% | 709 | — |
| | | | 2,057,174 | 2,112,111 |
| SUNCOR | | | | |
| Revolving credit | 2002-2003 | (g) | 110,000 | 94,000 |
| Notes payable | 2001-2006 | (h) | 8,163 | 3,404 |
| Bonds payable | 2039 | 5.85% | 5,215 | 5,335 |
| | | | 123,378 | 102,739 |
| PINNACLE WEST | | | | |
| Revolving credit | 2001 | (i) | 188,000 | 56,000 |
| Senior notes | 2001-2003 | (j) | 50,000 | 50,000 |
| | | | 238,000 | 106,000 |
| Total long-term debt | | | 2,418,552 | 2,320,850 |
| Less current maturities | | | 463,469 | 114,798 |
| Total long-term debt less current maturities | | | \$1,955,083 | \$2,206,052 |

- (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, 2000 was 4.06% and for December 31, 1999 was 3.15%. Changes in short-term interest rates would affect the costs associated with this debt.
- (c) The weighted-average rate for the year ended December 31, 2000 was 7.33% and for December 31, 1999 was 6.8525%.
- (d) APS currently has outstanding \$84 million of first mortgage bonds (senior note mortgage bonds) issued 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. When APS repays 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.
- (e) The weighted-average rate for the year ended December 31, 2000 was 6.53% and for December 31, 1999 was 5.5%. Changes in short-term interest rates would affect the costs associated with this debt. At December 31, 2000, we had no long-term bank borrowings outstanding.
- (f) 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. The capital lease was paid off early and the related asset was purchased in December 2000 (See Note 10).
- (g) The weighted-average rate at December 31, 2000 was 8.61% and at December 31, 1999 was 8.51%. Interest for 2000 and 1999 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 plus 1.75% and lenders' prime plus .25%.
- (i) The weighted-average rate at December 31, 2000 was 7.51% and at December 31, 1999 was 6.825%. Interest for 2000 was based on LIBOR plus 0.75% and interest for 1999 was based on LIBOR plus 0.33%.
- (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 2005:

- \$463 million in 2001;
- \$162 million in 2002;
- \$99 million in 2003;
- \$205 million in 2004; and
- \$400 million in 2005.

First mortgage bondholders share a lien on substantially all utility plant assets (other than nuclear fuel and transportation equipment). The mortgage bond indenture restricts the payment of common stock dividends under certain conditions. These conditions did not exist at December 31, 2000.

7. PREFERRED STOCK OF APS

On March 1, 1999, APS redeemed all of its preferred stock. Preferred stock balances of APS at December 31, 2000 and

1999 were zero. Redeemable preferred stock transactions of APS during each of the three years in the period ended December 31, 2000 are as follows:

| (dollars in thousands) | Number of Shares | Par Value Amount |
|----------------------------|---------------------|---------------------|
| 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 |
| Retirements | | |
| \$10.00 Series U | (94,011) | (9,401) |
| Balance, December 31, 1999 | — | — |
| Balance, December 31, 2000 | — | \$ — |

8. COMMON STOCK

Our common stock issued during each of the three years in the period ended December 31, 2000 is as follows:

| (dollars in thousands) | Number of Shares | Amount |
|----------------------------|---------------------|--------------|
| Balance, December 31, 1997 | 84,824,947 | \$ 1,553,771 |
| Common stock expense | — | (3,128)(a) |
| Balance, December 31, 1998 | 84,824,947 | 1,550,643 |
| Common stock expense | — | (13,194)(a) |
| Balance, December 31, 1999 | 84,824,947 | 1,537,449 |
| Common stock expense | — | (4,618) |
| Balance, December 31, 2000 | 84,824,947 | \$ 1,532,831 |

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

9. RETIREMENT PLANS AND OTHER BENEFITS

Pension Plans

Through 1999, Pinnacle West and its subsidiaries each sponsored defined benefit pension plans for their own employees. As of January 1, 2000, these plans were consolidated and now a single pension plan is sponsored by Pinnacle West for the employees of Pinnacle West and its subsidiaries. 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, 2000 were mostly domestic and international common stocks and bonds and real estate. Pension expense, including administrative costs, was:

- \$2 million in 2000;
- \$4 million in 1999; and
- \$11 million in 1998.

The following table shows the components of net pension cost before consideration of amounts capitalized or billed to others:

| (dollars in thousands) | <i>2000</i> | <i>1999</i> | <i>1998</i> |
|--|-------------|-------------|-------------|
| Service cost - benefits earned during the period | \$ 24,955 | \$ 24,982 | \$ 24,817 |
| Interest cost on projected benefit obligation | 58,361 | 52,905 | 51,524 |
| Expected return on plan assets | (77,231) | (68,335) | (54,513) |
| Amortization of: | | | |
| Transition asset | (3,227) | (3,226) | (3,226) |
| Prior service cost | 2,078 | 2,078 | 2,078 |
| Net actuarial gain | (1,633) | — | — |
| Net periodic pension cost | \$ 3,303 | \$ 8,404 | \$ 20,680 |

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

| (dollars in thousands) | <i>2000</i> | <i>1999</i> |
|--|-------------|-------------|
| Funded status – pension plan assets more than (less than) projected benefit obligation | \$ (20,730) | \$ 37,275 |
| Unrecognized net transition asset | (16,781) | (20,008) |
| Unrecognized prior service cost | 18,558 | 20,636 |
| Unrecognized net actuarial gains | (23,816) | (101,153) |
| Net pension liability recognized in the balance sheets | \$ (42,769) | \$ (63,250) |

The following table sets forth the defined benefit pension plans' change in projected benefit obligation for the plan years 2000 and 1999:

| (dollars in thousands) | <i>2000</i> | <i>1999</i> |
|---|-------------|-------------|
| Projected pension benefit obligation at beginning of year | \$ 742,638 | \$ 731,305 |
| Service cost | 24,955 | 24,982 |
| Interest cost | 58,361 | 52,905 |
| Benefit payments | (30,568) | (29,694) |
| Actuarial (gains)/losses | 540 | (36,860) |
| Projected pension benefit obligation at end of year | \$ 795,926 | \$ 742,638 |

The following table sets forth the defined benefit pension plans' change in the fair value of plan assets for the plan years 2000 and 1999:

| (dollars in thousands) | <i>2000</i> | <i>1999</i> |
|--|-------------|-------------|
| Fair value of pension plan assets at beginning of year | \$ 779,913 | \$ 690,271 |
| Actual return on plan assets | 1,851 | 93,977 |
| Employer contributions | 24,000 | 25,359 |
| Benefit payments | (30,568) | (29,694) |
| Fair value of pension plan assets at end of year | \$ 775,196 | \$ 779,913 |

We made the assumptions below to calculate the pension liability:

| | <i>2000</i> | <i>1999</i> |
|---|-------------|-------------|
| Discount rate | 7.75% | 7.75% |
| Rate of increase in compensation levels | 4.25% | 4.25% |
| Expected long-term rate of return on assets | 10.00% | 10.00% |

Employee Savings Plan Benefits

Through 1999, Pinnacle West and its subsidiaries each sponsored defined contribution savings plans for their own employees. As of January 1, 2000, these plans were consolidated and now a single defined contribution savings plan is sponsored by Pinnacle West for the employees of Pinnacle West and its subsidiaries. In a defined contribution plan, the benefits a participant will receive result from regular contributions they make to a participant account. Under this plan, we make matching contributions to participant accounts. We recorded expenses for this plan of approximately \$4 million for 2000, 1999, and 1998.

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:

- \$ 3 million for 2000
- \$ 7 million for 1999 and
- \$ 9 million for 1998.

The following table shows the components of net periodic postretirement benefit costs before consideration of amounts capitalized or billed to others:

| (dollars in thousands) | <i>2000</i> | <i>1999</i> | <i>1998</i> |
|--|-----------------|------------------|------------------|
| Service cost - benefits earned during the period | \$ 8,613 | \$ 8,939 | \$ 7,890 |
| Interest cost on accumulated benefit obligation | 19,315 | 17,366 | 15,763 |
| Expected return on plan assets | (22,381) | (18,454) | (12,001) |
| Amortization of: | | | |
| Transition obligation | 7,698 | 7,698 | 7,698 |
| Net actuarial gains | (7,983) | (5,117) | (2,952) |
| Net periodic postretirement benefit cost | \$ 5,262 | \$ 10,432 | \$ 16,398 |

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

| (dollars in thousands) | <i>2000</i> | <i>1999</i> |
|---|-------------------|-------------------|
| Funded status – postretirement plan assets more than (less than) projected benefit obligation | \$ (14,851) | \$ 25,549 |
| Unrecognized net obligation at transition | 92,446 | 100,145 |
| Unrecognized net actuarial gains | (81,280) | (128,309) |
| Net postretirement amount recognized in the balance sheets | \$ (3,685) | \$ (2,615) |

The following table sets forth the postretirement benefit plans' change in accumulated benefit obligation for the plan years 2000 and 1999:

| (dollars in thousands) | <i>2000</i> | <i>1999</i> |
|---|-------------------|-------------------|
| Accumulated postretirement benefit obligation at beginning of year | \$ 231,989 | \$ 237,679 |
| Service cost | 8,613 | 8,939 |
| Interest cost | 19,315 | 17,366 |
| Benefit payments | (8,905) | (8,761) |
| Actuarial (gains) losses | 12,994 | (23,234) |
| Accumulated postretirement benefit obligation at end of year | \$ 264,006 | \$ 231,989 |

The following table sets forth the postretirement benefit plans' change in the fair value of plan assets for the plan years 2000 and 1999:

| (dollars in thousands) | <i>2000</i> | <i>1999</i> |
|--|-------------------|-------------------|
| Fair value of postretirement plan assets at beginning of year | \$ 257,538 | \$ 213,410 |
| Actual return on plan assets | (4,436) | 42,975 |
| Employer contributions | 4,958 | 9,914 |
| Benefit payments | (8,906) | (8,761) |
| Fair value of postretirement plan assets at end of year | \$ 249,154 | \$ 257,538 |

We made the assumptions below to calculate the postretirement liability:

| | <i>2000</i> | <i>1999</i> |
|---|-------------|-------------|
| Discount rate | 7.75% | 7.75% |
| Expected long-term rate of return on assets – after tax | 8.77% | 8.77% |
| Initial health care cost trend rate – under age 65 | 7.00% | 7.00% |
| Initial health care cost trend rate – age 65 and over | 6.00% | 6.00% |
| Ultimate health care cost trend rate (reached in the year 2002) | 5.00% | 5.00% |

The following table shows the effect of a 1% increase or decrease in the health care cost trend rate:

| (dollars in millions) | 1% increase | 1% decrease |
|--|-------------|-------------|
| Effect on 2000 cost of postretirement benefits other than pensions | \$ 5 | \$ (4) |
| Effect on the accumulated postretirement benefit obligation at December 31, 2000 | 43 | (34) |

10. LEASES

In 1986, APS sold about 42% of its share of Palo Verde Unit 2 and certain common facilities in three separate sale lease-back transactions. APS accounts for these leases as operating leases. The gain of approximately \$140 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 approximately \$49 million per year for the years 2001-2015.

In accordance with the 1999 Settlement Agreement, APS is continuing to accelerate amortization of the regulatory asset for leases over an eight-year period that will end June 30, 2004 (see Note 1). The accelerated amortization is included in depreciation and amortization expense on the Statements of Income. The balance of this regulatory asset at December 31, 2000 was \$33 million.

In December 2000, APS purchased Units 1, 2, and 3 of West Phoenix Power Plant. These units were previously reflected as a capital lease.

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

Total lease expense was \$58 million in 2000, \$52 million in 1999, and \$55 million in 1998.

Estimated future minimum lease commitments, are approximately \$67 million for each of the years 2001 to 2005 and \$663 million thereafter.

11. JOINTLY-OWNED FACILITIES

APS shares ownership of some of its generating and transmission facilities with other companies. The following table shows APS' interest in those jointly-owned facilities at

December 31, 2000. APS' share of operating and maintaining these facilities is included in the income statement in operations and maintenance expense.

| (dollars in thousands) | Percent Owned by Company | Plant in Service | Accumulated Depreciation | Construction Work in Progress |
|--|--------------------------|------------------|--------------------------|-------------------------------|
| Generating Facilities: | | | | |
| Palo Verde Nuclear Generating Station Units 1 and 3 | 29.1% | \$1,824,480 | \$ 814,693 | \$ 7,414 |
| Palo Verde Nuclear Generating Station Unit 2 (see Note 10) | 17.0% | 571,573 | 265,571 | 29,593 |
| Four Corners Steam Generating Station Units 4 and 5 | 15.0% | 152,717 | 75,797 | — |
| Navajo Steam Generating Station Units 1, 2, and 3 | 14.0% | 231,509 | 99,623 | 4,899 |
| Cholla Steam Generating Station Common Facilities (a) | 62.8%(b) | 73,382 | 40,023 | 686 |
| Transmission Facilities: | | | | |
| ANPP 500KV System | 35.8%(b) | 67,987 | 22,813 | — |
| Navajo Southern System | 31.4%(b) | 27,290 | 17,804 | 55 |
| Palo Verde – Yuma 500KV System | 23.9%(b) | 9,712 | 3,844 | 1 |
| Four Corners Switchyards | 27.5%(b) | 3,071 | 1,925 | — |
| Phoenix – Mead System | 17.1%(b) | 36,418 | 2,681 | — |
| Palo Verde – Estrella 500KV system | 50.0%(b) | — | — | 610 |

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

(b) 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.

Power Service Agreement

APS is a party to a power service agreement with Citizens Communications Company (Citizens) under which APS supplies Citizens with power. By letter dated March 7, 2001, Citizens advised APS that it believes APS has over-charged Citizens by over \$50 million under the agreement since the summer of 2000. APS believes that its charges to Citizens under the agreement are fully in accordance with the terms of the agreement and APS will vigorously defend any contrary claims raised by Citizens.

Palo Verde Nuclear Generating Station

Pursuant to the Nuclear Waste Policy Act of 1982, the DOE must accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by domestic power reactors. The United States Nuclear Regulatory Commission (NRC) requires operators of nuclear power reactors to enter

into spent fuel disposal contracts with the DOE. Under the Nuclear Waste Policy Act of 1982, the DOE was to develop a permanent repository for the storage and disposal of spent nuclear fuel by 1998. The DOE has announced that such a permanent repository cannot be completed before 2010, and that it does not intend to begin accepting spent fuel prior to that date.

In November 1997, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued a decision precluding the DOE from excusing its own delay, but refused to order the DOE to begin accepting spent nuclear fuel. Based on this decision, a number of utilities filed damages actions against DOE in the court of Federal Claims. In decisions that became final in December 2000, the United States Court of Appeals for the Federal Circuit held that utilities do not have to exhaust the DOE administrative claims before filing lawsuits for damages against the DOE in the court of Federal Claims.

APS has existing fuel storage pools at Palo Verde and is in the process of completing construction of a new facility for on-site dry storage of spent fuel. With the existing storage pools and the addition of the new facility, APS believes that spent

fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation through the term of the operating license for each Palo Verde unit.

Although some low-level waste has been stored on-site in a low-level waste facility, 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 currently estimates that it will incur \$113 million (in 2000 dollars) over the life of Palo Verde for its share of the costs related to the on-site interim storage of spent nuclear fuel. As of December 31, 2000, APS had recorded a liability and regulatory asset of \$40 million for on-site interim nuclear fuel storage costs related to nuclear fuel burned to date.

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 our 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. 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 2001 through 2021 that include required purchase provisions. APS estimates its contract requirements to be approximately \$277 million in 2001; \$145 million in 2002; \$90 million in 2003; \$83 million in 2004; and \$55 million in 2005. 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 \$58 million at December 31, 2000 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 1999 Settlement Agreement with the ACC, APS is continuing to accelerate the amortization of the regulatory asset for coal mine reclamation 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, 2000 was about \$32 million.

California Energy Market Issues

SCE and PG&E have publicly disclosed that their liquidity has been materially and adversely affected because of, among other things, their inability to pass on to ratepayers the prices each has paid for energy and ancillary services procured through the PX and the ISO.

We are closely monitoring developments in the California energy market and the potential impact of these developments on us and our subsidiaries. We have evaluated, among other things, SCE's role as a Palo Verde and Four Corners participant; APS' transactions with the PX and the ISO; contractual relationships with SCE and PG&E; APS Energy Services' retail transactions involving SCE and PG&E; and power marketing exposures. Based upon financial transactions to date, we do not believe the foregoing matters will have a material adverse effect on our financial position or liquidity. We cannot predict with certainty, however, the impact that any future resolution or attempted resolution, of the California energy market situation may have on us or our subsidiaries or the regional energy market in general.

See "Generation Expansion" below for a discussion of Pinnacle West Energy's agreement to purchase SCE's Palo Verde interest.

Construction Program

Consolidated capital expenditures in 2001 are estimated at:

| (dollars in millions) | <i>2001</i> |
|-----------------------|-------------|
| APS | \$ 455 |
| Pinnacle West Energy | 659 |
| SunCor | 75 |
| Other | 21 |
| Total | \$ 1,210 |

Generation Expansion

Pinnacle West Energy has announced plans to build and acquire up to 2,800 MW of generating capacity from 2001-2006 at an estimated cost of about \$1.3 billion.

Pinnacle West Energy is also considering additional expansion over the next several years, which may result in additional expenditures. Pinnacle West Energy's expenditures are expected to be funded through internally generated cash and debt issued directly by Pinnacle West Energy, as well as capital infusions from Pinnacle West's internally generated cash and debt proceeds.

Pinnacle West Energy is currently planning a 650-megawatt expansion of the West Phoenix Power Plant and the construction of a natural gas-fired electric generating station of up to four, 530 MW units near Palo Verde, called Redhawk. Construction on the 120 MW West Phoenix Unit 4 began in June 2000, with commercial operation of the unit expected in the summer of 2001. Pinnacle West Energy expects construction to begin on the 530 MW Unit 5 in the fall of 2001, with commercial operation beginning in mid-2003. Construction began on the first two units of Redhawk in December 2000, and commercial operation is scheduled for the summer of 2002.

Pinnacle West Energy has entered into an agreement with NPC to purchase NPC's 72 MW gas-fired Harry Allen Power Station about 30 miles northeast of Las Vegas, Nevada, for a net purchase price, after adjustments for purchased power commitments, of approximately \$65.2 million. The purchase is subject to filing with and/or approval of various regulatory agencies, including FERC and the NPUC. The filing with the NPUC was made in February 2001. NPC will have the right, but not the obligation, to purchase the output from the Harry Allen plant at market rates, subject to a floor and a cap. As demand grows in the region during the next five years, Pinnacle West Energy expects to add a 480 MW gas-fired, combined cycle unit to the site. The Governor of Nevada has recently requested that the NPUC reexamine the divestiture of generation. The timing and results of any action by the NPUC is not yet known.

On April 27, 2000, Pinnacle West Energy entered into two separate agreements with SCE to purchase SCE's 15.8% ownership interest in Palo Verde and its 48% ownership interest in the Four Corners Power Plant. Consistent with the agreements, on January 5, 2001, Pinnacle West Energy informed SCE that it would not match a competing bid that SCE received for its Four Corners ownership interest. Therefore, Pinnacle West Energy will not purchase SCE's Four Corners interest under the April 2000 agreement unless the Palo Verde transaction closes, the competing Four Corners transaction does not close, and Pinnacle West

Energy acquires the Four Corners interest at the original \$300 million purchase price as a standby purchaser. SCE did not receive any qualified competing bids for its Palo Verde ownership interest, which Pinnacle West Energy agreed to purchase for \$250 million. However, recently-enacted California legislation provides that "no facility for the generation of electricity owned by a public utility may be disposed of prior to January 1, 2006." Unless this California law is amended, Pinnacle West Energy would not be able to acquire SCE's Palo Verde ownership interest pursuant to the original April 2000 agreement.

13. NUCLEAR DECOMMISSIONING COSTS

APS recorded \$11 million for nuclear decommissioning expense in each of the years 2000, 1999, and 1998. APS estimates it will cost about \$1.8 billion (\$493 million in 2000 dollars) to decommission its 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 decommissioning 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 NRC regulations. The trust accounts are reported in investments and other assets on the Consolidated Balance Sheets at their market value of \$205 million at December 31, 2000 and \$176 million at December 31, 1999. 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.

See Note 2 for a proposed accounting standard on accounting for certain liabilities related to closure or removal of long-lived assets.

14. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

Consolidated quarterly financial information for 2000 and 1999 is as follows:

(dollars in thousands, except per share amounts)

2000

| QUARTER ENDED | March 31 | June 30 | September 30 | December 31 |
|---|------------|------------|--------------|-------------|
| Operating revenues | | | | |
| Electric | \$ 446,228 | \$ 720,174 | \$ 1,567,960 | \$ 797,448 |
| Real Estate | 41,889 | 36,374 | 39,396 | 40,706 |
| Operating Income (a) | \$ 96,271 | \$ 201,153 | \$ 256,001 | \$ 122,546 |
| Net income | \$ 54,070 | \$ 89,901 | \$ 116,049 | \$ 42,312 |
| Earnings per average common share outstanding | | | | |
| Net income – basic | \$ 0.64 | \$ 1.06 | \$ 1.37 | \$ 0.50 |
| Net income – diluted | \$ 0.64 | \$ 1.06 | \$ 1.37 | \$ 0.50 |
| Dividends declared per share | \$ 0.35 | \$ 0.35 | \$ 0.35 | \$ 0.375 |

(dollars in thousands, except per share amounts)

1999

| QUARTER ENDED | March 31 | June 30 | September 30 | December 31 |
|--|------------|------------|--------------|-------------|
| Operating revenues | | | | |
| Electric | \$ 413,983 | \$ 511,434 | \$ 867,630 | \$ 500,137 |
| Real Estate | 24,533 | 32,697 | 26,640 | 46,299 |
| Operating Income (a) | \$ 91,599 | \$ 148,968 | \$ 240,294 | \$ 97,916 |
| Income from continuing operations | \$ 30,690 | \$ 68,702 | \$ 125,579 | \$ 44,801 |
| Income tax benefit from discontinued operations | — | — | 38,000 | — |
| Extraordinary charge – net of income tax | — | — | (139,885) | — |
| Net income | \$ 30,690 | \$ 68,702 | \$ 23,694 | \$ 44,801 |
| Earnings (loss) per average common share outstanding | | | | |
| Continuing operations – basic | \$ 0.36 | \$ 0.81 | \$ 1.48 | \$ 0.53 |
| Discontinued operations – basic | — | — | 0.45 | — |
| Extraordinary charge – basic | — | — | (1.65) | — |
| Net income – basic | \$ 0.36 | \$ 0.81 | \$ 0.28 | \$ 0.53 |
| Continuing operations – diluted | \$ 0.36 | \$ 0.81 | \$ 1.48 | \$ 0.53 |
| Discontinued operations – diluted | — | — | 0.45 | — |
| Extraordinary charge – diluted | — | — | (1.65) | — |
| Net income – diluted | \$ 0.36 | \$ 0.81 | \$ 0.28 | \$ 0.53 |
| Dividends declared per share (b) | \$ 0.325 | \$ 0.65 | \$ — | \$ 0.35 |

(a) Electric revenues are 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 quarter ending September 30, 1999 were declared in June 1999.

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, 2000 and 1999 due to their short maturities.

We hold investments in debt and equity securities for purposes other than trading. The December 31, 2000 and 1999 fair values of such investments, which we determine by using quoted market values, approximate their carrying amount.

The carrying value of our long-term debt (excluding a capitalized lease obligation) was \$2.42 billion on December 31, 2000, with an estimated fair value of \$2.48 billion. On December 31, 1999, the carrying value of our long-term debt (excluding a capitalized lease obligation) was \$2.31 billion, with an estimated fair value of \$2.29 billion. The fair value estimates are based on quoted market prices of the same or similar issues.

16. EARNINGS PER SHARE

The following table presents earnings per average common share outstanding (EPS):

| | <i>2000</i> | <i>1999</i> | <i>1998</i> |
|-------------------------|-------------|-------------|-------------|
| Basic EPS: | | | |
| Continuing operations | \$ 3.57 | \$ 3.18 | \$ 2.87 |
| Discontinued operations | — | 0.45 | — |
| Extraordinary charge | — | (1.65) | — |
| Net income | \$ 3.57 | \$ 1.98 | \$ 2.87 |
| Diluted EPS: | | | |
| Continuing operations | \$ 3.56 | \$ 3.17 | \$ 2.85 |
| Discontinued operations | — | 0.45 | — |
| Extraordinary charge | — | (1.65) | — |
| Net income | \$ 3.56 | \$ 1.97 | \$ 2.85 |

Dilutive stock options increased average common shares outstanding by 202,738 shares in 2000, 291,392 shares in 1999, and 571,728 shares in 1998. Total average common shares outstanding for the purposes of calculating diluted earnings per share were 84,935,282 shares in 2000, 85,008,527 shares in 1999, and 85,345,946 shares in 1998.

Options to purchase 517,614 shares of common stock were outstanding at December 31, 2000 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. Options to purchase shares of common stock that were not included in the computation of diluted EPS were 506,734 at December 31, 1999 and 244,200 at December 31, 1998.

17. STOCK-BASED COMPENSATION

Pinnacle West offers two stock incentive plans for our and our subsidiaries' officers and key employees.

The plan provides for the granting of new options (which may be non-qualified stock options or incentive stock options) of up to 3.5 million shares at a price per option not less than the fair market value on the date the option is granted. Options vest one-third of the grant per year beginning one year after the date the option is granted and expire ten years from the date of the grant. The plan also provides for the granting of any combination of shares of restricted stock, stock appreciation rights or dividend equivalents.

The awards outstanding under the incentive plans at December 31, 2000 approximate 1,569,171 non-qualified stock options, 193,992 shares of restricted stock, and no incentive stock options, stock appreciation rights or dividend equivalents.

The FASB issued SFAS No. 123, "Accounting for Stock-Based Compensation" which was effective beginning in 1996. The statement encourages, but does not require, that a company record compensation expense based on the fair value of options granted (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 and earnings per share would have been reduced to the following pro forma amounts:

| (dollars in thousands) | <i>2000</i> | | <i>1999</i> | <i>1998</i> |
|-------------------------------|-------------|------------|-------------|-------------|
| Net income | | | | |
| As reported | \$ 302,332 | \$ 167,887 | \$ 242,892 | |
| Pro forma (fair value method) | \$ 301,102 | \$ 166,913 | \$ 242,177 | |
| Earnings per share – basic | | | | |
| As reported | \$ 3.57 | \$ 1.98 | \$ 2.87 | |
| Pro forma (fair value method) | \$ 3.55 | \$ 1.97 | \$ 2.86 | |

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:

| | <i>2000</i> | <i>1999</i> | <i>1998</i> |
|-------------------------|-------------|-------------|-------------|
| Risk-free interest rate | 5.81% | 5.68% | 4.54% |
| Dividend yield | 3.48% | 3.33% | 3.03% |
| Volatility | 32.00% | 20.50% | 18.80% |
| Expected life (months) | 60 | 60 | 60 |

The following table is a summary of the status of our stock option plans as of December 31, 2000, 1999, and 1998 and changes during the years ending on those dates:

| (dollars in thousands) | 2000 Shares | 2000 Weighted Average Exercise Price | 1999 Shares | 1999 Weighted Average Exercise Price | 1998 Shares | 1998 Weighted Average Exercise Price |
|--|----------------|--|----------------|--|----------------|--|
| Outstanding at beginning of year | 1,441,124 | \$ 33.45 | 1,563,512 | \$ 27.95 | 1,554,631 | \$ 24.38 |
| Granted | 451,450 | 43.28 | 458,450 | 35.95 | 244,200 | 46.78 |
| Exercised | (283,819) | 20.90 | (516,838) | 18.19 | (217,317) | 23.09 |
| Forfeited | (39,584) | 39.86 | (64,000) | 40.36 | (18,002) | 33.42 |
| Outstanding at end of year | 1,569,171 | 37.55 | 1,441,124 | 33.45 | 1,563,512 | 27.95 |
| Options exercisable at year-end | 831,537 | 34.37 | 835,381 | 29.69 | 1,106,165 | 22.04 |
| Weighted average fair value of options granted during the year | | 11.81 | | 7.05 | | 8.15 |

The following table summarizes information about our stock option plans at December 31, 2000:

| Exercise Prices Per Share | Options Outstanding | Weighted Average Remaining Contract Life (Years) | Options Exercisable |
|---------------------------|---------------------|--|---------------------|
| \$10.06 | 7,000 | .50 | 7,000 |
| 15.75 | 10,000 | .90 | 10,000 |
| 17.68 | 4,900 | 1.10 | 4,900 |
| 18.13 | 14,000 | 1.50 | 14,000 |
| 19.00 | 58,618 | 3.90 | 58,618 |
| 19.56 | 15,000 | 1.90 | 15,000 |
| 22.13 | 33,250 | 3.00 | 33,250 |
| 23.25 | 14,000 | 2.50 | 14,000 |
| 27.16 | 20,000 | 9.20 | 5,000 |
| 27.44 | 84,918 | 4.90 | 84,918 |
| 31.44 | 87,335 | 5.90 | 87,335 |
| 34.66 | 327,113 | 8.90 | 118,124 |
| 36.56 | 5,000 | 8.80 | 2,083 |
| 39.75 | 170,636 | 7.00 | 170,636 |
| 41.00 | 70,000 | 8.10 | 44,722 |
| 44.03 | 431,450 | 9.90 | 11,985 |
| 46.78 | 215,951 | 7.90 | 149,966 |
| \$10.06 – \$46.78 | <u>1,569,171</u> | | <u>831,537</u> |

18. BUSINESS SEGMENTS

We have two principal business segments (determined by products, services and regulatory environment) which consist of the transmission and distribution of electricity and wholesale activities (delivery business segment) and the generation of electricity (generation business segment). The other

amounts include activity relating to the parent company and other subsidiaries including APS Energy Services, SunCor and El Dorado. Eliminations primarily relate to intersegment sales of electricity. Financial data for the business segments is provided as follows:

BUSINESS SEGMENTS FOR YEAR ENDED DECEMBER 31, 2000

| (dollars in thousands) | Generation | Delivery | Other | Eliminations | Total |
|-------------------------------|--------------|--------------|------------|--------------|--------------|
| Operating revenues | \$ 990,415 | \$ 3,531,810 | \$ 158,365 | \$ (990,415) | \$ 3,690,175 |
| Operating expense | 600,389 | 2,871,329 | 138,677 | (990,415) | 2,619,980 |
| Operating margin | 390,026 | 660,481 | 19,688 | — | 1,070,195 |
| Depreciation and amortization | 125,220 | 263,446 | 5,744 | — | 394,410 |
| Interest | 41,808 | 96,081 | 11,712 | — | 149,601 |
| Pretax margin | 222,998 | 300,954 | 2,232 | — | 526,184 |
| Income taxes | 87,828 | 134,692 | 1,332 | — | 223,852 |
| Earnings for common stock | \$ 135,170 | \$ 166,262 | \$ 900 | \$ — | \$ 302,332 |
| Total assets | \$ 2,606,046 | \$ 4,068,510 | \$ 474,595 | \$ — | \$ 7,149,151 |
| Capital expenditures | \$ 379,761 | \$ 285,455 | \$ 49,949 | \$ — | \$ 715,165 |

BUSINESS SEGMENTS FOR YEAR ENDED DECEMBER 31, 1999

| (dollars in thousands) | Generation | Delivery | Other | Eliminations | Total |
|---|--------------|--------------|------------|--------------|--------------|
| Operating revenues | \$ 853,755 | \$ 2,292,798 | \$ 130,555 | \$ (853,755) | \$ 2,423,353 |
| Operating expense | 522,925 | 1,672,169 | 106,876 | (853,755) | 1,448,215 |
| Operating margin | 330,830 | 620,629 | 23,679 | — | 975,138 |
| Depreciation and amortization | 121,683 | 260,374 | 3,511 | — | 385,568 |
| Interest and preferred stock dividend requirements | 40,753 | 101,855 | 9,125 | — | 151,733 |
| Pretax margin | 168,394 | 258,400 | 11,043 | — | 437,837 |
| Income taxes | 47,976 | 111,512 | 8,577 | — | 168,065 |
| Income tax benefit from discontinued operations – PNW | — | — | 38,000 | — | 38,000 |
| Extraordinary charge – net of income tax of \$94,115 | — | (139,885) | — | — | (139,885) |
| Earnings for common stock | \$ 120,418 | \$ 7,003 | \$ 40,466 | \$ — | \$ 167,887 |
| Total assets | \$ 2,342,291 | \$ 3,795,846 | \$ 470,369 | \$ — | \$ 6,608,506 |
| Capital expenditures | \$ 110,798 | \$ 241,469 | \$ 126,581 | \$ — | \$ 478,848 |

BUSINESS SEGMENTS FOR YEAR ENDED DECEMBER 31, 1998

| (dollars in thousands) | Generation | Delivery | Other | Eliminations | Total |
|--|--------------|--------------|------------|--------------|--------------|
| Operating revenues | \$ 858,340 | \$ 2,006,398 | \$ 124,188 | \$ (858,340) | \$ 2,130,586 |
| Operating expense | 522,696 | 1,414,753 | 104,061 | (858,340) | 1,183,170 |
| Operating margin | 335,644 | 591,645 | 20,127 | — | 947,416 |
| Depreciation and amortization | 135,406 | 241,168 | 3,105 | — | 379,679 |
| Interest and preferred stock dividend requirements | 37,045 | 108,670 | 14,537 | — | 160,252 |
| Pretax margin | 163,193 | 241,807 | 2,485 | — | 407,485 |
| Income taxes | 49,969 | 109,487 | 5,137 | — | 164,593 |
| Earnings for common stock | \$ 113,224 | \$ 132,320 | \$ (2,652) | \$ — | \$ 242,892 |
| Total assets | \$ 2,399,560 | \$ 3,993,740 | \$ 431,246 | \$ — | \$ 6,824,546 |
| Capital expenditures | \$ 85,767 | \$ 241,638 | \$ 73,133 | \$ — | \$ 400,538 |