

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 (principally NAC). Significant intercompany accounts and transactions between the consolidated companies have been eliminated.

APS is an electric utility that provides either retail or wholesale electric service to substantially all of the state of Arizona, with the major exceptions of the Tucson metropolitan area and about half of the Phoenix metropolitan area. Electricity is delivered through a distribution system owned by APS. APS also generates, sells and delivers electricity to wholesale customers in the western United States. In early 2003, the marketing and trading division of Pinnacle West was moved to APS for future marketing and trading activities (existing wholesale contracts will remain at Pinnacle West) as a result of the ACC's Track A Order prohibiting the previously required transfer of APS' generating assets to Pinnacle West Energy. See Note 3 for a discussion of the Track A Order. Pinnacle West Energy, which was formed in 1999, is the subsidiary through which we conduct our competitive generation operations. APS Energy Services was formed in 1998 and provides competitive commodity energy and energy-related products to key customers in competitive 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 an investment firm, and its principal investment is in NAC, which is a company specializing in spent nuclear fuel technology.

Accounting Records and Use of Estimates

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 management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. We have reclassified certain prior year amounts to conform to the current year presentation.

Derivative Accounting

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal and emissions allowances. We 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 and credits. The changes in market value of such contracts have a high correlation to price changes in the hedged commodities. In addition, subject to specified risk parameters monitored by the ERM, we

engage in marketing and trading activities intended to profit from market price movements.

We examine contracts at inception to determine the appropriate accounting treatment. If a contract does not meet the derivative criteria or if it qualifies for a SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," scope exception, we account for the contract on an accrual basis with associated revenues and costs recorded at the time the contracted commodities are delivered or received. SFAS No. 133 provides a scope exception for contracts that meet the normal purchases and sales criteria specified in the standard. Most of our non-trading electricity purchase and sales agreements qualify as normal purchases and sales and are exempted from recognition in the financial statements until the electricity is delivered.

For contracts that qualify as a derivative and do not meet a SFAS No. 133 scope exception, we further examine the contract to determine if it will qualify for hedge accounting. Changes in the fair value of the effective portion of derivative instruments that qualify for cash flow hedge accounting treatment are recognized as either an asset or liability and in common stock equity (as a component of accumulated other comprehensive income (loss)). Gains and losses related to derivatives that qualify as cash flow hedges of expected transactions are recognized in revenue or purchased power and fuel expense as an offset to the related item being hedged when the underlying hedged physical transaction impacts earnings. If a contract does not meet the hedging criteria in SFAS No. 133, we recognize the changes in the fair value of the derivative instrument in income each period through mark-to-market accounting.

On October 1, 2002, we adopted EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," which rescinded EITF 98-10. As a result, our energy trading contracts that are derivatives continue to be accounted for at fair value under SFAS No. 133. Contracts that were previously marked-to-market as trading activities under EITF 98-10 that do not meet the definition of a derivative are now accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received. Additionally, all gains and losses (realized and unrealized) on energy trading contracts that qualify as derivatives are included in marketing and trading segment revenues on the Consolidated Statements of Income on a net basis. The rescission of EITF 98-10 has no effect on the accounting for derivative instruments used for non-trading activities, which continue to be accounted for in accordance with SFAS No. 133. See Note 18 for more details on the change in accounting for energy trading contracts and for further discussion on derivative accounting.

Mark-to-Market Accounting

Under mark-to-market accounting, the purchase or sale of energy commodities is reflected at fair market value, net of valuation adjustments, with resulting unrealized gains and losses recorded as assets

and liabilities from risk management and trading activities in the Consolidated Balance Sheets.

We determine fair market value using actively-quoted prices when available. We consider quotes for exchange-traded contracts and over-the-counter quotes obtained from independent brokers to be actively-quoted.

When actively-quoted prices are not available, we use prices provided by other external sources. This includes quarterly and calendar year quotes from independent brokers. We convert quarterly and calendar year quotes into monthly prices based on historical relationships.

For options, long-term contracts and other contracts for which price quotes are not available, we use models and other valuation methods. The valuation models we employ utilize spot prices, forward prices, historical market data and other factors to forecast future prices. The primary valuation technique we use to calculate the fair value of contracts where price quotes are not available is based on the extrapolation of forward pricing curves using observable market data for more liquid delivery points in the same region and actual transactions at the more illiquid delivery points. We also value option contracts using a variation of the Black-Scholes option-pricing model.

For non-exchange traded contracts, we calculate fair market value based on the average of the bid and offer price, and we discount to reflect net present value. We maintain certain valuation adjustments for a number of risks associated with the valuation of future commitments. These include valuation adjustments for liquidity and credit risks based on the financial condition of counterparties. The liquidity valuation adjustment represents the cost that would be incurred if all unmatched positions were closed-out or hedged.

A credit valuation adjustment is also recorded to represent estimated credit losses on our overall exposure to counterparties, taking into account netting arrangements; expected default experience for the credit rating of the counterparties and the overall diversification of the portfolio. Counterparties in the portfolio consist principally of major energy companies, municipalities and local distribution companies. We maintain credit policies that management believes minimize overall credit risk. Determination of the credit quality of counterparties is based upon a number of factors, including credit ratings, financial condition, project economics and collateral requirements. When applicable, we employ standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. See Note 18 for further discussion on credit risk.

The use of models and other valuation methods to determine fair market value often requires subjective and complex judgment. Actual results could differ from the results estimated through application of these methods. Our marketing and trading portfolio includes structured activities hedged with a portfolio of forward purchases that protects the economic value of the sales transactions. Our practice is to hedge within timeframes established by the ERM.

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 its financial statements. As a result, we capitalize certain costs that would be included as expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections of costs not likely to be incurred.

We are required to discontinue applying SFAS No. 71 when deregulatory 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. In 1999, we discontinued the application of SFAS No. 71 for APS' generation operations due to the 1999 Settlement Agreement with the ACC. See Note 3 for a discussion of the 1999 Settlement Agreement.

As a result, we tested the generation assets for impairment and determined the generation assets were not impaired. Pursuant to the 1999 Settlement Agreement, a regulatory disallowance removed \$234 million pretax (\$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 1999 Consolidated Statement of Income.

In 2002, the ACC directed APS not to transfer its generation assets, as previously required by the 1999 Settlement Agreement (see "Track A Order" in Note 3). Accordingly, we now consider APS generation to be cost-based, rate-regulated and subject to the requirements of SFAS No. 71. The impact of this change was immaterial to our consolidated financial statements.

Management continually assesses whether our regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes and recent rate orders to other regulated entities in the same jurisdiction. This determination reflects the current political and regulatory climate in the state and is subject to change in the future. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings.

Prior to the 1999 Settlement Agreement, the ACC accelerated the amortization of substantially all of APS' 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 currently being amortized as follows (dollars in millions):

1999	2000	2001	2002	2003	2004	TOTAL
\$164	\$158	\$145	\$115	\$86	\$18	\$686

Regulatory assets are reported as deferred debits on the Consolidated Balance Sheets. As of December 31, 2002 and 2001, they are comprised of the following (dollars in millions):

December 31,	2002	2001
Remaining balance recoverable under the 1999 Settlement Agreement (a)	\$ 104	\$ 219
Spent nuclear fuel storage (Note 11)	46	43
Electric industry restructuring transition costs (Note 3)	40	34
Other	51	46
Total regulatory assets	\$ 241	\$ 342

(a) The majority of our unamortized regulatory assets above relates to deferred income taxes (See Note 4) and rate synchronization cost deferrals (see "Rate Synchronization Cost Deferrals" below).

Regulatory liabilities are included in deferred credits and other on the Consolidated Balance Sheets. As of December 31, 2002 and 2001, they are comprised of the following (dollars in millions):

December 31,	2002	2001
Deferred gains on utility property	\$ 20	\$ 20
Other	6	7
Total regulatory liabilities	\$ 26	\$ 27

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 in the Consolidated Statements of Income.

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 expense the costs of plant outages, major maintenance and routine maintenance as incurred. We charge retired utility plant, plus removal costs less salvage realized, to accumulated depreciation. See Note 2 for information on a new accounting standard that impacts accounting for removal costs.

We record depreciation on utility property on a straight-line basis over the remaining useful life of the related assets. The approximate remain-

ing average useful lives of our utility property at December 31, 2002 were as follows:

- Fossil plant – 22 years;
- Nuclear plant – 22 years;
- Transmission – 34 years;
- Distribution – 28 years; and
- Other utility property – 9 years.

For the years 2000 through 2002 the depreciation rates, as prescribed by our regulators, ranged from a low of 1.51% to a high of 20%. The weighted-average rate was 3.35% for 2002, 3.40% for 2001 and 2000. We depreciate non-utility property and equipment over the estimated useful lives of the related assets, ranging from 3 to 30 years.

EI Dorado Investments

EI Dorado accounts for its investments using the consolidated (if controlled), equity (if significant influence) and cost (less than 20% ownership) methods. Beginning in the third quarter of 2002, EI Dorado began consolidating the operations of NAC. See Note 22 for further details on EI Dorado's investment in NAC.

Capitalized Interest

Capitalized interest represents the cost of debt funds used to finance construction projects. 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 4.80% for 2002, 6.13% for 2001 and 6.62% for 2000.

Electric Revenues

Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of energy sales to individual Native Load customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading and the corresponding unbilled revenue are estimated. We exclude sales taxes on electric revenues from both revenue and taxes other than income taxes. Other than revenues and purchased power costs related to energy trading activities, revenues are reported on a gross basis in our Consolidated Statements of Income.

All gains and losses (realized and unrealized) on energy trading contracts that qualify as derivatives are included in marketing and trading segment revenues on the Consolidated Statements of Income on a net basis.

SunCor

SunCor recognizes revenue from land, home and qualifying commercial operating assets sales in full, provided (a) the income is determinable, that is, the collectibility of the sales price is reasonably assured or the amount that will not be collectible can be estimated, and (b) the earnings process is virtually complete, that is, SunCor is not obligated to perform significant activities after the sale to earn the income. Unless

both conditions exist, recognition of all or part of the income is postponed. A single method of recognizing income is applied to all sales transactions within an entire home, land or commercial development project. Commercial property and management revenues are recorded over the term of the lease or period in which services are provided.

Percentage of Completion – NAC

Certain NAC contract revenues are accounted for under the percentage-of-completion method. Revenues are recognized based upon total costs incurred to date compared to total costs expected to be incurred for each contract. Revisions in contract revenue and cost estimates are reflected in the accounting period when known. Provisions are made for the full amounts of anticipated losses in the periods in which they are first determined. Changes in job performance, job conditions and estimated profitability, including those arising from contract penalty provisions and final contract settlements, may result in revisions to costs and income, and are recognized in the period in which revisions are determined. Profit incentives are included in revenues when their realization is reasonably assured.

Contract costs include all direct material and labor costs and those indirect costs related to contract performance, such as indirect labor, supplies, tools, repairs and depreciation costs. General and administrative costs are charged to expense as incurred.

Cash and Cash Equivalents

For purposes of the Consolidated Statements of Cash Flows, we consider all highly liquid debt instruments purchased with an initial maturity of three months or less to be cash equivalents.

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 based on actual physical usage. APS divides the cost of the fuel by the estimated number of thermal units it expects to produce with that fuel. APS then multiplies that rate by the number of thermal units produced 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 DOE is responsible for the permanent disposal of spent nuclear fuel, and it charges APS \$0.001 per kWh of nuclear generation. See Note 11 for information about spent nuclear fuel disposal and Note 12 for information on nuclear decommissioning costs.

Income Taxes

Income taxes are provided using the asset and liability approach prescribed by SFAS No. 109, "Accounting for 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 first-tier 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 original 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. All regulatory asset amortization is included in depreciation and amortization expense in the Consolidated Statements of Income.

Real Estate Investments

Real estate investments primarily include SunCor's land, home inventory and investments in joint ventures. Land includes acquisition costs, infrastructure costs, property taxes and capitalized interest directly associated with the acquisition and development of each project. Land under development and land held for future development are stated at accumulated cost, except to the extent that such land is believed to be impaired, it is written down to fair value. Land held for sale is stated at the lower of accumulated cost or estimated fair value less costs to sell. Home inventory consists of construction costs, improved lot costs, capitalized interest and property taxes on homes under construction. Home inventory is stated at the lower of accumulated cost or estimated fair value less costs to sell. Investments in joint ventures for which SunCor does not have a controlling financial interest are not consolidated but are accounted for using the equity method of accounting.

Stock-Based Compensation

In 2002, we began applying the fair value method of accounting for stock-based compensation, as provided for in SFAS No. 123, "Accounting for Stock-Based Compensation." The fair value method of accounting is the preferred method. In accordance with the transition requirements of SFAS No. 123, we applied the fair value method prospectively, beginning with 2002 stock grants. In prior years, we recognized stock compensation expense based on the intrinsic value method allowed in Accounting Principles Board Opinion (APB) No. 25, "Accounting for Stock Issued to Employees."

The following chart compares our net income, stock compensation expense and earnings per share to what those items would have been if we had recorded stock compensation expense based on the fair value method for all stock grants through 2002 (dollars in thousands, except per share amounts):

	2002	2001	2000
Net Income:			
As reported	\$ 149,408	\$ 312,166	\$ 302,332
Pro forma (fair value method)	148,013	309,874	301,102
Stock compensation expense (net of tax):			
As reported	300	-	-
Pro forma (fair value method)	1,395	2,292	1,230
Earnings per share – basic:			
As reported	\$ 1.76	\$ 3.68	\$ 3.57
Pro forma (fair value method)	\$ 1.74	\$ 3.66	\$ 3.55
Earnings per share – diluted:			
As reported	\$ 1.76	\$ 3.68	\$ 3.56
Pro forma (fair value method)	\$ 1.74	\$ 3.65	\$ 3.55

In order to calculate the fair value of the 2002 stock option grants and 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:

	2002	2001	2000
Risk-free interest rate	4.17%	4.08%	5.81%
Dividend yield	4.17%	3.70%	3.48%
Volatility	22.59%	27.66%	32.00%
Expected life (months)	60	60	60

See Note 16 for further discussion about our stock compensation plans.

2. ACCOUNTING MATTERS

On January 1, 2003 we adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." The standard requires the fair value of asset retirement obligations to be recorded as a liability, along with an offsetting plant asset, when the obligation is incurred. Accretion of the liability due to the passage of time will be an operating expense and the capitalized cost is depreciated over the useful life of the long-lived asset. See Note 1 for more information regarding our previous accounting for removal costs.

We determined that we have asset retirement obligations for our nuclear facilities (nuclear decommissioning) and certain other fossil generation, transmission and distribution assets. On January 1, 2003 we recorded a liability of \$219 million for our asset retirement obligations including the accretion impacts; a \$67 million increase in the carrying amount of the associated assets; and a net reduction of \$192 million in accumulated depreciation related primarily to the reversal of previously recorded accumulated decommissioning and other removal costs related to these obligations. Additionally, we recorded a net regulatory liability of \$40 million for our asset retirement obligations related to our regulated utility. This regulatory liability represents the difference between the amount currently being recovered in regulated rates and the amount calculated under SFAS No. 143. We believe we can recover in regulated rates the transition costs and ongoing current period costs calculated in accordance with SFAS No. 143.

In November 2002, the EITF reached a consensus on EITF 00-21, "Revenue Arrangements with Multiple Deliverables." EITF 00-21 addresses certain aspects of the accounting by a vendor for arrangements under which it will perform multiple revenue-generating activities. EITF 00-21 specifically addresses how to determine whether an arrangement has identifiable, separable revenue-generating activities. EITF 00-21 does not address when the criteria for revenue recognition are met or provide guidance on the appropriate revenue recognition convention. EITF 00-21 is effective for revenue arrangements entered into after July 1, 2003. We are currently evaluating the impacts of this new guidance, but we do not believe it will have a material impact on our financial statements.

On January 1, 2002, we adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." This statement supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of," and the accounting and reporting provisions for the disposal of a segment of a business. This standard did not impact our financial statements at adoption. For each of the years 2002, 2001 and 2000, items requiring discontinued operations reporting were immaterial.

In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB Statements Nos. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections" which, among other things, supersedes previous guidance for reporting gains and losses from extinguishment of debt. This standard did not impact our financial statements at adoption.

In July 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." The standard requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan. The guidance will be applied to exit or disposal activities initiated after December 31, 2002. This standard did not impact our financial statements at adoption.

In 2001, the American Institute of Certified Public Accountants (AICPA) issued an exposure draft of a proposed Statement of Position (SOP), "Accounting for Certain Costs Related to Property, Plant, and Equipment." This proposed SOP would create a project timeline framework for capitalizing costs related to property, plant and equipment construction. It would require that property, plant and equipment assets be accounted for at the component level and require administrative and general costs incurred in support of capital projects to be expensed in the current period. In November 2002, the AICPA announced they would no longer issue general purpose SOPs. The work they have performed on the proposed SOP will be transitioned to the FASB staff. In February 2003, the FASB determined that the AICPA should continue their deliberations on certain aspects of the proposed SOP. We are waiting for further guidance from the FASB staff and the AICPA on the timing of the final guidance.

See the following Notes for other new accounting standards:

- Notes 1 and 16 for a new accounting standard (SFAS No. 148) related to stock-based compensation;
- Note 18 for a new EITF issue (EITF 02-3) related to accounting for energy trading contracts;
- Note 20 for a new interpretation (FIN No. 46) related to VIEs;
- Note 21 for a new standard (SFAS No. 142) related to goodwill and intangible assets; and
- Note 23 for a new interpretation (FIN No. 45) on guarantees.

3. REGULATORY MATTERS

Electric Industry Restructuring

STATE

Overview On September 21, 1999, the ACC approved Rules that provide a framework for the introduction of retail electric competition in Arizona. On September 23, 1999, the ACC approved a comprehensive settlement agreement among APS and various parties related to the implementation of retail electric competition in Arizona. Under the Rules, as modified by the 1999 Settlement Agreement, APS was required to transfer all of its competitive electric assets and services to an unaffiliated party or parties or to a separate corporate affiliate or affiliates no later than December 31, 2002. Consistent with that requirement, APS had been addressing the legal and regulatory requirements necessary to complete the transfer of its generation assets to Pinnacle West Energy on or before that date. On September 10, 2002, the ACC issued the Track A Order, which, among other things, directed APS not to transfer its generation assets to Pinnacle West Energy. See "Track A Order" below.

On September 16, 2002, APS filed an application with the ACC requesting the ACC to allow APS to borrow up to \$500 million and to lend the proceeds to Pinnacle West Energy or to the Company; to guarantee up to \$500 million of Pinnacle West Energy's or the Company's debt; or a combination of both, not to exceed \$500 million in the aggregate. In its application, APS stated that the ACC's reversal of the generation asset transfer requirement and the resulting bifurcation of generation assets between APS and Pinnacle West Energy under different regulatory regimes result in Pinnacle West Energy being unable to attain investment-grade credit ratings. This, in turn, precludes Pinnacle West Energy from accessing capital markets to refinance the bridge financing provided by the Company to fund the construction of Pinnacle West Energy generation assets or from effectively competing in the wholesale markets. On March 27, 2003, the ACC authorized APS to lend up to \$500 million to Pinnacle West Energy, guarantee up to \$500 million of Pinnacle West Energy debt, or a combination of both, not to exceed \$500 million in the aggregate. See "ACC Applications" below.

Competitive Procurement Process On September 10, 2002, the ACC issued an order that, among other things, established a requirement that APS competitively procure certain power requirements. On March 14, 2003, the ACC issued the Track B Order which documented the decision made by the ACC at its open meeting on February 27, 2003, addressing this requirement. Under the order, APS will be required to solicit bids for certain estimated capacity and energy requirements for periods beginning July 1, 2003. For 2003, APS will be required to solicit competitive bids for about 2,500 megawatts of capacity and about 4,600 gigawatt-hours of energy, or approximately 20% of APS' total retail energy requirements. The bid amounts are expected to increase in 2004 and 2005 based largely on growth in APS' retail load and APS' retail energy sales. The Track B Order also confirmed that it was "not intended to change the current rate base status of [APS'] existing assets." The order recognizes APS' right to reject any bids that are unreasonable, uneconomical or unreliable.

APS expects to issue requests for proposals in March 2003 and to complete the selection process by June 1, 2003. Pinnacle West Energy will be eligible to bid to supply APS' electricity requirements. See "Track B Order" below.

These regulatory developments and legal challenges to the Rules have raised considerable uncertainty about the status and pace of retail electric competition in Arizona. These matters are discussed in more detail below.

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

- 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 electricity price reductions of 1.5% on July 1 for each of the years 1999 to 2003 for a total of 7.5%. Based on the price reductions authorized in the 1999 Settlement Agreement, there were retail price decreases of approximately \$24 million (\$14 million after taxes), effective July 1, 1999; approximately \$28 million (\$17 million after taxes), effective July 1, 2000; approximately \$27 million (\$16 million after taxes), effective July 1, 2001; and approximately \$28 million (\$17 million after taxes), effective July 1, 2002. The final price reduction is to be implemented July 1, 2003. For customers having loads of three MW or greater, standard-offer rates have been 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; material changes in APS' cost of service for ACC-regulated services resulting from federal, tribal, state or local laws; regulatory requirements; or judicial decisions, actions or orders.
- APS will be permitted to defer for later recovery prudent and reasonable costs of complying with the Rules, system benefits costs in excess of the levels included in then-current (1999) 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 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. The regulatory developments and legal challenges to the Rules discussed in this note have raised considerable uncertainty about the status and pace of electric competition in Arizona. Although some very limited retail competition existed in APS' service area in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to APS' customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter APS' service territory.

- Prior to the 1999 Settlement Agreement, APS was recovering substantially all of its regulatory assets through July 1, 2004, pursuant to a 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 (in 1999 dollars). APS will not be allowed to recover \$183 million net present value (in 1999 dollars) of the above amounts. The 1999 Settlement Agreement provides that APS will have the opportunity to recover \$350 million net present value (in 1999 dollars) through a competitive transition charge that will remain in effect through December 31, 2004, at which time it will terminate. The costs subject to recovery under the adjustment clause described above will be decreased or increased by any over/under-recovery due to sales volume variances.
- APS will form, or cause to be formed, a separate corporate affiliate or affiliates and transfer to such affiliate(s) its competitive electric assets and services at book value as of the date of transfer, and will complete the transfers no later than December 31, 2002. APS will be allowed to defer and later collect, beginning July 1, 2004, 67% of its costs to accomplish the required transfer of generation assets to an affiliate. However, as noted above and discussed in greater detail below, in 2002 the ACC unilaterally modified this aspect of the 1999 Settlement Agreement by issuing an order preventing APS from transferring its generation assets.

Retail Electric Competition Rules The Rules approved by the ACC included the following major provisions:

- They apply to virtually all Arizona electric utilities regulated by the ACC, including APS.
- Effective January 1, 2001, retail access became available to all APS retail electricity customers.
- Electric service providers that get CC&N's 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 noncompetitive 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

electric assets and services to an unaffiliated party or parties or to a separate corporate affiliate or affiliates. Under the 1999 Settlement Agreement, APS received a waiver to allow transfer of its competitive electric assets and services to affiliates no later than December 31, 2002. However, as noted above and discussed in greater detail below, in 2002 the ACC reversed its decision, as reflected in the Rules, to require APS to transfer its generation assets.

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 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, to operate 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 Arizona Court of Appeals, as a result of which the Superior Court's ruling is automatically stayed pending further judicial review. That appeal is still pending. In a similar appeal concerning the issuance of competitive telecommunications CC&N's, the Arizona Court of Appeals invalidated rates for competitive carriers due to the ACC's failure to establish a fair value rate base for such carriers. That decision was upheld by the Arizona Supreme Court.

Provider of Last Resort Obligation Although the Rules allow retail customers to have access to competitive providers of energy and energy services, APS is the "provider of last resort" for standard-offer, full-service customers under rates that have been approved by the ACC. These rates are established until at least July 1, 2004. The 1999 Settlement Agreement allows APS to seek adjustment of these rates in the event of emergency conditions or circumstances, such as the inability to secure financing on reasonable terms; material changes in APS' cost of service for ACC-regulated services resulting from federal, tribal, state or local laws; regulatory requirements; or judicial decisions, actions or orders. Energy prices in the western wholesale market vary and, during the course of the last two years, have been volatile. At various times, prices in the spot wholesale market have significantly exceeded the amount included in APS' current retail rates. In the event of shortfalls due to unforeseen increases in load demand or generation or transmission outages, APS may need to purchase additional supplemental power in the wholesale spot market. Unless APS is able to

obtain an adjustment of its rates under the emergency provisions of the 1999 Settlement Agreement, there can be no assurance that APS would be able to fully recover the costs of this power.

Generic Docket In January 2002, the ACC opened a “generic” docket to “determine if changed circumstances require the [ACC] to take another look at electric restructuring in Arizona.” In February 2002, the ACC docket relating to APS’ October 2001 filing was consolidated with several other pending ACC dockets, including the generic docket. On May 2, 2002, the ACC issued a procedural order stating that hearings would begin on June 17, 2002 on various issues, including APS’ planned divestiture of generation assets to Pinnacle West Energy and associated market and affiliate issues. The procedural order also stated that consideration of the competitive bidding process required by the Rules would proceed concurrently with the Track A issues.

Track A Order On September 10, 2002, the ACC issued the Track A Order, which documents decisions made by the ACC at an open meeting on August 27, 2002. The major provisions of the Track A Order include, among other things:

Provisions related to the reversal of the generation asset transfer requirement:

- The ACC reversed its decision, as reflected in the Rules, to require APS to transfer its generation assets either to an unrelated third party or to a separate corporate affiliate; and
- the ACC unilaterally modified the 1999 Settlement Agreement, which authorized APS’ transfer of its generating assets, and directed APS to cancel its activities to transfer its generation assets to Pinnacle West Energy.

Provisions related to the wholesale competitive energy procurement process (Track B issues):

- The ACC stayed indefinitely the requirement of the Rules that APS acquire 100% of its energy needs for its standard offer customers from the competitive market, with at least 50% obtained through a competitive bid process;
- the ACC established a requirement that APS competitively procure, at a minimum, any required power that it cannot produce from its existing assets in accordance with the ultimate outcome of the Track B proceedings;
- the ACC directed the parties to develop a competitive procurement (“bidding”) process that can begin by March 1, 2003; and
- the ACC stated that “the [Pinnacle West Energy] generating assets that APS may acquire from [Pinnacle West Energy] shall not be counted as APS assets in determining the amount, timing and manner of the competitive solicitation” for Track B purposes, thereby bifurcating the regulatory treatment of the existing APS assets and the Pinnacle West Energy assets.

On November 15, 2002, APS filed appeals of the Track A Order in the Maricopa County, Arizona Superior Court and in the Arizona Court of Appeals. *Arizona Public Service Company vs. Arizona Corporation Commission*, CV 2002-0222 32. *Arizona Public Service Company vs.*

Arizona Corporation Commission, 1CA CC 02-0002. On December 13, 2002, APS and the ACC staff agreed to principles for resolving certain issues raised by APS in its appeals of the Track A Order. APS and the ACC are the only parties to the Track A Order appeals. The major provisions of this document include, among other things, the following:

- The parties agreed that it would be appropriate for the ACC to consider the following matters in APS’ upcoming general rate case, anticipated to be filed before June 30, 2003:
 - the generating assets to be included in APS’ rate base, including the question of whether certain power plants currently owned by Pinnacle West Energy (specifically, Redhawk Units 1 and 2, West Phoenix Units 4 and 5, and Saguaro Unit 3) should be included in APS’ rate base;
 - the appropriate treatment of the \$234 million pretax asset write-off agreed to by APS as part of a 1999 settlement agreement approved by the ACC among APS and various parties related to the implementation of retail competition in Arizona; and
 - the appropriate treatment of costs incurred by APS in preparation for the previously anticipated transfer of generation assets to Pinnacle West Energy.
- Upon the ACC’s issuance of a final decision that is no longer subject to appeal approving the Financing Application, with appropriate conditions, APS’ appeals of the Track A Order would be limited to the issues described in the preceding bullet points, each of which would be presented to the ACC for consideration prior to any final judicial resolution.

On February 21, 2003, a Notice of Claim was filed with the ACC and the Arizona Attorney General on behalf of APS, Pinnacle West and Pinnacle West Energy to preserve their and our rights relating to the Track A Order.

Track B Order The ACC Staff has conducted workshops on the Track B issues with various parties to determine and define the appropriate process to be used for competitive power procurement. On September 10, 2002, the ACC issued an order that, among other things, established a requirement that APS competitively procure certain power requirements. On March 14, 2003, the ACC issued the Track B Order which documented the decision made by the ACC at its open meeting on February 27, 2003 addressing this requirement. The order adopted most of the provisions of an ACC ALJ’s recommendation that was issued on January 30, 2003. Under the ACC’s Track B Order, APS will be required to solicit bids for certain estimated capacity and energy requirements for periods beginning July 1, 2003. For 2003, APS will be required to solicit competitive bids for about 2,500 megawatts of capacity and about 4,600 gigawatt-hours of energy, or approximately 20% of APS’ total retail energy requirements. The bid amounts are expected to increase in 2004 and 2005 based largely on growth in APS’ retail load and APS’ retail energy sales. The Track B Order also confirmed that it was “not intended to change the current rate base status of [APS’] existing assets.”

The order recognizes APS' right to reject any bids that are unreasonable, uneconomical or unreliable. The Track B procurement process will involve the ACC Staff and an independent monitor. The Track B Order also contains requirements relating to standards of conduct between APS and any affiliate of APS that may participate in the competitive solicitation, requires that APS treat bidders in a non-discriminatory manner and requires APS to file a protocol regarding short-term and emergency procurements. The order permits the provision of corporate oversight, support and governance as long as such activities do not favor Pinnacle West Energy in the procurement process or provide Pinnacle West Energy with confidential APS bidding information that is not available to other bidders. The order directs APS to evaluate bids on cost, reliability and reasonableness. The decision requires bidders to allow the ACC to inspect their plants and requires assurances of appropriate competitive market conduct from senior officers of such bidders. Following the solicitation, APS will prepare a report evaluating environmental issues relating to the procurement and a series of workshops on environmental risk management will be commenced thereafter.

APS expects to issue requests for proposals in March 2003 and to complete the selection process by June 1, 2003. Pinnacle West Energy will be eligible to bid to supply APS' electricity requirements.

ACC Applications

On September 16, 2002, APS filed a Financing Application requesting the ACC to allow APS to borrow up to \$500 million and to lend the proceeds to Pinnacle West Energy or the Company; to guarantee up to \$500 million of Pinnacle West Energy's or the Company's debt; or a combination of both, not to exceed \$500 million in the aggregate. The loan and/or the guarantee would be used to refinance debt incurred to fund the construction of Pinnacle West Energy generation assets.

The Financing Application addressed, among other things, the following matters:

- APS noted that its April 19, 2002 filing with the ACC had sought unification of "[Pinnacle West Energy] Assets" (West Phoenix Units 4 and 5, Redhawk Units 1 and 2 and Saguaro Unit 3) and APS generation assets under a common financial and regulatory regime. APS further noted that the Track A Order's language regarding the treatment of the Pinnacle West Energy Assets for Track B purposes appears to postpone a decision regarding the inclusion of the Pinnacle West Energy Assets in APS' rate base, thereby effectively precluding the consolidation of the Pinnacle West Energy Assets at APS under a common financial and regulatory regime at the present time.
- APS stated that it did not intend or desire to foreclose the possibility that it would acquire all or part of the Pinnacle West Energy Assets or that it may propose that the Pinnacle West Energy Assets be included in APS' rate base or afforded cost-of-service regulatory treatment to the extent the Pinnacle West Energy Assets are used by APS customers. APS stated that these issues would be appropriate topics in APS' 2003 general rate case and noted that the Track A Order specifi-

cally stated that the ACC would not pre-judge the eventual rate treatment of the Pinnacle West Energy Assets.

- APS stated that the Track A Order's reversal of the generation asset transfer requirement and the resulting bifurcation of generation assets between APS and Pinnacle West Energy under different regulatory regimes result in Pinnacle West Energy being unable to attain investment-grade credit ratings. This, in turn, precludes Pinnacle West Energy from accessing capital markets to refinance the bridge financing provided by the Company to fund the construction of the Pinnacle West Energy Assets or from effectively competing in the wholesale markets. APS noted that Pinnacle West Energy had previously received investment-grade credit ratings contingent upon its receipt of APS generation assets and that the Company's credit ratings could be adversely affected if Pinnacle West Energy is unable to finance its capital requirements. On November 4, 2002, Standard & Poor's lowered the Company's senior unsecured debt rating from "BBB" to "BBB-."
- APS stated that the amount of the requested loan and/or guarantee is APS' present estimate of the amount of credit support necessary through APS to restore Pinnacle West Energy and the Company to their credit status prior to the ACC's issuance of the Track A Order. APS further stated that if the requested amount proves to be inadequate, APS reserves the right to submit a second financing application seeking additional credit support.

On March 27, 2003, the ACC approved the Financing Application, subject to the following principal conditions:

- any debt issued by APS pursuant to the order must be unsecured;
- APS will be permitted to loan up to \$500 million to Pinnacle West Energy (the "APS Loan"), guarantee up to \$500 million of Pinnacle West Energy debt, or a combination of both, not to exceed \$500 million in the aggregate;
- the APS Loan must be callable and secured by certain Pinnacle West Energy assets;
- the APS Loan must bear interest at a rate equal to 264 basis points above the interest rate on APS debt that could be issued and sold on equivalent terms (including, but not limited to, maturity and security);
- the 264 basis points referred to in the previous bullet point will be capitalized as a deferred credit and used to offset retail rates in the future, with the deferred credit balance bearing an interest rate of six percent per annum;
- the APS Loan must have a maturity date of not more than four years, unless otherwise ordered by the ACC;
- any demonstrable increase in APS' cost of capital as a result of the transaction (such as from a decline in bond rating) will be excluded from future rate cases;
- APS must maintain a common equity ratio of at least forty percent and may not pay common dividends if such payment would reduce its common equity below that threshold, unless otherwise waived by the ACC. The ACC will process any waiver request within sixty days, and for this

sixty-day period this condition will be suspended. However, this condition, which will continue indefinitely, will not be permanently waived without an order of the ACC; and

certain waivers of the ACC's affiliated interest rules previously granted to APS and its affiliates will be withdrawn and, during the term of the APS Loan, neither Pinnacle West nor Pinnacle West Energy may reorganize or restructure, acquire or divest assets, or form, buy or sell affiliates (each a "Covered Transaction"), or pledge or otherwise encumber the Pinnacle West Energy assets without prior ACC approval, except that the foregoing restrictions will not apply to the following categories of Covered Transactions:

- Covered Transactions less than \$100 million, measured on a cumulative basis over the calendar year in which the Covered Transactions are made;
- Covered Transactions by SunCor of less than \$300 million through 2005, consistent with SunCor's anticipated accelerated asset sales activity during those years;
- Covered Transactions related to the payment of ongoing construction costs for Pinnacle West Energy's (a) West Phoenix Unit 5, located in Phoenix, with an expected commercial operation date in mid-2003, and (b) Silverhawk plant, located near Las Vegas, with an expected commercial operation date in mid-2004; and
- Covered Transactions related to the sale of 25% of the Silverhawk plant to SNWA if SNWA exercises its existing purchase option to do so.

The ACC also ordered the ACC staff to conduct an inquiry into our and our affiliates' compliance with the retail electric competition and related rules and decisions.

In mid-2003, the Company will need to refinance approximately \$475 million of parent company indebtedness. We expect that this indebtedness will be repaid through funds borrowed by Pinnacle West Energy from APS under the APS Loan.

On November 22, 2002, the ACC approved APS' request to permit APS to (a) make short-term advances to Pinnacle West in the form of an inter-affiliate line of credit in the amount of \$125 million, or (b) guarantee \$125 million of Pinnacle West's short-term debt, subject to certain conditions. See Note 5.

Federal

In July 2002, the FERC adopted a price mitigation plan that constrains the price of electricity in the wholesale spot electricity market in the western United States. The FERC has adopted a price cap of \$250 per MWh for the period subsequent to October 31, 2002. Sales at prices above the cap must be justified and are subject to potential refund.

On July 31, 2002, the FERC issued a Notice of Proposed Rulemaking for Standard Market Design for wholesale electric markets. Voluminous comments and reply comments were filed on virtually every aspect of the proposed rule, and the FERC has announced that it will issue an additional white paper on the proposed Standard Market Design in April

2003. We are reviewing the proposed rulemaking and cannot currently predict what, if any, impact there may be to the Company if the FERC adopts the proposed rule or any modifications proposed in the comments.

General

The regulatory developments and legal challenges to the Rules discussed in this Note have raised considerable uncertainty about the status and pace of retail electric competition in Arizona. Although some very limited retail competition existed in APS' service area in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to APS' customers.

As a result, we cannot predict when, and the extent to which, additional competitors will re-enter APS' service territory. 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.

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 Sheets 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 ACC settlement agreements, APS is continuing to accelerate amortization of a regulatory asset related to income taxes over an eight-year period that will end June 30, 2004 (see Note 1). Accordingly, we are including this accelerated amortization in depreciation and amortization expense on our Consolidated Statements of Income.

As a result of a change in IRS guidance, we claimed a tax deduction related to an APS tax accounting method change on the 2001 federal consolidated income tax return. The accelerated deduction has resulted in a \$200 million reduction in the current income tax liability and a corresponding increase in the plant-related deferred tax liability. In 2002, we received an income tax refund of approximately \$115 million related to our 2001 federal consolidated income tax return.

The components of income tax expense for income before accounting change are (dollars in thousands):

year ended December 31,	2002	2001	2000
Current:			
Federal	\$ (43,492)	\$ 184,893	\$ 189,779
State	(14,732)	45,845	42,306
Total current	(58,224)	230,738	232,085
Deferred	196,324	(17,203)	(37,885)
Total income tax expense	\$ 138,100	\$ 213,535	\$ 194,200

The following chart compares pretax income at the 35% federal income tax rate to income tax expense (dollars in thousands):

year ended December 31,	2002	2001	2000
Federal income tax expense at 35% statutory rate	\$ 123,639	\$ 189,316	\$ 173,786
Increases (reductions) in tax expense resulting from:			
State income tax net of federal income tax benefit	16,478	23,353	19,848
Other	(2,017)	866	566
Income tax expense	\$ 138,100	\$ 213,535	\$ 194,200

The following table sets forth the net deferred income tax liability recognized on the Consolidated Balance Sheets at December 31, 2002 and 2001 (dollars in thousands):

December 31,	2002	2001
Current asset/(liability)	\$ 4,094	\$ (3,244)
Long term liability	(1,209,074)	(1,064,993)
Accumulated deferred income taxes – net	\$ (1,204,980)	\$(1,068,237)

The components of the net deferred income tax liability were as follows (dollars in thousands):

December 31,	2002	2001
DEFERRED TAX ASSETS		
Pension liability	\$ 72,835	\$ 19,422
Risk management and trading activities	43,542	73,043
Deferred gain on Palo Verde Unit 2 sale-leaseback	23,562	25,374
Other	99,054	90,580
Total deferred tax assets	238,993	208,419
DEFERRED TAX LIABILITIES		
Plant-related	(1,316,636)	(1,069,207)
Regulatory asset for income taxes	(80,635)	(121,757)
Risk management and trading activities	(46,702)	(85,692)
Total deferred tax liabilities	(1,443,973)	(1,276,656)
Accumulated deferred income taxes – net	\$ (1,204,980)	\$(1,068,237)

5. LINES OF CREDIT AND SHORT-TERM BORROWINGS

APS had committed lines of credit with various banks of \$250 million at December 31, 2002 and 2001, which were available either to support the issuance of commercial paper or to be used for bank borrowings. These lines of credit mature in June 2003. The commitment fees at December 31, 2002 and 2001 for these lines of credit were 0.09% per annum. APS had no bank borrowings outstanding under these lines of credit at December 31, 2002 and 2001.

APS had no commercial paper borrowings outstanding at December 31, 2002 and \$171 million at December 31, 2001. The weighted average interest rate on commercial paper borrowings was 2.47% for the year ended December 31, 2002 and 4.72% for the year ended December 31, 2001. By Arizona statute, APS' short-term borrowings cannot exceed 7% of its total capitalization unless approved by the ACC.

Pinnacle West had committed lines of credit of \$475 million at December 31, 2002 and \$250 million at December 31, 2001, which were available either to support the issuance of commercial paper or to be used for bank borrowings. Outstanding amounts at December 31, 2002 were \$72 million, and there were no short-term bank borrowings outstanding at December 31, 2001. The commitment fees ranged from 0.10% to 0.15% in 2002 and 2001. Pinnacle West commercial paper borrowings outstanding were \$24 million at December 31, 2002 and \$235 million at December 31, 2001. The weighted average interest rate on commercial paper borrowings was 2.06% for the year ended December 31, 2002 and 3.50% for the year ended December 31, 2001.

On July 31, 2002, Pinnacle West completed a \$300 million bank credit facility, which was subsequently reduced to \$225 million by applying \$75 million of the proceeds from the equity offering in December 2002 (see Note 7). The borrowings are LIBOR-based, can be drawn upon as needed and are expected to be used primarily to fund Pinnacle West Energy capital requirements. The facility matures in July 2003. The majority of these borrowings were used to fund Pinnacle West Energy capital expenditures. At December 31, 2002, Pinnacle West had borrowed \$67 million under the credit facility.

On November 22, 2002, the ACC approved APS' request to permit APS to (a) make short-term advances to Pinnacle West in the form of an inter-affiliate line of credit in the amount of \$125 million, or (b) guarantee \$125 million of Pinnacle West's short-term debt, subject to certain conditions. This interim loan matures in December 2003. There have been no borrowings on this line.

SunCor had revolving lines of credit totaling \$140 million at December 31, 2002 and 2001. The commitment fees were 0.125% in 2002 and 2001. SunCor had \$126 million outstanding at December 31, 2002 and \$128 million outstanding at December 31, 2001. The balance is included in long-term debt on the Consolidated Balance Sheets (see Note 6). SunCor had short-term loans in the amount of \$6 million at December 31, 2002 and no short-term loans outstanding at December 31, 2001.

6. LONG-TERM DEBT

Borrowings under the APS mortgage bond indenture are secured by substantially all utility plant. APS also has unsecured debt. SunCor's debt is collateralized by interests in certain real property and Pinnacle West's debt is unsecured. The following table presents the components of long-term debt on the Consolidated Balance Sheets outstanding at December 31, 2002 and 2001 (dollars in thousands):

	December 31, 2001
	\$ 125,000
	80,000
	54,150
	121,668
	33,075
	25,000
	154,000
	(5,266)
	386,860
	90,000
	-
	125,000
	100,000
	300,000
	400,000
	-
	83,695
	1,343
	<u>2,074,525</u>
	128,000
	7,912
	5,215
	7,500
	-
	<u>148,627</u>
	325,000
	-
	250,000
	1,066
	<u>576,066</u>
	-
	-
	-
	<u>2,799,218</u>
	126,140
	<u>\$ 2,673,078</u>

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

(b) On March 15, 2002, APS redeemed at maturity \$125 million of its First Mortgage Bonds, 8.125% Series due 2002.

(c) On April 15, 2002, APS redeemed \$122 million of its First Mortgage Bonds, 8.75% Series due 2024.

(d) The weighted-average rate was 1.94% at December 31, 2002 and 2.55% at December 31, 2001. Changes in short-term interest rates would affect the costs associated with this debt.

(e) In November 2001, these bonds were converted to a one-year fixed rate of 3.30%. These bonds were previously adjustable rate and, from January 1, 2001 until October 31, 2001, the weighted average rate was 2.72%.

(f) On November 1, 2002, Maricopa County, Arizona Pollution Control Corporation issued \$90 million of 5.05% Pollution Control Revenue Refunding Bonds (Arizona Public Service Company Palo Verde Project) 2002 Series A, due 2029, and loaned the proceeds to APS pursuant to a loan agreement. The bonds were issued to refinance \$90 million of outstanding pollution control bonds. The bondholders were issued \$90 million of first mortgage bonds (senior note mortgage bonds) as collateral.

- (g) 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, as well as the \$90 million issue discussed in footnote (f) above. 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.
- (h) The weighted-average rate was 3.75% at December 31, 2002 and was 5.31% at December 31, 2001. Interest for 2002 and 2001 was based on LIBOR plus 2% or prime plus 0.5%.
- (i) Multiple notes primarily with variable interest rates based mostly on the lenders' prime plus 1.75% and lenders' prime plus .25%.
- (j) Includes three series of notes: \$25 million at 6.87% due in 2003, \$300 million at 6.4% due in 2006 and \$215 million at 4.5% due in 2004 as of December 31, 2002.
- (k) The weighted average rate was 2.85% at December 31, 2002 and was 4.65% at December 31, 2001. Interest for 2002 and 2001 was based on LIBOR plus 0.98%.

Pinnacle West's and APS' significant debt covenants related to their respective financing arrangements include a debt-to-total-capitalization ratio and an interest coverage test. Pinnacle West and APS are in compliance with such covenants and each anticipates it will continue to meet all the significant covenant requirement levels. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants.

Neither Pinnacle West's nor APS' financing agreements contain "ratings triggers" that would result in an acceleration of the required interest and principal payments in the event of a ratings downgrade. However, in the event of a ratings downgrade, Pinnacle West and/or APS may be subject to increased interest costs under certain financing agreements.

All of Pinnacle West's bank agreements contain "cross-default" provisions under which a default by it or APS in a specified amount under another agreement would result in a default and the potential acceleration of payment under the agreements. All of APS' bank agreements contain cross-default provisions under which a default by APS in a specified amount under another agreement would result in a default and the potential acceleration of payment under the agreements.

Pinnacle West's and APS' credit agreements generally contain provisions under which the lenders could refuse to advance loans in the event of a material adverse change in the borrower's financial condition or financial prospects.

The following is a list of payments due on total long-term debt and capitalized lease requirements through 2007:

- \$281 million in 2003;
- \$552 million in 2004;
- \$405 million in 2005;
- \$390 million in 2006;
- \$3 million in 2007; and
- \$1,539 million, thereafter.

APS' first mortgage bondholders share a lien on substantially all utility plant assets (other than nuclear fuel and transportation equipment and other excluded assets). The mortgage bond indenture restricts the payment of common stock dividends under certain conditions. APS may pay dividends on its common stock if there is a sufficient amount "available" from retained earnings and the excess of cumulative book depreciation (since the mortgage's inception) over mortgage depreciation, which is the cumulative amount of additional property pledged each year to address collateral depreciation. As of December 31, 2002, the amount "available" under the mortgage would have allowed APS to pay approximately \$3 billion of dividends compared to APS' current annual common stock dividends of \$170 million.

7. COMMON STOCK AND TREASURY STOCK

Our common stock and treasury stock activity during each of the three years 2002, 2001 and 2000 is as follows (dollars in thousands, except shares):

	Common Stock Shares	Common Stock Amount	Treasury Stock Shares	Treasury Stock Amount
Balance at December 31, 1999	84,824,947	\$ 1,540,197	(74,844)	\$ (2,748)
Purchase of treasury stock			(300,800)	(12,968)
Reissuance of treasury stock for stock compensation (net)			266,006	10,627
Other		(2,277)		
Balance at December 31, 2000	84,824,947	1,537,920	(109,638)	(5,089)
Purchase of treasury stock			(334,600)	(16,393)
Reissuance of treasury stock for stock compensation (net)			342,931	15,596
Other		(996)		
Balance at December 31, 2001	84,824,947	1,536,924	(101,307)	(5,886)
Common stock issuance – December 23, 2002	6,555,000	199,238		
Purchase of treasury stock			(150,500)	(5,971)
Reissuance of treasury stock for stock compensation (net)			126,977	7,499
Other		1,096		
Balance at December 31, 2002	91,379,947	\$ 1,737,258	(124,830)	\$ (4,358)

8. RETIREMENT PLANS AND OTHER BENEFITS

Pension Plans

Pinnacle West sponsors a qualified defined benefit pension plan and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and our subsidiaries. Effective January 1, 2003, Pinnacle West sponsored a new account balance pension plan for all new employees in place of the defined benefit plan and, effective April 1, 2003, the new plan will be offered as an alternative to the defined benefit plan for all existing employees. A defined benefit plan specifies the amount of benefits a plan participant is to receive using information about the participant. The pension plan covers nearly all of our employees. The supplemental excess benefit plan covers officers of the company and highly compensated employees designated for participation by the Board of Directors. Our employees do not contribute to the plans. Generally, we calculate the benefits based on age, years of service and pay. We fund the qualified plan by contributing at least the minimum amount required under IRS regulations but no more than the maximum tax-deductible amount. The assets in the qualified plan at December 31, 2002 were mostly domestic common stocks and bonds and real estate.

Total pension expense, including administrative costs and after consideration of amounts capitalized or billed to electric plant participants, was:

- \$14 million in 2002;
- \$11 million in 2001; and
- \$6 million in 2000.

The following table shows the components of net periodic pension cost before consideration of amounts capitalized or billed to electric plant participants for the years ended December 31, 2002, 2001 and 2000 (dollars in thousands):

	2002	2001	2000
Service cost – benefits earned during the period	\$ 30,333	\$ 27,640	\$ 26,040
Interest cost on projected benefit obligation	71,242	66,549	61,625
Expected return on plan assets	(75,652)	(77,340)	(77,231)
Amortization of:			
Transition asset	(3,227)	(3,227)	(3,227)
Prior service cost	2,912	3,008	2,370
Net actuarial loss/(gain)	1,846	907	(1,190)
Net periodic pension cost	\$ 27,454	\$ 17,537	\$ 8,387

The following table shows a reconciliation of the funded status of the plans to the amounts recognized in the Consolidated Balance Sheets as of December 31, 2002 and 2001 (dollars in thousands):

	2002	2001
Funded status – pension plan assets		
less than projected benefit obligation	\$ (348,770)	\$ (166,773)
Unrecognized net transition asset	(10,327)	(13,554)
Unrecognized prior service cost	23,148	26,170
Unrecognized net actuarial losses	293,223	108,422
Accrued pension benefit liability recognized in the Consolidated Balance Sheets	\$ (42,726)	\$ (45,735)

The following table sets forth the defined benefit pension plans' change in projected benefit obligation for the plan years 2002 and 2001 (dollars in thousands):

	2002	2001
Projected pension benefit obligation at beginning of year	\$ 931,646	\$ 840,485
Service cost	30,333	27,640
Interest cost	71,242	66,549
Benefit payments	(35,230)	(33,282)
Actuarial losses	71,696	21,632
Plan amendments	(110)	8,622
Projected pension benefit obligation at end of year	\$1,069,577	\$ 931,646

The following table sets forth the qualified defined benefit pension plan's change in the fair value of plan assets for the plan years 2002 and 2001 (dollars in thousands):

	2002	2001
Fair value of pension plan assets at beginning of year	\$ 764,873	\$ 775,196
Actual loss on plan assets	(36,966)	(22,876)
Employer contributions	26,600	44,200
Benefit payments	(33,700)	(31,647)
Fair value of pension plan assets at end of year	\$ 720,807	\$ 764,873

The following table sets forth the defined benefit pension plans' amounts recognized in the Consolidated Balance Sheets at December 31, 2002 and 2001 (dollars in thousands):

	2002	2001
Accrued pension benefit liability	\$ (42,726)	\$ (45,735)
Additional minimum liability	(141,155)	(3,297)
Intangible asset	23,148	1,697
Accumulated other comprehensive loss – pretax	118,007	1,600

The following table shows the accumulated benefit obligation in relation to the fair value of plan assets for the plan years 2002 and 2001 (dollars in thousands):

	2002	2001
Projected benefit obligation	\$ 1,069,577	\$ 931,646
Accumulated benefit obligation	904,687	752,230
Fair value of plan assets	720,807	764,873

The following are weighted-average assumptions as of December 31, 2002 and 2001:

	2002	2001
Discount rate	6.75%	7.50%
Rate of increase in compensation levels	4.00%	4.00%
Expected long-term rate of return on assets	9.00%	10.00%

Employee Savings Plan Benefits

Pinnacle West sponsors a defined contribution savings plan for the employees of Pinnacle West and our subsidiaries. In a defined contribution savings plan, the benefits a participant will receive result from regular contributions they make to a participant account. Under this plan, we make matching contributions in Pinnacle West stock to participant accounts. After a five-year vesting period, participants have a choice to change the employer contribution match to other investments. At December 31, 2002, approximately 25% of total plan assets were in Pinnacle West stock. We recorded expenses for this plan of approximately \$5 million for 2002 and 2001 and \$4 million for 2000.

Other Postretirement Benefits

Pinnacle West sponsors other postretirement benefits for the employees of Pinnacle West and our subsidiaries. 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. 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 other postretirement benefit expense after consideration of amounts capitalized or billed to electric plant participants, was:

- \$12 million for 2002;
- \$6 million for 2001; and
- \$3 million for 2000.

The following table shows the components of net periodic other post-retirement benefit costs before consideration of amounts capitalized or billed to electric plant participants for the years ended December 31, 2002, 2001 and 2000 (dollars in thousands):

	2002	2001	2000
Service cost – benefits earned during the period	\$ 12,036	\$ 9,438	\$ 8,613
Interest cost on accumulated benefit obligation	25,235	21,585	19,315
Expected return on plan assets	(21,116)	(21,985)	(22,381)
Amortization of:			
Transition obligation	4,001	7,698	7,698
Prior service credit	(75)	–	–
Net actuarial loss/(gain)	3,072	(4,066)	(7,983)
Net periodic other post-retirement benefit cost	\$ 23,153	\$ 12,670	\$ 5,262

The following table shows a reconciliation of the funded status of the plan to the amounts recognized in the Consolidated Balance Sheets at December 31, 2002 and 2001 (dollars in thousands):

	2002	2001
Funded status – other postretirement plan assets less than accumulated other postretirement benefit obligation	\$ (186,400)	\$ (80,544)
Unrecognized net obligation at transition	36,489	84,748
Unrecognized prior service credit	(1,673)	–
Unrecognized net actuarial loss/(gain)	148,268	(8,606)
Net other postretirement benefit liability recognized in the Consolidated Balance Sheets	\$ (3,316)	\$ (4,402)

The following table sets forth the other postretirement benefit plan's change in accumulated postretirement benefit obligation for the plan years 2002 and 2001 (dollars in thousands):

	2002	2001
Accumulated other postretirement benefit obligation at beginning of year	\$ 318,355	\$ 264,006
Service cost	12,036	9,438
Interest cost	25,235	21,585
Benefit payments	(10,473)	(10,194)
Actuarial losses	108,979	33,520
Plan amendments	(44,258) (a)	–
Accumulated other postretirement benefit obligation at end of year	\$ 409,874	\$ 318,355

(a) The plan was amended January 1, 2002 to increase the deductibles, out-of-pocket maximums and prescription drug co-pays. The plan was amended in June 2002 to increase the participants' portion of premiums.

The following table sets forth the other postretirement benefit plan's change in the fair value of plan assets for the plan years 2002 and 2001 (dollars in thousands):

	2001
	\$ 249,154
	(12,550)
	11,400
	(10,194)
	\$ 237,810

The following are weighted-average assumptions as of December 31, 2002 and 2001:

	2001
	7.50%
	10.00%
	8.71%
	7.00%
	7.00%
	5.00%
	2006

The following table shows the effect of a 1% increase or decrease in the initial and ultimate health care expense and cost trend rate (dollars in millions):

	1% Increase	1% Decrease
Effect on the 2002 other postretirement benefit expense, after consideration of amounts capitalized or billed to electric plant participants	\$ 5	\$ (4)
Effect on the 2002 service and interest cost components of net periodic other postretirement benefit costs	7	(6)
Effect on the accumulated other postretirement benefit obligation at December 31, 2002	54	(43)

Severance Charges

In July 2002, we implemented a voluntary workforce reduction as part of our cost reduction program. We recorded \$36 million before taxes in voluntary severance costs in 2002. No further charges are expected.

9. 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 resulting from the transaction of approximately \$140 million was deferred and is being amortized to operations and maintenance 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, a regulatory asset is recognized for the difference between lease payments and rent expense calculated on a straight-line basis. See Note 20 for a discussion of VIEs, including the SPEs involved in the Palo Verde sale-leaseback transactions.

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

Total lease expense recognized in the Consolidated Statements of Income was \$62 million in 2002, \$56 million in 2001 and \$58 million in 2000.

The amounts to be paid for the Palo Verde Unit 2 leases are approximately \$49 million per year for the years 2003 to 2015.

In accordance with the 1999 Settlement Agreement and previous settlement agreements, 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). All regulatory asset amortization is included in depreciation and amortization expense in the Consolidated Statements of Income. The balance of this regulatory asset at December 31, 2002 was \$14 million.

Estimated future minimum lease payments for our operating leases are approximately as follows (dollars in millions):

Year	
2003	\$ 70
2004	66
2005	64
2006	63
2007	63
Thereafter	478
Total future lease commitments	\$ 804

10. 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 recorded on the Consolidated Balance Sheets at December 31, 2002. APS' share of operating and maintaining these facilities is included in the Consolidated Statements of Income in 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%	\$ 1,829,225	\$ (905,278)	\$ 17,428
Palo Verde Nuclear Generating Station Unit 2 (see Note 9)	17.0%	574,745	(289,049)	68,475
Four Corners Steam Generating Station Units 4 and 5	15.0%	153,559	(82,434)	500
Navajo Steam Generating Station Units 1, 2, and 3	14.0%	235,743	(110,923)	3,010
Cholla Steam Generating Station Common Facilities (a)	62.8%(b)	76,322	(42,608)	1,733
Transmission Facilities:				
ANPP 500KV System	35.8%(b)	68,314	(25,655)	31
Navajo Southern System	31.4%(b)	27,129	(17,405)	664
Palo Verde – Yuma 500KV System	23.9%(b)	9,591	(4,168)	383
Four Corners Switchyards	27.5%(b)	3,071	(1,979)	–
Phoenix – Mead System	17.1%(b)	36,418	(2,906)	–
Palo Verde – Estrella 500KV System	50.0%(b)	–	–	50,450

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

(b) Weighted average of interests.

11. COMMITMENTS AND CONTINGENCIES

Enron

We recorded charges totaling \$21 million before income taxes for exposure to Enron and its affiliates in the fourth quarter of 2001. This amount is comprised of a \$15 million reserve for the Company's net exposure to Enron and its affiliates and additional expenses of \$6 million primarily related to 2002 power contracts with Enron that were canceled. These charges take into consideration our rights of set-off with respect to the Enron related contractual obligations. The APS portion of the write-off was \$13 million. The basis of the set-offs included, but was not limited to, provisions in the various contractual arrangements with Enron and its affiliates, including an International Swaps and Derivative Agreement (ISDA) between APS and Enron North America. The write-off is also net of the expected recovery based on secondary market quotes from the bond market. The amounts were written-off from the balances of the related assets and liabilities from risk management and trading activities on the Consolidated Balance Sheets.

Palo Verde Nuclear Generating Station

Nuclear power plant operators are required to enter into spent fuel disposal contracts with the DOE, and the DOE is required to accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by domestic power reactors. Although the Nuclear Waste Act required the DOE to develop a permanent repository for the storage and disposal of spent nuclear fuel by 1998, the DOE has announced that the repository cannot be completed before 2010 and it does not intend to begin accepting spent nuclear 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 preventing the DOE from excusing its own delay, but refused to order the DOE to begin accepting spent nuclear fuel. Based on this decision and the DOE's delay, a number of utilities filed damages actions against the DOE in the Court of Federal Claims.

In February 2002, the Secretary of Energy recommended to President Bush that the Yucca Mountain, Nevada site be developed as a permanent repository for spent nuclear fuel. The President transmitted this recommendation to Congress and the State of Nevada vetoed the President's recommendation. Congress approved the Yucca Mountain site, overriding the Nevada veto. It is now expected that the DOE will submit a license application to the NRC in late 2004.

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 nuclear fuel. With the existing storage pools and the addition of the new facility, APS believes spent nuclear 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 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 it will incur \$115 million (in 2002 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, 2002, APS had spent \$2 million and recorded accumulated spent nuclear fuel amortization of \$44 million and a regulatory asset of \$46 million for on-site interim spent 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 (\$300 million effective January 1, 2003) 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 on APS' 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.

Purchased Power and Fuel Commitments

APS and Pinnacle West are parties to various purchased power and fuel contracts with terms expiring from 2003 through 2025 that include required purchase provisions. We estimate the contract requirements to be approximately \$173 million in 2003; \$82 million in 2004; \$28 million in 2005; \$31 million in 2006; \$17 million in 2007 and \$162 million there-

after. However, these amounts may vary significantly pursuant to certain provisions in such contracts that permit us to decrease required purchases under certain circumstances.

Of the various purchased power and fuel contracts mentioned above some of those contracts have take-or-pay provisions. The contracts APS has for the supply of its coal and nuclear fuel supply have take-or-pay provisions. The current take-or-pay nuclear fuel contracts expire in 2003 and had not been renewed as of December 31, 2002. The current take-or-pay coal contracts have terms that expire in 2007.

The following table summarizes the estimated take-or-pay commitments for the existing terms (dollars in millions):

Years ended December 31,	Estimated				
	2003	2004	2005	2006	2007
Coal	\$ 43	\$ 44	\$ 9	\$ 9	\$ 9
Nuclear Fuel	22	-	-	-	-
Total take-or-pay commitments (a)	\$ 65	\$ 44	\$ 9	\$ 9	\$ 9

(a) Total take-or-pay commitments are approximately \$136 million. The total net present value of these commitments is approximately \$119 million.

Coal Mine Reclamation Obligations

APS must reimburse certain coal providers for amounts incurred for coal mine reclamation. Our coal mine reclamation obligation is about \$59 million at December 31, 2002 and is included in deferred credits-other in the Consolidated Balance Sheets.

A regulatory asset has been established for amounts not yet recovered from ratepayers related to the coal obligations. 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 Consolidated Statements of Income.

California Energy Market Issues and Refunds in the Pacific Northwest

In July 2001, the FERC ordered an expedited fact-finding hearing to calculate refunds for spot market transactions in California during a specified time frame. This order calls for a hearing, with findings of fact due to the FERC after the ISO and PX provide necessary historical data. The FERC directed an ALJ to make findings of fact with respect to: (1) the mitigated price in each hour of the refund period; (2) the amount of refunds owed by each supplier according to the methodology established in the order; and (3) the amount currently owed to each supplier (with separate quantities due from each entity) by the CAISO, the California Power Exchange, the investor-owned utilities and the State of California.

APS was a seller and a purchaser in the California markets at issue, and to the extent that refunds are ordered, APS should be a recipient as well as a payor of such amounts. On December 12, 2002, the ALJ issued Proposed Findings of Fact with respect to the refunds. On March 26, 2003, the FERC adopted the great majority of the proposed findings, revising only the calculation of natural gas prices for the final determination of mitigated prices in the California markets. Sellers who may actually have paid more for natural gas than the proxy prices adopted by the FERC have 40 days in which to submit necessary data to the FERC, after which a technical conference will be held. Finalization of refund amounts is expected in mid-2003. APS does not anticipate material changes in its exposure and still believes, subject to the finalization of the revised proxy prices, that it will be entitled to a net refund.

On November 20, 2002, the FERC reopened discovery in these proceedings pursuant to instructions of the United States Court of Appeals for the Ninth Circuit that the FERC permit parties to offer additional evidence of potential market manipulation for the period January 1, 2000 through June 20, 2001. Parties have submitted additional evidence and proposed findings, which the FERC continues to consider.

The FERC also ordered an evidentiary proceeding to discuss and evaluate possible refunds for the Pacific Northwest. The FERC required that the record establish the volume of the transactions, the identification of the net sellers and net buyers, the price and terms and conditions of the sales contracts and the extent of potential refunds. On September 24, 2001, an ALJ concluded that prices in the Pacific Northwest during the period December 25, 2000 through June 20, 2001 were the result of a number of factors in addition to price signals from the California markets, including the shortage of supply, excess demand, drought and increased natural gas prices. Under these circumstances, the ALJ ultimately concluded that the prices in the Pacific Northwest were not unreasonable or unjust and refunds should not be ordered in this proceeding. The FERC is currently reviewing the ALJ's report and recommendations.

On December 19, 2002, the FERC opened a new discovery period to permit the parties to offer additional evidence for the period January 1, 2000 through June 20, 2001. Additional evidence has been submitted and a FERC decision on the newly submitted evidence is expected soon. Based on public comments from the FERC, it is anticipated that this case will be sent back to the ALJ for further proceedings on spot market and balance of month transactions.

Although the FERC has not yet made a final ruling in the Pacific Northwest matter nor calculated the specific refund amounts due in California, we do not expect that the resolution of these issues, as to the amounts alleged in the proceedings, will have a material adverse impact on our financial position, results of operations or liquidity.

On March 26, 2003, FERC made public a Final Report on Price Manipulation in Western Markets, prepared by its Staff and covering spot markets in the West in 2000 and 2001. The report stated that a significant number of entities who participated in the California markets during 2000-2001 time period, including APS, may potentially have been involved in arbitrage transactions that allegedly violated certain provisions of the ISO tariff. The report also recommended that the FERC issue an order to show cause why these transactions did not violate the ISO tariff, with potential disgorgement of any unjust profits. Although APS has not yet had an opportunity to review the transactions at issue, it believes that it was not engaged in any such improper transactions. Based on the information available, it also appears that such transactions would not have a material adverse impact on our financial position, results of operations or liquidity.

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. PG&E filed for bankruptcy protection in 2001.

We are closely monitoring developments in the California energy market and the potential impact of these developments on us and our subsidiaries. Based on our evaluations, we previously reserved \$10 million before income taxes for our credit exposure related to the California energy situation, \$5 million of which was recorded in the fourth quarter of 2000 and \$5 million of which was recorded in the first quarter of 2001. Our evaluations took into consideration our range of exposure of approximately zero to \$38 million before income taxes and review of likely recovery rates in bankruptcy situations.

In the second quarter of 2002, PG&E filed its Modified Second Amended Disclosure Statement and the CPUC filed its Alternative Plan of Reorganization. Both plans generally indicated that PG&E would, at the close of bankruptcy proceedings, be able to pay in full all outstanding, undisputed debts. As a result of these developments, the probable range of our total exposure now is approximately zero to \$27 million before income taxes, and our best estimate of the probable loss is now approximately \$6 million before income taxes. Consequently, we reversed \$4 million of the \$10 million reserve in the second quarter of 2002. 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, our subsidiaries or the regional energy market in general.

California Energy Market Litigation. On March 19, 2002, the State of California filed a complaint with the FERC alleging that wholesale sellers of power and energy, including the Company, failed to properly file rate information at the FERC in connection with sales to California from 2000 to the present. *State of California v. British Columbia Power Exchange et.-al.*, Docket No. EL02-71-000. The complaint requests the FERC to require the wholesale sellers to refund any rates that are “found to exceed just and reasonable levels.” This complaint has been dismissed by FERC and the State of California is now appealing the matter to the Ninth Circuit Court of Appeals. In addition, the State of California and others have filed various claims, which have now been consolidated, against several power suppliers to California alleging antitrust violations. *Wholesale Electricity Antitrust Cases I and II*, Superior Court in and for the County of San Diego, Proceedings Nos. 4204-00005 and 4204-00006. Two of the suppliers who were named as defendants in those matters, Reliant Energy Services, Inc. (and other Reliant entities) and Duke Energy and Trading, LLP (and other Duke entities), filed cross-claims against various other participants in the PX and ISO markets, including APS, attempting to expand those matters to such other participants. APS has not yet filed a responsive pleading in the matter, but APS believes the claims by Reliant and Duke as they relate to APS are without merit.

APS was also named in a lawsuit regarding wholesale contracts in California. *James Millar, et al. v. Allegheny Energy Supply, et al.*, United States District Court in and for the District of Northern California, Case No. C02-2855 EMC. The complaint alleges basically that the contracts entered into were the result of an unfair and unreasonable market. The PX has filed a lawsuit against the State of California regarding the seizure of forward contracts and the State has filed a cross complaint against APS and numerous other PX participants. *Cal PX v. The State of California* Superior Court in and for the County of Sacramento, JCCP No. 4203. Various preliminary motions are being filed and we cannot currently predict the outcome of this matter. The “United States Justice Foundation” is suing numerous wholesale energy contract suppliers to California, including us, as well as the California Department of Water Resources, based upon an alleged conflict of interest arising from the activities of a consultant for Edison International who also negotiated long-term contracts for the California Department of Water Resources. *McClintock, et al. v. Yudhrajia*, Superior Court in and for the County of Los Angeles, Case No. GC 029447. The California Attorney General has indicated that an investigation by his office did not find evidence of improper conduct by the consultant. We believe the claims against APS and us in the lawsuits mentioned in this paragraph are without merit and will have no material adverse impact on our financial position, results of operations or liquidity.

Power Service Agreement

By letter dated March 7, 2001, Citizens, which owns a utility in Arizona, advised APS that it believes APS overcharged Citizens by over \$50 million under a power service agreement. APS believes its charges under the agreement were fully in accordance with the terms of the agreement. In addition, in testimony filed with the ACC on March 13, 2002, Citizens acknowledged, based on its review, “if Citizens filed a complaint with FERC, it probably would lose the central issue in the contract interpretation dispute.” APS and Citizens terminated the power service agreement effective July 15, 2001. In replacement of the power service agreement, the Company and Citizens entered into a power sale agreement under which the Company will supply Citizens with future specified amounts of electricity and ancillary services through May 31, 2008. This new agreement does not address issues previously raised by Citizens with respect to charges under the original power service agreement through June 1, 2001.

Construction Program

Consolidated capital expenditures in 2003 are estimated to be (dollars in millions):

APS	\$	401
Pinnacle West Energy		268
SunCor		64
Other (primarily APS Energy Services and Pinnacle West)		17
Total	\$	750

Pinnacle West Energy's Generation Construction

Pinnacle West Energy's generation construction plan is as follows:

- A 650 MW combined cycle expansion of the West Phoenix Power Plant in Phoenix. The 120 MW West Phoenix Unit 4 began commercial operation in June 2001. Construction has begun on the 530 MW West Phoenix Unit 5, with commercial operation expected to begin in mid-2003.
- The Redhawk Power Plant, two 530 MW combined cycle units, near Palo Verde. Commercial operation began in July 2002. Based on an analysis of the financial situation of the Company and the market as a whole, among other things, Pinnacle West has cancelled plans to construct the additional two 530 MW combined cycle units, Redhawk Units 3 and 4. As a result we recorded a pretax charge of approximately \$49 million in December 2002.
- The construction of an 80 MW simple-cycle power plant at Saguaro in Southern Arizona. Commercial operation began in July 2002.
- Development of the 570 MW Silverhawk combined-cycle plant 20 miles north of Las Vegas, Nevada. Construction of the plant began in August 2002, with an expected commercial operation date of mid-2004. Pinnacle West Energy has signed an agreement with Las Vegas-based SNWA under which SNWA has an option to purchase a 25% interest in the project for approximately \$100 million.
- A Pinnacle West Energy affiliate is exploring the possibility of creating an underground natural gas storage facility on Company-owned land west of Phoenix. An analysis to determine the feasibility of the project is in progress.

Litigation

We are party to various claims, legal actions and complaints arising in the ordinary course of business, including but not limited to environmental matters related to the Clean Air Act, Navajo Nation issues and ADEQ issues. In our opinion, the ultimate resolution of these matters will not have a material adverse effect on our consolidated financial statements, results of operations or liquidity.

12. NUCLEAR DECOMMISSIONING COSTS

APS recorded \$11 million for nuclear decommissioning expense in each of the years 2002, 2001 and 2000. APS estimates it will cost approximately \$1.8 billion (\$528 million in 2002 dollars) to decommission its share of the three Palo Verde units. The majority of 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 APS 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 2001 site-specific study for Palo Verde that assumes the prompt removal/dismantlement method of decommissioning. An independent consultant prepared this study. APS is required by the ACC 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 and ACC orders. 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 accordance with industry practice. The following table shows the cost and fair value of our nuclear decommissioning trust fund assets, which were reported in investments and other assets on the Consolidated Balance Sheets at December 31, 2002 and 2001 (dollars in millions):

	2002	2001
Trust fund assets – at cost:		
Fixed income securities	\$ 113	\$ 103
Domestic stock	68	61
Total	\$ 181	\$ 164
Trust fund assets – fair value:		
Fixed income securities	\$ 117	\$ 106
Domestic stock	77	96
Total	\$ 194	\$ 202

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

13. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

Consolidated quarterly financial information for 2002 and 2001 is as follows:

(dollars in thousands, except per share amounts)		2002			
QUARTER ENDED	March 31	June 30	September 30	December 31(a)	
Operating revenues (b)					
Regulated electricity segment	\$ 380,241	\$ 496,837	\$ 719,361	\$ 416,584	
Marketing and trading segment	75,815	49,503	87,258	113,355	
Real estate segment	41,185	69,152	45,108	80,943	
Other revenues (c)	4,277	2,881	21,224	33,555	
Operating income	\$ 119,438	\$ 166,706	\$ 213,025	\$ 16,878	
Income (loss) before accounting change	\$ 53,757	\$ 75,365	\$ 100,916	\$ (14,885)	
Cumulative effect of change in accounting – net of income tax	–	–	–	(65,745)	
Net income (loss)	\$ 53,757	\$ 75,365	\$ 100,916	\$ (80,630)	
Earnings (loss) per weighted average common share outstanding – basic:					
Income before accounting change	\$ 0.63	\$ 0.89	\$ 1.19	\$ (0.18)	
Cumulative effect of change in accounting	–	–	–	(0.77)	
Earnings per weighted average common share outstanding – basic	\$ 0.63	\$ 0.89	\$ 1.19	\$ (0.95)	
Earnings (loss) per weighted average common share outstanding – diluted:					
Income before accounting change	\$ 0.63	\$ 0.89	\$ 1.19	\$ (0.18)	
Cumulative effect of change in accounting	–	–	–	(0.77)	
Earnings per weighted average common share outstanding – diluted	\$ 0.63	\$ 0.89	\$ 1.19	\$ (0.95)	
Dividends declared per share	\$ 0.40	\$ 0.40	\$ 0.40	\$ 0.425	

(dollars in thousands, except per share amounts)		2001			
QUARTER ENDED	March 31	June 30	September 30	December 31	
Operating revenues (b)					
Regulated electricity segment	\$ 412,807	\$ 739,317	\$ 973,398	\$ 436,569	
Marketing and trading segment	258,296	233,841	141,674	17,419	
Real estate segment	32,335	32,454	43,024	61,095	
Other revenues	1,543	1,653	2,682	5,893	
Operating income	\$ 136,646	\$ 140,010	\$ 298,752	\$ 100,615	
Income before accounting change	\$ 62,205	\$ 66,857	\$ 162,499	\$ 35,806	
Cumulative effect of change in accounting – net of income tax	(2,755)	–	(12,446)	–	
Net income	\$ 59,450	\$ 66,857	\$ 150,053	\$ 35,806	
Earnings (loss) per weighted average common share outstanding – basic:					
Income before accounting change	\$ 0.73	\$ 0.79	\$ 1.92	\$ 0.42	
Cumulative effect of change in accounting	(0.03)	–	(0.15)	–	
Earnings per weighted average common share outstanding – basic	\$ 0.70	\$ 0.79	\$ 1.77	\$ 0.42	
Earnings (loss) per weighted average common share outstanding – diluted:					
Income before accounting change	\$ 0.73	\$ 0.79	\$ 1.91	\$ 0.42	
Cumulative effect of change in accounting	(0.03)	–	(0.14)	–	
Earnings per weighted average common share outstanding – diluted	\$ 0.70	\$ 0.79	\$ 1.77	\$ 0.42	
Dividends declared per share	\$ 0.375	\$ 0.375	\$ 0.375	\$ 0.40	

(a) The fourth quarter of 2002 included pretax losses of \$38 million related to our investment in NAC (see Note 22), a \$49 million pretax write-off related to the cancellation of Redhawk Units 3 and 4 and pretax severance costs of approximately \$11 million.

(b) 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. We have reclassified certain operating revenues to conform to the current presentation of netting energy trading contracts (see Note 18).

(c) NAC financial statements were fully consolidated starting in third quarter 2002 (see Note 22).

14. 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, 2002 and 2001 due to their short maturities.

We hold investments in debt and equity securities for purposes other than trading. The December 31, 2002 and 2001 fair values of such investments, which we determine by using quoted market prices, approximate their carrying amount.

On December 31, 2002, the carrying value of our long-term debt (excluding capitalized lease obligations) was \$3.15 billion, with an estimated fair value of \$3.25 billion. The carrying value of our long-term debt (excluding capitalized lease obligations) was \$2.80 billion on December 31, 2001, with an estimated fair value of \$2.82 billion. The fair value estimates are based on quoted market prices of the same or similar issues.

15. EARNINGS PER SHARE

The following table presents earnings per weighted average common share outstanding for the years ended December 31, 2002, 2001 and 2000:

	2002	2001	2000
Basic earnings per share:			
Income before accounting change	\$ 2.53	\$ 3.86	\$ 3.57
Cumulative effect of change in accounting	(0.77)	(0.18)	–
Earnings per share – basic	\$ 1.76	\$ 3.68	\$ 3.57
Diluted earnings per share:			
Income before accounting change	\$ 2.53	\$ 3.85	\$ 3.56
Cumulative effect of change in accounting	(0.77)	(0.17)	–
Earnings per share – diluted	\$ 1.76	\$ 3.68	\$ 3.56

Dilutive stock options increased average common shares outstanding by 60,975 shares in 2002, 212,491 shares in 2001 and 202,738 shares in 2000. Total average common shares outstanding for the purposes of calculating diluted earnings per share were 84,963,921 shares in 2002, 84,930,140 shares in 2001 and 84,935,282 shares in 2000.

Options to purchase 1,629,958 shares of common stock were outstanding at December 31, 2002 but were not included in the computation of diluted earnings per share 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 earnings per share were 212,562 at December 31, 2001 and 517,614 at December 31, 2000.

16. STOCK-BASED COMPENSATION

Pinnacle West offers stock-based compensation plans for officers and key employees of our company and our subsidiaries.

In May 2002, shareholders approved the 2002 Long-term Incentive Plan (2002 plan), which allows Pinnacle West to grant performance shares, stock ownership incentive awards and non-qualified and performance-accelerated stock options to key employees. The Company has reserved 6 million shares of common stock for issuance under the 2002 plan. No more than 1.8 million shares may be issued in relation to performance share awards and stock ownership incentive awards. The plan also provides for the granting of new non-qualified stock options at a price per option not less than the fair market value of the common stock at the time of grant. The stock options vest over three years, unless certain performance criteria are met which can accelerate the vesting period. The term of the option cannot be longer than 10 years and the option cannot be repriced during its term.

The 1994 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. The 1985 plan includes outstanding options but no new options will be granted from the plan. 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 1994 plan also provides for the granting of any combination of shares of restricted stock, stock appreciation rights or dividend equivalents.

In the third quarter of 2002, we began applying the fair value method of accounting for stock-based compensation, as provided for in SFAS No. 123. The fair value method of accounting is the preferred method. In accordance with the transition requirements of SFAS No. 123, we applied the fair value method prospectively, beginning with 2002 stock grants. In prior years, we recognized stock compensation expense based on the intrinsic value method allowed in APB No. 25. We recorded approximately \$500,000 in stock option expense before income taxes in our Consolidated Statements of Income in 2002. This amount may not be reflective of the stock option expense we will record in future years because stock options typically vest over several years and additional grants are generally made each year.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure." The standard amends SFAS No. 123 to provide alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based compensation. The standard also amends the disclosure requirements of SFAS No. 123. SFAS No. 148 is effective for fiscal years ending after December 15, 2002. We adopted the disclosure requirements in 2002. See Note 1 for our pro forma disclosures on stock-based compensation and our weighted-average assumptions used to calculate the fair value of our stock options.

Total stock-based compensation expense, including stock option expense, was \$5 million in 2002, \$3 million in 2001 and \$2 million in 2000.

The following table is a summary of the status of our stock option plans as of December 31, 2002, 2001 and 2000 and changes during the years ending on those dates:

	2002 Shares	2002 Weighted Average Exercise Price	2001 Shares	2001 Weighted Average Exercise Price	2000 Shares	2000 Weighted Average Exercise Price
Outstanding at beginning of year	1,832,725	\$ 39.52	1,569,171	\$ 37.55	1,441,124	\$ 33.45
Granted	603,900 (a)	38.37	444,200	42.55	451,450	43.28
Exercised	(163,381)	28.25	(162,229)	28.53	(283,819)	20.90
Forfeited	(88,115)	41.54	(18,417)	41.67	(39,584)	39.86
Outstanding at end of year	<u>2,185,129</u>	<u>39.96</u>	<u>1,832,725</u>	<u>39.52</u>	<u>1,569,171</u>	<u>37.55</u>
Options exercisable at year-end	<u>1,155,357</u>	<u>39.66</u>	<u>926,315</u>	<u>37.41</u>	<u>831,537</u>	<u>34.37</u>
Weighted average fair value of options granted during the year		6.16		8.84		11.81

(a) Beginning 2002, we recorded compensation expense related to stock options under SFAS No. 123 (see above discussion).

The following table summarizes information about our stock options at December 31, 2002:

Exercise Prices Per Share	Options Outstanding	Weighted-Average Exercise Price	Weighted Average Remaining Contract Life (Years)	Options Exercisable	Weighted-Average Exercise Price
\$18.71-23.39	50,584	\$ 20.73	1.3	50,584	\$ 20.73
23.39-28.07	48,417	27.40	3.4	41,750	27.44
28.07-32.75	46,000	31.44	3.9	46,000	31.44
32.75-37.42	235,160	34.70	6.7	235,160	34.70
37.42-42.10	779,700	38.85	8.3	181,900	40.01
42.10-46.78	<u>1,025,268</u>	<u>43.95</u>	<u>7.7</u>	<u>599,963</u>	<u>44.59</u>
	<u>2,185,129</u>			<u>1,155,357</u>	

The following table is a summary of the amount and weighted-average grant date fair value of stock compensation awards granted, other than options, during the years ended December 31, 2002, 2001 and 2000:

	2002 Shares	2002 Weighted Average Grant-Date Fair Value	2001 Shares	2001 Weighted Average Grant-Date Fair Value	2000 Shares	2000 Weighted Average Grant-Date Fair Value
Restricted stock	6,000	\$ 38.84	95,450	\$ 42.84	86,426	\$ 44.03
Performance share awards	115,975	38.37	-	-	-	-
Stock ownership incentive awards (a)	9,650	38.37	-	-	-	-

(a) Shares are based on estimated ownership of Pinnacle West common stock.

17. BUSINESS SEGMENTS

We have three principal business segments (determined by products, services and the regulatory environment):

- our regulated electricity segment, which consists of regulated traditional retail and wholesale electricity businesses and related activities, and includes electricity transmission, distribution and generation;
- our marketing and trading segment, which consists of our competitive business activities, including wholesale marketing and trading and APS Energy Services' commodity-related energy services; and
- our real estate segment, which consists of SunCor's real estate development and investment activities.

The amounts in our other segment include activity principally related to NAC in 2002 (see Note 22), as well as the parent company and other subsidiaries. Financial data for the years ended December 31, 2002, 2001 and 2000 by business segments is provided as follows (dollars in millions):

Business Segments for the Year Ended December 31, 2002					
	Regulated Electricity	Marketing and Trading	Real Estate	Other (principally NAC)	Total
Operating revenues	\$ 2,013	\$ 326	\$ 236	\$ 62	\$ 2,637
Purchased power and fuel costs	500	194	–	–	694
Other operating expenses	659	34	205	105	1,003
Operating margin	854	98	31	(43)	940
Depreciation and amortization	416	2	5	2	425
Interest and other expense	160	–	(5)	8	163
Pretax margin	278	96	31	(53)	352
Income taxes	108	38	12	(21)	137
Income (loss) before accounting change	170	58	19	(32)	215
Cumulative effect of change in accounting for trading activities – net of income taxes of \$43	–	(66)	–	–	(66)
Net income (loss)	\$ 170	\$ (8)	\$ 19	\$ (32)	\$ 149
Total assets	\$ 7,589	\$ 301	\$ 504	\$ 32	\$ 8,426
Capital expenditures	\$ 893	\$ 19	\$ 72	\$ –	\$ 984

Business Segments for the Year Ended December 31, 2001					
	Regulated Electricity	Marketing and Trading	Real Estate	Other	Total
Operating revenues	\$ 2,562	\$ 651	\$ 169	\$ 12	\$ 3,394
Purchased power and fuel costs	1,161	334	–	–	1,495
Other operating expenses	598	33	154	11	796
Operating margin	803	284	15	1	1,103
Depreciation and amortization	423	1	4	–	428
Interest and other expense	129	–	6	–	135
Pretax margin	251	283	5	1	540
Income taxes	99	112	2	–	213
Income before accounting change	152	171	3	1	327
Cumulative effect of change in accounting for derivatives – net of income taxes of \$10	(15)	–	–	–	(15)
Net income	\$ 137	\$ 171	\$ 3	\$ 1	\$ 312
Total assets	\$ 6,862	\$ 589	\$ 477	\$ 11	\$ 7,939
Capital expenditures	\$ 1,004	\$ 23	\$ 80	\$ 22	\$ 1,129

Business Segments for the Year Ended December 31, 2000					
	Regulated Electricity	Marketing and Trading	Real Estate	Other	Total
Operating revenues	\$ 2,539	\$ 418	\$ 158	\$ 4	\$ 3,119
Purchased power and fuel costs	1,066	292	–	–	1,358
Other operating expenses	532	18	134	1	685
Operating margin	941	108	24	3	1,076
Depreciation and amortization	426	1	5	–	432
Interest and other expense	152	–	–	(4)	148
Pretax margin	363	107	19	7	496
Income taxes	142	42	8	2	194
Net income	\$ 221	\$ 65	\$ 11	\$ 5	\$ 302
Total assets	\$ 6,213	\$ 459	\$ 429	\$ 22	\$ 7,123
Capital expenditures	\$ 665	\$ –	\$ 50	\$ –	\$ 715

18. DERIVATIVE AND TRADING ACCOUNTING

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal and emissions allowances. We 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 and credits. The changes in market value of such contracts have a high correlation to price changes in the hedged commodities. In addition, subject to specified risk parameters monitored by the ERM, we engage in marketing and trading activities intended to profit from market price movements.

Effective January 1, 2001, we adopted SFAS No. 133. 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 instruments are either recognized periodically in income or, if hedge criteria is met, in common stock equity (as a component of other comprehensive income). We use cash flow hedges to limit our exposure to cash flow variability on forecasted transactions. Hedge effectiveness is related to the degree to which the derivative contract and the hedged item are correlated. It is measured based on the relative changes in fair value between the derivative contract and the hedged item over time. We exclude the time value of certain options from our assessment of hedge effectiveness. Any change in the fair value resulting from ineffectiveness, or the amount by which the derivative contract and the hedged commodity are not directly correlated, is recognized immediately in net income. See Note 1 for further discussion on our derivative instrument accounting policy.

In 2001, we recorded a \$15 million after-tax charge in net income and a \$72 million after-tax credit in common stock equity (as a component of other comprehensive income), both as cumulative effects of a change in accounting for derivatives. The charge primarily resulted from electricity option contracts. The credit resulted from unrealized gains on cash flow hedges.

In December 2001, the FASB issued revised guidance on the accounting for electricity contracts with option characteristics and the accounting for contracts that combine a forward contract and a purchased option contract. The effective date for the revised guidance was April 1, 2002. The impact of this guidance was immaterial to our financial statements.

During 2002, the EITF discussed EITF 02-3 and reached a consensus on certain issues. EITF 02-3 rescinded EITF 98-10 and was effective October 25, 2002 for any new contracts and on January 1, 2003 for existing contracts, with early adoption permitted. We adopted the EITF 02-3 guidance for all contracts in the fourth quarter of 2002. We recorded a \$66 million after-tax charge in net income as a cumulative effect adjustment for the previously recorded accumulated unrealized mark-to-market on energy trading contracts that did not meet the accounting

definition of a derivative. As a result, our energy trading contracts that are derivatives continue to be accounted for at fair value under SFAS No. 133. Contracts that were previously marked-to-market as trading activities under EITF 98-10 that do not meet the definition of a derivative are now accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received. Additionally, all gains and losses (realized and unrealized) on energy trading contracts that qualify as derivatives are included in marketing and trading segment revenues on the Consolidated Statements of Income on a net basis. The rescission of EITF 98-10 has no effect on the accounting for derivative instruments used for non-trading activities, which continue to be accounted for in accordance with SFAS No. 133.

Both non-trading and trading derivatives are classified as assets and liabilities from risk management and trading activities in the Consolidated Balance Sheets. For non-trading derivative instruments that qualify for cash flow hedge accounting treatment, changes in the fair value of the effective portion are recognized in common stock equity (as a component of accumulated other comprehensive income (loss)). Non-trading derivatives, or any portion thereof, that are not effective hedges are adjusted to fair value through income. Gains and losses related to non-trading derivatives that qualify as cash flow hedges of expected transactions are recognized in revenue or purchased power and fuel expense as an offset to the related item being hedged when the underlying hedged physical transaction impacts earnings. If it becomes probable that a forecasted transaction will not occur, we discontinue the use of hedge accounting and recognize in income the unrealized gains and losses that were previously recorded in other comprehensive income (loss). In the event a non-trading derivative is terminated or settled, the unrealized gains and losses remain in other comprehensive income (loss), and are recognized in income when the underlying transaction impacts earnings.

Derivatives associated with trading activities are adjusted to fair value through income. Derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business are exempt from the requirements of SFAS No. 133 under the normal purchase and sales exception and are not reflected on the balance sheet at fair value. Most of our non-trading electricity purchase and sales agreements qualify as normal purchases and sales and are exempted from recognition in the financial statements until the electricity is delivered.

EITF 02-3 requires that derivatives held for trading purposes, whether settled financially or physically, be reported in the income statement on a net basis. Conversely, all non-trading contracts and derivatives are to be reported gross in the income statement. Previous guidance under EITF 98-10 permitted non-financially settled energy trading contracts to be reported either gross or net in the income statement. Beginning in the third quarter of 2002, we netted all of our energy trading activities on the Consolidated Statements of Income and restated prior year

amounts for all periods presented. Reclassification of such trading activity to a net basis of reporting resulted in reductions in both revenues and purchased power and fuel costs, but did not have any impact on our financial condition, results of operations or cash flows.

Our assets and liabilities from risk management and trading activities are presented in two categories consistent with our business segments:

- System – our regulated electricity business segment, which consists of non-trading derivative instruments that hedge our purchases and sales of electricity and fuel for our Native Load requirements; and
- Marketing and Trading – our non-regulated, competitive business segment, which includes both non-trading and trading derivative instruments.

The changes in derivative fair value included in the Consolidated Statements of Income for the years ended December 31, 2002 and 2001 are comprised of the following (dollars in thousands):

	2002	2001
Gains/(losses) on the ineffective portion of derivatives qualifying for hedge accounting (a)	\$ 11,198	\$ (6,056)
Losses from the discontinuance of cash flow hedges	(8,820)	(4,683)
Losses from non-hedge derivatives	(4,324)	(7,157)
Prior period mark-to-market losses realized upon delivery of commodities	8,005	25,948
Total pretax gain	\$ 6,059	\$ 8,052

(a) Time value component of options excluded from assessment of hedge effectiveness.

As of December 31, 2002, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted transactions is approximately seven years. During the twelve months ending December 31, 2003, we estimate that a net loss of \$26 million before income taxes will be reclassified from accumulated other comprehensive loss as an offset to the effect on earnings of market price changes for the related hedged transactions.

The following table summarizes our assets and liabilities from risk management and trading activities related to system and marketing and trading at December 31, 2002 and 2001 (dollars in thousands):

December 31, 2002	Current Assets	Investments	Current Liabilities	Other Liabilities	Net Asset/(Liability)
Mark-to-market:					
Marketing and Trading System	\$ 17,640	\$ 51,771	\$ (9,848)	\$ (2,583)	\$ 56,980
	41,522	6,971	(60,819)	(36,678)	(49,004)
Emission allowances – at cost	–	58,067	–	(14,328)	43,739
Collateral provided (held)	–	5,527	–	(22,053)	(16,526)
Total	\$ 59,162	\$ 122,336	\$ (70,667)	\$ (75,642)	\$ 35,189

December 31, 2001	Current Assets	Investments	Current Liabilities	Other Liabilities	Net Asset/(Liability)
Mark-to-market:					
Marketing and Trading System	\$ 56,876	\$ 148,457	\$ (14,154)	\$ (53,253)	\$ 137,926
	10,097	–	(21,840)	(95,159)	(106,902)
Emission allowances – at cost	–	(3,216)	–	(59,164)	(62,380)
Collateral provided	–	55,110	–	–	55,110
Total	\$ 66,973	\$ 200,351	\$ (35,994)	\$ (207,576)	\$ 23,754

Credit Risk

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We have risk management and trading contracts with many counterparties, including two counterparties for which a worst case exposure represents approximately 33% of our \$181 million of risk management and trading assets as of December 31, 2002. We use a risk management process to assess and monitor the financial exposure of those and all other counterparties. Despite the fact that the great majority of trading counterparties are rated as investment grade by the credit rating agencies, including the counterparties noted above,

there is still a possibility that one or more of these companies could default, resulting in a material impact on consolidated earnings for a given period. Counterparties in the portfolio consist principally of major energy companies, municipalities and local distribution companies. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. In many contracts, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a

single counterparty. Credit valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties. See "Mark-to-Market Accounting" in Note 1 for a discussion of our credit valuation adjustment policy.

19. OTHER INCOME AND OTHER EXPENSE

The following table provides detail of other income and other expense for the years ended December 31, 2002, 2001 and 2000 (dollars in thousands):

year ended December 31,	2002	2001	2000
Other income:			
Environmental insurance recovery	\$ -	\$ 12,349	\$ -
Equity earnings – net	-	-	6,882
Interest income	4,410	6,763	8,291
SunCor joint venture earnings	7,471	3,687	3,208
Miscellaneous	3,223	3,617	3,451
Total other income	\$ 15,104	\$ 26,416	\$ 21,832
Other expense:			
Equity losses – net (a)	\$ (10,439)	\$ (5,126)	\$ -
Non-operating costs – SunCor	-	(7,000)	-
Non-operating costs (b)	(19,430)	(16,807)	(16,044)
Miscellaneous	(3,786)	(4,644)	(9,285)
Total other expense	\$ (33,655)	\$ (33,577)	\$ (25,329)

(a) Primarily related to El Dorado's investment losses in NAC prior to consolidation in the third quarter of 2002 (see Note 22).

(b) As defined by the FERC, includes below-the-line non-operating utility costs (primarily community relations and environmental compliance).

20. VARIABLE INTEREST ENTITIES

In January 2003, the FASB issued FIN No. 46, "Consolidation of Variable Interest Entities." FIN No. 46 requires that we consolidate a VIE if we have a majority of the risk of loss from the VIE's activities or we are entitled to receive a majority of the VIE's residual returns or both. A VIE is a corporation, partnership, trust or any other legal structure that either does not have equity investors with voting rights or has equity investors that do not provide sufficient financial resources for the entity to support its activities. FIN No. 46 is effective immediately for any VIE created after January 31, 2003 and is effective July 1, 2003 for VIEs created before February 1, 2003.

In 1986, APS entered into agreements with three separate SPE lessors in order to sell and lease back interests in Palo Verde Unit 2. The leases are accounted for as operating leases in accordance with GAAP. See Note 9 for further information about the sale-leaseback transactions. Based on our preliminary assessment of FIN No. 46, we do not believe we will be required to consolidate the Palo Verde SPEs. However, we continue to evaluate the requirements of the new guidance to determine what impact, if any, it will have on our financial statements.

APS is also exposed to losses under the Palo Verde sale-leaseback agreements upon the occurrence of certain events that APS does not consider to be reasonably likely to occur. Under certain circumstances (for example, the NRC issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), APS would be required to assume the debt associated with the transactions, make specified payments to the equity participants and take title to the leased Unit 2 interests, which, if appropriate, may be required to be written down in value. If such an event had occurred as of December 31, 2002, APS would have been required to assume approximately \$285 million of debt and pay the equity participants approximately \$200 million.

21. INTANGIBLE ASSETS

On January 1, 2002, we adopted SFAS No. 142, "Goodwill and Other Intangible Assets." This statement addresses financial accounting and reporting for acquired goodwill and other intangible assets and supersedes APB Opinion No. 17, "Intangible Assets." We have no goodwill recorded and have separately disclosed other intangible assets on our Consolidated Balance Sheets. The intangible assets continue to be amortized over their finite useful lives. Thus, there was no impact on our financial position as a result of the adoption of SFAS No. 142. The Company's gross intangible assets (which are primarily software) were \$214 million at December 31, 2002 and \$175 million at December 31, 2001. The related accumulated amortization was \$104 million at December 31, 2002 and \$88 million at December 31, 2001.

Amortization expense was \$21 million in 2002, \$22 million in 2001 and \$20 million in 2000. Estimated amortization expense on existing intangible assets over the next five years is \$25 million in 2003, \$24 million in 2004, \$23 million in 2005, \$21 million in 2006 and \$15 million in 2007.

22. EL DORADO'S INVESTMENT IN NAC

Through our unregulated wholly-owned subsidiary, El Dorado, we own a majority interest in NAC, a company that develops, markets and contracts for the manufacture of cask designs for spent nuclear fuel storage and transportation. Prior to the third quarter of 2002, our investment in NAC was accounted for under the equity method and our share of NAC's earnings and losses was recorded in other income or expense in our Consolidated Statements of Income. Beginning in the third quarter of 2002, we fully consolidated NAC's financial statements after acquiring a controlling interest in NAC as a result of increased voting representation on NAC's Board of Directors. During the second and third quarters of 2002, we recorded cumulative losses of approximately \$21 million before tax (\$13 million after tax, \$0.15 per share) related to NAC, primarily as a result of expected losses under contracts with two customers, including a contract between NAC and Maine Yankee Atomic Power Company (Maine Yankee).

On January 15, 2003, Maine Yankee notified NAC of its intention to terminate its contract with NAC. We recorded additional NAC losses of approximately \$38 million before tax (\$23 million after tax, or \$0.27 per share) in the fourth quarter of 2002, the substantial majority of which relate to the termination of the Maine Yankee contract. As a result, in 2002, we recorded NAC losses of approximately \$59 million before tax (\$35 million after tax, or \$0.42 per share).

NAC Litigation On March 4, 2003, Maine Yankee Atomic Power Co. filed suit against Pinnacle West, NAC and a surety company in federal court in Portland, Maine. Maine Yankee Atomic Power Company v. United States Fire Insurance Company, Civil Action Docket No. 03-58-PC, United States District Court, District of Maine. The lawsuit alleges that NAC failed to meet its contractual obligations with respect to certain of NAC's activities relating to the decommissioning of the Maine Yankee nuclear power plant. The lawsuit was filed a few weeks after NAC initiated arbitration against Maine Yankee with respect to matters relating to the same contract. The lawsuit seeks recovery under a parental guarantee signed by Pinnacle West relating to certain of NAC's contractual obligations and under performance and payment bonds issued by the surety which are guaranteed (at least in part) by Pinnacle West. Maine Yankee also alleges damages in excess of \$1 million. We are currently evaluating the allegations of the lawsuit and expect to vigorously defend our position.

23. GUARANTEES

On January 1, 2003, we adopted FIN No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." FIN No. 45 elaborates on the disclosures to be made by a guarantor in its financial statements about its obligations under certain guarantees. It also clarifies that a guarantor is required to recognize, at inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. The disclosure provisions are effective for the year ended December 31, 2002. The initial recognition and measurement provisions of FIN No. 45 are effective on a prospective basis to guarantees issued or modified after December 31, 2002.

We have issued parental guarantees and letters of credit and obtained surety bonds on behalf of our unregulated subsidiaries. Our parental guarantees related to Pinnacle West Energy consist of equipment and performance guarantees related to our generation construction program, transmission service guarantees for West Phoenix Units 4 and 5 and long-term service agreement guarantees for new power plants. Our credit support instruments enable APS Energy Services to provide commodity energy and energy-related products and enable El Dorado to support the activities of NAC. SunCor has a debt guarantee on behalf of an affiliated joint venture. Non-performance or payment under the original contract by our unregulated subsidiaries would require us to perform under the guarantee or surety bond. No liability is currently recorded on the Consolidated Balance Sheets related to Pinnacle West's guarantees on behalf of its subsidiaries. Our guarantees have no recourse (except NAC) or collateral provisions to allow us to recover amounts paid under the guarantee.

The amounts and approximate terms of our guarantees and surety bonds for each subsidiary at December 31, 2002 are as follows (dollars in millions):

	Guarantees Amount	Guarantees Term (in years)	Surety Bonds Amount	Surety Bonds Term (in years)	Letters of Credit Amount	Letters of Credit Term (in years)
Parental:						
Pinnacle West Energy	\$ 126	1 to 2	\$ -	-	\$ 42	1 to 2
APS Energy Services	82	less than 2	43	less than 1	-	-
El Dorado (all NAC)	43	1 to 3	-	-	-	-
SunCor guarantees	33	1	-	-	-	-
Total	\$ 284		\$ 43		\$ 42	

At December 31, 2002, we had entered into approximately \$42 million of letters of credit which support various construction agreements. These letters of credit expire in 2003 and 2004. We intend to provide from either existing or new facilities for the extension, renewal or substitution of the letters of credit to the extent required.

APS has entered into various agreements that require letters of credit for financial assurance purposes. At December 31, 2002, approximately \$258 million of letters of credit were outstanding to support existing pollution control bonds of approximately \$253 million. The letters of credit are available to fund the payment of principal and interest of such debt obligations. These letters of credit have expiration dates in 2003. APS has also entered into approximately \$115 million of letters of credit to support certain equity lessors in the Palo Verde sale-leaseback transactions (see Note 9 for further details on the Palo Verde sale-leaseback transactions). These letters of credit expire in 2005. Additionally, APS has approximately \$5 million of letters of credit related to counterparty collateral requirements and approximately \$5 million of letters of credit related to workers' compensation expiring in 2003. APS intends to provide from either existing or new facilities for the extension, renewal or substitution of the letters of credit to the extent required.

In conjunction with our financing agreements, including our sale-leaseback transactions, we generally provide indemnifications relating to liabilities arising from or related to the agreements, except with certain limited exceptions depending on the particular agreement. APS has also provided indemnifications to the equity participants and other parties in the Palo Verde sale-leaseback transactions with respect to certain tax matters. Generally, a maximum obligation is not explicitly stated in the indemnification and therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. Based on historical experience and evaluation of the specific indemnities, we do not believe that any material loss related to such indemnifications is likely and therefore no related liability has been recorded.

24. SUBSEQUENT EVENTS

See "ACC Applications" in Note 3 for information regarding the ACC's approval on March 27, 2003 of a \$500 million financing arrangement between APS and Pinnacle West Energy and "Track B Order" in Note 3 for information regarding the ACC order issued on March 14, 2003, mandating a process by which APS must competitively procure energy.

See "California Energy Issues and Refunds in the Pacific Northwest" in Note 11 for information regarding the FERC's adoption on March 26, 2003 of an ALJ's proposed findings, and issuance on March 26, 2003 of a Final Report on Price Manipulation in Western Markets.

See Note 22 for information related to the March 4, 2003 NAC litigation.