

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Consolidation and Nature of Operations

Pinnacle West's 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). See Note 22 for a discussion of the sale of NAC in November 2004. Significant intercompany accounts and transactions between the consolidated companies have been eliminated.

APS is a vertically-integrated electric utility that provides either retail or wholesale electric service to substantially all of the state of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona. Through its marketing and trading division, APS also generates, sells and delivers electricity to wholesale customers in the western United States. Pinnacle West Energy, which was formed in 1999, is the subsidiary through which we conduct our unregulated 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, Idaho and Utah. El Dorado is an investment firm.

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 commodity price and transportation costs of electricity, natural gas, coal and emissions allowances and in interest rates. We manage risks associated with these market fluctuations by utilizing various instruments that qualify as derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. As part of our overall risk management program, we use such instruments to hedge purchases and sales of electricity, fuels, and emissions allowances and credits. 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 account for our derivative contracts in accordance with SFAS No. 133, as amended by SFAS No. 149, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 requires that entities recognize all derivatives as either assets or liabilities on the balance sheet and measure those instruments at fair value. Changes in the fair value of derivative instruments are either recognized periodically in income or, if certain hedge criteria are met, in common stock equity (as a component of other comprehensive income (loss)). SFAS No. 133 provides a scope exception for contracts that meet the normal purchases and sales criteria specified in the standard.

Prior to the fourth quarter of 2002, we accounted for our trading activity at fair value, with changes in fair value reported in earnings as required by EITF 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." In the fourth quarter of 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. 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. Our energy trading contracts that are derivatives are accounted for at fair value under SFAS No. 133, as amended. Energy trading contracts 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.

Under fair value (mark-to-market) accounting, derivative contracts for the purchase or sale of energy commodities are reflected at fair market value, net of valuation adjustments, with resulting unrealized gains and losses recorded as current or long-term assets and liabilities from risk management and trading activities on 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, which we convert into monthly prices using 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.

The credit valuation adjustment represents 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 and financial institutions. 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.

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 ERMC.

See Note 18 for additional information about our derivative and energy trading accounting policies.

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 expected future costs that have already been collected from customers.

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.

As part of the 1999 Settlement Agreement APS amortized certain regulatory assets over a period that ended June 30, 2004. Amortization in the last three years is as follows (dollars in millions):

2002	2003	2004
\$115	\$86	\$18

The detail of regulatory assets is as follows (dollars in millions):

	December 31,	
	2004	2003
Electric industry restructuring transition costs (Note 3)	\$ 50	\$ 46
Deferred compensation	24	24
Loss on reacquired debt (a)	17	12
Capital contributions on the Mead-Phoenix transmission line	13	11
Regulatory asset for deferred income taxes	12	9
Spent nuclear fuel storage (Note 11)	11	7
Balance recoverable under the 1999 Settlement Agreement	–	18
Other	8	5
Total regulatory assets	<u>\$ 135</u>	<u>\$ 132</u>

(a) See "Reacquired Debt Costs" below.

The detail of regulatory liabilities is as follows (dollars in millions):

	December 31,	
	2004	2003
Removal costs (a)	\$ 462	\$ 439
Deferred gains on utility property	20	20
Deferred interest income (b)	22	8
Other	3	2
Total regulatory liabilities	<u>\$ 507</u>	<u>\$ 469</u>

(a) See Note 12 for information on Asset Retirement Obligations.

(b) See "ACC Financing Orders" in Note 3 for information on the "APS Loan".

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;
- capitalized leases;
- 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 to accumulated depreciation. Prior to 2003, we charged removal costs, less salvage, to accumulated depreciation. Effective January 1, 2003, we applied the provisions of SFAS No. 143. The standard requires that liabilities associated with the retirement of tangible long-lived assets be recognized at fair value as incurred and capitalized as part of the related tangible long-lived assets. Accretion of the liability due to the passage of time is an operating expense and the capitalized cost is depreciated over the useful life of the long-lived asset. See Note 12.

APS records a regulatory liability for the asset retirement obligations related to its regulated assets. This regulatory liability represents the difference between the amount that has been recovered in regulated rates and the amount calculated under SFAS No. 143. APS believes it can recover in regulated rates the transition and ongoing current period costs calculated in accordance with SFAS No. 143.

We record depreciation on utility plant on a straight-line basis over the remaining useful life of the related assets. The approximate remaining average useful lives of our utility property at December 31, 2004 were as follows:

- Fossil plant – 23 years;
- Nuclear plant – 18 years;
- Other generation – 26 years;
- Transmission – 36 years;
- Distribution – 23 years; and
- Other – 8 years.

For the years 2002 through 2004, the depreciation rates, as prescribed by our regulators, ranged from a low of 1.51% to a high of 12.5%. The weighted-average rate was 3.36% for 2004, 3.35% for 2003 and 3.35% for 2002. We depreciate non-utility property and equipment over the estimated useful lives of the related assets, ranging from 3 to 55 years.

Investments

El Dorado accounts for its investments using the equity (if significant influence) and cost (less than 20% ownership) methods. See Note 22 for a discussion of the sale of NAC.

The Company's investments have been reviewed in accordance with EITF 03-1, "The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments," and no other-than-temporary impairments were identified.

Capitalized Interest

Capitalized interest represents the cost of debt funds used to finance non-regulated construction projects. Plant construction costs, including capitalized interest, are expensed through depreciation when completed projects are placed into commercial operation. The rate used to calculate capitalized interest was a composite rate of 4.44% for 2004, 4.55% for 2003 and 4.80% for 2002. Capitalized interest ceases to accrue when construction is complete.

Allowance for Funds Used During Construction

AFUDC represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction of regulated utility plant. Plant construction costs, including AFUDC, are recovered in authorized rates through depreciation when completed projects are placed into commercial operation.

AFUDC was calculated by using a composite rate of 8.42% for 2004 and 8.55% for 2003. APS compounds AFUDC monthly and ceases to accrue AFUDC when construction work is completed and the property is placed in service.

In 2003, APS returned to the AFUDC method of capitalizing interest and equity costs associated with construction projects in a regulated utility. This is consistent with APS returning to a vertically-integrated utility, as evidenced by APS' 2003 general rate case filing, which includes the request for rate recognition of generation assets. Prior to 2003, APS capitalized interest in accordance with SFAS No. 34, "Capitalization of Interest Cost." Although AFUDC both increases the plant balance and results in higher current earnings during the construction period, AFUDC is realized in future revenues through depreciation provisions included in rates. This change increased earnings by \$11 million in 2003 as compared to what it would have been under SFAS No. 34.

Electric Revenues

We derive electric revenues from sales of electricity to our regulated Native Load customers and sales to other parties from our marketing and trading activities. Revenues related to the sale of electricity are generally recorded when service is rendered or electricity is delivered to customers. However, the determination and billing of electricity 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 electricity delivered to customers since the date of the last meter reading and billing and the corresponding unbilled revenue are estimated. We exclude sales taxes on electric revenues from both revenue and taxes other than income taxes.

Revenues from our Native Load customers and non-derivative instruments are reported on a gross basis on Pinnacle West's Consolidated Statements of Income. In the electricity business, some contracts to purchase energy are netted against other contracts

to sell energy. This is called "book-out" and usually occurs in contracts that have the same terms (quantities and delivery points) and for which power does not flow. We net these book-outs, which reduces both revenues and purchased power and fuel costs.

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.

Real Estate Revenues

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 under the percentage of completion method per SFAS No. 66 "Accounting for Sales of Real Estate." SunCor recognizes income only after the assets' title has passed. 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. In addition, see Note 22 – Discontinued Operations.

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 that, 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. In 2003, SunCor acquired two joint ventures for \$10 million and consolidated \$53 million of assets and \$43 million of liabilities, which are included on the Consolidated Balance Sheets at December 31, 2003. The \$10 million cash investment is included on the other investing line of the Consolidated Statements of Cash Flow at December 31, 2003. In addition, see Note 22 – Discontinued Operations.

Cash and Cash Equivalents

We consider all highly liquid investments purchased with an initial maturity of three months or less to be cash equivalents.

We have investments in auction rate securities in which interest rates are reset on a short-term basis; however, the underlying contract maturity dates extend beyond three months. We classify the investments in auction rate securities as investments in debt securities on our Consolidated Balance Sheets. We have reclassified cash at December 31, 2003 of \$92 million to investment in debt securities. Included in that reclassification is \$70 million related to APS. The purchase and sale activities related to these investments have also been reclassified on the Consolidated Statement of Cash Flows.

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 subsidiary filed a separate income tax return. Any difference between that method and the consolidated (and unitary) income tax liability is attributed to the parent company. See Note 4.

Reacquired Debt Costs

For reacquired debt costs related to the regulated portion of APS' business, APS defers those gains and losses incurred upon early retirement and is seeking recovery of the net amount of losses in the APS general rate case (see Note 3).

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 2004 (dollars in thousands, except per share amounts):

	Year Ended December 31,		
	2004	2003	2002
Net Income as reported:	\$ 243,195	\$ 240,579	\$ 149,408
Add: Stock compensation expense included in reported net income (net of tax)	4,690	3,514	2,347
Deduct: Total stock compensation expense determined under fair value method (net of tax)	(5,311)	(5,220)	(3,742)
Pro forma net income	\$ 242,574	\$ 238,873	\$ 148,013
Earnings per share – basic:			
As reported	\$ 2.66	\$ 2.64	\$ 1.76
Pro forma (fair value method)	\$ 2.65	\$ 2.62	\$ 1.74
Earnings per share – diluted:			
As reported	\$ 2.66	\$ 2.63	\$ 1.76
Pro forma (fair value method)	\$ 2.65	\$ 2.61	\$ 1.74

In order to calculate the fair value of the 2004, 2003 and 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:

	2004	2003	2002
Risk-free interest rate	3.15%	3.35%	4.17%
Dividend yield	4.76%	5.26%	4.17%
Volatility	17.04%	38.03%	22.59%
Expected life (months)	60	60	60

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

Intangible Assets

We have no goodwill recorded and have separately disclosed other intangible assets on Pinnacle West's Consolidated Balance Sheets in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets." The intangible assets are amortized over their finite useful lives. Amortization expense was \$34 million in 2004, \$25 million in 2003, and \$21 million in 2002. Estimated amortization expense on existing intangible assets over the next five years is \$33 million in 2005, \$31 million in 2006, \$25 million in 2007, \$16 million in 2008, and \$1 million in 2009. At December 31, 2004, the weighted average amortization period for intangible assets is 7 years.

2. NEW ACCOUNTING STANDARDS

In December 2004, the FASB issued SFAS No. 123R, "Share-Based Payment." The standard establishes accounting for transactions in which an entity exchanges its equity instruments for goods or services. It also addresses transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity's equity instruments or that may be settled by the issuance of those equity instruments. SFAS No. 123R is effective as of the beginning of the first interim or annual period that begins after June 15, 2005. We are currently accounting for stock-based compensation using the fair value method and are evaluating the impacts of this new guidance, but we do not believe it will have a material impact on our financial statements.

See the following Notes for information about new accounting standards and other accounting matters:

- Note 8 for FSP 106-2 regarding the Medicare Prescription Drug, Improvement and Modernization Act related to retirement plans and other benefits;
- Note 18 for EITF 02-3 and DIG Issue No. C15 related to accounting for derivatives and energy contracts; and
- Note 20 for FIN No. 46R related to variable interest entities.

3. REGULATORY MATTERS

Electric Industry Restructuring

State

APS GENERAL RATE CASE; 2004 SETTLEMENT AGREEMENT On June 27, 2003, APS filed a general rate case with the ACC and requested a \$175.1 million, or 9.8%, increase in its annual retail electricity revenues, intended to become effective July 1, 2004. In this rate case, APS updated its cost of service and rate design.

The general rate case also addresses the implementation of rate adjustment mechanisms that were the subject of ACC hearings in April 2003. The rate adjustment mechanisms, which were authorized as a result of the 1999 Settlement Agreement, would allow APS to recover several types of costs, the most significant of which are power supply costs (fuel and purchased power costs) and costs associated with complying with the Rules.

On August 18, 2004, a substantial majority of the parties to the rate case, including APS, the ACC staff, the Arizona Residential Utility Consumer Office, other customer groups, and merchant power plant intervenors entered into an agreement that proposes terms under which the rate case would be settled (the "2004 Settlement Agreement").

Key financial components of the 2004 Settlement Agreement, which is subject to ACC approval are as follows:

- APS would receive an annual retail rate increase of approximately \$75.5 million, or 4.21%. The increase would consist of an increase in base rates of approximately 3.77% and an increase of approximately 0.44% for recovery over five years of the past costs of compliance with the ACC's retail electric competition rules.
- APS would acquire the PWEC Dedicated Assets from Pinnacle West Energy, with a net carrying value of approximately \$850 million, and rate base the PWEC Dedicated Assets at a rate base value of \$700 million, which would result in a mandatory rate base disallowance of \$150 million. As a result, for financial reporting purposes, APS would recognize a one-time, after-tax net plant write-off of approximately \$90 million in the period when the plant transfer to APS is completed and would reduce annual depreciation expense by approximately \$5 million.

- To bridge the time between the effective date of the rate increase and the actual date the PWEC Dedicated Assets transfer, APS and Pinnacle West Energy would enter into a cost-based purchase power agreement (the "Bridge PPA"), which would be based on the value of the PWEC Dedicated Assets described in the previous bullet point. The Bridge PPA would remain in effect until the FERC approves the transfer of the PWEC Dedicated Assets to APS and the transfer is completed.
 - If the FERC were to issue an order denying APS' request to acquire the PWEC Dedicated Assets, the Bridge PPA would become a 30-year purchased power agreement, with prices reflecting cost-of-service as if APS had acquired and rate-based the PWEC Dedicated Assets at the value described above.
 - If the FERC were to issue an order (a) approving APS' request to transfer the PWEC Dedicated Assets at a value materially less than \$700 million, (b) approving the transfer of fewer than all of the PWEC Dedicated Assets or (c) that was materially inconsistent with the 2004 Settlement Agreement, APS would file an appropriate application with the ACC so that rates could be adjusted. In these circumstances, the Bridge PPA would continue at least until the conclusion of the subsequent proceeding to consider any appropriate adjustment to APS' rates.
- A PSA would provide for the recovery of variations in fuel and purchased power costs, subject to specified parameters and procedures.
- APS would not restore and recover in rates the \$234 million write-off recorded in 1999 as a result of the 1999 Settlement Agreement. As a result, annual amortization expense for financial reporting purposes would be approximately \$16 million less than if the \$234 million write-off had been restored and amortized over a 15-year period as originally requested.
- APS would adopt longer service lives than originally requested for certain depreciable assets, which would have the effect of reducing annual depreciation expense for financial reporting purposes by approximately \$26 million.

On February 28, 2005, the administrative law judge in the general rate case issued a recommended order. The recommended order proposes ACC approval of the 2004 Settlement Agreement with two changes related to the PSA. First, the amount of gas costs that APS could recover under the annual PSA would be limited to \$500 million per year. Second, although the 2004 Settlement Agreement provides that the PSA would remain in effect for a minimum five-year period, under the recommended order the ACC would be able to eliminate the PSA at any time, if appropriate, if APS files a rate case before the expiration of the five-year period or APS does not comply with the terms of the PSA. If APS exceeds the gas costs that could be recoverable under the PSA or if the ACC eliminates the PSA, APS would retain the right to file a rate case to reset its base rates.

On March 14, 2005, the parties to the 2004 Settlement Agreement jointly filed suggested changes to the recommended order addressing, among other things, the recommended order's proposed treatment of the PSA. The ACC has scheduled open meetings on March 24 and March 28, 2005 to consider the recommended order and suggested changes. APS cannot predict the outcome of this matter.

ACC FINANCING ORDER On May 12, 2003, APS issued \$500 million of debt pursuant to the Financing Order and made a \$500 million loan to Pinnacle West Energy. Pinnacle West Energy distributed the net proceeds of that loan to us to fund the repayment of a portion of the debt we incurred to finance the construction of the PWEC Dedicated Assets.

The ACC granted the Financing Order subject to various conditions. One of these conditions is that 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 ratio below that threshold, unless otherwise waived by the ACC.

In addition, the Financing Order required the ACC staff to conduct an inquiry into our and our affiliates' compliance with the retail electric competition and related rules and decisions. On June 13, 2003, APS submitted its report on these matters to the ACC staff. As part of the 2004 Settlement Agreement, this inquiry would be concluded with no further action by the ACC.

RETAIL ELECTRIC COMPETITION RULES The Rules approved by the ACC include the following major provisions:

- They apply to virtually all Arizona electric utilities regulated by the ACC, including APS.
- Effective January 1, 2001, retail access 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 discussed 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 affected 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 appealed the ruling to the Arizona Court of Appeals, and in January 2004, the Court invalidated some, but not all, of the Rules as either violative of Arizona's constitutional requirement that the ACC consider the "fair value" of a utility's property in setting rates or as being beyond the ACC's constitutional and statutory powers. Other Rules were set aside for failure to submit such regulations to the Arizona Attorney General for approval as required by statute. A request for the Arizona Supreme Court to review the Court of Appeals decision was denied on January 4, 2005.

TRACK A ORDER On September 10, 2002, the ACC issued the Track A Order, in which the ACC, among other things:

- 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
- 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.

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. The major provisions of the principles include, among other things, the following:

- APS and the ACC staff agreed that it would be appropriate for the ACC to consider the following matters in APS' general rate case, which was filed on June 27, 2003:
 - the generating assets to be included in APS' rate base, including the question of whether the PWEC Dedicated Assets 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 the 1999 Settlement Agreement; and
 - the appropriate treatment of costs incurred by APS in preparation for the previously anticipated transfer of generation assets to Pinnacle West Energy.
- As a result of the ACC's issuance of the Financing Order, APS' appeals of the Track A Order are limited to the issues described in the preceding bullet points.

On August 27, 2003, APS, Pinnacle West and Pinnacle West Energy filed a lawsuit asserting damage claims relating to the Track A Order. Arizona Public Service Company et al. v. The State of Arizona ex rel., Superior Court of the State of Arizona, County of Maricopa, No. CV2003-016372.

Upon the ACC's issuance of a final, non-appealable order approving the 2004 Settlement Agreement, APS, Pinnacle West, and Pinnacle West Energy will dismiss the litigation described under this "Track A" heading.

TRACK B ORDER On March 14, 2003, the ACC issued the Track B Order, which required APS to solicit bids for certain estimated amounts of capacity and energy for periods beginning July 1, 2003. For 2003, APS was required to solicit competitive bids for about 2,500 MW of capacity and about 4,600 gigawatt-hours of energy, or approximately 20% of APS' total retail energy requirements. APS issued requests for proposals in March 2003 and, by May 6, 2003, APS entered into contracts to meet all or a portion of its requirements for the years 2003 through 2006 as follows:

- Pinnacle West Energy agreed to provide 1,700 MW in July through September of 2003 and in June through September of 2004, 2005 and 2006, by means of a unit contingent contract.
- PPL Energy Plus, LLC agreed to provide 112 MW in July through September of 2003 and 150 MW in June through September of 2004 and 2005, by means of a unit contingent contract.
- Panda Gila River LP agreed to provide 450 MW in October of 2003 and 2004 and May of 2004 and 2005, and 225 MW from November 2003 through April 2004 and from November 2004 through April 2005, by means of firm call options.

Effective upon final ACC approval of the 2004 Settlement Agreement and the closing of the purchase of the Sundance Plant discussed below, the Track B contracts with Pinnacle West Energy and PPL Energy Plus, LLC will be cancelled.

REQUEST FOR PROPOSALS AND ASSET PURCHASE AGREEMENT In early December 2003, APS issued a request for proposals ("2003 RFP") for long-term power supply resources. On June 1, 2004, APS and PPL Sundance, a wholly-owned subsidiary of PPL Corporation, entered into an asset purchase agreement by which APS agreed to purchase the Sundance Plant. The Sundance Plant, which began commercial operation in July 2002, would provide peaking generation support for APS' system and reduce APS' growing needs for new generation resources. The purchase price for the Sundance Plant is approximately \$190 million.

On June 1, 2004, APS and PPL Sundance filed a joint application with the ACC with respect to APS' proposed acquisition of the Sundance Plant. On January 20, 2005, the ACC issued an order confirming APS' authority to "self-build or buy new generation assets for native load" and stated that APS' acquisition of the Sundance Plant would be a proper purpose under APS' existing ACC financing authorizations. APS' filings with the ACC also had requested that the ACC allow APS to defer for future recovery certain

capital and operating costs (net of fuel and purchased power savings) associated with the Sundance Plant acquisition until rate treatment for the Sundance Plant could be considered in APS' next general rate case. APS' filings estimated that the deferrals would be approximately \$10 million to \$15 million before income taxes on an annualized basis. The order issued by the ACC allows APS to record the deferrals for up to 36 months, subject to a number of conditions. However, if APS has a general rate case pending at the end of the 36-month period, the deferral period could extend until the rate case had been decided. The conditions imposed by the order are expected to substantially limit the amount of deferrals that APS will be able to record.

APS' acquisition of the Sundance Plant is subject to FERC approval and to customary closing conditions. The transaction is targeted to close in the spring of 2005.

APS does not expect to enter into any additional transactions as a result of the 2003 RFP.

PROVIDER OF LAST RESORT OBLIGATION Although the Rules allow retail customers to have access to competitive providers of energy and energy services, APS is, under the Rules, the "provider of last resort" for standard-offer, full-service customers under rates that have been approved by the ACC. 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. At various times, prices in the spot wholesale market have significantly exceeded the amount included in APS' current retail rates. There can be no assurance that APS would be able to fully recover the costs of this power. The proposed settlement of APS' general rate case, discussed above, would, among other things, allow APS to recover purchased power costs.

1999 SETTLEMENT AGREEMENT The following are the major provisions of a settlement agreement entered into in 1999, as approved by the ACC:

- APS has reduced 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; approximately \$28 million (\$17 million after taxes), effective July 1, 2002; and approximately \$29 million (\$18 million after taxes), effective 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 was a moratorium on retail price changes for standard-offer and unbundled competitive direct access services until July 1, 2004.
- APS is being 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, or when the rate case is decided. See "APS General Rate Case; 2004 Settlement Agreement" above.
- 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" above), including an additional 140 MW being made available to eligible non-residential customers. APS opened its distribution system to retail access for all customers on January 1, 2001.

- Prior to the 1999 Settlement Agreement, APS was recovering substantially all of its regulatory assets through July 1, 2004, pursuant to a 1996 regulatory agreement. In addition, the 1999 Settlement Agreement stated 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). The 1999 Settlement Agreement also stated that APS will not be allowed to recover \$183 million net present value (in 1999 dollars) (\$234 million pretax) of the \$533 million. The 1999 Settlement Agreement provided 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 of the \$350 million due to sales volume variances. As part of its general rate case request, APS sought the recovery of amounts written off by APS as a result of the 1999 Settlement Agreement. That claim would be given up under the terms of the 2004 Settlement Agreement (see above).
- The 1999 Settlement Agreement required APS to form, or cause to be formed, a separate corporate affiliate or affiliates and transfer to such affiliate(s) its competitive electric assets and services no later than December 31, 2002. The 1999 Settlement Agreement provided that APS would 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 discussed above under "Track A Order," in 2002 the ACC unilaterally modified this aspect of the 1999 Settlement Agreement by issuing an order preventing APS from transferring its generation assets. Under the 2004 Settlement Agreement, APS would recover all costs incurred by APS in preparation for the previously anticipated transfer of generation assets to Pinnacle West Energy. See "APS General Rate Case; 2004 Settlement Agreement" above. Such full recovery of divestiture costs would be allowed under the 2004 Settlement Agreement (see above).

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 and of electric restructuring 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.

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 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. On April 28, 2003, the FERC Staff issued an additional white paper on the proposed Standard Market Design. The white paper discusses several policy changes to the proposed Standard Market Design, including a greater emphasis on flexibility for regional needs. We 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.

The FERC has been, through its Office of Market Oversight and Investigations (OMOI), in the process of auditing a number of electric utilities regarding compliance with its regulations. Such an audit of APS and its affiliates was recently completed, and the FERC has issued an order approving the OMOI audit report and directing certain compliance actions. Arizona Public Service Company, 109 FERC 61,271 (2004).

Chief among the FERC's findings, APS must pay \$4 million for its use of unauthorized point-to-point transmission service. Of the \$4 million, APS must distribute: (1) \$2.75 million to upgrade the West Phoenix-Lincoln Street 230kV transmission line with high capacity composite conductors; and (2) \$1.25 million as a contribution to established low income energy assistance programs in Arizona. APS must not recover these monies from any existing or future wholesale or retail rate recovery mechanism, nor may it announce the low income payment as a public interest contribution. APS must also take certain corrective actions and make quarterly filings detailing its progress in implementing these actions until all are completed.

APS believes that the resolution of these matters will not have a material adverse effect on its financial position, results of operations or liquidity.

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 and a regulatory liability related to income taxes on its Balance Sheets in accordance with SFAS No. 71. The regulatory asset is for certain temporary differences, primarily the allowance for equity funds used during construction. The regulatory liability relates to excess deferred taxes resulting primarily from the reduction in federal income tax rates as part of the Tax Reform Act of 1986. APS amortizes this amount as the differences reverse.

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 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 2001 federal consolidated income tax return is currently under examination by the IRS. As part of this ongoing examination, the IRS is reviewing this accounting method change and the resultant deduction. During 2004, the current income tax liability was increased, with a corresponding decrease to plant-related deferred tax liability, to reflect the expected outcome of this audit. We do not expect the ultimate outcome of this examination to have a material adverse impact on our financial position, results of operations or liquidity.

The income tax liability accounts reflect the tax and interest associated with the most probable resolution of all known and measurable tax exposures.

In 2004 and 2003, we resolved certain prior-year issues with the taxing authorities and recorded tax benefits associated with tax credits and other reductions to income tax expense.

The components of income tax expense are as follows (dollars in thousands):

	Year Ended December 31,		
	2004	2003	2002
Current:			
Federal	\$ 200,133	\$ 22,875	\$ (43,492)
State	48,054	3,752	(14,732)
Total current	<u>248,187</u>	<u>26,627</u>	<u>(58,224)</u>
Deferred:			
Income from continuing operations	(113,850)	81,756	191,135
Discontinued operations	–	3,706	5,189
Cumulative effect of accounting change	–	–	(43,123)
Total deferred	<u>(113,850)</u>	<u>85,462</u>	<u>153,201</u>
Total income tax expense	<u>134,337</u>	<u>112,089</u>	<u>94,977</u>
Less: income tax expense/(benefit) on discontinued operations	5,480	9,616	(14,045)
Less: income tax benefit for cumulative effect of accounting change	–	–	(43,123)
Total income tax expense for income from continuing operations	<u>\$ 128,857</u>	<u>\$ 102,473</u>	<u>\$ 152,145</u>

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

	Year Ended December 31,		
	2004	2003	2002
Federal income tax expense at 35% statutory rate	\$ 127,426	\$ 114,897	\$ 136,048
Increases (reductions) in tax expense resulting from:			
State income tax net of federal income tax benefit	13,705	11,522	18,114
Credits and favorable adjustments related to prior years resolved in current year	(6,138)	(17,944)	–
Medicare Subsidy Part-D (see Note 8)	(1,778)	–	–
Allowance for equity funds used during construction (see Note 1)	(1,547)	(4,984)	–
Other	(2,811)	(1,018)	(2,017)
Income tax expense	<u>\$ 128,857</u>	<u>\$ 102,473</u>	<u>\$ 152,145</u>

The following table sets forth the net deferred income tax liability recognized on the Consolidated Balance Sheets (dollars in thousands):

	December 31,	
	2004	2003
Current liability	\$ (9,057)	\$ (631)
Long term liability	(1,227,553)	(1,338,527)
Accumulated deferred income taxes – net	<u>\$ (1,236,610)</u>	<u>\$ (1,339,158)</u>

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

	December 31,	
	2004	2003
DEFERRED TAX ASSETS		
Regulatory liabilities:		
Asset Retirement Obligation	\$ 182,086	\$ 169,322
Federal excess deferred income taxes	16,341	18,936
Other	8,282	8,302
Pension liability	91,973	73,844
Risk management and trading activities	91,021	59,293
Deferred gain on Palo Verde Unit 2 sale leaseback	19,816	21,656
Other	70,849	64,770
Total deferred tax assets	<u>480,368</u>	<u>416,123</u>
DEFERRED TAX LIABILITIES		
Plant-related	(1,516,174)	(1,614,887)
Risk management and trading activities	(146,037)	(84,124)
Regulatory assets	(54,767)	(56,270)
Total deferred tax liabilities	<u>(1,716,978)</u>	<u>(1,755,281)</u>
Accumulated deferred income taxes – net	<u>\$ (1,236,610)</u>	<u>\$ (1,339,158)</u>

5. LINES OF CREDIT AND SHORT-TERM BORROWINGS

APS had committed lines of credit with various banks of \$325 million at December 31, 2004 and \$250 million at December 31, 2003, which were available either to support the issuance of up to \$250 million in commercial paper or to be used for bank borrowings, including issuance of letters of credit. The current line matures in May 2007. The commitment fees at December 31, 2004 and 2003 for these lines of credit were 0.15% and 0.175% per annum. APS had no bank borrowings outstanding under these lines of credit at December 31, 2004 and 2003. APS had approximately \$4.8 million letters of credit issued under the line at December 31, 2004.

APS had no commercial paper borrowings outstanding at December 31, 2004 and 2003. 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 \$300 million at December 31, 2004 and \$275 million at December 31, 2003, which were available either to support the issuance of up to \$250 million in commercial paper or to be used for bank borrowings, including issuance of letters of credit. The current lines mature in October 2007. Pinnacle West had no outstanding borrowings at December 31, 2004 and December 31, 2003. Pinnacle West had approximately \$13 million of letters of credit issued under the line at December 31, 2004 and approximately \$15 million of letters of credit issued under the line at December 31, 2003. The commitment fees were 0.175% in 2004 and ranged from 0.125% to 0.175% in 2003. Pinnacle West had no commercial paper borrowings outstanding at December 31, 2004 and 2003. All APS and Pinnacle West bank lines of credit and commercial paper agreements are unsecured.

SunCor had revolving lines of credit totaling \$90 million at December 31, 2004 and \$120 million at December 31, 2003. The commitment fees were 0.125% in 2004 and 2003. SunCor had \$35 million outstanding at December 31, 2004 and \$50 million outstanding at December 31, 2003. The weighted-average interest rate was 4.50% at December 31, 2004 and 2003. Interest for 2004 and 2003 was based on LIBOR plus 2% or prime plus 0.5%. The balance is included in short-term debt on the Consolidated Balance Sheets. SunCor had other short-term loans in the amount of \$36 million at December 31, 2004 and December 31, 2003. These loans are made up of multiple notes primarily with variable interest rates based on LIBOR plus 2.5% at December 31, 2004 and 2003.

6. LONG-TERM DEBT

APS has retired all first mortgage bonds issued under its 1946 mortgage and deed of trust, including the first mortgage bonds securing APS senior notes. On April 30, 2004, APS terminated its mortgage and deed of trust and, as a result, is not able to issue any additional first mortgage bonds under that mortgage. SunCor's short and long-term 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, 2004 and 2003 (dollars in thousands):

	Maturity Dates (a)	Interest Rates	December 31,	
			2004	2003
APS				
First mortgage bonds (b)	2004	6.625%	\$ -	\$ 80,000
First mortgage bonds (c)	2028	5.50%	-	25,000
First mortgage bonds (d)	2028	5.875%	-	154,000
Unamortized discount and premium			(7,968)	(8,631)
Pollution control bonds (e)	2024-2034	(f)	565,860	386,860
Pollution control bonds with senior notes	2029	5.05%	90,000	90,000
Unsecured notes (g)	2004	5.875%	-	125,000
Unsecured notes	2005	6.25%	100,000	100,000
Unsecured notes	2005	7.625%	300,000	300,000
Unsecured notes	2011	6.375%	400,000	400,000
Unsecured notes	2012	6.50%	375,000	375,000
Unsecured notes	2033	5.625%	200,000	200,000
Unsecured notes	2015	4.650%	300,000	300,000
Unsecured notes (h)	2014	5.80%	300,000	-
Secured note	2014	6.00%	1,900	-
Senior notes (i)	2006	6.75%	83,695	83,695
Capitalized lease obligations	2006-2012	(j)	9,854	11,749
Subtotal			<u>2,718,341</u>	<u>2,622,673</u>
SUNCOR				
Notes payable	2006-2008	(k)	15,467	17,125
Capitalized lease obligations	2005-2007	8.91%	507	728
Subtotal			<u>15,974</u>	<u>17,853</u>
PINNACLE WEST				
Senior notes (l)	2006	6.40%	302,589	515,000
Unamortized discount and premium			(143)	(270)
Floating rate senior notes	2005	(m)	165,000	165,000
Capitalized lease obligations	2005-2007	5.45%	389	1,243
Subtotal			<u>467,835</u>	<u>680,973</u>
Total long-term debt (n)			<u>3,202,150</u>	<u>3,321,499</u>
Less current maturities (n)			<u>617,165</u>	<u>704,914</u>
TOTAL LONG-TERM DEBT LESS				
CURRENT MATURITIES			<u>\$ 2,584,985</u>	<u>\$ 2,616,585</u>

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

(b) On March 1, 2004, APS redeemed at maturity \$80 million of its First Mortgage Bonds, 6.625% Series due 2004.

(c) On March 31, 2004, APS redeemed \$25 million of its First Mortgage Bonds, 5.5% Series due 2028.

(d) On March 31, 2004, APS redeemed \$154 million of its First Mortgage Bonds, 5.875% Series due 2028.

(e) On March 31, 2004, Navajo County, Arizona Pollution Control Corporation issued \$166 million of variable interest rate pollution control bonds, 2004 Series A-E, due 2034. The bonds were issued to refinance \$166 million of outstanding pollution control bonds. The refinanced bonds were all \$25 million of the Navajo 5.50% bonds due 2028 (see (c) above) and \$141 million of the Navajo 5.875% bonds due 2028 (see (d) above). The Series A-E bonds are payable solely from revenues obtained from APS pursuant to a loan agreement between APS and Navajo County, Arizona Pollution Control Corporation. Also on March 31, 2004, Coconino County, Arizona Pollution Control Corporation issued \$13 million of variable interest rate pollution control bonds, 2004 Series A, due 2034. The bonds were issued to refinance \$13 million of outstanding pollution control bonds. The refinanced bonds were \$13 million of the Coconino 5.875% bonds due 2028 (see (d) above). The Series A bonds are payable solely from revenues obtained from APS pursuant to a loan agreement between APS and Coconino County, Arizona Pollution Control Corporation.

- (f) The weighted-average rate was 1.89% at December 31, 2004 and 1.51% at December 31, 2003. Changes in short-term interest rates would affect the costs associated with this debt.
- (g) On February 15, 2004, APS redeemed at maturity \$125 million of its 5.875% Notes due 2004.
- (h) On June 29, 2004, APS issued \$300 million of 5.80% senior unsecured notes due June 30, 2014. The proceeds from the sale of the notes were used to redeem \$100 million in aggregate principal amount of APS' 6.25% Notes due January 15, 2005 and a portion of \$300 million in aggregate principal amount of APS' 7.625% Notes due August 1, 2005.
- (i) Through April 30, 2004, APS had 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 due in 2029. The senior note mortgage bonds had the same interest rate, interest payment dates, maturity and redemption provisions as the senior notes. As long as the senior note mortgage bonds secured the senior notes, the senior notes effectively ranked equally with the first mortgage bonds. On April 30, 2004, when APS repaid all of its first mortgage bonds, other than those that secure senior notes, the senior note mortgage bonds were released from the senior note indenture, resulting in their no longer securing the senior notes and ceasing to be outstanding.
- (j) The weighted average rate was 5.78% at December 31, 2004 and 5.55% at December 31, 2003. Capital leases are included in property, plant and equipment on the Consolidated Balance Sheets for both December 31, 2004 and December 31, 2003.
- (k) Multiple notes with variable interest rates based on the lenders' prime plus 0.25%, lenders' prime plus 1.75% and LIBOR plus 2.50%. There are also two notes at fixed rates of 8.00% and 10.00%.
- (l) On January 29, 2004, we entered into a fixed-for-floating interest rate swap transaction on the \$300 million 6.40% senior note. The transaction qualifies as a fair value hedge under SFAS No. 133.
- (m) The weighted average rate was 2.06% at December 31, 2004 and 1.98% at December 31, 2003.
- (n) \$281 million of pollution control bonds at December 31, 2003 have been reclassified from long-term to current maturities. The bond holders had the ability to put these bonds to APS in the short-term on the interest rate reset date. Without a demonstrated intent to finance on a long-term basis (by use of credit agreements that extend for more than one year, etc.), GAAP requires the classification of the obligations as current maturities.

Pinnacle West's and APS' debt covenants related to their respective bank financing arrangements include a debt-to-total-capitalization ratio and an interest coverage test. Pinnacle West and APS comply with these covenants and each anticipates it will continue to meet those and significant covenant requirements. These covenants require that the ratio of debt to total capitalization cannot exceed 65% for the Company and for APS. At December 31, 2004, the ratio was approximately 53% for Pinnacle West and 54% for APS. The provisions regarding interest coverage require a minimum cash coverage of two times the interest requirements for each of the Company and APS. Based on 2004 results, the coverages were approximately 4 times for the Company and 4 times for APS. 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 that would result in defaults and the potential acceleration of payment under these loan agreements if Pinnacle West or APS were to default under other agreements. All of APS' bank agreements contain cross-default provisions that would result in defaults and the potential acceleration of payment under these bank agreements if APS were to default under other 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 our financial condition or financial prospects, except that Pinnacle West and APS do not have a material adverse change restriction for revolver borrowings equal to outstanding commercial paper amounts.

The following is a list of principal payments due on Pinnacle West's total long-term debt and capitalized lease requirements:

- \$618 million in 2005;
- \$398 million in 2006;
- \$174 million in 2007;
- \$7 million in 2008;
- \$1 million in 2009; and
- \$2,012 million, thereafter.

7. COMMON STOCK AND TREASURY STOCK

Our common stock and treasury stock activity during each of the three years 2004, 2003 and 2002 is as follows (dollars in thousands):

	Common Stock Shares	Common Stock Amount	Treasury Stock Shares	Treasury Stock Amount
Balance at December 31, 2001	84,824,947	\$ 1,536,924	(101,307)	\$ (5,886)
Common stock issuance	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)
Reissuance of treasury stock for stock compensation (net)	–	–	32,815	1,085
Other	–	7,096	–	–
Balance at December 31, 2003	91,379,947	1,744,354	(92,015)	(3,273)
Common stock issuance	422,914	18,291	–	–
Purchase of treasury stock	–	–	(80,000)	(2,986)
Reissuance of treasury stock for stock compensation (net)	–	–	162,493	5,831
Other	–	6,402	–	–
Balance at December 31, 2004	91,802,861	\$ 1,769,047	(9,522)	\$ (428)

8. RETIREMENT PLANS AND OTHER BENEFITS

Pinnacle West sponsors a qualified defined benefit and account balance 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 plan for all new employees in place of the defined benefit plan and, as of April 1, 2003, the plan was 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 retirement 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.

Pinnacle West also 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.

Pinnacle West uses a December 31 measurement date for its pension and other postretirement benefit plans.

On December 8, 2003, the President signed the "Medicare Prescription Drug, Improvement and Modernization Act of 2003" (the Act). One feature of the Act is a government subsidy of prescription drug cost. The FASB issued FSP 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," to address the accounting for the effects of the Act. During the third quarter of 2004, we retroactively adopted the provisions of FSP 106-2, resulting in the remeasurement of our postretirement benefit plans' accumulated postretirement benefit obligation as of December 31, 2003. The impact of the subsidy is a decrease in the accumulated projected benefit obligation of approximately \$65 million and a decrease of approximately \$11 million in the net periodic postretirement benefit cost for 2004. The 2004 after-tax reduction to expense is approximately \$5 million, excluding amounts capitalized as construction overhead or billed to electric plant participants.

The following table provides details of the plans' benefit costs. Also included is the portion of these costs charged to expense, including administrative costs and excluding amounts capitalized as overhead construction or billed to electric plant participants (dollars in thousands):

	Pension			Other Benefits		
	2004	2003	2002	2004	2003	2002
Service cost – benefits earned during the period	\$ 41,207	\$ 37,662	\$ 30,333	\$ 17,557	\$ 15,858	\$ 12,036
Interest cost on benefit obligation	81,873	76,951	71,242	29,488	30,163	25,235
Expected return on plan assets	(78,790)	(65,046)	(75,652)	(24,773)	(18,762)	(21,116)
Amortization of:						
Transition (asset)/obligation	(3,227)	(3,227)	(3,227)	3,005	3,005	4,001
Prior service cost/(credit)	2,401	2,401	2,912	(125)	(125)	(75)
Net actuarial loss	17,946	18,135	1,846	7,414	9,714	3,072
Net periodic benefit cost	\$ 61,410	\$ 66,876	\$ 27,454	\$ 32,566	\$ 39,853	\$ 23,153
Portion of cost charged to expense	\$ 25,792	\$ 30,094	\$ 13,727	\$ 13,678	\$ 17,934	\$ 11,577
APS share of costs charged to expense	\$ 22,483	\$ 25,450	\$ 10,947	\$ 11,923	\$ 15,166	\$ 9,232

The following table sets forth the plans' changes in the benefit obligations for the plan years 2004 and 2003 (dollars in thousands):

	Pension		Other Benefits	
	2004	2003	2004	2003
Benefit obligation at January 1	\$ 1,307,628	\$ 1,069,577	\$ 540,181	\$ 409,874
Service cost	41,207	37,662	17,557	15,858
Interest cost	81,873	76,951	29,488	30,163
Benefit payments	(45,195)	(43,869)	(14,332)	(15,749)
Actuarial losses/(gains)	68,731	171,420	(36,681)	106,475
Plan amendments	–	(4,113)	–	(6,440)
Benefit obligation at December 31	\$ 1,454,244	\$ 1,307,628	\$ 536,213	\$ 540,181

The following table sets forth the qualified pension plan and other benefit plan changes in the fair value of plan assets for the years 2004 and 2003 (dollars in thousands):

	Pension		Other Benefits	
	2004	2003	2004	2003
Fair value of plan assets at January 1	\$ 887,311	\$ 720,807	\$ 294,051	\$ 223,474
Actual return on plan assets	102,829	162,571	32,433	46,071
Employer contributions	35,000	46,000	32,600	39,852
Benefit payments	(42,858)	(42,067)	(7,000)	(15,346)
Fair value of plan assets at December 31	\$ 982,282	\$ 887,311	\$ 352,084	\$ 294,051

The following table shows a reconciliation of the funded status of the plans to the amounts recognized on the Consolidated Balance Sheets as of December 31, 2004 and 2003 (dollars in thousands):

	Pension		Other Benefits	
	2004	2003	2004	2003
Funded status at December 31	\$ (471,962)	\$ (420,317)	\$ (184,129)	\$ (246,130)
Unrecognized net transition (asset)/obligation	(3,873)	(7,099)	24,039	27,044
Unrecognized prior service cost/(credit)	14,234	16,634	(1,422)	(1,547)
Unrecognized net actuarial losses	375,980	348,982	158,271	217,611
Benefit liability recognized in the Consolidated Balance Sheets	\$ (85,621)	\$ (61,800)	\$ (3,241)	\$ (3,022)

The following sets forth the details related to benefits included on the Consolidated Balance Sheets at December 31, 2004 and 2003 (dollars in thousands):

	Pension		Other Benefits	
	2004	2003	2004	2003
Accrued benefit cost	\$ (85,621)	\$ (61,800)	\$ (3,241)	\$ (3,022)
Additional minimum liability	(148,824)	(126,241)	-	-
Total liability	(234,445)	(188,041)	(3,241)	(3,022)
Intangible asset	14,234	16,634	-	-
Accumulated other comprehensive loss (pretax)	134,590	109,607	-	-
Net amount recognized	\$ (85,621)	\$ (61,800)	\$ (3,241)	\$ (3,022)

The following table sets forth the other comprehensive income arising from the change in additional minimum liability for the years ended December 31, 2004 and 2003 (dollars in thousands):

	2004	2003
Decrease/(increase) in minimum liability included in other comprehensive income – net of tax:		
Pinnacle West consolidated	\$ (15,225)	\$ 4,700
APS share	\$ (13,930)	\$ 4,329

The following table sets forth the projected benefit obligation and the accumulated benefit obligation for pension plans in excess of plan assets for the plan years 2004 and 2003 (dollars in thousands):

	Year Ended December 31,	
	2004	2003
Projected benefit obligation	\$ 1,454,244	\$ 1,307,628
Accumulated benefit obligation	\$ 1,216,727	\$ 1,075,352
Less fair value of plan assets	982,282	887,311
Pinnacle West pension liability	\$ 234,445	\$ 188,041
APS share of pension liability	\$ 203,668	\$ 160,639

Below are the weighted-average assumptions for both the pension and other benefits used to determine each respective benefit obligation and net periodic benefit cost:

	Benefit Obligations		Benefit Costs For the	
	As of December 31,		Years Ended December 31,	
	2004	2003	2004	2003
Discount rate – pension	5.84%	6.10%	6.10%	6.75%
Discount rate – other benefits	5.92%	6.10%	6.10%	6.75%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Expected long-term return on plan assets	N/A	N/A	9.00%	9.00%
Initial health care cost trend rate	8.00%	8.00%	8.00%	8.00%
Ultimate health care cost trend rate	5.00%	5.00%	5.00%	5.00%
Year ultimate health care trend rate is reached	2009	2008	2008	2007

In selecting the pretax expected long-term rate of return on plan assets we consider past performance and economic forecasts for the types of investments held by the plan. For the year 2005, we are assuming a 9% rate of return on plan assets. As recent history has demonstrated, markets may decline and increase dramatically. However, we believe the long-term rate of return on plan assets of 9% is reasonable given our asset allocation in relation to historical and expected future performance.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A 1% change in the assumed initial and ultimate health care cost trend rates would have the following effects (dollars in millions):

	1% Increase	1% Decrease
Effect on other postretirement benefits expense, after consideration of amounts capitalized or billed to electric plant participants	\$ 6	\$ (5)
Effect on service and interest cost components of net periodic other postretirement benefit costs	\$ 10	\$ (8)
Effect on the accumulated other postretirement benefit obligation	\$ 96	\$ (76)

Plan Assets

Pinnacle West's qualified pension plan asset allocation at December 31, 2004 and 2003 is as follows:

ASSET CATEGORY	Percentage of Plan Assets at December 31,		Target Asset Allocation
	2004	2003	
Equity securities	60%	65%	60%
Fixed Income	27	23	30%
Other	13	12	10%
Total	100%	100%	

The Board of Directors has established an investment policy for the pension plan assets and has delegated oversight of the plan assets to an Investment Management Committee. The investment policy sets forth the objective of providing for future pension benefits by maximizing return consistent with acceptable levels of risk. The primary investment strategies are diversification of assets, stated asset allocation targets and ranges, prohibition of investments in Pinnacle West securities, and external management of plan assets.

Pinnacle West's other postretirement benefit plans' asset allocation at December 31, 2004 and 2003, is as follows:

ASSET CATEGORY	Percentage of Plan Assets at December 31,		Target Asset Allocation
	2004	2003	
Equity securities	71%	71%	70%
Fixed Income	23	25	27%
Other	6	4	3%
Total	100%	100%	

The Investment Management Committee, described above, has also been delegated oversight of the plan assets for the postretirement benefit plans. The investment policy for other postretirement benefit plans assets is similar to that of the pension plan assets described above.

Contributions

The minimum required contribution to be made to our pension plan in 2005 is estimated to be approximately \$50 million. The contribution to be made to other postretirement benefit plans in 2005 is estimated to be approximately \$40 million. APS' share is approximately 92% of both plans.

Estimated Future Benefit Payments

Benefit payments, which reflect estimated future employee service, for the next five years and the succeeding five years thereafter are estimated to be as follows (dollars in thousands):

	Pension	Other Benefits (a)
2005	\$ 47,365	\$ 15,595
2006	50,848	15,470
2007	54,381	16,947
2008	59,021	18,404
2009	64,858	20,095
Years 2010-2014	443,578	139,329

(a) The expected future other benefit payments take into account the Medicare Part D subsidy.

Employee Savings Plan Benefits

Pinnacle West sponsors a defined contribution savings plan for eligible employees of Pinnacle West and subsidiaries. In 2004, APS represented 91% of the total cost of this plan. In a defined contribution savings plan, the benefits a participant receives result from regular contributions participants make to their own individual account. Under this plan, the Company matches a percentage of the participants' contributions in the form of Pinnacle West stock. After a five year vesting period, participants have an option to transfer the Company matching contributions out of the Pinnacle West Stock Fund to other investment funds within the plan. At December 31, 2004, approximately 22% of total plan assets were in Pinnacle West stock. Pinnacle West recorded expenses for this plan of approximately \$5 million for each of the years 2004, 2003 and 2002. APS recorded expenses for this plan of approximately \$5 million in 2004, \$5 million in 2003 and \$4 million in 2002.

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. Rent expense is 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 \$69 million in 2004, \$67 million in 2003 and \$67 million in 2002.

The amounts to be paid for the Palo Verde Unit 2 leases are approximately \$49 million per year for the years 2005 to 2015.

Estimated future minimum lease payments for Pinnacle West's operating leases are approximately as follows (dollars in millions):

Year	
2005	\$ 73
2006	70
2007	69
2008	67
2009	65
Thereafter	<u>368</u>
Total future lease commitments	<u>\$ 712</u>

10. JOINTLY-OWNED FACILITIES

APS shares ownership of some of its generating and transmission facilities with other companies. Pinnacle West Energy shares ownership of its Silverhawk Plant. Our share of operating and maintaining these facilities is included in the Consolidated Statements of Income in operations and maintenance expense. The following table shows APS' and Pinnacle West Energy's interests in those jointly-owned facilities recorded on the Consolidated Balance Sheets at December 31, 2004 (dollars in thousands):

	Percent Owned	Plant in Service	Accumulated Depreciation	Construction Work in Progress
APS				
Generating Facilities:				
Palo Verde Units 1 and 3	29.1%	\$ 1,877,846	\$ (915,611)	\$ 51,914
Palo Verde Unit 2 (see Note 9)	17.0%	665,994	(253,083)	15,816
Four Corners Units 4 and 5	15.0%	147,067	(83,525)	457
Navajo Generating Station Units 1, 2, and 3	14.0%	248,509	(117,922)	2,132
Cholla common facilities (a)	62.4%(b)	80,122	(47,134)	1,553
Transmission Facilities:				
ANPP500KV System	35.8%(b)	67,762	(27,898)	1,026
Navajo Southern System	31.4%(b)	27,044	(16,880)	1,576
Palo Verde – Yuma 500KV System	23.9%(b)	10,347	(4,545)	26
Four Corners Switchyards	27.5%(b)	2,852	(1,801)	–
Phoenix – Mead System	17.1%(b)	36,418	(2,723)	–
Palo Verde – Estrella 500KV System	55.5%(b)	72,613	(2,907)	841
Palo Verde – Southeast Valley Project	15.0%(b)	–	–	1,136
Harquahala	80.0%(b)	–	–	10
PINNACLE WEST ENERGY				
Generating Facilities:				
Silverhawk	75.0%	301,288	(6,954)	21

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

(b) Weighted average of interests.

11. COMMITMENTS AND CONTINGENCIES

Palo Verde Nuclear Generating Station

Spent Nuclear Fuel and Waste Disposal

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, including APS (on behalf of itself and the other Palo Verde owners), filed damages actions against the DOE in the Court of Federal Claims. [Arizona Public Service Company v. United States of America](#), United States Court of Federal Claims, 03-2832C.

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. The State of Nevada has filed several lawsuits relating to the Yucca Mountain site. We cannot currently predict what further steps will be taken in this area.

APS has existing fuel storage pools at Palo Verde and is operating 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 2004 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, 2004, APS had spent \$11 million for on-site interim spent nuclear fuel storage. APS has recorded a regulatory asset of \$11 million and is currently seeking recovery of these costs through future rates (see "APS General Rate Case; 2004 Settlement Agreement" in Note 3).

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

Nuclear Insurance

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 \$300 million and the balance by an industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the programs exceed the accumulated funds, APS could be assessed retrospective premium adjustments. The maximum assessment per reactor under the program for each nuclear incident is approximately \$101 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 \$88 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 2005 through 2025 that include required purchase provisions. We estimate the contract requirements to be approximately \$187 million in 2005; \$90 million in 2006; \$81 million in 2007; \$66 million in 2008; \$68 million in 2009 and \$363 million thereafter. 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 supply have take-or-pay provisions. The current take-or-pay coal contracts have terms that expire in 2016.

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

	Estimated Years Ending December 31,					
	2005	2006	2007	2008	2009	Thereafter
Coal take-or-pay commitments (a)	\$ 48	\$ 48	\$ 49	\$ 42	\$ 44	\$ 311

(a) Total take-or-pay commitments are approximately \$542 million. The total net present value of these commitments is approximately \$389 million.

Coal Mine Reclamation Obligations

APS must reimburse certain coal providers for amounts incurred for coal mine reclamation. APS' coal mine reclamation obligation was \$61 million at December 31, 2004 and \$60 million at December 31, 2003 and is included in deferred credits-other on the Consolidated Balance Sheets.

California Energy Market Issues and Refunds in the Pacific Northwest

FERC

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. 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. The FERC is still considering the evidence and refund amounts have not yet been finalized. 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 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 under market-based rates. 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 was dismissed by the FERC and the State of California appealed the matter to the Ninth Circuit Court of Appeals. In an order issued September 9, 2004, the Ninth Circuit upheld the FERC’s authority to permit market-based rates, but rejected the FERC’s claim that it was without authority to consider retroactive refunds when a utility has not strictly adhered to the quarterly reporting requirements of the market-based rate system. On September 9, 2004, the Ninth Circuit remanded the case to the FERC for further proceedings. State of California ex rel. Bill Lockyer, Attorney General v. FERC, No. 02-73093. Several of the intervenors in this appeal filed a petition for rehearing of this decision on October 25, 2004. The outcome of the further proceedings cannot be predicted at this time.

The FERC also ordered an evidentiary proceeding to discuss and evaluate possible refunds for the Pacific Northwest. The FERC affirmed the ALJ’s conclusion that the prices in the Pacific Northwest were not unreasonable or unjust and refunds should not be ordered in this proceeding. This decision has now been appealed to the Court of Appeals (Ninth Circuit). Although the FERC ruling in the Pacific Northwest matter is being appealed and the FERC has not yet 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 the 2000-2001 time period, including APS, may potentially have been involved in arbitrage transactions that allegedly violated certain provisions of the ISO tariff. After reviewing the matter, along with the data supplied by APS, the FERC staff moved to dismiss the claims against APS and to dismiss the proceeding. The motion to dismiss was granted by the FERC on January 22, 2004. Certain parties have sought rehearing of this order, and that request is pending.

California Civil Energy Market Litigation

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 California independent system operator 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, which, after moving to state court, has been removed to the federal court for a second time. James Millar, et al. v. Allegheny Energy Supply, et al., San Francisco Superior Court, Case No. 407867, U.S. District Court (Northern District) C-04-0519 SBA. The First Amended Complaint alleges basically that the contracts entered into were the result of an unfair and unreasonable market, in violation of California unfair competition laws.

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 motions continue to be filed, and we currently believe these claims will have no material adverse impact on our financial position, results of operations or liquidity.

Construction Program

Consolidated capital expenditures in 2005 are estimated to be (dollars in millions):

APS	\$ 772
Pinnacle West Energy	7
SunCor	114
Other	<u>8</u>
Total	<u>\$ 901</u>

Natural Gas Supply

Pursuant to the terms of a comprehensive settlement entered into in 1996 with El Paso Natural Gas Company, the rates charged for natural gas transportation are subject to a rate moratorium through December 31, 2005.

On July 9, 2003, the FERC issued an order that altered the capacity rights of parties to the 1996 settlement, but maintained the cost responsibility provisions agreed to by parties to that settlement. The D.C. Court of Appeals recently upheld the FERC's authority to alter the capacity rights of parties to the settlement. With respect to the FERC's authority to maintain the cost of responsibility provisions of the settlement, a party has sought appellate review and is seeking to reallocate the costs responsibility associated with the changed contractual obligations in a way that would be less favorable to APS and Pinnacle West Energy than under the FERC's July 9, 2003 order. Should this party prevail on this point, APS and Pinnacle West Energy's annual capacity cost could be increased by approximately \$3 million per year, from September 2003 through December 2005.

El Paso is required under the terms of the 1996 settlement to file a new rate case by July 1, 2005, with new rates to become effective on January 1, 2006. APS cannot currently assess the financial impact that El Paso's filing could have on rates.

Navajo Nation Litigation

In June 1999, the Navajo Nation served Salt River project with a lawsuit naming Salt River Project, several Peabody Coal Company entities (collectively, "Peabody"), Southern California Edison Company and other defendants, and citing various claims in connection with the renegotiations of the coal royalty and lease agreements under which Peabody mines coal for the Navajo Generating Station and the Mohave Generating Station. The Navajo Nation v. Peabody Holding Company, Inc., et al., United States District Court for the District of Columbia, CA-99-0469-EGS (the "D.C. Lawsuit"). APS is a 14% owner of the Navajo Generating Station, which, Salt River Project operates. The D.C. Lawsuit alleges, among other things, that the defendants obtained a favorable coal royalty rate by improperly influencing the outcome of a federal administrative process under which the royalty rate was to be adjusted. The suit seeks \$600 million in damages, treble damages, punitive damages of not less than \$1 billion, and the ejection of defendants "from all possessory interests and Navajo Tribal lands arising out of the (primary coal lease)." In July 2001, the court dismissed all claims against Salt River Project.

In January, 2005, Peabody served APS with a lawsuit naming APS and the other Navajo Generating Station participants and seeking, among other things, a declaration that the participants "are obligated to reimburse Peabody for any royalty tax, or other obligation arising out of the D.C. Lawsuit". Peabody Western Coal Company v. Salt River Project Agricultural Improvement and Power District, et al., Circuit Court for the City of St. Louis, Division No. 1, Cause No. 042-08561. Based on APS' ownership interest in the Navajo Generating Station, APS could be liable for up to 14% of any such obligation. Because the litigation is in preliminary stages, APS cannot currently predict the outcome of this matter.

Litigation

We are party to various other 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 EPA and ADEQ issues. In our opinion, the ultimate resolution of these matters will not have a material adverse effect on our financial position, results of operations or liquidity.

12. ASSET RETIREMENT OBLIGATIONS

APS has asset retirement obligations for its Palo Verde nuclear facilities and certain other generation, transmission and distribution assets. The Palo Verde asset retirement obligation primarily relates to final plant decommissioning. This obligation is based on the NRC's requirements for disposal of radiated property or plant and agreements APS reached with the ACC for final decommissioning of the plant. The non-nuclear generation asset retirement obligations primarily relate to requirements for removing portions of those plants at the end of the plant life or lease term. Some of APS' transmission and distribution assets have asset retirement obligations because they are subject to right of way and easement agreements that require final removal. These agreements have a history of uninterrupted renewal that APS expects to continue. As a result, APS cannot reasonably estimate the fair value of the asset retirement obligation related to such distribution and transmission assets. The asset retirement obligations associated with our non-regulated assets are immaterial.

To fund the costs APS expects to incur to decommission Palo Verde, APS established external decommissioning trusts in accordance with NRC regulations. APS invests the trust funds in fixed income and domestic equity securities and classifies them as available for sale. The following table shows the cost and fair value of APS' nuclear decommissioning trust fund assets which are on the Consolidated Balance Sheets at December 31, 2004 and December 31, 2003 (dollars in millions):

	December 31,	
	2004	2003
Trust fund assets – at cost		
Fixed income securities	\$ 134	\$ 124
Domestic stock	83	74
Total	<u>\$ 217</u>	<u>\$ 198</u>
Trust fund assets – at fair value		
Fixed income securities	\$ 150	\$ 140
Domestic stock	118	101
Total	<u>\$ 268</u>	<u>\$ 241</u>

The following schedule shows the change in our asset retirement obligations during the years ended December 31, 2004 and 2003 (dollars in millions):

	2004	2003
At beginning of year	\$ 234	\$ 219
Changes attributable to:		
Liabilities incurred	-	-
Liabilities settled	(1)	-
Accretion expense	17	15
Estimated cash flow revisions	2	-
At end of year	<u>\$ 252</u>	<u>\$ 234</u>

In accordance with SFAS No. 71, APS accrues for removal costs for its regulated assets, even if there is no legal obligation for removal. At December 31, 2004, regulatory liabilities shown on Pinnacle West's Consolidated Balance Sheets included approximately \$462 million of estimated future removal costs that are not considered legal obligations.

13. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following note presents quarterly financial information for 2004 and 2003. We are disclosing originally reported amounts and revised amounts in the first and second quarters of 2004 due to the adoption of FSP 106-2, which was implemented on June 30, 2004 (see Note 8) and in each period for the reclassification of NAC as discontinued operations (see Note 22).

Consolidated quarterly financial information for 2004 and 2003 is as follows (dollars in thousands, except per share amounts):

	2004 Quarter Ended				2004
	March 31,	June 30,	Sept. 30,	Dec. 31,	Total
As originally reported:					
Operating Revenues	\$ 574,369	\$ 722,686	\$ 886,779	\$ 734,718	\$ 2,918,552
Operations and Maintenance	138,656	140,245	160,765	159,431	599,097
Operating Income	83,371	121,160	210,836	90,745	506,112
Income Taxes	15,627	44,027	58,900	11,283	129,837
Income from Continuing Operations	29,768	71,057	103,886	29,318	234,029
Net Income (a)	30,156	71,370	105,400	33,729	240,655
NAC Reclassifications (see Note 22):					
Operating Revenues	(8,024)	(10,803)	-	-	(18,827)
Operating Income	(443)	(1,950)	-	-	(2,393)
Income Taxes	(159)	(821)	-	-	(980)
Income from Continuing Operations	(247)	(1,104)	-	-	(1,351)
Medicare Subsidy Adoption (See Note 8):					
Operations and Maintenance	(1,270)	(1,270)	-	-	(2,540)
Operating Income	1,270	1,270	-	-	2,540
Income from Continuing Operations	1,270	1,270	-	-	2,540
Net Income	1,270	1,270	-	-	2,540
After NAC Reclassifications and Medicare Subsidy Adoption:					
Operating Revenues	566,345	711,883	886,779	734,718	2,899,725
Operations and Maintenance	137,386	138,975	160,765	159,431	596,557
Operating Income	84,198	120,480	210,836	90,745	506,259
Income Taxes	15,468	43,206	58,900	11,283	128,857
Income from Continuing Operations	30,791	71,223	103,886	29,318	235,218
Net Income (a) (b)	31,426	72,640	105,400	33,729	243,195
2003 Quarter Ended					
	March 31,	June 30,	Sept. 30,	Dec. 31,	Total
As originally reported:					
Operating Revenues	\$ 552,643	\$ 683,302	\$ 847,703	\$ 734,204	\$ 2,817,852
Operating Income	69,255	132,482	198,850	81,466	482,053
Income Taxes	12,754	35,248	50,528	7,030	105,560
Income from Continuing Operations	20,153	54,889	109,538	45,996	230,576
Net Income (a)	25,298	56,142	110,048	49,091	240,579
NAC Reclassifications (see Note 22):					
Operating Revenues	(11,382)	(19,637)	(16,701)	(10,638)	(58,358)
Operating Income	(3,675)	(1,347)	(1,489)	(1,600)	(8,111)
Income Taxes	(1,402)	(507)	(567)	(611)	(3,087)
Income from Continuing Operations	(2,167)	(783)	(878)	(945)	(4,773)
Reclassified:					
Operating Revenues	541,261	663,665	831,002	723,566	2,759,494
Operating Income	65,580	131,135	197,361	79,866	473,942
Income Taxes	11,352	34,741	49,961	6,419	102,473
Income from Continuing Operations	17,986	54,106	108,660	45,051	225,803
Net Income (a) (b)	25,298	56,142	110,048	49,091	240,579

(a) Includes income from discontinued operations at SunCor (see Note 22).

(b) Includes income (loss) from NAC's discontinued operations (see Note 22).

	2004 Quarter Ended			
	March 31,	June 30,	Sept. 30,	Dec. 31,
As originally reported – Basic earnings per share (a):				
Income From Continuing Operations	\$ 0.33	\$ 0.78	\$ 1.14	\$ 0.32
Net Income	0.33	0.78	1.15	0.37
After NAC reclassification and Medicare subsidy adoption –				
Basic earnings per share (a):				
Income from Continuing Operations	0.34	0.78	1.14	0.32
Net Income	0.34	0.80	1.15	0.37
As originally reported – Diluted earnings per share (a):				
Income From Continuing Operations	0.33	0.78	1.14	0.32
Net Income	0.33	0.78	1.15	0.37
After NAC reclassification and Medicare subsidy adoption –				
Diluted earnings per share (a):				
Income From Continued Operations	0.34	0.78	1.14	0.32
Net Income	0.34	0.79	1.15	0.37

	2003 Quarter Ended			
	March 31,	June 30,	Sept. 30,	Dec. 31,
As originally reported – Basic earnings per share (b):				
Income From Continuing Operations	\$ 0.22	\$ 0.60	\$ 1.20	\$ 0.50
Net Income	0.28	0.62	1.21	0.54
Reclassified – Basic earnings per share (b):				
Income From Continuing Operations	0.20	0.59	1.19	0.49
Net Income	0.28	0.62	1.21	0.54
As originally reported – Diluted earnings per share (b):				
Income From Continuing Operations	0.22	0.60	1.20	0.50
Net Income	0.28	0.61	1.20	0.54
Reclassified – Diluted earnings per share (b):				
Income From Continued Operations	0.20	0.59	1.19	0.49
Net Income	0.28	0.61	1.20	0.54

- (a) The difference between originally reported and revised basic and diluted earnings per share related to the sale of NAC (see Note 22) and the adoption of the Medicare subsidy which changed reported amounts for the first and second quarter of 2004 (See Note 8). The earnings per share impact from the sale of NAC or the adoption of the Medicare subsidy did not change earnings per share by more than \$0.02 in any given quarter in 2004.
- (b) The difference between originally reported and reclassified basic and diluted earnings per share for income from continuing operations related to the sale of NAC (see Note 22). The earnings per share impact from the sale of NAC did not change earnings per share by more than \$0.02 in any given quarter in 2003.

14. FAIR VALUE OF FINANCIAL INSTRUMENTS

We believe that the carrying amounts of our cash equivalents are reasonable estimates of their fair values at December 31, 2004 and 2003 due to their short maturities.

We hold investments in debt securities for purposes other than trading. We believe that the carrying amounts of these investments represent reasonable estimates of their fair values at December 31, 2004 and 2003 due to the short-term reset of interest rates.

We also hold investments in fixed income and domestic equity securities for purposes other than trading. The December 31, 2004 and 2003 fair values of such investments, which we determine by using quoted market prices, approximate their carrying amount. For further information, see disclosure of cost and fair value of APS' nuclear decommissioning trust fund assets in Note 12.

On December 31, 2004, the carrying value of our long-term debt (excluding capitalized lease obligations) was \$3.19 billion, with an estimated fair value of \$3.30 billion. The carrying value of our long-term debt (excluding capitalized lease obligations) was \$3.31 billion on December 31, 2003, with an estimated fair value of \$3.46 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, 2004, 2003 and 2002:

	2004	2003	2002
Basic earnings per share:			
Income from continuing operations	\$ 2.57	\$ 2.47	\$ 2.79
Income (loss) from discontinued operations	0.09	0.17	(0.26)
Cumulative effect of change in accounting	-	-	(0.77)
Earnings per share – basic	<u>\$ 2.66</u>	<u>\$ 2.64</u>	<u>\$ 1.76</u>
Diluted earnings per share:			
Income from continuing operations	\$ 2.57	\$ 2.47	\$ 2.78
Income (loss) from discontinued operations	0.09	0.16	(0.25)
Cumulative effect of change in accounting	-	-	(0.77)
Earnings per share – diluted	<u>\$ 2.66</u>	<u>\$ 2.63</u>	<u>\$ 1.76</u>

Dilutive stock options increased average common shares outstanding by approximately 135,000 shares in 2004, 140,000 shares in 2003 and 61,000 shares in 2002. Total average common shares outstanding for the purposes of calculating diluted earnings per share were 91,532,473 shares in 2004, 91,405,134 shares in 2003 and 84,963,921 shares in 2002.

Options to purchase 1,058,616 shares of common stock were outstanding at December 31, 2004 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 2,291,646 at December 31, 2003 and 1,629,958 at December 31, 2002.

16. STOCK-BASED COMPENSATION

Pinnacle West offers stock-based compensation plans for officers and key employees of the 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 share 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 includes outstanding options but no new options will be granted under the plan. Options vested 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 provided 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.

In addition, see Note 2 for discussion of a new standard on share based payments (SFAS No. 123R).

Total stock-based compensation cost, including restricted stock, performance shares, stock options, and stock ownership incentives was \$8 million in 2004, \$6 million in 2003 and \$5 million in 2002 for Pinnacle West, and \$6 million in 2004, \$3 million in 2003 and \$3 million in 2002 for APS.

The following table is a summary of the status of outstanding stock options under our equity incentive plans as of December 31, 2004, 2003 and 2002 and changes during the years ending on those dates:

	2004 Shares	2004 Weighted Average Exercise Price	2003 Shares	2003 Weighted Average Exercise Price	2002 Shares	2002 Weighted Average Exercise Price
Outstanding at beginning of year	2,698,246	\$ 38.56	2,185,129	\$ 39.96	1,832,725	\$ 39.52
Granted	37,580	37.85	621,875	32.29	603,900	38.37
Exercised	(372,205)	34.02	(62,366)	26.09	(163,381)	28.25
Forfeited	(87,498)	42.31	(46,392)	37.61	(88,115)	41.54
Outstanding at end of year	<u>2,276,123</u>	<u>39.14</u>	<u>2,698,246</u>	<u>38.56</u>	<u>2,185,129</u>	<u>39.96</u>
Options exercisable at year-end	<u>1,859,340</u>	<u>40.59</u>	<u>1,787,622</u>	<u>40.35</u>	<u>1,155,357</u>	<u>39.66</u>
Weighted average fair value of options granted during the year		\$ 3.53		\$ 7.37		\$ 6.16

The following table summarizes information about our stock options at December 31, 2004:

Exercise Prices Per Share	Options Outstanding	Weighted-Average Exercise Price	Weighted Average Remaining Contract Life (Years)	Options Exercisable	Weighted-Average Exercise Price
\$23.39 – 28.07	4,750	\$ 27.44	0.5	4,750	\$ 27.44
28.07 – 32.75	515,344	32.24	7.8	129,706	32.10
32.75 – 37.42	138,863	34.72	4.4	138,863	34.72
37.42 – 42.10	693,482	38.83	5.9	662,337	38.87
42.10 – 46.78	923,684	43.95	5.4	923,684	43.95
	<u>2,276,123</u>			<u>1,859,340</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, 2004, 2003 and 2002:

	2004 Shares	2004 Grant Price	2003 Shares	2003 Grant Price	2002 Shares	2002 Grant Price
Restricted stock	4,000	\$ 37.68(a)	4,000	\$ 32.20(a)	6,000	\$ 38.84(a)
Performance share awards	215,285	37.85(b)	119,085	32.29(b)	115,975	38.37(b)
Stock ownership incentive awards	9,015	40.29(c)	–	–	–	–

(a) Restricted stock priced at the average of the high and low market price on the grant date.

(b) Performance shares priced at the closing market price on the grant date.

(c) 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 traditional regulated retail and wholesale electricity businesses (primarily electricity service to Native Load customers) and related activities and includes electricity generation, transmission and distribution;
- our marketing and trading segment, which consists of our competitive energy 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.

In 2004, our other segment includes a \$35 million gain (\$21 million after-tax) related to the sale of El Dorado's limited partnership interest in the Phoenix Suns. The other segment also includes activity related to APS Energy Services' non-commodity trading activities, as well as the parent company and other subsidiaries.

Financial data for the years ended December 31, 2004, 2003 and 2002 by business segments is provided as follows (dollars in millions):

	Business Segments for the Year Ended December 31, 2004				
	Regulated Electricity	Marketing and Trading	Real Estate	Other	Total
Operating revenues	\$ 2,035	\$ 462	\$ 360	\$ 43	\$ 2,900
Purchased power and fuel costs	568	382	–	–	950
Other operating expenses	685	34	290	34	1,043
Operating margin	782	46	70	9	907
Depreciation and amortization	384	11	6	–	401
Interest expense	169	8	2	–	179
Other expense/(income)	4	(2)	(5)	(34)	(37)
Pretax margin	225	29	67	43	364
Income taxes	74	11	27	17	129
Income from continuing operations	151	18	40	26	235
Income from discontinued operations – net of income taxes of \$5 (see Note 22)	–	–	4	4	8
Net income	\$ 151	\$ 18	\$ 44	\$ 30	\$ 243
Total assets	\$ 8,674	\$ 746	\$ 454	\$ 23	\$ 9,897
Capital expenditures	\$ 483	\$ 34	\$ 81	\$ –	\$ 598

	Business Segments for the Year Ended December 31, 2003				
	Regulated Electricity	Marketing and Trading	Real Estate	Other	Total
Operating revenues	\$ 1,978	\$ 392	\$ 362	\$ 27	\$ 2,759
Purchased power and fuel costs	517	345	–	–	862
Other operating expenses	625	34	306	23	988
Operating margin	836	13	56	4	909
Depreciation and amortization	428	1	6	–	435
Interest expense	172	–	2	1	175
Other expense/(income)	(4)	–	(25)	–	(29)
Pretax margin	240	12	73	3	328
Income taxes	70	3	28	1	102
Income from continuing operations	170	9	45	2	226
Income from discontinued operations – net of income taxes of \$10 (see Note 22)	–	–	10	5	15
Net income	\$ 170	\$ 9	\$ 55	\$ 7	\$ 241
Total assets	\$ 8,373	\$ 680	\$ 439	\$ 27	\$ 9,519
Capital expenditures	\$ 686	\$ 9	\$ 72	\$ –	\$ 767

	Business Segments for the Year Ended December 31, 2002				
	Regulated Electricity	Marketing and Trading	Real Estate	Other	Total
Operating revenues	\$ 1,890	\$ 287	\$ 201	\$ 27	\$ 2,405
Purchased power and fuel costs	377	155	–	–	532
Other operating expenses	659	34	185	22	900
Operating margin	854	98	16	5	973
Depreciation and amortization	416	2	4	–	422
Interest expense	141	–	2	–	143
Other expense/(income)	19	–	(7)	7	19
Pretax margin	278	96	17	(2)	389
Income taxes	108	38	7	(1)	152
Income (loss) from continuing operations	170	58	10	(1)	237
Income (loss) from discontinued operations – net of income taxes of \$14 (see Note 22)	–	–	9	(31)	(22)
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
Capital expenditures	\$ 893	\$ 19	\$ 72	\$ –	\$ 984

18. DERIVATIVE AND ENERGY TRADING ACCOUNTING

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal, emissions allowances and in interest rates. We manage risks associated with these market fluctuations by utilizing various instruments that qualify as derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. As part of our overall risk management program, we use such instruments to hedge our exposure to changes in interest rates and to hedge purchases and sales of electricity, fuels, and emissions allowances and credits. As of December 31, 2004, we hedged exposures to the price variability of the commodities for a maximum of eight years. The changes in market value of such contracts have a high correlation to price changes in the hedged transactions. In addition, subject to specified risk parameters monitored by the ERMC, we engage in marketing and trading activities intended to profit from market price movements.

We recognize all derivatives, except those which receive a scope exception, as either assets or liabilities on the balance sheet and measure those instruments at fair value in accordance with SFAS No. 133, as amended by SFAS No. 149. Derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business receive the normal purchase and sales exception and are accounted for under the accrual method of accounting. Changes in the fair value of derivative instruments are recognized periodically in income unless certain hedge criteria are met. For cash flow hedges, changes in the fair value of the derivative are recognized in common stock equity (as a component of other comprehensive income (loss)). For fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item associated with the hedged risk are recognized in earnings. We use cash flow hedges to limit our exposure to cash flow variability on forecasted transactions. We use fair value hedges to limit our exposure to changes in fair value of an asset or liability.

We assess hedge effectiveness both at inception and on a continuing basis. 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.

Both non-trading and trading derivatives that do not receive a scope exception are classified as assets and liabilities from risk management and trading activities on the Consolidated Balance Sheets. Certain of our non-trading derivatives qualify for cash flow hedge accounting treatment. 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.

All gains and losses (realized and unrealized) on trading contracts that qualify as derivatives are included in marketing and trading segment revenues on the Consolidated Statements of Income on a net basis. Trading contracts that do not meet the definition of a derivative are accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received.

In the electricity business, some contracts to purchase energy are netted against other contracts to sell energy. This is called "book-out" and usually occurs in contracts that have the same terms (quantities and delivery points) and for which power does not flow. We net these book-outs, which reduces both revenues and purchased power and fuel costs in our Consolidated Statement of Income, but this does not impact our financial condition, net income or cash flows.

In November 2003, the FASB revised its derivative guidance in DIG Issue No. C15, "Normal Purchases and Normal Sales Exception for Option-Type Contracts and Forward Contracts in Electricity." Effective January 1, 2004, the new guidance changed the criteria for the normal purchases and sales scope exception for electricity contracts. The implementation of this guidance did not have a material impact on our consolidated 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.

Cash Flow Hedges

The changes in the fair value of our hedged positions included in the Consolidated Statements of Income for the years ended December 31, 2004, 2003 and 2002 are comprised of the following (dollars in thousands):

	2004	2003	2002
Gains/(losses) on the ineffective portion of derivatives qualifying for hedge accounting	\$ (1,568)	\$ 8,237	\$ 9,763
Gains/(losses) from the change in options' time value excluded from measurement of effectiveness	185	181	(2,484)
Gains from the discontinuance of cash flow hedges	1,137	-	386

During the twelve months ending December 31, 2005, we estimate that a net gain of \$44 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.

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

- Regulated Electricity – non-trading derivative instruments that hedge our purchases and sales of electricity and fuel for APS' Native Load requirements of our regulated electricity business segment; and
- Marketing and Trading – both non-trading and trading derivative instruments of our competitive business segment.

The following table summarizes our assets and liabilities from risk management and trading activities at December 31, 2004 and 2003 (dollars in thousands):

	December 31, 2004				
	Current Assets	Investments	Current Liabilities	Other Liabilities	Net Asset/ (Liability)
Regulated electricity:					
Mark-to-market	\$ 45,220	\$ 19,417	\$ (19,191)	\$ (12,000)	\$ 33,446
Options and margin account	18,821	118	(8,879)	–	10,060
Marketing and trading:					
Mark-to-market	102,855	204,512	(68,008)	(132,683)	106,676
Emission allowances – at cost and margin account	–	294	(17,328)	(11,579)	(28,613)
Total	<u>\$ 166,896</u>	<u>\$ 224,341</u>	<u>\$ (113,406)</u>	<u>\$ (156,262)</u>	<u>\$ 121,569</u>

	December 31, 2003				
	Current Assets	Investments	Current Liabilities	Other Liabilities	Net Asset/ (Liability)
Regulated electricity:					
Mark-to-market	\$ 44,079	\$ 5,900	\$ (47,268)	\$ (3,028)	\$ (317)
Options	–	12,101	–	–	12,101
Marketing and trading:					
Mark-to-market	53,551	116,363	(37,023)	(63,398)	69,493
Emission allowances – at cost	–	4,582	(8,464)	(16,304)	(20,186)
Total	<u>\$ 97,630</u>	<u>\$ 138,946</u>	<u>\$ (92,755)</u>	<u>\$ (82,730)</u>	<u>\$ 61,091</u>

Cash or other assets may be required to serve as collateral against our open positions on certain energy-related contracts. Collateral provided to counterparties is \$1 million at December 31, 2004 and \$1 million at December 31, 2003, and is included in other current assets on the Consolidated Balance Sheet. Collateral provided to us by counterparties is \$18 million at December 31, 2004 and \$12 million at December 31, 2003, and is included in other current liabilities on the Consolidated Balance Sheet.

Fair Value Hedges

On January 29, 2004, we entered into two fixed-for-floating interest rate swap transactions on our \$300 million 6.4% Senior Notes. The purpose of these hedges is to protect against significant fluctuations in the fair value of our debt. Our interest rate swaps are considered to be fully effective with any resulting gains or losses on the derivative offset by a similar loss or gain amount on the underlying fair value of debt. The fair value of the interest rate swaps was \$2.6 million at December 31, 2004 and is included in investments and other assets with the corresponding offset in long-term debt less current maturities on the Consolidated Balance Sheets.

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 35% of Pinnacle West's \$391 million of risk management and trading assets as of December 31, 2004. Our risk management process assesses and monitors the financial exposure of these 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, local distribution companies and financial institutions. 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. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties. See Note 1 "Derivative Accounting" 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, 2004, 2003 and 2002 (dollars in thousands):

	Year Ended December 31,		
	2004	2003	2002
Other income:			
Investment gains (a)	\$ 38,256	\$ 3,649	\$ -
Interest income	7,470	4,412	4,332
SunCor non-operating income (b)	4,458	24,740	7,355
Asset sales	3,026	618	568
Miscellaneous	779	2,144	2,655
Total other income	<u>\$ 53,989</u>	<u>\$ 35,563</u>	<u>\$ 14,910</u>
Other expense:			
Non-operating costs (c)	\$ (15,524)	\$ (14,959)	\$ (12,958)
Asset sales	(1,382)	(1,522)	(6,472)
Investment losses (d)	-	-	(10,439)
Miscellaneous	(4,604)	(4,093)	(3,786)
Total other expense	<u>\$ (21,510)</u>	<u>\$ (20,574)</u>	<u>\$ (33,655)</u>

- (a) Primarily related to the gain on the sale of El Dorado's limited partnership interest in the Phoenix Suns in the second quarter of 2004 for \$35 million (\$21 million after tax).
- (b) Primarily related to the sale at SunCor of a land interest and profit participation agreement in the fourth quarter of 2003 for \$18 million. In 2002, SunCor received \$2.5 million for the profit participation.
- (c) As defined by the FERC, includes below-the-line non-operating utility costs (primarily community relations).
- (d) Primarily related to El Dorado's investment losses in NAC prior to consolidation in the third quarter of 2002.

20. VARIABLE INTEREST ENTITIES

In 1986, APS entered into agreements with three separate VIE 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. We are not the primary beneficiary of the Palo Verde VIEs and, accordingly, do not consolidate them.

APS is 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, 2004, APS would have been required to assume approximately \$250 million of debt and pay the equity participants approximately \$192 million.

In the first quarter of 2004, we adopted FIN No. 46R, "Consolidation of Variable Interest Entities" for all non-SPE contractual arrangements. SunCor has certain land development arrangements that are required to be consolidated under FIN No. 46R. The assets and non-controlling interests reflected in our Consolidated Balance Sheets related to these arrangements were approximately \$34 million at December 31, 2004.

21. GUARANTEES

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, and long-term service agreement guarantees for new power plants. Our credit support instruments enable APS Energy Services to offer commodity energy and energy-related products. 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 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, 2004 are as follows (dollars in millions):

	Guarantees		Surety Bonds	
	Amount	Term (in years)	Amount	Term (in years)
Parental:				
Pinnacle West Energy	\$ 25	1	\$ -	-
APS Energy Services	46	1	51	1
Total	<u>\$ 71</u>		<u>\$ 51</u>	

At December 31, 2004, we had entered into approximately \$39 million of letters of credit which support various transmission and construction agreements. These letters of credit expire in 2005 and 2006. 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. At December 31, 2004, Pinnacle West has approximately \$3 million of letters of credit related to workers' compensation expiring in 2006.

APS has entered into various agreements that require letters of credit for financial assurance purposes. At December 31, 2004, approximately \$200 million of letters of credit were outstanding to support existing pollution control bonds of approximately \$200 million. The letters of credit are available to fund the payment of principal and interest of such debt obligations. In July 2004, \$150 million of these letters of credit were renewed for a three-year term and expire in 2007. The remainder expire in 2005. APS has also entered into approximately \$102 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 expiring in 2006. 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.

We provide indemnifications relating to liabilities arising from or related to certain of our agreements. APS has 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.

22. DISCONTINUED OPERATIONS

The following table provides a summary of SunCor and NAC income (loss) from discontinued operations (after income taxes) for the years ended December 31, 2004, 2003 and 2002 (dollars in millions):

	2004	2003	2002
SunCor	\$ 4	\$ 10	\$ 9
NAC	4	5	(31)
Total Income (loss) from discontinued operations	<u>\$ 8</u>	<u>\$ 15</u>	<u>\$ (22)</u>

SunCor

Certain components of SunCor's real estate sales activities, which are included in the real estate segment, are required to be reported as discontinued operations on Pinnacle West's Consolidated Statements of Income in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." Among other guidance, SFAS No. 144 prescribes accounting for discontinued operations and defines certain activities as discontinued operations.

In the second quarter of 2002, SunCor sold a retail center, but maintained a continuing involvement through a management contract. In the first quarter of 2003, this management contract was canceled. As a result, the after-tax gain of \$6 million (\$10 million pretax) recorded in operations in 2002 related to this property was reclassified as discontinued operations on our Consolidated Statements of Income. The income from discontinued operations in the year ended December 31, 2002 primarily reflects this sale.

In 2003, SunCor sold its water utility company, which resulted in an after-tax gain of \$8 million (\$14 million pretax). The amounts of the gain on the sale and operating income of the water utility company in 2003 and 2002 are classified as discontinued operations on Pinnacle West's Consolidated Statements of Income.

In the fourth quarter of 2003, SunCor sold a retail center, which resulted in an after-tax gain of \$2 million (\$3 million pretax). The gain on the sale and the operating income related to this property in 2003 are classified as discontinued operations on Pinnacle West's Consolidated Statements of Income. There were no prior-year operations related to this retail center.

In 2004, SunCor sold commercial property, which resulted in an after-tax gain of \$1 million (\$2 million pretax). The gain on the sale and the operating income related to this property in 2004 are classified as discontinued operations on Pinnacle West's Consolidated Statements of Income. There were no prior-year operations related to this property.

The following table provides SunCor's revenue and income before income taxes (including the gains on disposals as noted above) related to properties classified as discontinued operations on Pinnacle West's Consolidated Statements of Income for the years ended December 31, 2004, 2003 and 2002 (dollars in millions):

	2004	2003	2002
Revenue	\$ 11	\$ 71	\$ 35
Income before taxes	6	17	15

NAC

In July 2004, we entered into an agreement to sell our investment in NAC. The transaction closed on November 18, 2004 and resulted in a pre-tax gain of \$4 million, which is classified as discontinued operations in 2004. El Dorado began consolidating the operations of NAC in the third quarter of 2002. All related revenues and expenses for NAC have been reclassified to discontinued operations for the years ended December 31, 2003 and 2002 on Pinnacle West's Consolidated Statements of Income.

The following table provides the revenue and income before taxes (including the gain on disposal as noted above) for El Dorado's investment in NAC that was classified as discontinued operations for the years ended December 31, 2004, 2003 and 2002 (dollars in millions):

	2004	2003	2002
Revenue	\$ 31	\$ 58	\$ 35
Income (loss) before taxes	7	8	(50)

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.

Assets and Liabilities Related to Discontinued Operations

Due to the sale of NAC, all NAC assets and liabilities have been reclassified to assets and liabilities related to discontinued operations on the Consolidated Balance Sheets at December 31, 2003 and are provided in the following table (dollars in thousands):

	2003
Cash	\$ 5,867
Customer and other receivables	11,066
Net property, plant and equipment	5,404
Other	<u>728</u>
Assets related to discontinued operations	<u>\$ 23,065</u>
Accounts payable	\$ 10,406
Long-term debt less current maturities	800
Other	<u>5,221</u>
Liabilities related to discontinued operations	<u>\$ 16,427</u>

CERTIFICATIONS

On June 18, 2004, in accordance with Section 303A.12 of the Listed Company Manual, our Chief Executive Officer certified to the New York Stock Exchange that he was not aware of any violation by the Company of NYSE corporate governance listing standards as of such date. In addition, on March 16, 2005, our Chief Executive Officer and Chief Financial Officer each filed a certification under Section 302 of the Sarbanes-Oxley Act (regarding the quality of the Company's public disclosure) as exhibits of the Company's Annual Report on Form 10-K for fiscal year 2004.