PNW

2008

2008_Annual Report (Actually 2003)

PINNACLE WEST CAPITAL CORPORATION

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ABOUT OUR COMPANY

Pinnacle West is a Phoenix-based company with consolidated assets of approximately $9.5 billion and consolidated revenues of $2.8 billion. Through our subsidiaries, we generate, sell and deliver electricity and sell energy-related products and services to retail and wholesale customers in the western United States. We also develop residential, commercial and industrial real estate products.

ABOUT THIS YEAR'S ANNUAL REPORT

No, this is not actually our 2008 Annual Report. However, at Pinnacle West we take a long-term view, and the issues we will face five years from now are the issues we must address today. This is why we, and our Annual Report, are focused on the future – for shareholders, for customers and for Arizona.

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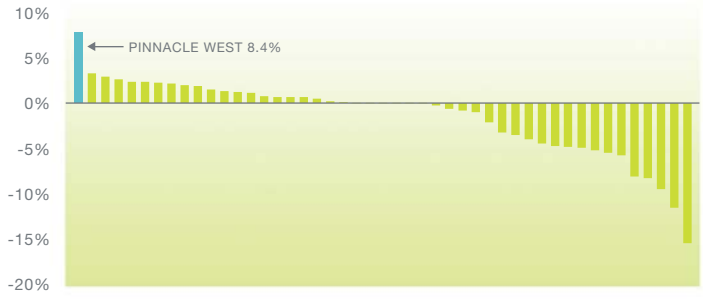
CORE STRATEGIC OBJECTIVES

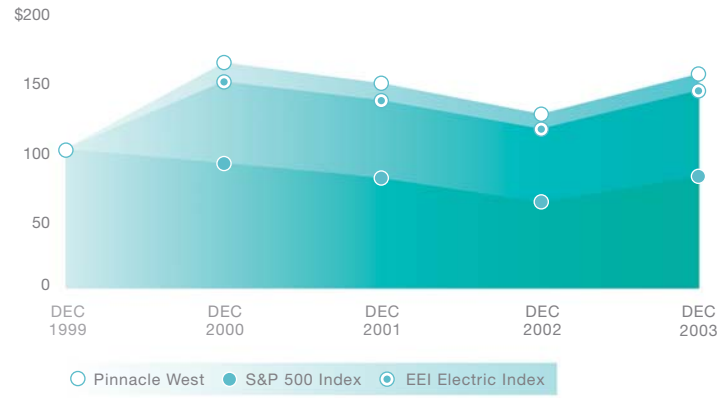
- Focus on superior long-term total returns for shareholders
- Provide Arizona electricity customers with reliable energy at stable prices
- Capture growth opportunities in our electricity markets
- Actively manage our costs and business risks
- Maximize the long-term value of our assets
- Maintain a disciplined focus on our long-term goals while remaining agile
- Increase our generation portfolio consistent with our native load, cash flow and market conditions

ELECTRIC UTILITIES AVERAGE ANNUAL DIVIDEND GROWTH 1994 TO 2003



PINNACLE WEST STOCK PERFORMANCE COMPARISON

Value of $100 invested on December 31, 1999, with dividends reinvested



FINANCIAL HIGHLIGHTS

(dollars in thousands, except per share amounts)

Year Ended December 31,	2003	2002	2001	Growth Rate 2003 VS 2002	Growth Rate 2002 VS 2001
INCOME HIGHLIGHTS					
Operating revenues	$ 2,817,852	$ 2,440,288	$ 2,634,768	15.5%	(7.4)%
Income from continuing operations	$ 230,576	$ 206,198	$ 327,367	11.8%	(37.0)%
Net income	$ 240,579	$ 149,408	$ 312,166	61.0%	(52.1)%
BALANCE SHEET HIGHLIGHTS					
Total assets – year-end	$ 9,536,378	$ 9,139,157	$ 8,529,124	4.3%	7.2 %
Common stock equity – year-end	$ 2,829,779	$ 2,686,153	$ 2,499,323	5.3%	7.5 %
PER SHARE HIGHLIGHTS					
Earnings per share from continuing operations – diluted	$ 2.52	$ 2.43	$ 3.85	3.7%	(36.9)%
Net income – diluted	$ 2.63	$ 1.76	$ 3.68	49.4%	(52.2)%
Indicated annual dividend – year-end	$ 1.80	$ 1.70	$ 1.60	5.9%	6.3 %
Book value per share – year-end	$ 30.97	$ 29.40	$ 29.46	5.3%	(0.2)%
STOCK PERFORMANCE					
Stock price per share – year-end	$ 40.02	$ 34.09	$ 41.85		
Stock price appreciation	17.4%	(18.5)%	(12.1)%		
Total return	23.1%	(14.8)%	(9.0)%		
Market capitalization – year-end	$ 3,653,343	$ 3,115,142	$ 3,549,924	17.3%	(12.2)%

To Our Shareholders

You read correctly, our cover says "2008 Annual Report." There's a good reason. This is where we spend a lot of our time – planning to meet the energy needs of customer demand that's growing 4 to 5 percent each year.
For Pinnacle West, 2008 is here – now.

This emphasis on the future is more than a clever idea. It's a way to bring our vision into sharp focus for customers, investors and policymakers. A long-term view has always been critically important to us. Growth makes our future orientation even more crucial today. There is simply no room for error or delay – or extended regulatory uncertainty.

We are focused with laser-like intensity on the outcome of our current rate case and what it will say about the future – for our customers and our state.

Understanding how we got to this point – at the end of one state regulatory era but not yet firmly in a new era – requires a quick look at where we are now and how we got here.

HOW WE GOT TO NOW

In 2003, our year-end earnings were in line with expectations, and we strengthened our liquidity position. We had another strong year of operating performance. Our gas- and coal-fired power plants recorded some of their best production years ever. And the Palo Verde Nuclear Generating Station was the largest power producer of any kind in the U.S. for the 12th straight year.

We also achieved regulatory milestones. With approval from the Arizona Corporation Commission (ACC), APS loaned funds to Pinnacle West Energy to relieve the debt burden incurred in the construction of new gas-fired power plants. We also completed a bidding process to secure more than 2,200 megawatts of capacity, including about 1,800 megawatts from Pinnacle West Energy's Arizona plants that were specifically built to serve APS customers. And our service area remained vibrant, as evidenced by customer growth of three times the national average and record levels of electricity consumption by our retail customers.

That growth, however, came at a price. Over the past few years, we've invested about $2 billion in new infrastructure to increase system reliability. In addition to expanding our generation portfolio, we completed a new 500-kilovolt transmission line from Palo Verde to the metropolitan Phoenix area. The 1,200-plus megawatt line played a significant role in APS' ability to avoid delivery problems during the summer of 2003.

To recover these and other costs – and as required by our 1999 Settlement Agreement with the ACC – we filed our first general rate case in more than a decade. This rate case covers our cost of service, return on equity, and fuel and purchased power adjustors. Just as important, it addresses a host of issues left unresolved when the ACC reversed its position on deregulation in 2002.

In 1999, we signed a regulatory agreement with the ACC that brought competitive choice to our customers, required us to transfer our APS power plants to an unregulated subsidiary and lowered prices by an average of 1.5 percent per year for five years. This agreement provided a foundation for Pinnacle West to form a business plan consistent with the ACC's wishes. It also explicitly recognized that our unregulated subsidiary could include our low-cost coal and nuclear units in one consolidated generating company.

In 2002, when the ACC reversed course and ordered us not to consolidate our power plants, we had been preparing for deregulation for nearly a decade. We built new gas-fired plants needed for APS customers in Arizona expecting they would be part of a much larger generation fleet that would include APS' fossil and nuclear units. As directed, we stopped course. But the ACC reversal changed everything, leaving many important issues open, including the financial integrity of those plants.

Because of unresolved issues – such as the critical need to consolidate our power plants going forward – our 2003 rate filing goes beyond a rate case. It's really about the future. In that sense, our current rate case is similar to our 1999 Settlement Agreement. The 1999 Settlement Agreement set out a path to the future. *That* future was the last five years and our performance was outstanding.

HOW FOCUSING ON THE FUTURE LED TO SUCCESS: 1999 TO 2003

Our future focus is not a new concept. In fact, it has been a necessity. During the last five years, we honed the traits that allowed us to navigate previously unseen industry volatility.

It took agility and adaptability. In 1999, like now, there was conflict between federal and state regulators, not to mention the unfettered presence of public power in the West. We insisted on keeping our existing power plants, and we didn't speculate in large merchant generation. We built much-needed new units to serve APS' new customers.

It took the ability to manage risk. Upon approval of the 1999 Settlement Agreement, we embarked upon a two-pronged approach to address customer reliability and price exposure. First, we announced the construction of 1,800 megawatts of new generation under Pinnacle West Energy to cover a portion of APS' needed generation. Second, we immediately began a short-term electric and natural gas hedging program to cover the interim period. We didn't panic and sign purchase power agreements at the peak of market prices, and our two-pronged approach allowed us to navigate the western fuel and power markets without harming customers or investors.

In the summer of 2000 and again in 2001, when wholesale power markets erupted, we were almost fully protected against price spikes with a combination of supply contracts, new generation and financial hedges. At no time did we dedicate the output of our new generation to anyone else.

It took commitment to meeting customer needs. We knew the generation capacity we would need wasn't going to be found in the wholesale marketplace. We were wary of the California market structure, so we fought from the very beginning against the divestiture of APS generation to a third party. We had envisioned what a decent wholesale market should look like and we didn't see one – and still don't – anywhere in the western United States.

Under the electric competition rules adopted by the ACC in 1999, we could not build any new generation at APS, and without new plants under construction we would have been forced to enter the wholesale energy market at the worst possible time. As our requests for proposals from the wholesale market have shown, no one else could have supplied the power our customers needed last year – and will need in the future – as economically as our new plants.

It took a focus on creating customer value. While other utilities were going bankrupt or passing along unheard-of price increases, we lowered our rates by 16 percent over a 10-year period. We delivered these price decreases,

as promised, and delivered the best customer satisfaction of any investor-owned utility in the West.

For the years 1999 through 2003, our peak demand grew nearly 25 percent. When combined with the 1,200-megawatt shortage APS had in 1999, APS' shortage grew to 2,500 megawatts, approximately one-third of our total responsibility. We met that shortage. During that time, we didn't have a single outage because of generation shortages or transmission congestion. We kept the lights on with outstanding operations – at our coal, nuclear and gas plants and throughout our "wires" organization.

It took a focus on creating shareholder value. We've proven adept at translating customer growth into financial results for our shareholders. While our market grew substantially, our workforce count remained flat. Since 1999, we've deployed more than $140 million of cash distributions from our real estate operations to improve liquidity and fund operating capital. Our common stock dividend growth over the last decade has been the best in our industry. And, the total return on our stock has consistently outpaced the S&P 500 Index.

WHY THE CURRENT RATE CASE IS SO IMPORTANT

We remain focused on the future, just as we were in 1999. But today we're in a state of regulatory transition, without sufficient structure to meet our rapidly growing customer demand. That regulatory structure is needed now so we can continue our outstanding performance for customers and investors.

The unresolved issues in the rate case we filed last year include consolidating Pinnacle West Energy's Arizona units into APS and restoring the $234 million write-off we were ordered to take as part of the 1999 Settlement Agreement. These issues, while important in themselves, point to the central regulatory issue confronting the ACC and this company – establishing the rules for the future.

In the past, we have been clear that a focus on the future required a firm grounding in regulatory consistency. We thought with the signing of the 1999 Agreement, we had achieved sufficient predictability and certainty, and we kept our commitments. With our agile approach to regulation and competition, we were able to secure the power we needed to keep the lights on, our customers satisfied and Arizona's economy running.

Today, that predictability and consistency are lacking. We have unfinished business, but we are confident we and our regulators can work together to re-establish a framework that balances customer value with investment risk and reward.

WHY THE FUTURE IS DEJA VU: 2004 TO 2008

Looking ahead, we're focused on ensuring that our company can build on its stellar performance of the last decade. To re-create our past successes – to make the long-term investment in infrastructure we will need in Arizona – requires a clear and consistent regulatory path. With that clarity in place, we will continue to:

Manage the future with agility and adaptability. Agility will always be fundamental. We will retain a sensitivity and responsiveness to the market and to regulatory uncertainty, which can be managed but never completely eliminated. And we'll remain focused on customer needs and Arizona's growth potential.

Utilize our risk management skills. We clearly know our way around western energy markets. Over the next five years, the skills we used to navigate the market storms of 2000 and 2001 will repeatedly prove their value. We will use every tool we possess to sidestep the ill effects of any future boom-bust cycle and protect our customers from market spikes.

Keep the lights on for our customers. We see no slowdown in customer growth, and likely a modest acceleration. To serve customers reliably, we must take action now, just as we made decisions in 1999 that gave us the power we needed. Our forecast shows we'll need about 1,800 more

megawatts of generating capacity by 2008, and a total of more than 3,000 by 2012. Those figures are in addition to the Pinnacle West Energy units we are asking to include in APS. That's why we issued a request for proposal late last year seeking additional capacity by 2007.

Our preference is to buy an existing station or build one ourselves. As long as power markets are rudimentary, illiquid and volatile, increasing reliance on the wholesale market presents unacceptable risk to customers and investors. But at present, we have no assurance that we would be allowed to recover the cost of a prudently planned and constructed plant.

Provide ongoing value for our customers. Providing value to our customers is the driving force of the people of our company. Through their dedication, creativity and commitment we will continue to achieve an enviable combination of price and service.

On the horizon, there are many exciting developments in technology, such as the "self-healing" grid, advances in metering and customer information, distributed generation, solar and other renewable energy sources. These new technologies, combined with the spirit of our people, will continue to produce excellent customer value.

Create shareholder value. For you, the owners of our company, we will continue to produce solid shareholder returns by capitalizing on our region's growth, concentrating on our core business and focusing on our future. We will continue to emphasize dividends, while striving to achieve a regulatory structure that recognizes the importance of aligning investment expectations with potential returns.

WHY THE FUTURE IS NOW

We are poised to become a new kind of vertically integrated utility – one that provides customers with reliable power at a reasonable price but remains subject to the discipline of the energy marketplace. A utility that uses its skills to navigate the energy market for the benefit of both customers and investors.

As I said in last year's Annual Report letter, competition and regulation will co-exist and we must operate effectively in both worlds. The fundamental forces of market structure, electric reliability, customer value and investment risk/reward will shape the consistency and alignment between the two, and as a new kind of vertically integrated utility we must anticipate their evolution. Since competitive markets often move faster than regulation, it's imperative that the regulatory structure considers the future, and that regulators go beyond traditional, historical regulation.

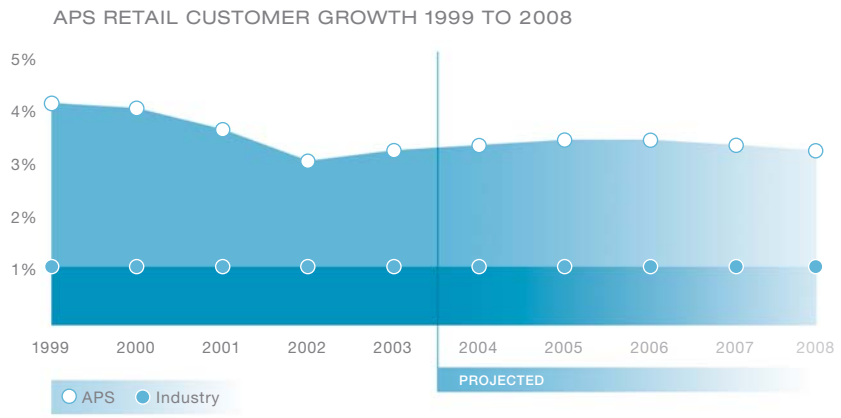
Our Arizona regulators recognize the absolute need to manage electric reliability and price volatility on behalf of customers and the importance of a financially solid electric utility. The regulatory decisions needed in 2004 are critical to the foundation of operating and resource decisions we must make now for 2008 and beyond. I believe our commissioners understand the long-term need to have a reliable and affordable electric infrastructure as a base to fuel Arizona's economy.

Resolving our current rate case fairly means balancing customer and shareholder interests by recognizing that those interests are frequently aligned. Over the long term, a financially strong utility and low customer rates go hand-in-hand.

We are committed to achieving a regulatory outcome that sets a firm foundation for important operating and resource decisions. Simultaneously, we will continue to meet our customers' growing needs, improve service levels, build on our excellent operating performance and manage our resources in a safe and ethical manner while providing our shareholders a fair return on their investment.

This is our hallmark.

William J. Post, Chairman



Our customer base will continue to grow rapidly – about three times the industry average.

LOOKING AHEAD_ growth 2008

APS' unique customer growth continues to be the envy of the industry. By the end of 2008 the company adds about 170,000 new customers, and serves a total of more than 1.1 million Arizona customers. Electric system peak load expands as well, growing by about 25 percent.

Whether 2003 or 2008, customer growth is the fuel that powers our industry's financial engine. In this area, APS has few peers. In 2003, our customer growth was again rapid and unique. APS experienced 3.3 percent customer growth (roughly 30,000 new customers). This was about three times the industry average.

The epicenter of this growth is found in the heart of our service territory – the Greater Phoenix area. In 2003, approximately 3.4 million residents called the Phoenix area home – a 17 percent increase from just five years earlier. In 2003, the Phoenix metro area also issued more than 47,000 building permits, the highest number of permits in the last 18 years.

Of course, growth benefits the company's bottom line only if it is met with sufficient resources. In 2003, our company completed a 530-megawatt unit at the West Phoenix Power Plant. By the end of 2004, the company will have added nearly 2,400 megawatts of new generating capacity (including about 1,800 megawatts in Arizona) in the last four years.

In addition to increasing our generating capabilities, we continue to expand our transmission and distribution system. In 2003, we energized a new 37-mile 500-kilovolt transmission line that runs from the Palo Verde Nuclear Generating Station to the Phoenix area. Completion of the line allowed more than 1,200 megawatts of additional power to flow into Arizona's largest metropolitan area and played a vital role in APS' ability to avoid severe delivery problems during the summer of 2003.

Renewable energy resources will clearly be a large part of Arizona's energy future. Construction is currently underway on the Prescott (Ariz.) Airport Solar Power Plant, which will be one of the largest photovoltaic solar plants in the world. We are also a major participant in a new biomass plant in northeastern Arizona, which can take the by-products of negative situations – Arizona's vast Rodeo-Chedeski fires of 2002 and our state's devastating bark beetle infestation – and convert them into fuel. Most recently, APS announced it will partner with Western Wind Energy Corporation to establish Arizona's first commercial wind farm.

No other electric utility in the U.S. can match our dividend growth over the last 10 years. In that period, Pinnacle West's average dividend growth rate was 8.4 percent per year, ranking us number one industry-wide. In 2003, our annual dividend was increased 10 cents per share for the 10th consecutive year. We recognize that dividends underpin stock performance. Our track record in growing our dividend has been a distinguishing investment characteristic for our company.

Just as Pinnacle West's previous planning efforts played a vital role in 2003, today's planning will help ensure the successes and manage the challenges of 2008.

As required by a 1999 Settlement Agreement approved by the Arizona Corporation Commission, APS filed a general rate case in mid-2003 – our first in well over a decade. That filing requested a 9.8 percent retail revenue increase, which would be the company's first price increase in more than 13 years. Even with the requested increase, APS' rates would be about 6 percent below what they were in 1993.

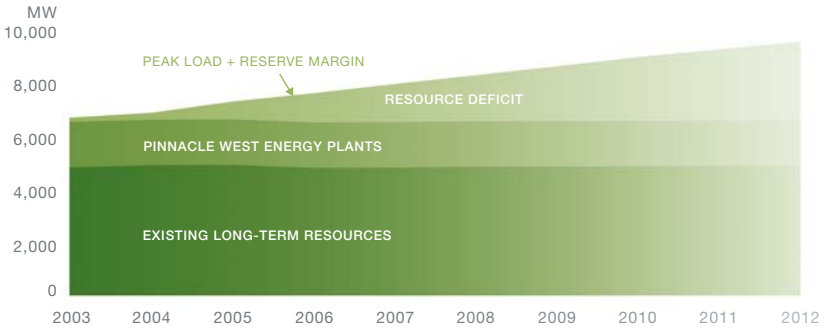
Through the regulatory process, our goal is to find a workable structure that helps ensure long-term reliability and price stability for our customers, and supports continuing growth in the state of Arizona while providing a reasonable return for our shareholders.

In 2003, APS implemented the last of a series of rate reductions that have lowered customer prices an average of 16 percent since 1993. This decrease represented the largest cumulative price decrease among investor-owned utilities nationwide during that time period, and saved our customers well over $1 billion.

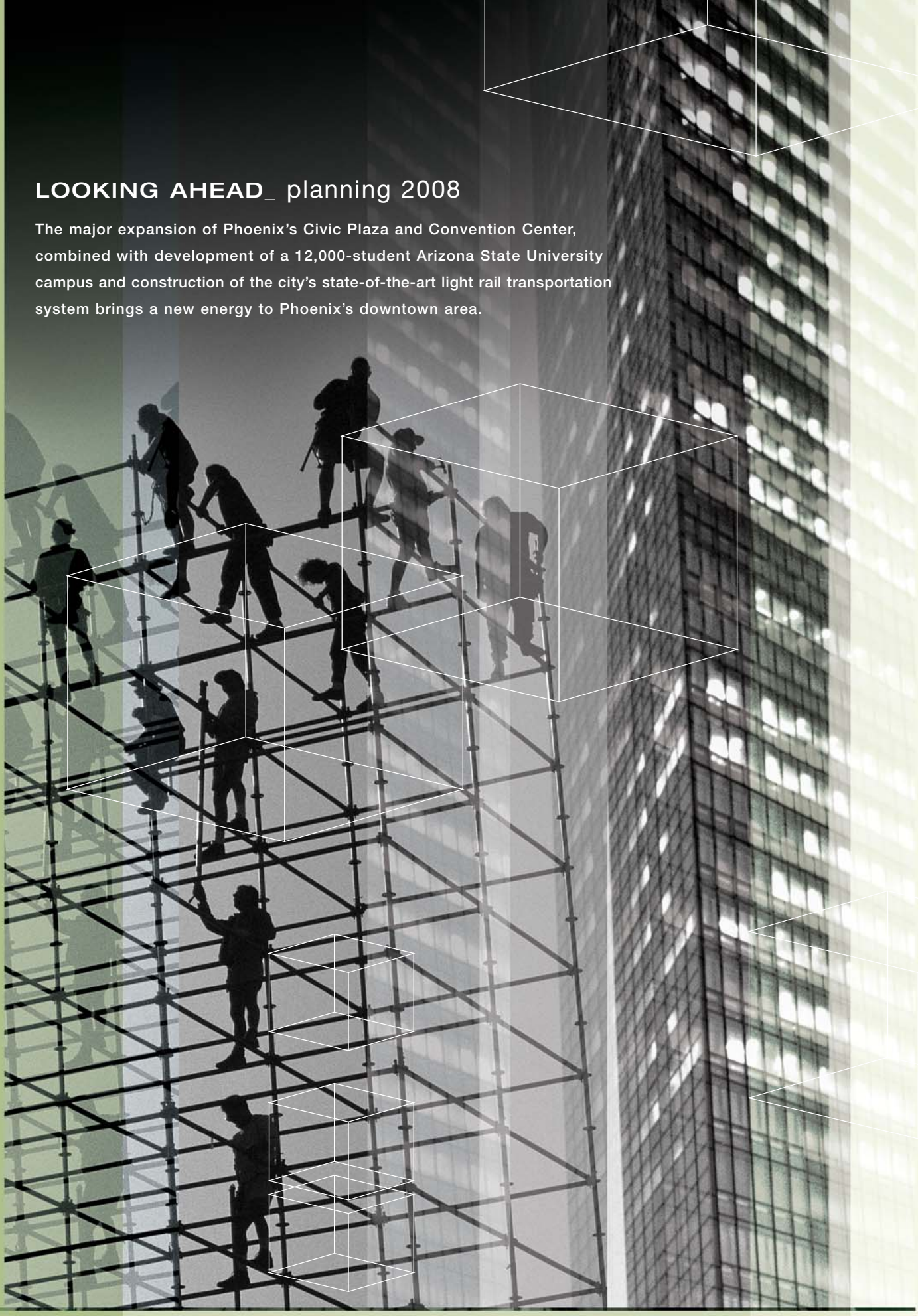
Providing reliable electricity is at the top of our agenda as we plan for Arizona's energy future. As APS' customer base has grown, individual energy usage has also risen dramatically. From 1991 to 2003, household usage of electricity in Arizona has increased an average of 23 percent. In 2003, APS' peak energy load demand rose more than 9 percent over the previous year. APS' peak load, over the last two years, has grown more than 600 megawatts, approximately equal to the output of one of our units at our new Redhawk Power Plant.

We completed a large-scale maintenance project at the Palo Verde Nuclear Generating Station in the fall of 2003, to improve the efficiency and reliability of our lowest-cost power source. Two 800-ton steam generators were successfully replaced in Unit 2, completing more than five years of planning and careful management of the manufacture and transportation of the generators from Italy. During the replacement process, plant employees set a world record for the lowest collective radiation exposure during a steam generator replacement.

APS ELECTRIC SYSTEM LOAD AND RESOURCES 2003 TO 2012



Moving forward, our customer demand will grow, and so will our need for new power resources.



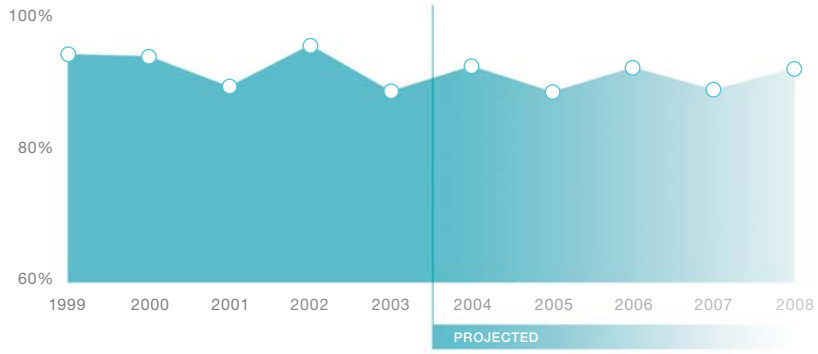
LOOKING AHEAD_ planning 2008

The major expansion of Phoenix's Civic Plaza and Convention Center, combined with development of a 12,000-student Arizona State University campus and construction of the city's state-of-the-art light rail transportation system brings a new energy to Phoenix's downtown area.

LOOKING AHEAD_ performance 2008

New transmission technology is pioneered that allows the company to increase electric conductor capacity in its transmission lines. The new technology allows the lines to handle increased power flow, providing greater energy efficiency.

APS NUCLEAR GENERATION CAPACITY FACTOR 1999 TO 2008



Our nuclear generation performance has consistently outpaced the industry.

It's likely that in our 117 years as a company, no employees have been asked to accomplish more than our current staff. They are the embodiment of "doing more with less." In the last five years, APS has added more than 150,000 customers, while our workforce numbers have remained virtually the same. Added demands have pushed us to find ways to work more efficiently. The result has been an energetic, innovative and purposeful workforce.

One example of our company's strong productivity comes from the Palo Verde Nuclear Generating Station west of Phoenix. In 2003, Palo Verde marked its 12th consecutive year as the largest power producer of any kind in the United States.

In addition, our gas-fired plants – including our new units at West Phoenix and Redhawk – operated at about 90 percent availability, and the combined capacity factor for our Four Corners and Cholla power plants ranked near the top of the industry.

Taking advantage of opportunities in a favorable real estate market, SunCor Development Co., Pinnacle West's real estate subsidiary, delivered solid performance, reporting 2003 net income of $56 million, compared with net income of $19 million for 2002. SunCor's performance is expected to augment the company's earnings pending the outcome of APS' rate case.

APS Energy Services continued to deliver solid earnings, while building a stellar customer reputation. Commodity electricity sales to key California businesses and government customers remained strong, and the company saw significant growth in energy services and energy efficiency sales in Arizona, California and Nevada. Northwind, the company's district cooling and heating operations expanded from downtown Phoenix, adding operation of a site in Tucson, Ariz.

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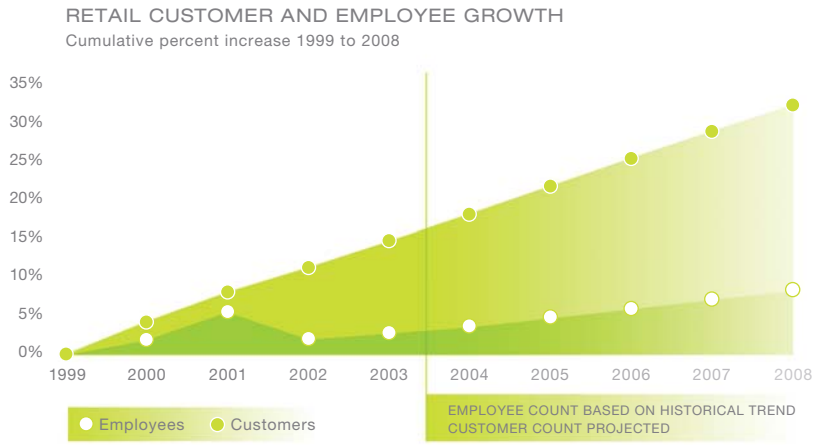

Our employees continue to serve more customers, more efficiently.

Focusing on the needs of customers has resulted in steadily improving customer satisfaction scores as measured by the J.D. Power and Associates Electric Utility Residential Customer Satisfaction Study. In 2003, APS ranked second among electric utilities in the West, and earned the highest score among investor-owned utilities in the region. APS improved its scores in all five of the survey's factors, which measure customer attitudes about power quality and reliability, company image, price and value, billing and payment, and customer service.

Our utility Web site – aps.com – continues to reduce operating costs, while providing customers another convenient way to work with our company. Customers can connect and disconnect their service, receive and pay their electricity bills and get helpful information online. The site handles more than 70,000 payments each month, far surpassing company goals. Such performance helped the site earn its second consecutive Best Energy Web Site WebAward from the Web Marketing Association, a national organization of Internet marketing, advertising, public relations and design professionals.

A company-wide emphasis on safety in 2003 resulted in decreased preventable recordable injuries – the third such reduction in as many years. Employees at the West Phoenix and Yucca power plants contributed to this improvement by working 22 and 19 years, respectively, without a lost-time accident.

Dedication to a safe and healthy workforce is one of the reasons Pinnacle West earned a spot on AARP's list of "Best Employers for Workers Over 50." The advocacy organization recognized the company's efforts to retain older employees by promoting continuing education and flexible schedules. Pinnacle West was one of two Arizona employers on the national list.

We take a very broad view of business performance, which includes not only earnings and stock price, but also the value of safety, environmental and social performance, customer service and integrity. In 2003, our performance in these areas earned Pinnacle West a "10" rating, on a scale of 1 to 10, from governance ratings agency GovernanceMetrics International, which ranked 1,000 U.S. electric utilities in the area of Corporate Governance.

LOOKING AHEAD_ people 2008

To counteract the loss of experience and talent as many employees reach retirement age, Pinnacle West adopts a new human performance improvement initiative. The approach results in fewer employee injuries, as well as improved cost per customer, system reliability and customer satisfaction.

2003 Consolidated Financial Information

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SELECTED CONSOLIDATED FINANCIAL DATA (dollars in thousands, except shares and per share amounts)

	2003	2002	2001	2000	1999
OPERATING RESULTS					
Operating revenues:					
Regulated electricity segment (a)	$ 1,978,075	$ 1,890,391	$ 1,984,305	$ 2,538,752	$ 1,915,108
Marketing and trading segment (a)	391,886	286,879	469,784	418,532	154,125
Real estate segment	361,604	201,081	168,908	158,365	130,169
Other revenues	86,287	61,937	11,771	3,873	439
Income from continuing operations	$ 230,576	$ 206,198	$ 327,367	$ 302,332	$ 269,772
Discontinued operations – net of income taxes (b) (c)	10,003	8,955	–	–	38,000
Extraordinary charge – net of income taxes (d)	–	–	–	–	(139,885)
Cumulative effect of change in accounting – net of income taxes (e) (f)	–	(65,745)	(15,201)	–	–
Net income	$ 240,579	$ 149,408	$ 312,166	$ 302,332	$ 167,887
COMMON STOCK DATA					
Book value per share – year-end	$ 30.97	$ 29.40	$ 29.46	$ 28.09	$ 26.00
Earnings (loss) per weighted average common share outstanding:					
Continuing operations – basic	$ 2.53	$ 2.43	$ 3.86	$ 3.57	$ 3.18
Discontinued operations	0.11	0.10	–	–	0.45
Extraordinary charge	–	–	–	–	(1.65)
Cumulative effect of change in accounting	–	(0.77)	(0.18)	–	–
Net income – basic	$ 2.64	$ 1.76	$ 3.68	$ 3.57	$ 1.98
Continuing operations – diluted	$ 2.52	$ 2.43	$ 3.85	$ 3.56	$ 3.17
Net income – diluted	$ 2.63	$ 1.76	$ 3.68	$ 3.56	$ 1.97
Dividends declared per share	$ 1.725	$ 1.625	$ 1.525	$ 1.425	$ 1.325
Indicated annual dividend rate per share – year-end	$ 1.80	$ 1.70	$ 1.60	$ 1.50	$ 1.40
Weighted-average common shares outstanding – basic	91,264,696	84,902,946	84,717,649	84,732,544	84,717,135
Weighted-average common shares outstanding – diluted	91,405,134	84,963,921	84,930,140	84,935,282	85,008,527
BALANCE SHEET DATA					
Total assets	$ 9,536,378	$ 9,139,157	$ 8,529,124	$ 7,697,558	$ 7,095,441
Liabilities and equity:					
Long-term debt less current maturities	$ 2,897,725	$ 2,743,741	$ 2,673,078	$ 1,955,083	$ 2,206,052
Other liabilities	3,808,874	3,709,263	3,356,723	3,359,761	2,683,656
Total liabilities	6,706,599	6,453,004	6,029,801	5,314,844	4,889,708
Common stock equity	2,829,779	2,686,153	2,499,323	2,382,714	2,205,733
Total liabilities and equity	$ 9,536,378	$ 9,139,157	$ 8,529,124	$ 7,697,558	$ 7,095,441

(a) Includes reclassifications of revenues in 2003, 2002 and 2001 for the adoption of EITF 03-11. See Note 18 of Notes to Consolidated Financial Statements.
(b) Tax benefit stemming from the resolution of income tax matters related to a former subsidiary, MeraBank, A Federal Savings Bank in 1999.
(c) Real estate discontinued operations in 2003 and 2002. See Note 22 of Notes to Consolidated Financial Statements.
(d) Charges associated with a regulatory disallowance. See "Regulatory Accounting" in Note 1 of Notes to Consolidated Financial Statements.
(e) Change in accounting standards related to derivatives in 2001. See Note 18 of Notes to Consolidated Financial Statements.
(f) Change in accounting standards related to energy trading activities in 2002. See Note 18 of Notes to Consolidated Financial Statements.

QUARTERLY STOCK PRICES AND DIVIDENDS PER SHARE

Stock Symbol: PNW

2003	High	Low	Close	Dividends Per Share
1st Quarter	$ 37.13	$ 28.34	$ 33.24	$ 0.425
2nd Quarter	39.59	31.35	37.45	0.425
3rd Quarter	38.03	32.87	35.50	0.425
4th Quarter	40.48	34.91	40.02	0.450

2002	High	Low	Close	Dividends Per Share
1st Quarter	$ 45.60	$ 39.36	$ 45.35	$ 0.400
2nd Quarter	46.68	37.08	39.50	0.400
3rd Quarter	39.72	25.82	27.76	0.400
4th Quarter	34.36	21.70	34.09	0.425

GLOSSARY

ACC – Arizona Corporation Commission

ADEQ – Arizona Department of Environmental Quality

AFUDC – allowance for funds used during construction

ALJ – Administrative Law Judge

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

APS – Arizona Public Service Company, a subsidiary of the Company

APS Energy Services – APS Energy Services Company, Inc., a subsidiary of the Company

CC&N – Certificate of Convenience and Necessity

Cholla – Cholla Power Plant

Citizens – Citizens Communications Company

Clean Air Act – the Clean Air Act, as amended

Company – Pinnacle West Capital Corporation

CPUC – California Public Utility Commission

DOE – United States Department of Energy

EITF – the FASB's Emerging Issues Task Force

El Dorado – El Dorado Investment Company, a subsidiary of the Company

EPA – United States Environmental Protection Agency

ERMC – the Company's Energy Risk Management Committee

FASB – Financial Accounting Standards Board

FERC – United States Federal Energy Regulatory Commission

FIN – FASB Interpretation

Financing Order – ACC Order that authorized APS' $500 million loan to Pinnacle West Energy in May 2003

Four Corners – Four Corners Power Plant

GAAP – accounting principles generally accepted in the United States of America

IRS – United States Internal Revenue Service

ISO – California Independent System Operator

kW – kilowatt, one thousand watts

kWh – kilowatt-hour, one thousand watts per hour

Moody's – Moody's Investors Service

MW – megawatt, one million watts

MWh – megawatt-hours, one million watts per hour

NAC – NAC International Inc., a subsidiary of El Dorado

Native Load – retail and wholesale sales supplied under traditional cost-based rate regulation

1999 Settlement Agreement – comprehensive settlement agreement related to the implementation of retail electric competition

NRC – United States Nuclear Regulatory Commission

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

OCI – other comprehensive income

Palo Verde – Palo Verde Nuclear Generating Station

PCAOB – Public Company Accounting Oversight Board

PG&E – PG&E Corp.

Pinnacle West – Pinnacle West Capital Corporation, the Company

Pinnacle West Energy – Pinnacle West Energy Corporation, a subsidiary of the Company

PWEC Dedicated Assets – the following Pinnacle West Energy power plants, each of which is dedicated to serving APS' customers: Redhawk Units 1 and 2, West Phoenix Units 4 and 5 and Saguaro Unit 3

PX – California Power Exchange

Rules – ACC retail electric competition rules

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

SCE – Southern California Edison Company

SEC – United States Securities and Exchange Commission

SFAS – Statement of Financial Accounting Standards

SNWA – Southern Nevada Water Authority

SPE – special-purpose entity

Standard & Poor's – Standard & Poor's Corporation

SunCor – SunCor Development Company, a subsidiary of the Company

T&D – transmission and distribution

Track A Order – ACC order dated September 10, 2002 regarding generation asset transfers and related issues

Track B Order – ACC order dated March 14, 2003 regarding competitive solicitation requirements for power purchases by Arizona's investor-owned electric utilities

Trading – energy-related activities entered into with the objective of generating profits on changes in market prices

VIE – variable interest entity

INTRODUCTION

The following discussion should be read in conjunction with the Consolidated Financial Statements and the related Notes.

OVERVIEW

We own all of the outstanding common stock of APS. 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 the Tucson metropolitan area and about one-half of the Phoenix metropolitan area. Through its marketing and trading division, APS also generates, sells and delivers electricity to wholesale customers in the western United States. APS has historically accounted for a substantial part of our revenues and earnings. Growth in APS' service territory is about three times the national average and remains a fundamental driver of our revenues and earnings.

Pinnacle West Energy is our unregulated generation subsidiary. We formed Pinnacle West Energy in 1999 as a result of the ACC's requirement that APS transfer all of its competitive assets and services to an affiliate or to a third party by the end of 2002. We planned to transfer APS' generation assets to Pinnacle West Energy. Additionally, Pinnacle West Energy constructed several power plants to meet growing energy needs (1790 MW in Arizona and 570 MW in Nevada). In September 2002, the ACC issued the Track A Order, which prohibited APS from transferring its generation assets to Pinnacle West Energy. As a result of the Track A Order, we are seeking to transfer the plants built by Pinnacle West Energy in Arizona to APS to unite the Arizona generation under one common owner, as originally intended.

SunCor, our real estate development subsidiary, has been and is expected to be an important source of earnings and cash flow, particularly during the years 2003 through 2005 due to accelerated asset sales activity. Our subsidiary, APS Energy Services, provides competitive commodity-related energy services and energy-related products and services to commercial, industrial and institutional retail customers in the western United States.

The earnings contributions of our marketing and trading segment significantly decreased over the past two years due to lower market liquidity and deteriorating counterparty credit in the wholesale power markets in the western United States. The marketing and trading division focuses primarily on managing APS' purchased power and fuel risks in connection with APS' costs of serving retail customer energy requirements. We currently expect contributions from our trading activities to be negligible for 2004 and approximately $10 million (pretax) annually thereafter.

We continue to focus on solid operational performance in our electricity generation and delivery activities. In the generation area, 2003 represented the twelfth consecutive year Palo Verde was the largest power producer in the United States. In the delivery area, we focus on superior reliability and expanding our transmission and distribution system to meet growth and sustain reliability.

We believe APS' general rate case pending before the ACC is the key issue affecting our outlook. As discussed in greater detail in Note 3, in this rate case APS has requested, among other things, a 9.8% retail rate increase (approximately $175 million annually) rate treatment for the PWEC Dedicated Assets and the recovery of $234 million written off by APS as part of the 1999 Settlement Agreement. In its filed testimony, the ACC staff recommended, among other things, that the ACC decrease APS' rates by approximately 8% (approximately $143 million annually), not allow the PWEC Dedicated Assets to be included in APS' rate base, and not allow APS to recover any of the $234 million written off as a result of the 1999 Settlement Agreement. The ACC staff recommendations, if implemented as proposed, could have a material adverse impact on our results of operations, financial position, liquidity, dividend sustainability, credit ratings and access to capital markets. We believe that APS' rate case requests are supported by, among other things, APS' demonstrated need for the PWEC Dedicated Assets; APS' need to attract capital at reasonable rates of return to support the required capital investment to ensure continued customer reliability in APS' high-growth service territory; and the conditions in the western energy market. As a result, we believe it is unlikely that the ACC would adopt the ACC staff recommendations in their present form, although we can give no assurances in that regard. The hearing on the rate case is scheduled to begin on May 25, 2004. We believe the ACC will be able to make a decision by the end of 2004.

Other factors affecting our past and future financial results include customer growth; purchased power and fuel costs; operations and maintenance expenses, including those relating to plant outages; weather variations; depreciation and amortization expenses, which are affected by net additions to existing utility plant and other property and changes in regulatory asset amortization; and the expected performance of our subsidiaries, SunCor and El Dorado.

EARNINGS CONTRIBUTIONS BY SUBSIDIARY AND 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 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. In early 2003, we moved our marketing and trading activities to APS from Pinnacle West (existing wholesale contracts remained at Pinnacle West) as a result of the ACC's Track A Order prohibiting the previously required transfer of APS' generating assets to Pinnacle West Energy; and
- our real estate segment, which consists of SunCor's real estate development and investment activities.

The following tables summarize net income and segment details for the years ended December 31, 2003, 2002 and 2001 for Pinnacle West and each of our subsidiaries (dollars in millions):

2003	TOTAL	Regulated Electricity	Marketing and Trading	Real Estate(a)	Other(b)
APS (c)	$ 181	$ 184	$ (3)	$ –	$ –
Pinnacle West Energy (c)	(1)	–	(1)	–	–
APS Energy Services	16	–	13	–	3
SunCor	46	–	–	46	–
El Dorado (principally NAC) (d)	7	–	–	–	7
Parent company (d)	(18)	(14)	–	(1)	(3)
Income from continuing operations	231	170	9	45	7
Income from discontinued operations – net of income taxes	10	–	–	10	–
Net income	$ 241	$ 170	$ 9	$ 55	$ 7

2002	TOTAL	Regulated Electricity	Marketing and Trading	Real Estate(a)	Other(b)
APS (c)	$ 199	$ 198	$ 1	$ –	$ –
Pinnacle West Energy (c) (e)	(19)	(21)	2	–	–
APS Energy Services (d)	28	–	23	–	5
SunCor	10	–	–	10	–
El Dorado (principally NAC) (d)	(55)	–	–	–	(55)
Parent company (d)	43	(7)	32	–	18
Income (loss) from continuing operations	206	170	58	10	(32)
Income from discontinued operations – net of income taxes	9	–	–	9	–
Cumulative effect of change in accounting – net of income taxes (f)	(66)	–	(66)	–	–
Net income (loss)	$ 149	$ 170	$ (8)	$ 19	$ (32)

2001	TOTAL	Regulated Electricity	Marketing and Trading	Real Estate(a)	Other
APS (c)	$ 281	$ 139	$ 142	$ –	$ –
Pinnacle West Energy (c)	18	18	–	–	–
APS Energy Services (d)	(10)	–	(11)	–	1
SunCor	3	–	–	3	–
El Dorado (d)	–	–	–	–	–
Parent company (d)	35	(5)	40	–	–
Income before accounting change	327	152	171	3	1
Cumulative effect of change in accounting – net of income taxes (g)	(15)	(15)	–	–	–
Net income	$ 312	$ 137	$ 171	$ 3	$ 1

(a) See Note 22, "Real Estate Activities – Discontinued Operations."
(b) The "Other" segment primarily includes activities related to El Dorado's investment in NAC. We recorded pretax losses of $59 million in 2002, primarily related to NAC contracts with three customers.

(c) Consistent with APS' October 2001 ACC filing, APS entered into contracts with its affiliates to buy power through June 2003. The contracts reflected prices based on the fully-dispatchable dedication of the PWEC Dedicated Assets to APS' Native Load customers (customers receiving power under traditional cost-based rate regulation). Beginning July 1, 2003, under the ACC Track B Order, APS was required to solicit bids for certain estimated capacity and energy requirements. Pinnacle West Energy bid and entered into a contract to supply most of these purchase power requirements in summer months through September 2006. See "Track B Order" in Note 3 for more information.

(d) APS Energy Services' net income prior to 2003 and El Dorado's net income (loss) are primarily reported before income taxes. The income tax expense or benefit for these subsidiaries is recorded at the parent company.

(e) In the fourth quarter of 2002 Pinnacle West Energy recorded a charge related to the cancellation of Redhawk Units 3 and 4 of approximately $30 million after income taxes ($49 million pretax).

(f) As of October 1, 2002, we recorded a $66 million after-tax charge for the cumulative effect of a change in accounting for trading activities, for the early adoption of EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." See Note 18.

(g) APS recorded a $15 million after-tax charge in 2001 for the cumulative effect of a change in accounting for derivatives related to the adoption of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." See Note 18.

See Note 17 for additional financial information regarding our business segments.

RESULTS OF OPERATIONS

General

Throughout the following explanations of our results of operations, we refer to "gross margin." With respect to our regulated electricity segment and our marketing and trading segment, gross margin refers to electric operating revenues less purchased power and fuel costs. Our real estate segment gross margin refers to real estate revenues less real estate operations costs of SunCor. Other gross margin refers to other operating revenues less other operating expenses, which primarily includes El Dorado's investment in NAC, which we began consolidating in our financial statements in July 2002. Other gross margin also includes amounts related to APS Energy Services' energy consulting services. In addition, we have reclassified certain prior period amounts to conform to our current period presentation, including netting of certain revenues and purchased power amounts as a result of the adoption of EITF 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not 'Held for Trading Purposes' As Defined in Issue No. 02-3" (see Note 18).

2003 Compared with 2002

Our consolidated net income for the year ended December 31, 2003 was $241 million compared with $149 million for the prior year. The 2002 net income includes a $66 million after-tax charge for the cumulative effect of a change in accounting for trading activities due to the adoption of EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (see Note 18). Excluding the accounting change, the $26 million increase in the period-to-period comparison reflects the following changes in earnings by segment:

- Regulated Electricity Segment – Net income was flat when comparing the two years, due to offsetting factors. Net income in 2003 was negatively impacted by higher purchased power and fuel costs resulting from higher prices for hedged gas and purchased power; higher costs related to new power plants, net of purchased power savings; higher replacement power costs from plant outages due to higher market prices and more unplanned outages (Unit 3 of the Cholla Power Plant experienced an unplanned outage from August 3, 2003 through November, 2003 and Units 1 and 2 of the Redhawk Power Plant were substantially restricted for almost one-half of the fourth quarter to correct an equipment design defect); higher operations and maintenance costs related to increased pension and other benefits; two retail electricity price reductions; and higher depreciation expense related to increased delivery and other assets. These negative factors were offset by higher retail sales primarily due to customer growth and favorable weather; the absence of the 2002 write-off of Redhawk Units 3 and 4; lower operating costs primarily related to severance costs recorded in 2002; lower regulatory asset amortization; tax credits and favorable income tax adjustments related to prior years resolved in 2003; and higher income related to APS' return to the AFUDC method of capitalizing construction finance costs.
- Marketing and Trading Segment – Income from continuing operations decreased approximately $49 million primarily due to lower market liquidity and deteriorating counterparty credit in the wholesale power markets in the western United States.
- Real Estate Segment – Net income improved approximately $36 million primarily due to increased asset, land and home sales.
- Other Segment – Net income increased approximately $39 million primarily due to NAC losses recognized in 2002.

Additional details on the major factors that increased (decreased) income from continuing operations and net income for the year ended December 31, 2003 compared with the prior year are contained in the following table (dollars in millions).

	Increase/(Decrease)	
	Pretax	After Tax
Regulated electricity segment gross margin:		
Increased purchased power and fuel costs primarily due to higher prices for hedged gas and purchased power	$ (60)	$ (36)
Higher replacement power costs from plant outages due to higher market prices and more unplanned outages	(47)	(28)
Retail electricity price reductions effective July 1, 2002 and July 1, 2003	(27)	(16)
Higher retail sales volumes due to customer growth, excluding weather effects	48	29
Decreased purchased power costs due to new power plants in service	16	10
Effects of weather on retail sales	13	8
Miscellaneous factors, net	5	2
Net decrease in regulated electricity segment gross margin	(52)	(31)
Marketing and trading segment gross margin:		
Lower mark-to-market gains for future delivery due to lower market liquidity and deteriorating counterparty credit	(59)	(35)
Lower realized margins on wholesale sales primarily due to lower unit margins, partially offset by higher volumes	(32)	(19)
Higher margin related to structured contracts originated in prior years	13	7
Decrease in generation sales other than Native Load primarily due to lower unit margins partially offset by higher sales volumes, including sales from new power plants in service	(7)	(4)
Net decrease in marketing and trading segment gross margin	(85)	(51)
Net decrease in regulated electricity and marketing and trading segments' gross margins	(137)	(82)
Higher income primarily related to NAC losses recognized in 2002	66	40
Higher real estate segment contribution primarily due to higher asset, land and home sales	58	36
Operations and maintenance expense decreases (increases):		
Write-off of Redhawk Units 3 and 4 in 2002	47	28
Severance costs recorded in 2002	36	21
Increased pension and other benefit costs	(28)	(17)
Costs for new power plants in service	(20)	(12)
Net other items	1	1
Higher interest expense and lower capitalized interest primarily related to new power plants in service	(26)	(16)
Depreciation and amortization decreases (increases):		
New power plants in service	(19)	(11)
Increased delivery and other assets	(24)	(14)
Decreased regulatory asset amortization	29	17
APS' return to the AFUDC method of capitalizing construction finance costs	8	11
Miscellaneous items, net	7	7
Tax credits and favorable income tax adjustments related to prior years resolved in 2003	–	17
Net (decrease)/increase in income from continuing operations	$ (2)	26
Increase due to 2002 cumulative effect of a change in accounting for trading activities – net of income taxes		66
Net increase in net income		$ 92

The increase in operating and interest costs related to new power plants placed in service by Pinnacle West Energy, net of purchased power savings and increased gross margin from generation sales other than Native Load, totaled approximately $30 million after income taxes in the year ended December 31, 2003 compared with the prior-year period.

Regulated Electricity Segment Revenues

Regulated electricity segment revenues were $88 million higher in the year ended December 31, 2003 compared with the prior year, primarily as a result of:

- an $85 million increase in retail revenues related to customer growth and higher average usage, excluding weather effects;
- a $21 million increase in retail revenues related to weather;
- a $6 million increase related to traditional wholesale sales as a result of higher prices and higher sales volumes;
- a $27 million decrease in retail revenues related to two reductions in retail electricity prices; and
- a $3 million net increase due to miscellaneous factors.

Marketing and Trading Segment Revenues

Marketing and trading segment revenues were $105 million higher in the year ended December 31, 2003 compared with the prior year, primarily as a result of:

- $74 million of higher revenues related to the adoption of EITF 02-3 in the fourth quarter of 2002, primarily due to structured contracts that were reported gross in the current period and net in most of the prior period;
- a $69 million increase from higher competitive retail sales in California by APS Energy Services;
- a $38 million increase from generation sales other than Native Load primarily due to higher prices and sales volumes, including sales from new power plants in service;
- $59 million in lower mark-to-market gains for future-period deliveries primarily as a result of lower market liquidity and lower price volatility; and
- $17 million of lower realized wholesale revenues primarily due to lower unit margins on trading activities that are reported on a net basis.

Real Estate Segment Revenues

Real estate segment revenues were $161 million higher in the year ended December 31, 2003 compared with the prior year primarily as a result of increased asset, land and home sales related to SunCor's effort to accelerate asset sales.

Other Revenues

Other revenues were $24 million higher in the year ended December 31, 2003 compared with the prior year primarily due to our consolidation of NAC's financial statements beginning in the third quarter of 2002, partially offset by decreased sales activity at NAC.

2002 Compared with 2001

Our consolidated net income for the year ended December 31, 2002 was $149 million compared with $312 million for the prior year. We recognized a $66 million after-tax charge in 2002 for the cumulative effect of a change in accounting for trading activities for the early adoption of EITF 02-3 on October 1, 2002 (see Note 18). In 2001, we recognized a $15 million after-tax charge for the cumulative effect of a change in accounting for derivatives, as required by SFAS No. 133 (see Note 18). Net income for 2002 includes income from discontinued operations of $9 million after-tax related to our real estate segment (see Note 22). Excluding the accounting changes and discontinued operations, the $121 million decrease in the period-to-period comparison reflects the following changes in earnings by segment:

- Regulated Electricity Segment – Income from continuing operations increased $18 million primarily due to lower replacement power costs for power plants outages, retail customer growth and higher average customer usage. These positive factors were partially offset by a write-off of Redhawk Units 3 and 4, higher operating costs primarily related to severance costs recorded in 2002, retail electricity price decreases, the effects of milder weather, and higher costs for purchased power and gas due to higher hedged gas and power prices.
- Marketing and Trading Segment – Income from continuing operations decreased $113 million primarily due to lower liquidity and lower price volatility in the wholesale power markets in the western United States.
- Other Segment – Net income decreased approximately $33 million, primarily due to 2002 losses related to our investment in NAC.
- Real Estate Segment – Income from continuing operations increased by $7 million primarily due to increased asset, land and home sales.

Additional details on the major factors that increased (decreased) income from continuing operations and net income for the year ended December 31, 2002 compared with the prior year are contained in the following table (dollars in millions).

	Increase/(Decrease)	
	Pretax	After Tax
Regulated electricity segment gross margin:		
Lower replacement power costs for plant outages due to lower market prices and fewer unplanned outages	$ 127	$ 76
Higher retail sales volumes due to customer growth and higher average usage, excluding weather effects	38	23
2001 charges related to purchased power contracts with Enron and its affiliates	13	8
Retail price reductions effective July 1, 2001 and July 1, 2002	(28)	(17)
Effects of milder weather on retail sales	(27)	(16)
Increased purchased power and fuel costs due to higher hedged gas and power prices, partially offset by improved hedge management, net of mark-to-market reversals	(9)	(5)
Miscellaneous factors, net	(2)	(2)
Net increase in regulated electricity segment gross margin	112	67
Marketing and trading segment gross margin:		
Lower realized wholesale margins net of related mark-to-market reversals due to lower prices and volumes	(91)	(55)
Lower mark-to-market gains for future delivery due to lower market liquidity and lower price volatility	(76)	(45)
Decrease in generation sales other than Native Load due to lower market prices partially offset by higher sales volumes	(66)	(40)
Higher competitive retail sales in California by APS Energy Services	32	19
2001 write-off of prior period mark-to-market value related to trading with Enron and its affiliates	8	5
Lower mark-to-market reversals due to the adoption of EITF 02-3	8	5
Net decrease in marketing and trading segment gross margin	(185)	(111)
Net decrease in regulated electricity and marketing and trading segments' gross margins	(73)	(44)
Lower other gross margin primarily related to NAC losses	(44)	(26)
Higher operations and maintenance expense related to a $47 million write-off of Redhawk Units 3 and 4 and 2002 severance costs of approximately $36 million, partially offset by lower generation reliability costs	(54)	(32)
Higher taxes other than income taxes	(7)	(4)
Lower other income primarily due to a 2001 insurance recovery of environmental remediation costs	(12)	(7)
Higher net interest expense primarily due to higher debt balances and lower capitalized interest	(16)	(10)
Miscellaneous factors, net	4	2
Net decrease in income from continuing operations	$ (202)	(121)
Decrease due to 2002 cumulative effect of change in accounting for trading activities – net of income taxes		(66)
Increase due to 2001 cumulative effect of change in accounting for derivatives – net of income taxes		15
Increase due to 2002 discontinued operations – net of income taxes		9
Net decrease in net income		$ (163)

Regulated Electricity Segment Revenues

Regulated electricity segment revenues related to our regulated retail and wholesale electricity businesses were $94 million lower in the year ended December 31, 2002, compared with the prior year as a result of:

- a $64 million decrease in revenues related to traditional wholesale sales as a result of lower sales volumes and lower prices;
- a $60 million decrease in retail revenues related to milder weather;
- a $69 million increase in retail revenues related to customer growth and higher average usage, excluding weather effects;
- a $28 million decrease in retail revenues related to reductions in retail electricity prices; and
- an $11 million decrease due to other miscellaneous factors.

Marketing and Trading Segment Revenues

Marketing and trading segment revenues were $183 million lower in the year ended December 31, 2002, compared with the prior year as a result of:

- a $98 million decrease in revenues from generation sales other than Native Load primarily due to lower market prices partially offset by higher sales volumes;
- $131 million of lower realized wholesale revenues net of related mark-to-market reversals primarily due to lower prices partially offset by higher volumes;
- a $105 million increase in revenues from higher competitive retail sales in California by APS Energy Services;
- an $8 million increase in revenues due to the absence of a 2001 write-off of prior period mark-to-market value related to trading with Enron and its affiliates;

- $8 million of higher revenues related to the adoption of EITF 02-3; and
- $75 million of lower mark-to-market gains for future delivery primarily as a result of lower market liquidity and lower price volatility, resulting in lower volumes.

Real Estate Segment Revenues

Real Estate segment revenues were $32 million higher in the year ended December 31, 2002 compared with the prior year primarily as a result of increased land, asset and home sales.

Other Revenues

Other revenues were $50 million higher in the year ended December 31, 2002 compared with the prior year primarily due to the consolidation of NAC's financial statements beginning in the third quarter of 2002.

LIQUIDITY AND CAPITAL RESOURCES

Capital Needs and Resources

Capital Expenditure Requirements

The following table summarizes the actual capital expenditures for the year ended December 31, 2003 and estimated capital expenditures for the next three years (dollars in millions):

	Actual	Estimated		
	2003	2004	2005	2006
APS				
Delivery	$ 288	$ 309	$ 390	$ 453
Generation (a)	136	107	160	200
Other	5	10	12	2
Subtotal	429	426	562	655
Pinnacle West Energy (a)(b)	250	61	24	4
SunCor (c)	72	83	27	17
Other (d)	16	11	18	16
Total	$ 767	$ 581	$ 631	692

(a) As discussed in Note 3 under "APS General Rate Case and Retail Rate Adjustment Mechanisms," as part of its 2003 general rate case, APS requested rate base treatment of the PWEC Dedicated Assets. Pinnacle West Energy actual capital expenditures related to PWEC Dedicated Assets were $49 million for 2003 and are estimated to be $15 million in 2004, $21 million in 2005 and $4 million in 2006.

(b) See "Capital Needs and Resources by Company – Pinnacle West Energy" below for further discussion of Pinnacle West Energy's generation construction program. These amounts do not include an expected reimbursement by SNWA of about $100 million (plus capitalized interest), based upon SNWA's agreement to purchase a 25% interest in the Silverhawk project upon completion in 2004.

(c) Consists primarily of capital expenditures for land development and retail and office building construction reflected in "Real estate investments" on the Consolidated Statements of Cash Flows.

(d) Primarily related to the parent company and APS Energy Services.

Delivery capital expenditures are comprised of T&D infrastructure additions and upgrades, capital replacements, new customer construction and related information systems and facility costs. Examples of the types of projects included in the forecast include T&D lines and substations, line extensions to new residential and commercial developments and upgrades to customer information systems. APS completed the Southwest Valley transmission project in 2003 at a cost of approximately $70 million. Major transmission projects are driven by strong regional customer growth. APS will begin major projects each year for the next several years, and expects to spend about $200 million on major transmission projects during the 2004 to 2006 time frame. These amounts are included in "APS-Delivery" in the table above. Completion of these projects will stretch from 2005 through at least 2008.

Generation capital expenditures are comprised of various improvements to APS' existing fossil and nuclear plants and the replacement of Palo Verde steam generators. Examples of the types of projects included in this category are additions, upgrades and capital replacements of various power plant equipment such as turbines, boilers and environmental equipment. Generation also includes nuclear fuel expenditures of approximately $30 million annually for 2004 to 2006.

Replacement of the steam generators in Palo Verde Unit 2 was completed during the fall outage of 2003 at a cost to APS of approximately $70 million. The Palo Verde owners have approved the manufacture of two additional sets of steam generators. These generators will be installed in Unit 1 (scheduled completion in 2005) and Unit 3 (scheduled completion in 2007). Our portion of steam generator expenditures for Units 1 and 3 is approximately $140 million, which will be spent through 2008. In 2004 through 2006, approximately $90 million of the Unit 1 and Unit 3 costs are included in the generation capital expenditures table above and will be funded with internally-generated cash or external financings.

Contractual Obligations

The following table summarizes contractual requirements as of December 31, 2003 (dollars in millions):

	2004	2005-2006	2007-2008	Thereafter	TOTAL
Long-term debt payments, including interest: (a)					
APS	$ 342	$ 699	$ 192	$ 2,567	$ 3,800
Pinnacle West	242	497	–	–	739
SunCor	4	12	5	–	21
El Dorado	1	1	–	–	2
Short-term debt payments, including interest (b)	88	–	–	–	88
Capital lease payments	3	5	2	3	13
Operating lease payments	73	138	132	421	764
Minimum pension funding requirement (c)	100	–	–	–	100
Purchase power and fuel commitments (d)	209	134	102	461	906
Purchase obligations (e)	85	22	5	68	180
Nuclear decommissioning funding requirements	11	22	22	158	213
Total contractual commitments	$ 1,158	$ 1,530	$ 460	$ 3,678	$ 6,826

(a) The long-term debt matures at various dates through fiscal year 2034 and bears interest principally at fixed rates. Interest on variable long-term debt is set at the December 31, 2003 rates. The short-term debt matures within 12 months. The weighted-average interest rate of the short-term debt is 4.26% at December 31, 2003.

(b) The short-term debt matures within 12 months. The weighted-average interest rate of the short-term debt is 4.26% at December 31, 2003.

(c) If currently pending legislation is enacted, our required pension contribution in 2004 would decrease to the $25 to $50 million range. Future pension contributions are not determinable for time periods after 2004.

(d) Our purchase power and fuel commitments include purchases of coal, electricity, natural gas and nuclear fuel (see Note 11).

(e) These contractual obligations include commitments for capital expenditures and other obligations.

Off-Balance Sheet Arrangements

In 2003, we adopted FIN No. 46R, "Consolidation of Variable Interest Entities," as it applies to special-purpose entities. FIN No. 46R requires that we consolidate a VIE if we have a majority of the risk of loss from the VIE's activities or we are entitled to receive a majority of the VIE's residual returns or both. A VIE is a corporation, partnership, trust or any other legal structure that either does not have equity investors with voting rights or has equity investors that do not provide sufficient financial resources for the entity to support its activities. In 1986, APS entered into agreements with three separate SPE lessors in order to sell and lease back interests in Palo Verde Unit 2. The leases are accounted for as operating leases in accordance with GAAP. See Note 9 for further information about the sale leaseback transactions. Based on our assessment of FIN No. 46R, we are not required to consolidate the Palo Verde VIEs. Certain provisions of FIN No. 46R have a future effective date. We do not expect these provisions to have a material impact on our financial statements.

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, 2003, APS would have been required to assume approximately $268 million of debt and pay the equity participants approximately $200 million.

Guarantees and Letters of Credit

We and certain of our subsidiaries have issued guarantees and letters of credit in support of our unregulated businesses. We have also obtained surety bonds on behalf of APS Energy Services. We have not recorded any liability on our Consolidated Balance Sheets with respect to these obligations. See Note 21 for additional information regarding guarantees and letters of credit.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of March 11, 2004 are shown below and are considered to be "investment-grade" ratings. The ratings reflect the respective views of the rating agencies, from which an explanation of the significance of their ratings may be obtained. There is no assurance that these ratings will continue for any given period of time. The ratings may be revised or withdrawn entirely by the rating agencies, if, in their respective judgments, circumstances so warrant. Any downward revision or withdrawal may adversely affect the market price of Pinnacle West's or APS' securities and serve to increase those companies' cost of and access to capital. It may also require additional collateral related to certain derivative instruments (see Note 18).

	Moody's	Standard & Poor's
PINNACLE WEST		
Senior unsecured	Baa2	BBB-
Commercial paper	P-2	A-2
Outlook	Negative	Stable
APS		
Senior secured	A3	A-
Senior unsecured	Baa1	BBB
Secured lease obligation bonds	Baa2	BBB
Commercial paper	P-2	A-2
Outlook	Negative	Stable

Debt Provisions

Pinnacle West's and APS' debt covenants related to their respective 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 the covenant requirement levels. The ratio of debt to total capitalization cannot exceed 65% for each of the Company and APS individually. At December 31, 2003, the ratio was approximately 54% for Pinnacle West. At December 31, 2003, the ratio was approximately 53% 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 2003 results, the coverages were approximately 4 times for the Company, 4 times for the APS bank financing agreements and 15 times for the APS mortgage indenture. 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 financial condition or financial prospects.

Capital Needs and Resources by Company

Pinnacle West (Parent Company)

Our primary cash needs are for dividends to our shareholders; interest payments and optional and mandatory repayments of principal on our long-term debt (see the table above for our contractual requirements, including our debt repayment obligations, but excluding optional repayments) and equity infusions into our subsidiaries, primarily Pinnacle West Energy. On October 22, 2003, our board of directors increased the common stock dividend to an indicated annual rate of $1.80 per share from $1.70 per share, effective with the December 1, 2003 dividend payment. The level of our common dividends and future dividend growth will be dependent on a number of factors including, but not limited to, payout ratio trends, free cash flow and financial market conditions.

Our primary sources of cash are dividends from APS, external financings and cash distributions from our other subsidiaries, primarily SunCor. For the years 2001 through 2003, total dividends from APS were $510 million and total distributions from SunCor were $121 million. For the year ended December 31, 2003, dividends from APS were approximately $170 million and distributions from SunCor were approximately $108 million. We expect SunCor to make cash distributions to the parent company of $80 to $100 million annually in 2004 and 2005 due to anticipated accelerated asset sales activity. As discussed in Note 3 under "ACC Financing Orders," APS must maintain a common equity ratio of at least 40% and may not pay common dividends if the payment would reduce its common equity below that threshold. As defined in the Financing Order, common equity ratio is common equity divided by common equity plus long-term debt, including current maturities of long-term debt. At December 31, 2003, APS' common equity ratio was approximately 46%.

On May 12, 2003, APS issued $500 million of debt as follows: $300 million aggregate principal amount of its 4.65% Notes due 2015 and $200 million aggregate principal amount of its 5.625% Notes due 2033. Also on May 12, 2003, APS made a $500 million loan to Pinnacle West Energy, and Pinnacle West Energy distributed the net proceeds of that loan to us to fund our repayment of a portion of the debt incurred to finance the construction of the PWEC Dedicated Assets. See "ACC Financing Order" in Note 3 for additional information. With Pinnacle West Energy's distribution to us on May 12, 2003, we repaid the outstanding balance ($167 million) under a credit facility. We used a portion of the remaining proceeds to redeem our $250 million Floating Rate Notes due 2003 on June 2, 2003 and to repay other short-term debt. On November 12, 2003, we issued $165 million of our Floating Rate Senior Notes due 2005.

At December 31, 2003, the parent company's outstanding long-term debt, including current maturities, was $681 million. At December 31, 2003, we had unused credit commitments from various banks totaling $275 million, which were available to support the issuance of commercial paper or to be used as bank borrowings. At December 31, 2003, we had no commercial paper outstanding and no short-term borrowings. We ended 2003 in an invested position.

Pinnacle West sponsors a pension plan that covers employees of Pinnacle West and our subsidiaries. We contribute at least the minimum amount required under IRS regulations, but no more than the maximum tax-deductible amount. The minimum required funding takes into consideration the value of the fund assets and our pension obligation. We elected to contribute cash to our pension plan in each of the last five years; our minimum required contributions during each of those years was zero. Specifically, we contributed $73 million for 2002 ($46 million of which was contributed in June 2003); $24 million for 2001; $44 million for 2000 ($20 million of

which was contributed in 2001); and $25 million for 1999. APS and other subsidiaries fund their share of the pension contribution, of which APS represents approximately 89% of the total funding amounts described above. The assets in the plan are mostly domestic common stocks, bonds and real estate. Future year contribution amounts are dependent on fund performance and fund valuation assumptions. Under current law, we are required to contribute approximately $100 million to our pension plans in 2004 and expect to contribute approximately $50 million to our other postretirement benefit plan in 2004. If currently pending legislation is enacted, our required pension contribution in 2004 would decrease to the $25 to $50 million range.

APS

APS' capital requirements consist primarily of capital expenditures and optional and mandatory redemptions of long-term debt. See "Pinnacle West (Parent Company)" above and Note 3 for discussion of the $500 million financing arrangement between APS and Pinnacle West Energy approved by the ACC in 2003 and discussion of a $125 million financing arrangement between APS and Pinnacle West.

APS pays for its capital requirements with cash from operations and, to the extent necessary, external financings. APS has historically paid for its dividends to Pinnacle West with cash from operations. See "Pinnacle West (Parent Company)" above for a discussion of common equity ratio that APS must maintain in order to pay dividends to Pinnacle West.

On April 7, 2003, APS redeemed approximately $33 million of its First Mortgage Bonds, 8% Series due 2025, and on August 1, 2003, APS redeemed approximately $54 million of its First Mortgage Bonds, 7.25% Series due 2023.

On February 15, 2004, $125 million of APS 5.875% Notes due 2004 were redeemed at maturity and on March 1, 2004, $80 million of APS' First Mortgage Bonds, 6.625% Series due 2004 were redeemed at maturity. APS used cash from operations and short-term debt to redeem the maturing debt.

APS' outstanding debt was approximately $2.6 billion at December 31, 2003. At December 31, 2003, APS had unused credit commitments from various banks totaling about $250 million, which were available either to support the issuance of commercial paper or to be used as bank borrowings. At December 31, 2003, APS had no outstanding commercial paper or bank borrowings. APS ended 2003 in an invested position.

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

Pinnacle West Energy

The costs of Pinnacle West Energy's construction of 2,360 MW of generating capacity from 2000 through 2004 are expected to be about $1.4 billion, of which $1.35 billion has been incurred through December 31, 2003. This does not reflect the proceeds from an anticipated sale in 2004 to SNWA of a 25% interest in the 570 MW Silverhawk Combined Cycle Plant 20 miles north of Las Vegas, Nevada, which would equal about $100 million (plus capitalized interest) of Pinnacle West Energy's cumulative capital expenditures in the project. SNWA has agreed to purchase a 25% interest in the project upon completion. Such purchase is subject to an appropriation of funds by SNWA. Pinnacle West Energy's capital requirements are currently funded through capital infusions from Pinnacle West, which finances those infusions through debt and equity financings and internally-generated cash. See the capital expenditures table above for actual capital expenditures in 2003 and projected capital expenditures for the next three years.

See Note 3 and "Pinnacle West (Parent Company)" above for a discussion of the $500 million financing arrangement between APS and Pinnacle West Energy authorized by the ACC pursuant to the Financing Order.

Other Subsidiaries

During the past three years, SunCor funded its cash requirements with cash from operations and its own external financings. SunCor's capital needs consist primarily of capital expenditures for land development and retail and office building construction. See the capital expenditures table above for actual capital expenditures in 2003 and projected capital expenditures for the next three years. SunCor expects to fund its capital requirements with cash from operations and external financings.

In 2003, SunCor acquired or issued $10 million in long-term debt, and redeemed, refinanced or repaid $1 million in long-term debt (see Note 6).

SunCor's outstanding long and short-term debt was approximately $104 million as of December 31, 2003. SunCor's total short-term debt was $86 million at December 31, 2003. SunCor had a $120 million line of credit, under which $50 million of short-term borrowings were outstanding at December 31, 2003. SunCor's long-term debt, including current maturities, totaled $18 million at December 31, 2003.

We expect SunCor to make cash distributions to the parent company of $80 to $100 million annually in 2004 and 2005 due to anticipated accelerated asset sales activity.

El Dorado funded its cash requirements during the past three years, primarily for NAC in 2002, with cash infused by the parent company and with cash from operations. El Dorado expects minimal capital requirements over the next three years and intends to focus on prudently realizing the value of its existing investments.

APS Energy Services' cash requirements during the past three years were funded with cash infusions from the parent company and with cash from operations. See the capital expenditures table above regarding APS Energy Services' actual capital expenditures for 2003 and projected capital expenditures for the next three years.

CRITICAL ACCOUNTING POLICIES

In preparing the financial statements in accordance with GAAP, management must often make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures at the date of the financial statements and during the reporting period. Some of those judgments can be subjective and complex, and actual results could differ from those estimates. We consider the following accounting policies to be our most critical because of the uncertainties, judgments and complexities of the underlying accounting standards and operations involved.

Regulatory Accounting

Regulatory accounting allows for the actions of regulators, such as the ACC and the FERC, to be reflected in our financial statements. Their actions may cause us to capitalize costs that would otherwise be included as an expense in the current period by unregulated companies. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings. We had $165 million of regulatory assets on the Consolidated Balance Sheets at December 31, 2003. See Notes 1 and 3 for more information about regulatory assets and APS' general rate case.

Pensions and Other Postretirement Benefit Accounting

Changes in our actuarial assumptions used in calculating our pension and other postretirement benefit liability and expense can have a significant impact on our earnings and financial position. The most relevant actuarial assumptions are the discount rate used to measure our liability and net periodic cost, the expected long-term rate of return on plan assets used to estimate earnings on invested funds over the long-term, and the assumed healthcare cost trend rates. We review these assumptions on an annual basis and adjust them as necessary.

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the 2003 projected benefit obligation, our 2003 reported pension liability on the Consolidated Balance Sheets and our 2003 reported pension expense, after consideration of amounts capitalized or billed to electric plant participants, on our Consolidated Statements of Income (dollars in millions):

	Increase/(Decrease)		
Actuarial Assumption (a)	Impact on Projected Benefit Obligation	Impact on Pension Liability	Impact on Pension Expense
Discount rate:			
Increase 1%	$ (165)	$ (123)	$ (8)
Decrease 1%	189	139	6
Expected long-term rate of return on plan assets:			
Increase 1%	–	–	(3)
Decrease 1%	–	–	3

(a) Each fluctuation assumes that the other assumptions of the calculation are held constant.

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the 2003 accumulated other postretirement benefit obligation and our 2003 reported other postretirement benefit expense, after consideration of amounts capitalized or billed to electric plant participants, on our Consolidated Statements of Income (dollars in millions):

	Increase/(Decrease)	
Actuarial Assumption (a)	Impact on Accumulated Postretirement Benefit Obligation	Impact on Other Postretirement Benefit Expense
Discount rate:		
Increase 1%	$ (81)	$ (5)
Decrease 1%	96	5
Health care cost trend rate (b):		
Increase 1%	95	7
Decrease 1%	(76)	(5)
Expected long-term rate of return on plan assets – pretax:		
Increase 1%	–	(1)
Decrease 1%	–	1

(a) Each fluctuation assumes that the other assumptions of the calculation are held constant.
(b) This assumes a 1% change in the initial and ultimate health care cost trend rate.

See Note 8 for further details about our pension and other postretirement benefit plans.

Derivative Accounting

Derivative accounting requires evaluation of rules that are complex and subject to varying interpretations. Our evaluation of these rules, as they apply to our contracts, will determine whether we use accrual accounting or fair value (mark-to-market) accounting. Mark-to-market accounting requires that changes in fair value be recorded in earnings or, if certain hedge accounting criteria are met, in common stock equity (as a component of other comprehensive income (loss)). See "Market Risks – Commodity Price Risk" below for quantitative analysis. See Note 18 for a further discussion on derivative and energy trading accounting.

Mark-to-Market Accounting

The market value of our derivative contracts is not always readily determinable. In some cases, we use models and other valuation

techniques to determine fair value. The use of these models and valuation techniques sometimes requires subjective and complex judgment. Actual results could differ from the results estimated through application of these methods. Our marketing and trading portfolio consists of structured activities hedged with a portfolio of forward purchases that protects the economic value of the sales transactions. See "Market Risks – Commodity Price Risk" below for quantitative analysis. See Note 1 for discussion on accounting policies and Note 18 for a further discussion on derivative and energy trading accounting.

OTHER ACCOUNTING MATTERS

Accounting for Derivative and Trading Activities

We adopted EITF 03-11 effective October 1, 2003. EITF 03-11 provides guidance on whether realized gains and losses on physically settled derivative contracts not held for trading purposes should be reported on a net or gross basis and concluded such classification is a matter of judgment that depends on the relevant facts and circumstances. 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 netted these book-outs reducing both revenues and purchased power and fuel costs in 2003, 2002 and 2001, but this did not impact our financial condition, net income or cash flows.

We adopted EITF 02-3 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. Our energy trading contracts that are derivatives are accounted for at fair value under SFAS No. 133. 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.

In 2001, we adopted SFAS No. 133 and recorded a $15 million after-tax charge in net income and a $72 million after-tax credit in common stock equity (as a component of other comprehensive income), both as a cumulative effect of a change in accounting for derivatives.

See Notes 1 and 18 for further information on accounting for derivatives.

Asset Retirement Obligations

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

We determined that we have asset retirement obligations for our nuclear facilities (nuclear decommissioning) and certain other generation, transmission and distribution assets. On January 1, 2003, we recorded a liability of $219 million for our asset retirement obligations including the accretion impacts; a $67 million increase in the carrying amount of the associated assets; and a net reduction of $192 million in accumulated depreciation related primarily to the reversal of previously recorded accumulated decommissioning and other removal costs related to these obligations. Additionally, we recorded a regulatory liability of $40 million for our asset retirement obligations related to our regulated utility. This regulatory liability represents the difference between the amount currently being recovered in regulated rates and the amount calculated under SFAS No. 143. We believe we can recover in regulated rates the transition costs and ongoing current period costs calculated in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (see Note 1) and SFAS No. 143 (see Note 12). Adopting SFAS No. 143 had no impact on our Consolidated Statements of Income or our Consolidated Statements of Cash Flow.

Variable Interest Entities

See "Liquidity and Capital Resources – Off-Balance Sheet Arrangements" and Note 20 for discussion of VIEs.

FACTORS AFFECTING OUR FINANCIAL OUTLOOK

APS General Rate Case

We believe APS' general rate case pending before the ACC is the key issue affecting our outlook. As discussed in greater detail in Note 3, in this rate case APS has requested, among other things, a 9.8% retail rate increase (approximately $175 million annually), rate treatment for the PWEC Dedicated Assets and the recovery of $234 million written off by APS as part of the 1999 Settlement Agreement. In its filed testimony, the ACC staff recommended, among other things, that the ACC decrease APS' rates by approximately 8% (approximately $143 million annually), not allow the PWEC Dedicated Assets to be included in APS' rate base, and not allow APS to recover any of the $234 million written off as a result of the 1999 Settlement Agreement. The ACC staff recommendations, if implemented as proposed, could have a material adverse impact on our results of operations, financial position, liquidity, dividend sustainability, credit ratings and access to capital markets. We believe that APS' rate case requests are supported by, among other things, APS' demonstrated need for the PWEC Dedicated Assets; APS' need to attract capital at reasonable rates of return to support the required capital investment to ensure continued customer reliability in APS' high-growth service territory; and the conditions in the western energy market. As a result, we believe it is unlikely that the ACC would adopt the ACC staff recommendations in their present form, although we can give no assurances in that

regard. The hearing on the rate case is scheduled to begin on May 25, 2004. We believe the ACC will be able to make a decision by the end of 2004.

Wholesale Power Market Conditions

The marketing and trading division focuses primarily on managing APS' purchased power and fuel risks in connection with its costs of serving retail customer demand. We moved this division to APS in early 2003 for future marketing and trading activities (existing wholesale contracts remained at Pinnacle West) as a result of the ACC's Track A Order prohibiting APS' transfer of generating assets to Pinnacle West Energy. Additionally, the marketing and trading division, subject to specified parameters, markets, hedges and trades in electricity, fuels and emission allowances and credits. Our future earnings will be affected by the strength or weakness of the wholesale power market. The market has suffered a substantial reduction in overall liquidity because there are fewer creditworthy counterparties and because several key participants have exited the market or scaled back their activities. Based on the erosion in the market and on the market outlook, we currently expect contributions from our trading activities to be negligible for 2004, and approximately $10 million (pretax) annually thereafter.

Generation Construction Program

See "Liquidity and Capital Resources – Pinnacle West Energy" for information regarding Pinnacle West Energy's generation construction program, which is nearing completion. The additional generation is expected to increase revenues, fuel expenses, operating expenses and financing costs.

Factors Affecting Operating Revenues

General Electric operating revenues are derived from sales of electricity in regulated retail markets in Arizona and from competitive retail and wholesale power markets in the western United States. These revenues are expected to be affected by electricity sales volumes related to customer mix, customer growth and average usage per customer as well as electricity prices and variations in weather from period to period. Competitive sales of energy and energy-related products and services are made by APS Energy Services in western states that have opened to competitive supply.

Customer Growth Customer growth in APS' service territory averaged about 3.4% a year for the three years 2001 through 2003; we currently expect customer growth to average about 3.5% per year from 2004 to 2006. We currently estimate that total retail electricity sales in kilowatt-hours will grow 4.9% on average, from 2004 through 2006, before the retail effects of weather variations. The customer and sales growth referred to in this paragraph applies to Native Load customers. Customer growth for the year ended December 31, 2003 compared with the prior year period was 3.3%.

Retail Rate Changes As part of the 1999 Settlement Agreement, APS agreed to 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%. The final price reduction was implemented July 1, 2003. See "1999 Settlement Agreement" in Note 3 for further information. In addition, the Company has requested a 9.8% retail rate increase to be effective July 1, 2004. See "APS General Rate Case and Retail Rate Adjustment Mechanisms" in Note 3 for further information.

Other Factors Affecting Future Financial Results

Purchased Power and Fuel Costs Purchased power and fuel costs are impacted by our electricity sales volumes, existing contracts for purchased power and generation fuel, our power plant performance, prevailing market prices, new generating plants being placed in service and our hedging program for managing such costs. See "Natural Gas Supply" in Note 11 for more information on fuel costs.

Operations and Maintenance Expenses Operations and maintenance expenses are impacted by growth, power plant additions and operations, inflation, outages, higher trending pension and other postretirement benefit costs and other factors.

Depreciation and Amortization Expenses Depreciation and amortization expenses are impacted by net additions to existing utility plant and other property, changes in regulatory asset amortization and our generation construction program. West Phoenix Unit 4 was placed in service in June 2001. Redhawk Units 1 and 2 and the new Saguaro Unit 3 began commercial operations in July 2002. West Phoenix Unit 5 was placed in service in July 2003 and Silverhawk is expected to be in service in mid-2004. The regulatory assets to be recovered under the 1999 Settlement Agreement are currently being amortized as follows (dollars in millions):

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

Property Taxes Taxes other than income taxes consist primarily of property taxes, which are affected by tax rates and the value of property in-service and under construction. The average property tax rate for APS, which currently owns the majority of our property, was 9.3% of assessed value for 2003 and 9.7% for 2002. We expect property taxes to increase primarily due to our generation construction program, as the plants phase-in to the property tax base over a five-year period, and our additions to existing facilities.

Interest Expense Interest expense is affected by the amount of debt outstanding and the interest rates on that debt. The primary factors affecting borrowing levels in the next several years are expected to be our capital requirements and our internally generated cash flow. Capitalized interest offsets a portion of interest expense while capital projects are under construction. We stop accruing capitalized interest on a project when it is placed in commercial

operation. As noted above, we placed new power plants in commercial operation in 2001, 2002 and 2003 and we expect to bring an additional plant on-line in 2004. Interest expense is also affected by interest rates on variable-rate debt and interest rates on the refinancing of the Company's future liquidity needs. In addition, see Note 1 for a discussion of AFUDC.

Retail Competition The regulatory developments and legal challenges to the Rules discussed in Note 3 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.

Subsidiaries In the case of SunCor, efforts to accelerate asset sales activities in 2003 were successful. A portion of these sales have been, and additional amounts may be required to be, reported as discontinued operations on our Consolidated Statements of Income. The annual earnings contribution from SunCor was $56 million after tax in 2003. See Note 22 for further discussion. We anticipate SunCor's annual earnings contributions in 2004 and 2005 will be in the $30 to $40 million range after tax.

The annual earnings contribution from APS Energy Services is expected to be positive over the next several years due primarily to a number of retail electricity contracts in California. APS Energy Services had after tax earnings of $16 million in 2003.

We expect SunCor and APS Energy Services to have combined earnings of approximately $10 million per year after tax beyond 2005.

El Dorado's historical results are not necessarily indicative of future performance for El Dorado. In addition, we do not currently expect material losses related to NAC in the future.

General Our financial results may be affected by a number of broad factors. See "Forward-Looking Statements" below for further information on such factors, which may cause our actual future results to differ from those we currently seek or anticipate.

Market Risks

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

Interest Rate and Equity Risk

Our major financial market risk exposure is changing interest rates. Changing interest rates will affect interest paid on variable-rate debt and interest earned by our nuclear decommissioning trust fund (see Note 12). Our policy is to manage interest rates through the use of a combination of fixed-rate and floating-rate debt. On January 29, 2004, we entered into a fixed-for-floating interest rate swap transaction (see Note 6 for additional information). The nuclear decommissioning fund also has risk associated with changing market values of equity investments. Nuclear decommissioning costs are recovered in regulated electricity prices.

The table below presents contractual balances of our consolidated long-term and short-term debt at the expected maturity dates as well as the fair value of those instruments on December 31, 2003. The interest rates presented in the tables below represent the weighted-average interest rates for the year ended December 31, 2003 (dollars in thousands):

	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
December 31, 2003	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
2004	4.26%	$ 86,081	2.68%	$ 1,209	5.33%	$ 424,271
2005	–	–	1.99%	166,269	7.27%	403,204
2006	–	–	6.55%	2,937	6.49%	391,585
2007	–	–	4.99%	373	5.54%	1,256
2008	–	–	5.19%	5,269	5.55%	1,098
Years thereafter	–	–	1.51%	386,860	5.83%	1,547,775
Total		$ 86,081		$ 562,917		$ 2,769,189
Fair Value		$ 86,081		$ 563,047		$ 2,913,190

Commodity Price Risk

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal and emissions allowances. We manage risks associated with these market fluctuations by utilizing various commodity instruments that qualify as derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. Our ERMC, consisting of officers and key management personnel, oversees company-wide energy risk management activities and monitors the results of marketing and trading

activities to ensure compliance with our stated energy risk management and trading policies. As part of our risk management program, we use such instruments to hedge purchases and sales of electricity, fuels and emissions allowances and credits. The changes in market value of such contracts have a high correlation to price changes in the hedged commodities. In addition, subject to specified risk parameters monitored by the ERMC, we engage in marketing and trading activities intended to profit from market price movements.

The mark-to-market value of derivative instruments related to our 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 – non-trading and trading derivative instruments of our competitive business segment.

The following tables show the pretax changes in mark-to-market of our non-trading and trading derivative positions in 2003 and 2002 (dollars in millions):

	Regulated Electricity	Marketing and Trading
Mark-to-market of net positions at December 31, 2002	$ (49)	$ 57
Change in mark-to-market losses for future period deliveries	(5)	(7)
Changes in cash flow hedges recorded in OCI	41	44
Ineffective portion of changes in fair value recorded in earnings	8	–
Mark-to-market losses/(gains) realized during the year	5	(25)
Mark-to-market of net positions at December 31, 2003	$ –	$ 69

	Regulated Electricity	Marketing and Trading
Mark-to-market of net positions at December 31, 2001	$ (107)	$ 138
Cumulative effect adjustment due to adoption of EITF 02-3	–	(109)
Change in mark-to-market (losses)/ gains for future period deliveries	(13)	52
Changes in cash flow hedges recorded in OCI	57	16
Ineffective portion of changes in fair value recorded in earnings	11	–
Mark-to-market losses/(gains) realized during the year	3	(43)
Change in valuation techniques	–	3
Mark-to-market of net positions at December 31, 2002	$ (49)	$ 57

The tables below show the fair value of maturities of our non-trading and trading derivative contracts (dollars in millions) at December 31, 2003 by maturities and by the type of valuation that is performed to calculate the fair values. See Note 1, "Mark-to-Market Accounting," for more discussion on our valuation methods.

Regulated Electricity

Source of Fair Value	2004	2005	Years Thereafter	Total Fair Value
Prices actively quoted	$ (4)	$ 3	$ –	$ (1)
Prices provided by other external sources	2	–	–	2
Prices based on models and other valuation methods	(1)	–	–	(1)
Total by maturity	$ (3)	$ 3	$ –	$ –

Marketing and Trading

Source of Fair Value	2004	2005	2006	2007	2008	Years Thereafter	Total Fair Value
Prices actively quoted	$ (18)	$ –	$ –	$ 10	$ 10	$ –	$ 2
Prices provided by other external sources	22	23	25	20	8	(2)	96
Prices based on models and other valuation methods	12	(7)	(13)	(14)	(6)	(1)	(29)
Total by maturity	$ 16	$ 16	$ 12	$ 16	$ 12	$ (3)	$ 69

The table below shows the impact that hypothetical price movements of 10% would have on the market value of our risk management and trading assets and liabilities included on the Consolidated Balance Sheets at December 31, 2003 (dollars in millions).

	Gain (Loss)	
Commodity	Price Up 10%	Price Down 10%
Mark-to-market changes reported in earnings (a):		
Electricity	$ (2)	$ 2
Natural gas	(1)	1
Other	1	–
Mark-to-market changes reported in OCI (b):		
Electricity	36	(36)
Natural gas	30	(30)
Total	$ 64	$ (63)

(a) These contracts are primarily structured sales activities hedged with a portfolio of forward purchases that protects the economic value of the sales transactions.
(b) These contracts are hedges of our forecasted purchases of natural gas and electricity. The impact of these hypothetical price movements would substantially offset the impact that these same price movements would have on the physical exposures being hedged.

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 37% of our $237 million of risk management and trading assets as of December 31, 2003. See Note 1, “Mark-to-Market Accounting” for a discussion of our credit valuation adjustment policy. See Note 18 for further discussion of credit risk.

Forward-Looking Statements

This document contains forward-looking statements based on current expectations, and we assume no obligation to update these statements or make any further statements on any of these issues, except as required by applicable law. These forward-looking statements are often identified by words such as “predict,” “hope,” “may,” “believe,” “anticipate,” “plan,” “expect,” “require,” “intend,” “assume” and similar words. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from results or outcomes currently expected or sought by us. These factors include, but are not limited to:

- state and federal regulatory and legislative decisions and actions, including the outcome of the rate case APS filed with the ACC on June 27, 2003 and the wholesale electric price mitigation plan adopted by the FERC;
- the outcome of regulatory, legislative and judicial proceedings relating to the restructuring;
- the ongoing restructuring of the electric industry, including the introduction of retail electric competition in Arizona and decisions impacting wholesale competition;
- market prices for electricity and natural gas;
- power plant performance and outages;
- weather variations affecting local and regional customer energy usage;
- energy usage;
- regional economic and market conditions, including the results of litigation and other proceedings resulting from the California energy situation, volatile purchased power and fuel costs and the completion of generation and transmission construction in the region, which could affect customer growth and the cost of power supplies;
- the cost of debt and equity capital and access to capital markets;
- our ability to compete successfully outside traditional regulated markets (including the wholesale market);
- the performance of our marketing and trading activities due to volatile market liquidity and deteriorating counterparty credit and the use of derivative contracts in our business (including the interpretation of the subjective and complex accounting rules related to these contracts);
- changes in accounting principles generally accepted in the United States of America;
- the successful completion of our generation construction program;
- regulatory issues associated with generation construction, such as permitting and licensing;
- the performance of the stock market and the changing interest rate environment, which affect the amount of our required contributions to our pension plan and nuclear decommissioning trust funds, as well as our reported costs of providing pension and other postretirement benefits;
- technological developments in the electric industry;
- the strength of the real estate market in SunCor’s market areas, which include Arizona, Idaho, New Mexico and Utah;
- conservation programs; and
- other uncertainties, all of which are difficult to predict and many of which are beyond our control.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management at Pinnacle West has always understood and accepted responsibility for our financial statements and related disclosures and the effectiveness of internal control over financial reporting ("internal control"). Just as we do throughout all aspects of our business, we continuously strive to identify opportunities to enhance the effectiveness and efficiency of internal control.

SEC rules implementing Section 404 of the Sarbanes-Oxley Act will require our 2004 Annual Report to contain a management's report and an independent accountants' report regarding the effectiveness of internal control. However, in this 2003 Annual Report, we chose to voluntarily include this report on internal control. As a basis for our report, we tested and evaluated the design, documentation and operating effectiveness of internal control.

In early March 2004, the PCAOB issued its auditing standard, which may require changes to the processes we utilize to test and evaluate the design, documentation and operating effectiveness of internal control and may affect our future internal control disclosures. Based on our assessment as of December 31, 2003, we make the following assertion:

- Management is responsible for establishing and maintaining effective internal control over financial reporting of Pinnacle West Capital Corporation and Subsidiaries (the "Company"). The internal control contains monitoring mechanisms, and actions are taken to correct deficiencies identified.
- There are inherent limitations in the effectiveness of any internal control, including the possibility of human error and the circumvention or overriding of controls. Accordingly, even effective internal controls can provide only reasonable assurance with respect to financial statement preparation. Further, because of changes in conditions, the effectiveness of internal control may vary over time.
- Management evaluated the Company's internal control over financial reporting as of December 31, 2003. This assessment was based on criteria for effective internal control over financial reporting described in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2003.

March 11, 2004

INDEPENDENT ACCOUNTANTS' REPORT

Board of Directors and Stockholders
Pinnacle West Capital Corporation
Phoenix, Arizona

We have examined the accompanying management's assertion that Pinnacle West Capital Corporation and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2003, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting. Our responsibility is to express an opinion on management's assertion based on our examination.

Our examination was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants ("AICPA") and, accordingly, included obtaining an understanding of the internal control over financial reporting, testing and evaluating the design and operating effectiveness of the internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our examination provides a reasonable basis for our opinion.

Because of inherent limitations in any internal control, misstatements due to error or fraud may occur and not be detected. Also, projections of any evaluation of the internal control over financial reporting to future periods are subject to the risk that the internal control may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assertion that the Company maintained effective internal control over financial reporting as of December 31, 2003 is fairly stated, in all material respects, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

An examination of management's assertion regarding the effectiveness of internal control under AICPA standards may not be the same in scope as an audit of internal control under the current proposed standards of the Public Company Accounting Oversight Board (the "PCAOB") and, accordingly, may not necessarily result in the same conclusion or disclose all matters in internal control that might ultimately be noted in performing an audit under PCAOB standards when they are finally adopted. Accordingly, our examination of the accompanying Management's Report on Internal Control Over Financial Reporting is not intended to comply with, and should not be relied upon for compliance with, the U.S. Securities and Exchange Commission rule relating to Section 404 or Section 103 of the Sarbanes-Oxley Act of 2002.

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Phoenix, Arizona
March 11, 2004

INDEPENDENT AUDITORS' REPORT

Board of Directors and Stockholders
Pinnacle West Capital Corporation
Phoenix, Arizona

We have audited the accompanying consolidated balance sheets of Pinnacle West Capital Corporation and subsidiaries (the "Company") as of December 31, 2003 and 2002, and the related consolidated statements of income, changes in common stock equity and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Pinnacle West Capital Corporation and subsidiaries at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 18 to the consolidated financial statements, in 2003 the Company changed its method of accounting for non-trading derivatives in order to comply with the provisions of Emerging Issues Task Force Issue No. 03-11, *Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not "Held for Trading Purposes" as Defined in Issue No. 02-3.*

As discussed in Note 18 to the consolidated financial statements, in 2002 the Company changed its method of accounting for trading activities in order to comply with the provisions of Emerging Issues Task Force Issue No. 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.*

As discussed in Note 18 to the consolidated financial statements, in 2001 the Company changed its method of accounting for derivatives and hedging activities in order to comply with the provisions of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities.*

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Phoenix, Arizona
March 11, 2004

CONSOLIDATED STATEMENTS OF INCOME (dollars and shares in thousands, except per share amounts)

Year Ended December 31,	2003	2002	2001
OPERATING REVENUES			
Regulated electricity segment	$ 1,978,075	$ 1,890,391	$ 1,984,305
Marketing and trading segment	391,886	286,879	469,784
Real estate segment	361,604	201,081	168,908
Other revenues	86,287	61,937	11,771
Total	2,817,852	2,440,288	2,634,768
OPERATING EXPENSES			
Regulated electricity segment purchased power and fuel	517,320	376,911	583,080
Marketing and trading segment purchased power and fuel	344,862	154,987	152,762
Operations and maintenance	548,732	584,538	530,095
Real estate operations segment	305,974	185,925	153,462
Depreciation and amortization	438,143	424,082	427,903
Taxes other than income taxes	110,270	107,952	101,068
Other expenses	70,498	104,959	10,375
Total	2,335,799	1,939,354	1,958,745
OPERATING INCOME	482,053	500,934	676,023
OTHER			
Allowance for equity funds used during construction	14,240	–	–
Other income	35,563	14,910	26,416
Other expenses	(20,574)	(33,655)	(33,577)
Total	29,229	(18,745)	(7,161)
INTEREST EXPENSE			
Interest charges	204,590	187,512	175,822
Capitalized interest	(29,444)	(43,749)	(47,862)
Total	175,146	143,763	127,960
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	336,136	338,426	540,902
INCOME TAXES	105,560	132,228	213,535
INCOME FROM CONTINUING OPERATIONS	230,576	206,198	327,367
Income from discontinued operations – net of income taxes of $6,529 and $5,872	10,003	8,955	–
Cumulative effect of a change in accounting for derivatives – net of income taxes of $9,892	–	–	(15,201)
Cumulative effect of a change in accounting for trading activities – net of income taxes of $43,123	–	(65,745)	–
NET INCOME	$ 240,579	$ 149,408	$ 312,166
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING – BASIC	91,265	84,903	84,718
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING – DILUTED	91,405	84,964	84,930
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING			
Income from continuing operations – basic	$ 2.53	$ 2.43	$ 3.86
Net income – basic	2.64	1.76	3.68
Income from continuing operations – diluted	2.52	2.43	3.85
Net income – diluted	2.63	1.76	3.68
DIVIDENDS DECLARED PER SHARE	$ 1.725	$ 1.625	$ 1.525

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS (dollars in thousands)

December 31,	2003	2002
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 228,779	$ 77,566
Customer and other receivables	365,732	362,587
Allowance for doubtful accounts	(9,223)	(9,607)
Accrued utility revenues	88,629	94,504
Materials and supplies (at average cost)	96,099	91,652
Fossil fuel (at average cost)	28,367	28,185
Deferred income taxes (Note 4)	–	4,094
Assets from risk management and trading activities (Note 18)	97,630	102,664
Real estate assets held for sale (Note 22)	–	42,339
Other current assets	73,034	66,388
Total current assets	969,047	860,372
INVESTMENTS AND OTHER ASSETS		
Real estate investments – net (Notes 1 and 6)	343,322	384,427
Assets from risk management and trading activities – long-term (Note 18)	138,946	191,754
Decommissioning trust accounts	240,645	194,440
Other assets	88,816	76,843
Total investments and other assets	811,729	847,464
PROPERTY, PLANT AND EQUIPMENT (NOTES 1, 6, 9, 10 AND 12)		
Plants in service and held for future use	9,925,344	9,058,900
Less accumulated depreciation and amortization	3,160,675	2,917,552
Total	6,764,669	6,141,348
Construction work in progress	554,876	777,542
Intangible assets, net of accumulated amortization	108,534	109,815
Nuclear fuel, net of accumulated amortization of $58,053 and $59,163	52,011	51,124
Net property, plant and equipment	7,480,090	7,079,829
DEFERRED DEBITS		
Regulatory assets (Notes 1, 3 and 4)	164,804	241,045
Other deferred debits	110,708	110,447
Total deferred debits	275,512	351,492
TOTAL ASSETS	$ 9,536,378	$ 9,139,157

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS (dollars in thousands)

December 31,	2003	2002
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 293,427	$ 332,441
Accrued taxes	69,769	71,107
Accrued interest	51,825	53,018
Short-term borrowings (Note 5)	86,081	227,683
Current maturities of long-term debt (Note 6)	425,480	280,888
Customer deposits	49,783	42,190
Deferred income taxes (Note 4)	631	–
Liabilities from risk management and trading activities (Note 18)	92,755	111,329
Real estate liabilities held for sale (Note 22)	–	28,855
Other current liabilities	81,223	85,585
Total current liabilities	1,150,974	1,233,096
LONG-TERM DEBT LESS CURRENT MATURITIES (NOTE 6)	2,897,725	2,743,741
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	1,329,253	1,209,074
Regulatory liabilities (Notes 1, 3 and 4)	510,423	26,264
Liability for asset retirements and removals (Note 12)	234,440	600,431
Pension liability (Note 8)	188,041	183,880
Liabilities from risk management and trading activities – long-term (Note 18)	82,730	147,900
Unamortized gain – sale of utility plant (Note 9)	54,909	59,484
Other	258,104	249,134
Total deferred credits and other	2,657,900	2,476,167
COMMITMENTS AND CONTINGENCIES (NOTES 3, 11 AND 12)		
COMMON STOCK EQUITY (NOTE 7)		
Common stock, no par value; authorized 150,000,000 shares; issued 91,379,947 at end of 2003 and 2002	1,744,354	1,737,258
Treasury stock at cost; 92,015 shares at end of 2003 and 124,830 shares at end of 2002	(3,273)	(4,358)
Total common stock	1,741,081	1,732,900
Accumulated other comprehensive income (loss):		
Minimum pension liability adjustment	(66,564)	(71,264)
Derivative instruments	27,563	(20,020)
Total accumulated other comprehensive loss	(39,001)	(91,284)
Retained earnings	1,127,699	1,044,537
Total common stock equity	2,829,779	2,686,153
TOTAL LIABILITIES AND EQUITY	$ 9,536,378	$ 9,139,157

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS (dollars in thousands)

Year Ended December 31,	2003	2002	2001
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 240,579	$ 149,408	$ 312,166
Adjustment to reconcile net income to net cash provided by operating activities:			
Gain on sale of discontinued operations	(10,003)	(8,955)	–
Cumulative effect of accounting change, net of tax	–	65,745	15,201
Depreciation and amortization	438,143	424,082	427,903
Nuclear fuel amortization	28,757	31,185	28,362
Allowance for equity funds used during construction	(14,240)	–	–
Deferred income taxes	81,756	191,135	(17,203)
Change in mark-to-market valuations	17,410	(18,146)	(133,573)
Redhawk Units 3 and 4 cancellation charge	–	49,192	–
Changes in current assets and liabilities:			
Customer and other receivables	(3,529)	40,343	146,581
Accrued utility revenues	5,875	(18,373)	(1,565)
Materials, supplies and fossil fuel	(4,629)	(11,599)	(16,867)
Other current assets	(6,646)	(7,247)	64
Accounts payable	(34,303)	54,592	(128,017)
Accrued taxes	(1,338)	(36,041)	7,483
Accrued interest	(1,193)	4,212	5,852
Other current liabilities	4,918	32,366	3,761
Proceeds from the sale of real estate assets	163,700	57,178	35,783
Real estate investments	(71,618)	(72,412)	(80,603)
Increase in regulatory assets	(11,697)	(11,029)	(17,516)
Change in risk management and trading – assets	46,911	(11,700)	(51,894)
Change in risk management and trading – liabilities	(11,613)	(22,783)	45,330
Change in customer advances	7,270	(23,780)	28,599
Change in pension liability	19,074	(3,009)	(30,205)
Change in other long-term assets	5,598	(23,554)	14,746
Change in other long-term liabilities	12,648	10,420	(23,345)
Net cash flow provided by operating activities	901,830	841,230	571,043
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(693,475)	(895,522)	(1,055,574)
Capitalized interest	(29,444)	(43,749)	(47,862)
Proceeds from sale of assets from discontinued operations	27,193	28,917	–
Other	(21,040)	36,635	(16,481)
Net cash flow used for investing activities	(716,766)	(873,719)	(1,119,917)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	656,850	674,919	995,447
Short-term borrowings and payments – net	(173,303)	(306,079)	322,987
Dividends paid on common stock	(157,417)	(137,721)	(129,199)
Repayment of long-term debt	(368,162)	(351,545)	(621,057)
Common stock equity issuance	–	199,238	–
Other	8,181	2,624	(1,048)
Net cash flow (used for) provided by financing activities	(33,851)	81,436	567,130
NET INCREASE IN CASH AND CASH EQUIVALENTS	151,213	48,947	18,256
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	77,566	28,619	10,363
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 228,779	$ 77,566	$ 28,619
Supplemental disclosure of cash flow information			
Cash paid during the period for:			
Income taxes paid/(refunded)	$ 32,816	$ (17,918)	$ 223,037
Interest paid, net of amounts capitalized	$ 161,581	$ 126,322	$ 115,276

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCK EQUITY (dollars in thousands)

Year Ended December 31,	2003	2002	2001
COMMON STOCK (NOTE 7)			
Balance of beginning of year	$ 1,737,258	$ 1,536,924	$ 1,537,920
Issuance of common stock	–	199,238	–
Other	7,096	1,096	(996)
Balance at end of year	1,744,354	1,737,258	1,536,924
TREASURY STOCK (NOTE 7)			
Balance at beginning of year	(4,358)	(5,886)	(5,089)
Purchase of treasury stock	–	(5,971)	(16,393)
Reissuance of treasury stock used for stock compensation, net	1,085	7,499	15,596
Balance at end of year	(3,273)	(4,358)	(5,886)
RETAINED EARNINGS			
Balance at beginning of year	1,044,537	1,032,850	849,883
Net income	240,579	149,408	312,166
Common stock dividends	(157,417)	(137,721)	(129,199)
Balance at end of year	1,127,699	1,044,537	1,032,850
ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)			
Balance at beginning of year	(91,284)	(64,565)	–
Minimum pension liability adjustment, net of tax of $3,700, $46,109 and $634	4,700	(70,298)	(966)
Cumulative effect of a change in accounting for derivatives, net of tax of $47,404	–	–	72,274
Unrealized gain/(loss) on derivative instruments, net of tax of $33,298, $28,820 and $71,720	51,089	43,939	(109,346)
Reclassification of realized gain to income, net of tax of $2,343, $237 and $17,399	(3,506)	(360)	(26,527)
Balance at end of year	(39,001)	(91,284)	(64,565)
TOTAL COMMON STOCK EQUITY	$ 2,829,779	$ 2,686,153	$ 2,499,323
COMPREHENSIVE INCOME (LOSS)			
Net income	$ 240,579	$ 149,408	$ 312,166
Other comprehensive income (loss)	52,283	(26,719)	(64,565)
Comprehensive income	$ 292,862	$ 122,689	$ 247,601

See Notes to Consolidated Financial Statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Consolidation and Nature of Operations

The consolidated financial statements include the accounts of Pinnacle West and our subsidiaries: APS, Pinnacle West Energy, APS Energy Services, SunCor and El Dorado (principally NAC). Significant intercompany accounts and transactions between the consolidated companies have been eliminated.

APS is 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 the Tucson metropolitan area and about one-half of the Phoenix metropolitan area. APS also generates, sells and delivers electricity to wholesale customers in the western United States. In early 2003, the marketing and trading division of Pinnacle West was moved to APS for future marketing and trading activities (existing wholesale contracts remained at Pinnacle West) as a result of the ACC's Track A Order prohibiting the previously required transfer of APS' generating assets to Pinnacle West Energy. See Note 3 for a discussion of the Track A Order. Pinnacle West Energy, which was formed in 1999, is the subsidiary through which we conduct our 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, and its principal investment is in NAC, which is a company specializing in spent nuclear fuel technology.

Accounting Records and Use of Estimates

Our accounting records are maintained in accordance with accounting principles generally accepted in the United States of America (GAAP). The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. We have reclassified certain prior year amounts to conform to the current year presentation.

Derivative Accounting

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal and emissions allowances. We manage risks associated with these market fluctuations by utilizing various commodity 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 ERMC, 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, "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 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. 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.

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

Mark-to-Market Accounting

Under 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 in the Consolidated Balance Sheets.

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

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

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

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

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. We maintain credit policies that management believes minimize overall credit risk. Determination of the credit quality of counterparties is based upon a number of factors, including credit ratings, financial condition, project economics and collateral requirements. When applicable, we employ standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. See Note 18 for further discussion on credit risk.

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

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 the recovery of expected future costs in current customer rates.

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 with the ACC (see Note 3), we continue to amortize certain regulatory assets over an eight-year period as follows (dollars in millions):

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

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

December 31,	2003	2002
Remaining balance recoverable under the 1999 Settlement Agreement (a)	$ 18	$ 104
Spent nuclear fuel storage (Note 11)	49	46
Electric industry restructuring transition costs (Note 3)	46	40
Deferred compensation	24	23
Contributions in aid of construction	11	10
Loss on reacquired debt (b)	12	9
Other	5	9
Total regulatory assets	$ 165	$ 241

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

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

December 31,	2003	2002
Removal costs (a)	$ 480	$ –
Deferred gains on utility property	20	20
Deferred interest income (b)	8	–
Other	2	6
Total regulatory liabilities	$ 510	$ 26

(a) See Note 12 for information on Asset Retirement Obligations.
(b) See "ACC Financing Orders" in Note 3 for information on the "APS Loan".

Rate Synchronization Cost Deferrals

As authorized by the ACC, operating costs (excluding fuel) and financing costs of Palo Verde Units 2 and 3 were deferred from the commercial operation dates (September 1986 for Unit 2 and January 1988 for Unit 3) until the date the units were included in a rate order (April 1988 for Unit 2 and December 1991 for Unit 3). In accordance with the 1999 Settlement Agreement, we are continuing to accelerate the amortization of the deferrals over an eight-year period that will end June 30, 2004. Amortization of the deferrals is included in depreciation and amortization expense in the Consolidated Statements of Income.

Utility Plant and Depreciation

Utility plant is the term we use to describe the business property and equipment that supports electric service, consisting primarily of generation, transmission and distribution facilities. We report utility plant at its original cost, which includes:

- material and labor;
- contractor costs;
- 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 143 (see Note 12).

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, 2003 were as follows:

- Fossil plant – 23 years;
- Nuclear plant – 20 years;
- Other generation – 29 years;
- Transmission – 36 years;
- Distribution – 23 years; and
- Other – 9 years.

For the years 2001 through 2003, 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 3.35% for 2003, 3.35% for 2002 and 3.40% for 2001. We depreciate non-utility property and equipment over the estimated useful lives of the related assets, ranging from 3 to 30 years.

El Dorado Investments

El Dorado accounts for its investments using the consolidated (if controlled), equity (if significant influence) and cost (less than 20% ownership) methods. Beginning in the third quarter of 2002, El Dorado began consolidating the operations of NAC.

Capitalized Interest

Capitalized interest represents the cost of debt funds used to finance construction projects. Plant construction costs, including capitalized interest, are expensed through depreciation when completed projects are placed into commercial operation. The rate used to calculate capitalized interest was a composite rate of 4.55% for 2003, 4.80% for 2002 and 6.13% for 2001. 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 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 8.55% 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' recent general rate case filing, which includes the request for rate recognition of generation assets. Previously, 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 in our Consolidated Statements of Income.

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

We adopted EITF 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not 'Held for Trading Purposes' As Defined in Issue No. 02-3," effective October 1, 2003. EITF 03-11 provides guidance on whether realized gains and losses on physically settled derivative contracts not held for trading purposes should be reported on a net or gross basis and concluded such classification is a matter of judgment that depends on the relevant facts and circumstances. 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 netted these book-outs reducing both revenues and purchased power and fuel costs in 2003, 2002 and 2001, but this did not impact our financial condition, net income or cash flows (see Note 18 for additional information).

SunCor

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

Percentage of Completion – NAC

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

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

Cash and Cash Equivalents

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

Nuclear Fuel

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

APS also charges nuclear fuel expense for the permanent disposal of spent nuclear fuel. The DOE is responsible for the permanent disposal of spent nuclear fuel, and it charges APS $0.001 per kWh of nuclear generation. See Note 11 for information about spent nuclear fuel disposal and Note 12 for information on nuclear decommissioning costs.

Income Taxes

Income taxes are provided using the asset and liability approach prescribed by SFAS No. 109, "Accounting for Income Taxes." We file our federal income tax return on a consolidated basis and we file our state income tax returns on a consolidated or unitary basis. In accordance with our intercompany tax sharing agreement, federal and state income taxes are allocated to each subsidiary as though each first-tier subsidiary filed a separate income tax return. Any difference between that method and the consolidated (and unitary) income tax liability is attributed to the parent company. See Note 4.

Reacquired Debt Costs

For debt related to the regulated portion of APS' business, APS defers those gains and losses incurred upon early retirement and is seeking recovery in the APS general rate case (see Note 3). In accordance with the 1999 Settlement Agreement, APS is continuing to accelerate the amortization of reacquired debt costs over an eight-year period that will end June 30, 2004. All regulatory asset amortization is included in depreciation and amortization expense in the Consolidated Statements of Income.

Real Estate Investments

Real estate investments primarily include SunCor's land, home inventory and investments in joint ventures. Land includes acquisition costs, infrastructure costs, property taxes and capitalized interest directly associated with the acquisition and development of each project. Land under development and land held for future development are stated at accumulated cost, except 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 in 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 – Real Estate Activities – Discontinued Operations.

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 2003 (dollars in thousands, except per share amounts):

Year Ended December 31,	2003	2002	2001
Net Income as reported:	$240,579	$ 149,408	$ 312,166
Add: Stock compensation expense included in reported net income (net of tax)	1,288	300	–
Deduct: Total stock compensation expense determined under fair value method (net of tax)	(2,994)	(1,695)	(2,292)
Pro forma net income	$238,873	$148,013	$ 309,874
Earnings per share – basic:			
As reported	$ 2.64	$ 1.76	$ 3.68
Pro forma (fair value method)	$ 2.62	$ 1.74	$ 3.66
Earnings per share – diluted:			
As reported	$ 2.63	$ 1.76	$ 3.68
Pro forma (fair value method)	$ 2.61	$ 1.74	$ 3.65

In order to calculate the fair value of the 2003, 2002 and 2001 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:

Year Ended December 31,	2003	2002	2001
Risk-free interest rate	3.35%	4.17%	4.08%
Dividend yield	5.26%	4.17%	3.70%
Volatility	38.03%	22.59%	27.66%
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 our Consolidated Balance Sheets in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets." The intangible assets are amortized over their finite useful lives. The Company's gross intangible assets (which are primarily capitalized software costs) were $237 million at December 31, 2003 and $214 million at December 31, 2002. The related accumulated amortization was $128 million at December 31, 2003 and $104 million at December 31, 2002. Amortization expense was $25 million in 2003, $21 million in 2002, and $22 million in 2001. Estimated amortization expense on existing intangible assets over the next five years is $28 million in 2004, $27 million in 2005, $25 million in 2006, $20 million

in 2007, and $9 million in 2008. At December 31, 2003, the weighted average amortization period for intangible assets is 7 years.

2. ACCOUNTING MATTERS

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

- Note 8 for amended disclosure requirements (SFAS No. 132) on retirement plans and other benefits;
- Note 12 for a new accounting standard (SFAS No. 143) on asset retirement obligations;
- Note 16 for a new accounting standard (SFAS No. 148) related to stock-based compensation;
- Note 18 for EITF issues (EITF 02-3 and 03-11), DIG Issue No. C15, and a new accounting standard (SFAS No. 149) related to accounting for derivatives and energy contracts;
- Note 20 for a new FASB interpretation (FIN No. 46R) related to VIEs;
- Note 21 for a new FASB interpretation (FIN No. 45) on guarantees; and
- Note 22 for a standard (SFAS No. 144) on accounting for the impairment or disposal of long-lived assets.

3. REGULATORY MATTERS

Electric Industry Restructuring

State

1999 Settlement Agreement The following are the major provisions of the 1999 Settlement Agreement, 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 is a moratorium on retail price changes for standard-offer and unbundled competitive direct access services until July 1, 2004, except for the price reductions described above and certain other limited circumstances. Neither the ACC nor APS is prevented from seeking or authorizing rate changes prior to July 1, 2004 in the event of conditions or circumstances that constitute an emergency, such as an inability to finance on reasonable terms; material changes in APS' cost of service for ACC-regulated services resulting from federal, tribal, state or local laws; regulatory requirements; or judicial decisions, actions or orders.
- APS will be permitted to defer for later recovery prudent and reasonable costs of complying with the Rules, system benefits costs in excess of the levels included in then-current (1999) rates, and costs associated with the "provider of last resort" and standard-offer obligations for service after July 1, 2004. These costs are to be recovered through an adjustment clause or clauses commencing on July 1, 2004. See "APS General Rate Case and Retail Rate Adjustment Mechanisms" below.
- APS' distribution system opened for retail access effective September 24, 1999. Customers were eligible for retail access in accordance with the phase-in adopted by the ACC under the Rules (see "Retail Electric Competition Rules" below), including an additional 140 MW being made available to eligible non-residential customers. APS opened its distribution system to retail access for all customers on January 1, 2001. The regulatory developments and legal challenges to the Rules discussed in this Note have raised considerable uncertainty about the status and pace of electric competition 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.
- Prior to the 1999 Settlement Agreement, APS was recovering substantially all of its regulatory assets through July 1, 2004, pursuant to a 1996 regulatory agreement. In addition, the 1999 Settlement Agreement states that APS has demonstrated that its allowable stranded costs, after mitigation and exclusive of regulatory assets, are at least $533 million net present value (in 1999 dollars). The 1999 Settlement Agreement also states that APS will not be allowed to recover $183 million net present value (in 1999 dollars) of the $533 million. The 1999 Settlement Agreement provides that APS will have the opportunity to recover $350 million net present value (in 1999 dollars) through a competitive transition charge that will remain in effect through December 31,

2004, at which time it will terminate. The costs subject to recovery under the adjustment clause described above will be decreased or increased by any over/under-recovery of the $350 million due to sales volume variances. As discussed below under "APS General Rate Case and Retail Rate Adjustment Mechanisms," APS is seeking to recover amounts written off by APS as a result of the 1999 Settlement Agreement.

- 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 below, in 2002 the ACC unilaterally modified this aspect of the 1999 Settlement Agreement by issuing the Track A Order, an order preventing APS from transferring its generation assets. APS is seeking to 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 and Retail Rate Adjustment Mechanisms" below.

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 affects the 1999 Settlement Agreement. The 1999 Settlement Agreement was not at issue in the consolidated cases before the judge. Further, the ACC made findings related to the fair value of APS' property in the order approving the 1999 Settlement Agreement. The ACC and other parties aligned with the ACC 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.

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. These rates are established until at least July 1, 2004. The 1999 Settlement Agreement allows APS to seek adjustment of these rates in the event of emergency conditions or circumstances, such as the inability to secure financing on reasonable terms; material changes in APS' cost of service for ACC-regulated services resulting from federal, tribal, state or local laws; regulatory requirements; or judicial decisions, actions or orders. Energy prices in the western wholesale market vary and, during the course of the last two years, have been volatile. At various times, prices in the spot wholesale market have significantly exceeded the amount included in APS' current retail rates. In the event of shortfalls due to unforeseen increases in load demand or generation or transmission outages, APS may need to purchase additional supplemental power in the wholesale spot market. Unless APS is able to obtain an adjustment of its rates under the emergency provisions of the 1999 Settlement Agreement, there can be no assurance that APS would be able to fully recover the costs of this power. See "APS General Rate Case and Retail Rate Adjustment Mechanisms" below for a discussion of retail rate adjustment mechanisms that were the subject of ACC hearings in April 2003.

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. APS and the ACC are the only parties to the Track A Order appeals. 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.
- Upon the ACC's issuance of a final decision that is no longer subject to appeal approving APS' request to provide $500 million of financing or credit support to Pinnacle West Energy or the Company, with appropriate conditions, APS' appeals of the Track A Order would be limited to the issues described in the preceding bullet points, each of which would be presented to the ACC for consideration prior to any final judicial resolution. As noted below, the ACC issued the Financing Order on April 4, 2003. The Financing Order is final and no longer subject to appeal. As a result, 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.

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. The bid amounts are expected to increase in 2004 and 2005 based largely on growth in APS' retail load and APS' retail energy sales. The Track B Order also confirmed that it was "not intended to change the current rate base status of [APS'] existing assets."

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

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:

(1) 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.

(2) PPL EnergyPlus, 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.

(3) 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.

ACC Financing Orders On April 4, 2003, the ACC issued the Financing Order authorizing APS to lend up to $500 million to Pinnacle West Energy, guarantee up to $500 million of Pinnacle West Energy debt, or a combination of both, not to exceed $500 million in the aggregate (the "APS Loan"), subject to the following principal conditions:

- any debt issued by APS pursuant to the order must be unsecured;
- the APS Loan must be callable and secured by the PWEC Dedicated Assets;
- the APS Loan must bear interest at a rate equal to 264 basis points above the interest rate on APS debt that could be issued and sold on equivalent terms (including, but not limited to, maturity and security);
- the 264 basis points referred to in the previous bullet point will be capitalized as a deferred credit and used to offset retail rates in the future, with the deferred credit balance bearing an interest rate of six percent per annum;
- the APS Loan must have a maturity date of not more than four years, unless otherwise ordered by the ACC;
- any demonstrable increase in APS' cost of capital as a result of the transaction (such as from a decline in bond rating) will be excluded from future rate cases;
- APS must maintain a common equity ratio of at least forty percent and may not pay common dividends if such payment would reduce its common equity ratio below that threshold, unless otherwise waived by the ACC. The ACC will process any waiver request within sixty days, and for this sixty-day period this condition will be suspended. However, this condition, which will continue indefinitely, will not be permanently waived without an order of the ACC; and
- certain waivers of the ACC's affiliated interest rules previously granted to APS and its affiliates will be temporarily withdrawn and, during the term of the APS Loan, neither Pinnacle West nor Pinnacle West Energy may reorganize or restructure, acquire or divest assets, or form, buy or sell affiliates (each, a "Covered Transaction"), or pledge or otherwise encumber the Pinnacle West Energy assets without prior ACC approval, except that the foregoing restrictions will not apply to the following categories of Covered Transactions:
    - Covered Transactions less than $100 million, measured on a cumulative basis over the calendar year in which the Covered Transactions are made;
    - Covered Transactions by SunCor of less than $300 million through 2005, consistent with SunCor's anticipated accelerated asset sales activity during those years;
    - Covered Transactions related to the payment of ongoing construction costs for Pinnacle West Energy's (a) West Phoenix Unit 5, located in Phoenix, and (b) Silverhawk plant, located near Las Vegas, with an expected commercial operation date in mid-2004; and
    - Covered Transactions related to the sale of 25% of the Silverhawk plant to SNWA pursuant to an agreement between SNWA and Pinnacle West Energy.

The ACC also ordered the ACC staff to conduct an inquiry into our and our affiliates' compliance with the retail electric competition and related rules and decisions. On June 13, 2003, APS submitted its report on these matters to the ACC staff. The ACC has indicated that the preliminary investigation would be addressed in the pending general rate case (see below).

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. See Note 6.

On November 22, 2002, the ACC issued an order approving APS' request to permit APS to make short-term advances to Pinnacle West in the form of an interaffiliate line of credit in the amount of $125 million. As of December 31, 2003, there were no borrowings outstanding under this financing arrangement, and this authority expired on December 4, 2003.

APS General Rate Case and Retail Rate Adjustment Mechanisms As noted above, 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, to become effective July 1, 2004. In this rate case, APS updated its cost of service and rate design.

Major Components of the Request The major reasons for the request include:

- complying with the provisions of the 1999 Settlement Agreement;
- incorporating significant increases in fuel and purchased power costs, including results of purchases through the ACC's Track B procurement process;
- recognizing changes in APS' cost of service, cost allocation and rate design;
- obtaining rate recognition of the PWEC Dedicated Assets;
- recovering $234 million written off by APS as a result of the 1999 Settlement Agreement; and

- recovering restructuring and compliance costs associated with the ACC's Rules.

Requested Rate Increase The requested rate increase totals $175.1 million, or 9.8%, and is comprised of the following items (dollars in millions):

	Annual Revenue	Percent
Increase in base rates	$ 166.8	9.3%
Rules compliance charge	8.3	0.5%
Total increase	$ 175.1	9.8%

Test Year The filing is based on an adjusted historical test year ended December 31, 2002.

Cost of Capital The proposed weighted average cost of capital for the test year ended December 31, 2002 is 8.67%, including an 11.5% return on equity.

Rate Base The request is based on a rate base of $4.2 billion, calculated using Original Cost Less Depreciation ("OCLD") methodology. The OCLD rate base approximates the ACC-jurisdictional portion of the net book value of utility plant, net of accumulated depreciation and deferred taxes, as of December 31, 2002, except as set forth below.

The requested rate base includes the PWEC Dedicated Assets, with a total combined capacity of approximately 1,800 MW. These assets were included at their estimated July 1, 2004 net book value. Upon approval of the request, the PWEC Dedicated Assets would be transferred to APS from Pinnacle West Energy.

The filing also includes calculated amounts for Fair Value Rate Base and Replacement Cost New Depreciated ("RCND") rate base. The ACC is required by the Arizona Constitution to make a finding of Fair Value Rate Base, which has traditionally been defined by the ACC as the arithmetic average of OCLD rate base and RCND rate base.

Recovery of Previous $234 Million Write-Off The request includes recovery, over a fifteen year period, of the write-off of $234 million pretax of regulatory assets by APS as a result of the 1999 Settlement Agreement. See "1999 Settlement Agreement" above.

Estimated Timeline APS has asked the ACC to approve the requested rate increase by July 1, 2004. The ACC ALJ has issued a procedural schedule setting a hearing date on the application of May 25, 2004. Based on the schedule and existing ACC regulations, we believe the ACC will be able to make a decision in this general rate case by the end of 2004.

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 November 4, 2003, the ACC approved the issuance of an order which authorizes a rate adjustment mechanism allowing APS to recover changes in purchased power costs (but not changes in fuel costs) incurred after July 1, 2004. The other rate adjustment mechanisms authorized in the 1999 Settlement Agreement (such as the costs associated with complying with the ACC electric competition rules) were also tentatively approved for subsequent implementation in the general rate case. The provisions of this order will not become effective until there is a final order in the general rate case, and the ACC further reserved the right to amend, modify or reconsider, in its entirety, this November 4 order during the rate case.

Testimony As required by the procedural schedule, on February 3, 2004, the following parties filed their initial written testimony with the ACC on all issues except cost of service (i.e., cost allocation among customer classes) and rate design:

- the ACC "litigation" staff;
- the Arizona Residential Utility Consumers Office ("RUCO"), an office established by the Arizona legislature to represent the interests of residential utility consumers before the ACC; and
- other approved rate case interveners.

ACC Staff Recommendations In its filed testimony, the ACC staff recommended, among other things, that the ACC:

- decrease APS' annual retail electricity revenues by at least $142.7 million, which would result in a rate decrease of approximately 8%, based on a 9% return on equity;
- not allow the PWEC Dedicated Assets to be included in APS' rate base;
- not allow APS to recover any of the $234 million written off as a result of the 1999 Settlement Agreement; and
- not implement any adjustment mechanisms for fuel and purchased power.

The ACC staff recommendations, if implemented as proposed, could have a material adverse impact on our results of operations, financial position, liquidity, dividend sustainability, credit ratings, and access to capital markets. We believe that APS' rate case requests are supported by, among other things, APS' demonstrated need for the PWEC Dedicated Assets; APS' need to attract capital at reasonable rates of return to support the required capital investment to ensure continued customer reliability in APS' high-growth service territory; and the conditions in the western energy market. As a result, we believe it is unlikely that the ACC would adopt the ACC staff recommendations in their present form, although we can give no assurances in that regard.

The ACC staff also submitted testimony indicating that APS and its affiliates had violated the "spirit, if not the letter" of the Rules, the Code of Conduct and the 1999 Settlement Agreement.

RUCO Recommendations In its filed testimony, RUCO recommended, among other things, that the ACC:

- decrease APS' annual retail electricity revenues by $53.6 million, which would result in a rate decrease of approximately 2.84%, based on a 9.5% return on equity;
- not allow the PWEC Dedicated Assets to be included in APS' rate base;
- not allow APS to recover any of the $234 million written off as a result of the 1999 Settlement Agreement; and
- not implement any adjustment mechanisms for fuel and purchased power.

APS believes that its rate request is necessary to ensure APS' continued ability to reliably serve one of the fastest growing regions in the country and views any ultimate decision that would deny recovery of the Company's investment in the PWEC Dedicated Assets as constituting a regulatory "taking." APS will vigorously oppose the recommendations of the ACC staff, RUCO, and other parties offering similar recommendations.

Request for Proposals In early December 2003, APS issued a request for proposals ("RFP") for long-term power supply resources, and on January 8, 2004, an ACC Administrative Law Judge issued an order requiring, among other things, APS to file a summary of the proposals with the ACC. On January 27, 2004, APS filed a summary of the proposals with the ACC. APS is negotiating with certain of the parties that submitted proposals.

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.

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.

4. INCOME TAXES

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

APS has recorded a regulatory asset related to income taxes on its Balance Sheets in accordance with SFAS No. 71. This regulatory asset is for certain temporary differences, primarily the allowance for equity funds used during construction. APS amortizes this amount as the differences reverse. In accordance with ACC settlement agreements, APS is continuing to accelerate amortization of a regulatory asset related to income taxes over an eight-year period that will end June 30, 2004 (see Note 1). Accordingly, we are including this accelerated amortization in depreciation and amortization expense on our Consolidated Statements of Income.

As a result of a change in IRS guidance, we claimed a tax deduction related to an APS tax accounting method change on the 2001 federal consolidated income tax return. The accelerated deduction 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. In 2003, we resolved certain prior-year issues with the taxing authorities and recorded an $18 million tax benefit associated with tax credits and other reductions to income tax expense.

The components of income tax expense for income from continuing operations are as follows (dollars in thousands):

Year Ended December 31,	2003	2002	2001
Current:			
Federal	$ 22,875	$ (43,492)	$ 184,893
State	929	(15,415)	45,845
Total current	23,804	(58,907)	230,738
Deferred	81,756	191,135	(17,203)
Total income tax expense	$ 105,560	$132,228	$ 213,535

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

Year Ended December 31,	2003	2002	2001
Federal income tax expense at 35% statutory rate	$ 117,648	$118,449	$ 189,316
Increases (reductions) in tax expense resulting from:			
State income tax net of federal income tax benefit	14,353	15,796	23,353
Credits and favorable adjustments related to prior years resolved in 2003	(17,944)	–	–
Allowance for equity funds used during construction (see Note 1)	(5,616)	–	–
Other	(2,881)	(2,017)	866
Income tax expense	$ 105,560	$132,228	$ 213,535

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

December 31,	2003	2002
Current asset/(liability)	$ (631)	$ 4,094
Long term liability	(1,329,253)	(1,209,074)
Accumulated deferred income taxes – net	$ (1,329,884)	$(1,204,980)

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

December 31,	2003	2002
DEFERRED TAX ASSETS		
Pension liability	$ 73,844	$ 72,835
Risk management and trading activities	59,293	43,542
Regulatory liabilities:		
Federal excess deferred income taxes	18,936	20,887
Other	33,542	9,818
Deferred gain on Palo Verde Unit 2 sale leaseback	21,656	23,562
Other	64,769	89,236
Total deferred tax assets	272,040	259,880
DEFERRED TAX LIABILITIES		
Plant-related	(1,448,730)	(1,316,636)
Regulatory assets	(69,070)	(101,522)
Risk management and trading activities	(84,124)	(46,702)
Total deferred tax liabilities	(1,601,924)	(1,464,860)
Accumulated deferred income taxes – net	$ (1,329,884)	$ (1,204,980)

5. LINES OF CREDIT AND SHORT-TERM BORROWINGS

APS had committed lines of credit with various banks of $250 million at December 31, 2003 and 2002, which were available either to support the issuance of commercial paper or to be used for bank borrowings. The current line matures in May 2004, and the document allows for a 364-day extension of the termination date without lender consent. The commitment fees at December 31, 2003 and 2002 for these lines of credit were 0.175% and 0.09% per annum. APS had no bank borrowings outstanding under these lines of credit at December 31, 2003 and 2002.

APS had no commercial paper borrowings outstanding at December 31, 2003 and 2002. 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 $275 million at December 31, 2003 and $475 million at December 31, 2002, which were available either to support the issuance of commercial paper or to be used for bank borrowings. The current lines mature in November and December of 2004 and the $150 million facility allows for a 364-day extension of the termination date without lender consent. Pinnacle West had no outstanding borrowings at December 31, 2003 and $72 million was outstanding at December 31, 2002. The commitment fees ranged from 0.125% to 0.175% in 2003 and ranged from 0.10% to 0.15% in 2002. Pinnacle West had no commercial paper borrowings outstanding at December 31, 2003. Commercial paper borrowings outstanding were $24 million at December 31, 2002. The weighted average interest rate on commercial paper borrowings was 2.06% for the year ended December 31, 2002.

All APS and Pinnacle West bank lines of credit and commercial paper agreements are unsecured.

On November 22, 2002, the ACC approved APS' request to permit APS to make short-term advances to Pinnacle West in the form of an inter-affiliate line of credit in the amount of $125 million. This interim loan matured in December 2003, and there were never any borrowings on this line.

SunCor had revolving lines of credit totaling $120 million at December 31, 2003 and $140 million at December 31, 2002. The commitment fees were 0.125% in 2003 and 2002. SunCor had $50 million outstanding at December 31, 2003 and $126 million outstanding at December 31, 2002. The weighted-average interest rate was 4.50% at December 31, 2003 and was 3.75% at December 31, 2002. Interest for 2003 and 2002 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, 2003 and $6 million outstanding at December 31, 2002. These loans are made up of multiple notes primarily with variable interest rates based on LIBOR plus 2.5% at December 31, 2003 and 2002. In addition, two notes acquired in 2003 had interest rates of 3.37% and 3.87%.

6. LONG-TERM DEBT

Borrowings under the APS mortgage bond indenture are secured by substantially all utility plant. APS also has unsecured debt. SunCor's 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, 2003 and 2002 (dollars in thousands):

December 31,	Maturity Dates (a)	Interest Rates	2003	2002
APS				
First mortgage bonds	2004	6.625%	$ 80,000	$ 80,000
	2023	7.25% (b)	–	54,150
	2025	8.0% (c)	–	33,075
	2028	5.5%	25,000	25,000
	2028	5.875%	154,000	154,000
Unamortized discount and premium			(8,631)	(6,337)
Pollution control bonds	2024-2034	(d)	386,860	386,860
Pollution control bonds with senior notes (e)	2029	5.05%	90,000	90,000
Unsecured notes	2004	5.875%	125,000	125,000
Unsecured notes	2005	6.25%	100,000	100,000
Unsecured notes	2005	7.625%	300,000	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	–
Unsecured notes	2015	4.650%	300,000	–
Senior notes (f)	2006	6.75%	83,695	83,695
Capitalized lease obligations	2004-2012	(g)	11,749	20,400
Subtotal			2,622,673	2,220,843
SUNCOR				
Notes payable	2004-2008	(h)	17,125	7,647
Capitalized lease obligations	2004-2005	8.91%	728	1,299
Subtotal			17,853	8,946
PINNACLE WEST				
Senior notes	2004-2006	(i)	515,000	540,000
Unamortized discount and premium			(270)	(530)
Floating rate notes	2003	(j)	–	250,000
Floating senior notes	2005	(k)	165,000	–
Capitalized lease obligations	2004-2007	5.48%	1,243	1,999
Subtotal			680,973	791,469
EL DORADO				
Construction loan	2005	1.22%	1,600	2,600
Capitalized lease obligations	2004-2005	(l)	106	771
Subtotal			1,706	3,371
Total long-term debt			3,323,205	3,024,629
Less current maturities			425,480	280,888
TOTAL LONG-TERM DEBT LESS CURRENT MATURITIES			$ 2,897,725	$ 2,743,741

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

(b) On August 15, 2003, APS redeemed at maturity $54 million of its First Mortgage Bonds, 7.25% Series due 2023.

(c) On April 7, 2003, APS redeemed $33 million of its First Mortgage Bonds, 8.00% Series due 2025.

(d) The weighted-average rate was 1.51% at December 31, 2003 and 1.94% at December 31, 2002. Changes in short-term interest rates would affect the costs associated with this debt.

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

(f) APS currently has outstanding $84 million of first mortgage bonds (senior note mortgage bonds) issued to the senior note trustee as collateral for the senior notes, as well as the $90 million issue discussed in footnote (e) above. The senior note mortgage bonds have the same interest rate, interest payment dates, maturity and redemption provisions as the senior notes. APS' payments of principal, premium and/or interest on the senior notes satisfy its corresponding payment obligations on the senior note mortgage bonds. As long as the senior note mortgage bonds secure the senior notes, the senior notes will effectively rank equally with the first mortgage bonds. When APS repays all of its first mortgage bonds, other than those that secure senior notes, the senior note mortgage bonds will no longer secure the senior notes and will cease to be outstanding.

(g) The weighted average rate was 5.55% at December 31, 2003 and 5.78% at December 31, 2002. Capital leases are included in property, plant and equipment on the Consolidated Balance Sheets for both December 31, 2003 and December 31, 2002.
(h) Multiple notes with variable interest rates based on the lenders' prime plus 0.25%, lenders' prime plus 1.75% and LIBOR plus 2.5%. There is also one note at a fixed rate of 7.96%.
(i) Includes two series of notes: $300 million at 6.4% due in 2006 and $215 million at 4.5% due in 2004 as of December 31, 2002. In December 2003, we repaid the $25 million note. On January 29, 2004, we entered into a fixed-for-floating interest rate swap transaction on the $300 million 6.4% note. The transaction qualifies as a fair value hedge under SFAS No. 133.
(j) The weighted average rate was 2.85% at December 31, 2002. Interest for 2002 was based on LIBOR plus 0.98%. In June 2003, we repaid the $250 million floating note.
(k) The weighted average rate was 1.980% at December 31, 2003. Interest for 2003 was based on LIBOR plus 0.80%.
(l) The weighted average rate was 7.9% at December 31, 2003 and 7.04% at December 31, 2002.

Pinnacle West's and APS' debt covenants related to their respective 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 the covenant requirement levels. The ratio of debt to total capitalization cannot exceed 65% for each of the Company and APS individually. At December 31, 2003, the ratio was approximately 54% for Pinnacle West. At December 31, 2003, the ratio was approximately 53% 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 2003 results, the coverages were approximately 4 times for the Company, 4 times for the APS bank agreements and 15 times for the APS mortgage indenture. 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.

The following is a list of payments due on total long-term debt and capitalized lease requirements through 2008:

- $425 million in 2004;
- $569 million in 2005;
- $395 million in 2006;
- $2 million in 2007;
- $6 million in 2008; and
- $1,935 million, thereafter.

APS' first mortgage bondholders share a lien on substantially all utility plant assets (other than nuclear fuel and transportation equipment and other excluded assets). The mortgage bond indenture restricts the payment of common stock dividends under certain conditions. APS may pay dividends on its common stock if there is a sufficient amount "available" from retained earnings and the excess of cumulative book depreciation (since the mortgage's inception) over mortgage depreciation, which is the cumulative amount of additional property pledged each year to address collateral depreciation. As of December 31, 2003, the amount "available" under the mortgage would have allowed APS to pay approximately $3 billion of dividends compared to APS' current annual common stock dividends of $170 million.

The mortgage currently constitutes a lien on substantially all of the property of APS. We anticipate that in early April 2004, all first mortgage bonds issued by APS under its existing mortgage and deed of trust, other than the first mortgage bonds securing APS' senior notes, will have been paid and retired. At that time, APS' obligation to make payment on the first mortgage bonds securing the senior notes will also be deemed to be satisfied and discharged and the senior note first mortgage bonds will cease to secure the senior notes. APS is then obligated to take all steps necessary to terminate its existing mortgage and deed of trust and cannot issue any additional first mortgage bonds under that mortgage.

7. COMMON STOCK AND TREASURY STOCK

Our common stock and treasury stock activity during each of the three years 2003, 2002 and 2001 is as follows (dollars in thousands):

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

8. RETIREMENT PLANS AND OTHER BENEFITS

Pinnacle West sponsors a qualified defined benefit pension plan and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and our subsidiaries. Effective January 1, 2003, Pinnacle West sponsored a new account balance 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.

In December 2003, FASB revised SFAS No. 132, “Employers’ Disclosures about Pensions and Other Postretirement Benefits,” to enhance disclosures of relevant accounting information by providing additional information on plan assets, obligations, cash flows, and net cost. The revisions are reflected in this Note. Pinnacle West uses a December 31 measurement date for its 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 costs. We have not yet quantified the effect, if any, on accumulated projected benefit obligation or the net periodic postretirement benefit cost in our financial statements and accompanying notes. Specific accounting guidance for this subsidy, including transition rules, is pending.

The following table provides details of the plan’s 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		
	2003	2002	2001	**2003**	2002	2001
Service cost – benefits earned during the period	$ 37,662	$ 30,333	$ 27,640	$ 15,858	$ 12,036	$ 9,438
Interest cost on benefit obligation	76,951	71,242	66,549	30,163	25,235	21,585
Expected return on plan assets	(65,046)	(75,652)	(77,340)	(18,762)	(21,116)	(21,985)
Amortization of:						
Transition (asset)/obligation	(3,227)	(3,227)	(3,227)	3,005	4,001	7,698
Prior service cost/(credit)	2,401	2,912	3,008	(125)	(75)	–
Net actuarial loss/(gain)	18,135	1,846	907	9,714	3,072	(4,066)
Net periodic benefit cost	$ 66,876	$ 27,454	$ 17,537	$ 39,853	$ 23,153	$ 12,670
Portion of cost charged to expense	$ 30,094	$ 13,727	$ 8,944	$ 17,934	$ 11,577	$ 6,462

The following table sets forth the plan's change in the benefit obligations for the plan years 2003 and 2002 (dollars in thousands):

	Pension		Other Benefits	
Year Ended December 31,	**2003**	2002	**2003**	2002
Benefit obligation at January 1	$ 1,069,577	$ 931,646	$ 409,874	$ 318,355
Service cost	37,662	30,333	15,858	12,036
Interest cost	76,951	71,242	30,163	25,235
Benefit payments	(43,869)	(35,230)	(15,749)	(10,473)
Actuarial losses	171,420	71,696	106,475	108,979
Plan amendments	(4,113)	(110)	(6,440)	(44,258)(a)
Benefit obligation at December 31	$ 1,307,628	$ 1,069,577	$ 540,181	$ 409,874

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

The following table sets forth the qualified defined benefit plan and other benefit plan changes in the fair value of plan assets for the years 2003 and 2002 (dollars in thousands):

	Pension		Other Benefits	
Year Ended December 31,	**2003**	2002	**2003**	2002
Fair value of plan assets at January 1	$ 720,807	$ 764,873	$ 223,474	$ 237,810
Actual gain/(loss) on plan assets	162,571	(36,966)	46,071	(27,802)
Employer contributions	46,000	26,600	39,852	23,600
Benefit payments	(42,067)	(33,700)	(15,346)	(10,134)
Fair value of plan assets at December 31	$ 887,311	$ 720,807	$ 294,051	$ 223,474

The following table shows a reconciliation of the funded status of the plans to the amounts recognized in the Consolidated Balance Sheets as of December 31, 2003 and 2002 (dollars in thousands):

	Pension		Other Benefits	
December 31,	**2003**	2002	**2003**	2002
Funded status at December 31	$ (420,317)	$ (348,770)	$ (246,130)	$ (186,400)
Unrecognized net transition (asset)/obligation	(7,099)	(10,327)	27,044	36,489
Unrecognized prior service cost/(credit)	16,634	23,148	(1,547)	(1,673)
Unrecognized net actuarial losses/(gains)	348,982	293,223	217,611	148,268
Benefit liability recognized in the Consolidated Balance Sheet	$ (61,800)	$ (42,726)	$ (3,022)	$ (3,316)

The following sets forth the details related to benefits included on the Consolidated Balance Sheets (dollars in thousands):

	Pension		Other Benefits	
December 31,	**2003**	2002	**2003**	2002
Accrued benefit cost	$ (61,800)	$ (42,726)	$ (3,022)	$ (3,316)
Additional minimum liability	(126,241)	(141,154)	–	–
Total liability	(188,041)	(183,880)	(3,022)	(3,316)
Intangible asset	16,634	23,147	–	–
Accumulated other comprehensive income (pretax)	109,607	118,007	–	–
Net amount recognized	$ (61,800)	$ (42,726)	$ (3,022)	$ (3,316)

The following table sets forth the other comprehensive income arising from the change in additional minimum liability for the years ended December 31, 2003 and 2002 (dollars in thousands):

Year Ended December 31,	**2003**	2002
Decrease/(Increase) in minimum liability included in other comprehensive income – net of tax	$ 4,700	$ (70,298)

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 2003 and 2002 (dollars in thousands):

Year Ended December 31,	**2003**	2002
Projected benefit obligation	$ 1,307,628	$ 1,069,577
Accumulated benefit obligation	$ 1,075,352	$ 904,687
Less fair value of plan assets	887,311	720,807
Pension liability	$ 188,041	$ 183,880

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 As of December 31,		Benefit Costs For the Years Ended December 31,	
	2003	2002	**2003**	2002
Discount rate	6.10%	6.75%	6.75%	7.50%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Expected long-term return on plan assets	9.00%	9.00%	9.00%	10.00%
Initial health care cost trend rate	8.00%	8.00%	8.00%	7.00%
Ultimate health care cost trend rate	5.00%	5.00%	5.00%	5.00%
Year ultimate health care cost trend rate is reached	2008	2007	2007	2006

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 2003, we decreased our pretax expected long-term rate of return on plan assets from 10% to 9%, as a result of continued declines in general equity and bond market conditions. For the year 2004 we are assuming a 9% rate of return on plan assets. This rate is reflective of the market returns earned historically on our target asset allocation. As recent history has demonstrated, markets may decline and increase dramatically. However, 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	$ 7	$ (5)
Effect on service and interest cost components of net periodic other postretirement benefit costs	$ 9	$ (7)
Effect on the accumulated other postretirement benefit obligation	$ 95	$ (76)

Plan Assets

Pinnacle West's qualified pension plan asset allocation at December 31, 2003, and 2002 is as follows:

	Percentage of Plan Assets at December 31,		Target Asset Allocation
	2003	2002	
Asset Category:			
Equity securities	65%	56%	50 – 70%
Debt securities	23	31	20 – 40%
Other	12	13	5 – 15%
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 a stated tolerance 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 plan asset allocation at December 31, 2003, and 2002, is as follows:

	Percentage of Plan Assets at December 31,		Target Asset Allocation
	2003	2002	
Asset Category:			
Equity securities	71%	62%	60 – 80%
Fixed Income	25	34	20 – 35%
Other	4	4	1 – 6%
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 post retirement benefit plan assets is similar to that of the pension plan assets described above.

Contributions

Under current law, we are required to contribute approximately $100 million to our pension plans in 2004 and expect to contribute approximately $50 million to our other postretirement benefit plans in 2004. If currently pending legislation is enacted, our required pension contribution in 2004 would decrease to the $25 to $50 million range.

Employee Savings Plan Benefits

Pinnacle West sponsors a defined contribution savings plan for eligible employees of Pinnacle West and subsidiaries. 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, 2003, approximately 23% of total plan assets were in Pinnacle West stock. We recorded expenses for this plan of approximately $5 million for each of the years 2003, 2002 and 2001.

Severance Charges

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

9. LEASES

In 1986, APS sold about 42% of its share of Palo Verde Unit 2 and certain common facilities in three separate sale leaseback transactions. APS accounts for these leases as operating leases. The gain resulting from the transaction of approximately $140 million was deferred and is being amortized to operations and maintenance expense over 29.5 years, the original term of the leases. There are options to renew the leases for two additional years and to purchase the property for fair market value at the end of the lease terms. Consistent with the ratemaking treatment, a regulatory asset is recognized for the difference between lease payments and rent expense calculated on a straight-line basis. See Note 20 for a discussion of VIEs, including the SPEs involved in the Palo Verde sale leaseback transactions.

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

Total lease expense recognized in the Consolidated Statements of Income was $67 million in 2003, $67 million in 2002 and $59 million in 2001.

The amounts to be paid for the Palo Verde Unit 2 leases are approximately $49 million per year for the years 2004 to 2015.

In accordance with the 1999 Settlement Agreement and previous settlement agreements, APS is continuing to accelerate amortization of the regulatory asset for leases over an eight-year period that will end June 30, 2004 (see Note 1). All regulatory asset amortization is included in depreciation and amortization expense in the Consolidated Statements of Income. The balance of this regulatory asset at December 31, 2003 was $5 million.

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

Year		
2004	$	73
2005		70
2006		68
2007		66
2008		66
Thereafter		421
Total future lease commitments	$	764

10. JOINTLY-OWNED FACILITIES

APS shares ownership of some of its generating and transmission facilities with other companies. The following table shows APS' interest in those jointly-owned facilities recorded on the Consolidated Balance Sheets at December 31, 2003. APS' share of operating and maintaining these facilities is included in the Consolidated Statements of Income in operations and maintenance expense (dollars in thousands):

	Percent Owned by APS	Plant in Service	Accumulated Depreciation	Construction Work in Progress
Generating Facilities:				
Palo Verde Nuclear Generating Station Units 1 and 3	29.1%	$ 1,880,218	$ (867,322)	$ 21,620
Palo Verde Nuclear Generating Station Unit 2 (see Note 9)	17.0%	681,744	(242,131)	9,771
Four Corners Steam Generating Station Units 4 and 5	15.0%	154,111	(81,369)	2,580
Navajo Steam Generating Station Units 1, 2, and 3	14.0%	242,987	(111,744)	2,352
Cholla Steam Generating Station Common Facilities (a)	62.4%(b)	78,500	(44,379)	1,338
Transmission Facilities:				
ANPP 500KV System	35.8%(b)	68,457	(27,050)	40
Navajo Southern System	31.4%(b)	26,903	(17,971)	128
Palo Verde – Yuma 500KV System	23.9%(b)	9,583	(4,364)	602
Four Corners Switchyards	27.5%(b)	2,852	(1,734)	–
Phoenix – Mead System	17.1%(b)	36,418	(3,567)	–
Palo Verde – Estrella 500KV System	55.5%(b)	70,972	(1,615)	1,632
Palo Verde SE Valley Project	15.0%(b)	–	–	648

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

11. COMMITMENTS AND CONTINGENCIES

Enron

We recorded charges totaling $21 million before income taxes for exposure to Enron and its affiliates in the fourth quarter of 2001. This amount is comprised of a $15 million reserve for the Company's net exposure to Enron and its affiliates and additional expenses of $6 million primarily related to 2002 power contracts with Enron that were canceled. These charges take into consideration our rights of set-off with respect to the Enron related contractual obligations. The APS portion of the write-off was $13 million. The basis of the set-offs included, but was not limited to, provisions in the various contractual arrangements with Enron and its affiliates, including an International Swaps and Derivative Agreement (ISDA) between APS and Enron North America. The write-off is also net of the expected recovery based on secondary market quotes from the bond market. The amounts were written-off from the balances of the related assets and liabilities from risk management and trading activities on the Consolidated Balance Sheets. In February 2004, Enron filed an adversary proceeding against APS in bankruptcy court regarding differences in the valuation of trading positions involving APS. Enron North America v. Arizona Public Service Company, Adversary Proceeding No. 04-02366 (ALJ). APS will vigorously defend this action and does not believe it will have any material adverse impact on its anticipated exposure to Enron described above.

Palo Verde Nuclear Generating Station

Spent 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. It is now expected that the DOE will submit a license application to the NRC in late 2004. 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 2003 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, 2003, APS had spent $7 million and recorded a liability of $42 million for on-site interim spent nuclear fuel storage costs related to nuclear fuel burned to date. APS has recorded a corresponding regulatory asset of $49 million and is seeking recovery of these costs through future rates (see "APS General Rate Case and Retail Rate Mechanisms" in Note 3).

APS has reclassified prior year spent nuclear fuel costs of approximately $44 million previously included in accumulated amortization of nuclear fuel to the liability for asset retirements and removals on our Consolidated Balance Sheets at December 31, 2002. Upon adoption of SFAS No. 143 in 2003, APS reclassified this liability to a regulatory liability because no legal obligation for removal exists.

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 2004 through 2025 that include required purchase provisions. We estimate the contract requirements to be approximately $209 million in 2004; $68 million in 2005; $66 million in 2006; $51 million in 2007; $51 million in 2008 and $461 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 and nuclear fuel supply have take-or-pay provisions. The current take-or-pay coal contracts have terms that expire in 2016. The current take-or-pay nuclear fuel contracts expire in 2004 and had not been renewed as of December 31, 2003.

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

Estimated Years Ending December 31,	2004	2005	2006	2007	2008	Thereafter
Coal	$ 41	$ 42	$ 43	$ 44	$ 43	$306
Nuclear	11	–	–	–	–	–
Total take-or-pay commitments (a)	$ 52	$ 42	$ 43	$ 44	$ 43	$306

(a) Total take-or-pay commitments are approximately $530 million.The total net present value of these commitments is approximately $340 million.

Coal Mine Reclamation Obligations

APS must reimburse certain coal providers for amounts incurred for coal mine reclamation. Our coal mine reclamation obligation was $60 million at December 31, 2003 and $59 million at December 31, 2002 and is included in deferred credits-other in the Consolidated Balance Sheets.

A regulatory asset has been established for amounts not yet recovered from ratepayers related to the coal obligations. In accordance with the 1999 Settlement Agreement with the ACC, APS is continuing to accelerate the amortization of the regulatory asset for coal mine reclamation over an eight-year period that will end June 30, 2004. Amortization is included in depreciation and amortization expense on the Consolidated Statements of Income.

California Energy Market Issues and Refunds in the Pacific Northwest

In July 2001, the FERC ordered an expedited fact-finding hearing to calculate refunds for spot market transactions in California during a specified time frame. 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.

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. APS and the FERC staff have settled this matter, and the settlement was approved by the FERC.

SCE and PG&E have publicly disclosed that their liquidity has been materially and adversely affected because of, among other things, their inability to pass on to ratepayers the prices each has paid for energy and ancillary services procured through the PX and the ISO. PG&E filed for bankruptcy protection in 2001.

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

In the second quarter of 2002, PG&E filed its Modified Second Amended Disclosure Statement and the CPUC filed its Alternative Plan of Reorganization. Both plans generally indicated that PG&E would, at the close of bankruptcy proceedings, be able to pay in full all outstanding, undisputed debts. As a result of these developments, the probable range of our total exposure now is approximately zero to $27 million before income taxes, and our best estimate of the probable loss is now approximately $6 million before income taxes. Consequently, we reversed $4 million of the $10 million reserve in the second quarter of 2002. We cannot predict with certainty, however, the impact that any future resolution or attempted resolution, of the California energy market situation may have on us, our subsidiaries or the regional energy market in general.

California Energy Market Litigation

On March 19, 2002, the State of California filed a complaint with the FERC alleging that wholesale sellers of power and energy, including the Company, failed to properly file rate information at the FERC in connection with sales to California from 2000 to the present. State of California v. British Columbia Power Exchange et al., Docket No. EL02-71-000. The complaint requests the FERC to require the wholesale sellers to refund any rates that are "found to exceed just and reasonable levels." This complaint has been dismissed by the FERC and the State of California is now appealing the matter to the Ninth Circuit Court of Appeals. In addition, the State of California and others have filed various claims, which have now been consolidated, against several power suppliers to California alleging antitrust violations. Wholesale Electricity Antitrust Cases I and II, Superior Court in and for the County of San Diego, Proceedings Nos. 4204-00005 and 4204-00006. Two of the suppliers who were named as defendants in those matters, Reliant Energy Services, Inc. (and other Reliant entities) and Duke Energy and Trading, LLP (and other Duke entities), filed cross-claims against various other participants in the PX and 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 has now been moved back to state court. James Millar, et al. v. Allegheny Energy Supply, et al., San Francisco Superior Court, Case No. 407867. 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.

Citizens Power Service Agreement

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

Construction Program

Consolidated capital expenditures in 2004 are estimated to be (dollars in millions):

APS	$	426
Pinnacle West Energy		61
SunCor		83
Other (primarily APS Energy Services and Pinnacle West)		11
Total	$	581

Natural Gas Supply

APS and Pinnacle West Energy purchase the majority of their natural gas requirements for their gas-fired plants under contracts with a number of natural gas suppliers. Effective September 1, 2003, APS' and Pinnacle West Energy's natural gas supply is transported pursuant to a firm, contract demand service agreement with El Paso Natural Gas Company. Pursuant to the terms of a comprehensive settlement entered into in 1996, the rates charged for transportation are subject to a 10-year rate moratorium extending through December 31, 2005.

Prior to September 1, 2003, APS' and Pinnacle West Energy's natural gas supply was transported pursuant to a firm, full requirements transportation service agreement. On July 9, 2003, the FERC issued an order that altered the contractual obligations and the rights of parties to the 1996 settlement by requiring all firm, full requirements contract holders to convert to contract demand service agreements effective September 1, 2003. This required conversion has imposed additional limitations on the former full requirements contract holders' ability to nominate firm transportation capacity. In order for APS and Pinnacle West Energy to meet their natural gas supply and capacity requirements, they must make market purchases, which we expect to increase costs by approximately $5 million per year for natural gas supply and by approximately $14 million per year for capacity. APS and Pinnacle West Energy have sought appellate review of the FERC's July 9 order and related issues on the grounds that the FERC decision to abrogate the full requirements contracts is arbitrary and capricious and is not supported by substantial evidence. Arizona Public Service Company and Pinnacle West Energy Corporation v. Federal Energy Regulatory Commission, United States Court of Appeals for the District of Columbia Circuit, No. 03-1209. This petition for review was consolidated with a petition filed by the ACC and other full requirements contract holders. Arizona Corporation Commission et al v. Federal Energy Regulatory Commission, United States Court of Appeals for the District of Columbia Circuit, No. 03-1206. We are continuing to analyze the market to determine the most favorable source and method of meeting our natural gas requirements.

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 consolidated financial statements, results of operations or liquidity.

12. ASSET RETIREMENT OBLIGATIONS

On January 1, 2003, we adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. The standard requires that these liabilities 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. Prior to January 1, 2003, we accrued asset retirement obligations over the life of the related asset through depreciation expense.

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.

On January 1, 2003 and in accordance with SFAS No. 143, APS recorded a liability of $219 million for its asset retirement obligations, including the accretion impacts; a $67 million increase in the carrying amount of the associated assets; and a net reduction of $192 million in accumulated depreciation related primarily to the reversal of previously recorded accumulated decommissioning and other removal costs related to these obligations. Additionally, APS recorded a net regulatory liability of $40 million for the asset retirement obligations related to its regulated assets. This regulatory liability represents the difference between the amount currently being recovered in regulated rates and the amount calculated under SFAS No. 143. APS believes it can recover in regulated rates the transition costs and ongoing current period costs calculated in accordance with SFAS No. 143. The adoption of SFAS No. 143 did not have a material impact on our net income for the year ended December 31, 2003.

APS has reclassified prior year removal costs of approximately $557 million previously included in accumulated depreciation to the liability for asset retirements and removals on our Consolidated Balance Sheets. In 2003, APS reclassified the portion of this liability for which no legal obligation for removal exists to a regulatory liability.

In accordance with SFAS No. 71, APS will continue to accrue for removal costs for its regulated assets, even if there is no legal obligation for removal. At December 31, 2003, regulatory liabilities shown on our Consolidated Balance Sheets included approximately $480 million of estimated future removal costs that are not considered legal obligations.

The following schedule shows the change in our asset retirement obligations during the twelve-month period ended December 31, 2003 (dollars in millions):

Balance at January 1, 2003	$	219
Changes attributable to:		
Liabilities incurred		–
Liabilities settled		–
Accretion expense		15
Estimated cash flow revisions		–
Balance at December 31, 2003	$	234

The following schedule shows the change in our pro forma liability for the years ended December 31, 2002 and 2001, as if we had recorded an asset retirement obligation based on the guidance in SFAS No. 143 (dollars in millions):

Years Ended December 31,		2002		2001
Balance at beginning of year	$	204	$	190
Accretion expense		15		14
Balance at end of year	$	219	$	204

The pro forma effects on net income for 2002 and 2001 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, 2003 and December 31, 2002 (dollars in millions):

December 31,		2003		2002
Trust fund assets – at cost:				
Fixed income securities	$	124	$	113
Domestic stock		74		68
Total	$	198	$	181
Trust fund assets – at fair value:				
Fixed income securities	$	140	$	117
Domestic stock		101		77
Total	$	241	$	194

13. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

Consolidated quarterly financial information for 2003 and 2002 is as follows (dollars in thousands, except per share amounts):

	Operating Revenues as Previously Disclosed (a)	Reclassification Adjustment (b)	Operating Revenues	Operating Income	Income from Continuing Operations	Net Income (d)
2003 quarter ended:						
March 31	$ 603,962	$ 51,319	$ 552,643	$ 69,255	$ 20,153	$ 25,298
June 30	757,483	74,181	683,302	132,482	54,889	56,142
September 30	946,570	98,867	847,703	198,850	109,538	110,048
December 31	734,204	–	734,204	81,466	45,996	49,091
Total		$ 224,367	$ 2,817,852	$ 482,053	$ 230,576	$ 240,579

	Operating Revenues as Previously Disclosed (a)	Reclassification Adjustment (b)(c)	Operating Revenues	Operating Income	Income (Loss) from Continuing Operations	Net Income (Loss) (d)
2002 quarter ended:						
March 31	$ 499,844	$ 16,365	$ 483,479	$ 118,736	$ 53,251	$ 53,757
June 30	593,516	18,962	574,554	155,832	68,803	75,365
September 30	871,390	103,450	767,940	212,491	100,713	100,916
December 31 (f)	644,436	30,121	614,315	13,875	(16,569)	(80,630)
Total		$ 168,898	$ 2,440,288	$ 500,934	$ 206,198	$ 149,408

(a) Operating revenues previously disclosed in the March 31, 2003, June 30, 2003 and September 30, 2003 Quarterly Reports on Form 10-Q, except for the fourth quarter ended December 31, 2003, which was disclosed in a Pinnacle West Form 8-K dated January 29, 2004 and the fourth quarter ended December 31, 2002, which was disclosed in a Pinnacle West Form 8-K dated February 4, 2003.
(b) Reclassification adjustment of $224 million in 2003 and $162 million in 2002 related to the adoption of EITF 03-11 (see Note 18).
(c) Reclassification adjustment of $7 million in the fourth quarter of 2002 related to discontinued operations at SunCor (see Note 22).
(d) Includes income from discontinued operations at SunCor (see Note 22).
(e) Includes a $66 million after-tax charge for the cumulative effect of a change in accounting for trading activities (see Note 18).
(f) The fourth quarter of 2002 included pretax losses of $38 million related to our investment in NAC, a $49 million pretax write-off related to the cancellation of Redhawk Units 3 and 4 and pretax severance costs of approximately $11 million.

Income From Continuing Operations – EPS:

	2003		2002	
	Basic	Diluted	Basic	Diluted
Quarter ended:				
March 31	$ 0.22	$ 0.22	$ 0.63	$ 0.63
June 30	0.60	0.60	0.81	0.81
September 30	1.20	1.20	1.19	1.19
December 31	0.50	0.50	(0.19)	(0.19)

Net Income – EPS:

	2003		2002	
	Basic	Diluted	Basic	Diluted
Quarter ended:				
March 31	$ 0.28	$ 0.28	$ 0.63	$ 0.63
June 30	0.62	0.61	0.89	0.89
September 30	1.21	1.20	0.19	1.19
December 31	0.54	0.54	(0.95)	(0.95)

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, 2003 and 2002 due to their short maturities.

We hold investments in fixed income and domestic equity securities for purposes other than trading. The December 31, 2003 and 2002 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, 2003, the carrying value of our long-term debt (excluding capitalized lease obligations) was $3.32 billion, with an estimated fair value of $3.46 billion. The carrying value of our long-term debt (excluding capitalized lease obligations) was $3.00 billion on December 31, 2002, with an estimated fair value of $3.21 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, 2003, 2002 and 2001:

	2003	2002	2001
Basic earnings per share:			
Income from continuing operations	$ 2.53	$ 2.43	$ 3.86
Income from discontinued operations	0.11	0.10	–
Cumulative effect of change in accounting	–	(0.77)	(0.18)
Earnings per share – basic	$ 2.64	$ 1.76	$ 3.68
Diluted earnings per share:			
Income from continuing operations	$ 2.52	$ 2.43	$ 3.85
Income from discontinued operations	0.11	0.10	–
Cumulative effect of change in accounting	–	(0.77)	(0.17)
Earnings per share – diluted	$ 2.63	$ 1.76	$ 3.68

Dilutive stock options increased average common shares outstanding by approximately 140,000 shares in 2003, 61,000 shares in 2002 and 212,000 shares in 2001. Total average common shares outstanding for the purposes of calculating diluted earnings per share were 91,405,134 shares in 2003, 84,963,921 shares in 2002 and 84,930,140 shares in 2001.

Options to purchase 2,291,646 shares of common stock were outstanding at December 31, 2003 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 1,629,958 at December 31, 2002 and 212,562 at December 31, 2001.

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 and the 1985 plan each include outstanding options but no new options will be granted under either plan. Options vest one-third of the grant per year beginning one year after the date the option is granted and expire ten years from the date of the grant. The 1994 plan also provided for the granting of any combination of shares of restricted stock, stock appreciation rights or dividend equivalents. Following the approval of the 2002 plan, no further grants have been made under the 1994 plan, except for awards for the annual award of up to 20,000 shares of stock to satisfy stock award obligations under employment contracts to certain executives.

In the third quarter of 2002, we began applying the fair value method of accounting for stock-based compensation, as provided for in SFAS No. 123. The fair value method of accounting is the preferred method. In accordance with the transition requirements of SFAS No. 123, we applied the fair value method prospectively, beginning with 2002 stock grants. In prior years, we recognized stock compensation expense based on the intrinsic value method allowed in APB No. 25. We recorded approximately $2.1 million in stock option expense before income taxes in our Consolidated Statements of Income in 2003 and approximately $0.5 million in 2002. This amount may not be reflective of the stock option expense we will record in future years because stock options typically vest over several years and additional grants are generally made each year.

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

Total stock-based compensation cost, including stock option cost, was $6 million in 2003, $5 million in 2002 and $3 million in 2001.

The following table is a summary of the status of our stock option plans as of December 31, 2003, 2002 and 2001 and changes during the years ending on those dates:

	2003 Shares	2003 Weighted Average Exercise Price	2002 Shares	2002 Weighted Average Exercise Price	2001 Shares	2001 Weighted Average Exercise Price
Outstanding at beginning of year	2,185,129	$ 39.96	1,832,725	$ 39.52	1,569,171	$ 37.55
Granted	621,875	32.29	603,900	38.37	444,200	42.55
Exercised	(62,366)	26.09	(163,381)	28.25	(162,229)	28.53
Forfeited	(46,392)	37.61	(88,115)	41.54	(18,417)	41.67
Outstanding at end of year	2,698,246	38.56	2,185,129	39.96	1,832,725	39.52
Options exercisable at year-end	1,787,622	40.35	1,155,357	39.66	926,315	37.41
Weighted average fair value of options granted during the year		$ 7.37		$ 6.16		$ 8.84

The following table summarizes information about our stock options at December 31, 2003:

Exercise Prices Per Share	Options Outstanding	Weighted-Average Exercise Price	Weighted Average Remaining Contract Life (Years)	Options Exercisable	Weighted-Average Exercise Price
$18.71-23.39	10,584	$ 19.00	0.8	10,584	$ 19.00
23.39-28.07	48,417	27.40	2.3	48,417	27.40
28.07-32.75	647,400	32.23	8.7	49,625	31.50
32.75-37.42	220,994	34.70	5.4	220,994	34.70
37.42-42.10	759,333	38.86	6.7	579,854	38.95
42.10-46.78	1,011,518	43.96	6.1	878,148	44.17
	2,698,246			1,787,622	

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, 2003, 2002 and 2001:

	2003 Shares	2003 Grant Price	2002 Shares	2002 Grant Price	2001 Shares	2001 Grant Price
Restricted stock	4,000	$ 32.20(a)	6,000	$ 38.84(a)	95,450	$ 42.84(a)
Performance share awards	119,085	32.29(b)	115,975	38.37(b)	–	–

(a) Restricted stock priced at the average of the high and low market price for the grant date.
(b) Performance shares priced at the closing market price for the grant date.

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 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. In early 2003, we moved our marketing and trading activities to APS from Pinnacle West (existing wholesale contracts remained at Pinnacle West) as a result of the ACC's Track A Order prohibiting the previously required transfer of APS' generating assets to Pinnacle West Energy; and
- our real estate segment, which consists of SunCor's real estate development and investment activities.

The amounts in our other segment include activity principally related to El Dorado's investment in NAC, as well as the parent company and other subsidiaries. See Note 18 for information about reclassifications related to the adoption of EITF 03-11. Financial data for the years ended December 31, 2003, 2002 and 2001 by business segments is provided as follows (dollars in millions):

	Business Segments for the Year Ended December 31, 2003				
	Regulated Electricity	Marketing and Trading	Real Estate	Other (principally NAC)	Total
Operating revenues	$ 1,978	$ 392	$ 362	$ 86	$ 2,818
Purchased power and fuel costs	517	345	–	–	862
Other operating expenses	625	34	306	71	1,036
Operating margin	836	13	56	15	920
Depreciation and amortization	428	1	6	3	438
Interest expense	172	–	2	1	175
Other expense/(income)	(4)	–	(25)	–	(29)
Pretax margin	240	12	73	11	336
Income taxes	70	3	28	4	105
Income from continuing operations	170	9	45	7	231
Income from discontinued operations – net of income taxes of $6 (see Note 22)	–	–	10	–	10
Net income	$ 170	$ 9	$ 55	$ 7	$ 241
Total assets	$ 8,761	$ 324	$ 424	$ 27	$ 9,536
Capital expenditures	$ 686	$ 9	$ 72	$ –	$ 767

	Business Segments for the Year Ended December 31, 2002				
	Regulated Electricity	Marketing and Trading	Real Estate	Other (principally NAC)	Total
Operating revenues	$ 1,890	$ 287	$ 201	$ 62	$ 2,440
Purchased power and fuel costs	377	155	–	–	532
Other operating expenses	659	34	185	105	983
Operating margin	854	98	16	(43)	925
Depreciation and amortization	416	2	4	2	424
Interest expense	141	–	2	1	144
Other expense/(income)	19	–	(7)	7	19
Pretax margin	278	96	17	(53)	338
Income taxes	108	38	7	(21)	132
Income (loss) from continuing operations	170	58	10	(32)	206
Income from discontinued operations – net of income taxes of $6 (see Note 22)	–	–	9	–	9
Cumulative effect of change in accounting for trading activities – net of income taxes of $43	–	(66)	–	–	(66)
Net income (loss)	$ 170	$ (8)	$ 19	$ (32)	$ 149
Total assets	$ 8,185	$ 414	$ 504	$ 36	$ 9,139
Capital expenditures	$ 893	$ 19	$ 72	$ –	$ 984

	Business Segments for the Year Ended December 31, 2001				
	Regulated Electricity	Marketing and Trading	Real Estate	Other	Total
Operating revenues	$ 1,984	$ 470	$ 169	$ 12	$ 2,635
Purchased power and fuel costs	583	153	–	–	736
Other operating expenses	598	33	154	11	796
Operating margin	803	284	15	1	1,103
Depreciation and amortization	423	1	4	–	428
Interest expense	125	–	3	–	128
Other expense/(income)	4	–	3	–	7
Pretax margin	251	283	5	1	540
Income taxes	99	112	2	–	213
Income before accounting change	152	171	3	1	327
Cumulative effect of change in accounting for derivatives – net of income taxes of $10	(15)	–	–	–	(15)
Net income	$ 137	$ 171	$ 3	$ 1	$ 312
Capital expenditures	$ 1,004	$ 23	$ 80	$ 22	$ 1,129

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 and emissions allowances. We manage risks associated with these market fluctuations by utilizing various commodity 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. The changes in market value of such contracts have a high correlation to price changes in the hedged commodities. In addition, subject to specified risk parameters monitored by the ERMC, we engage in marketing and trading activities intended to profit from market price movements.

Effective January 1, 2001, we adopted SFAS No. 133. SFAS No. 133 requires that entities recognize all derivatives as either assets or liabilities on the balance sheet and measure those instruments at fair value. Changes in the fair value of derivative instruments are either recognized periodically in income or, if hedge criteria is met, in common stock equity (as a component of other comprehensive income (loss)). We use cash flow hedges to limit our exposure to cash flow variability on forecasted transactions. Hedge effectiveness is related to the degree to which the derivative contract and the hedged item are correlated. It is measured based on the relative changes in fair value between the derivative contract and the hedged item over time. We exclude the time value of certain options from our assessment of hedge effectiveness. Any change in the fair value resulting from ineffectiveness, or the amount by which the derivative contract and the hedged commodity are not directly correlated, is recognized immediately in net income.

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

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. Our energy trading contracts that are derivatives are accounted for at fair value under SFAS No. 133. Energy 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. Additionally, all gains and losses (realized and unrealized) on energy trading contracts that qualify as derivatives are included in marketing and trading segment revenues on the Consolidated Statements of Income on a net basis. Derivative instruments used for non-trading activities are accounted for in accordance with SFAS No. 133.

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

that were previously recorded in other comprehensive income (loss). In the event a non-trading derivative is terminated or settled, the unrealized gains and losses remain in other comprehensive income (loss), and are recognized in income when the underlying transaction impacts earnings. Derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business are exempt from the requirements of SFAS No. 133 under the normal purchase and sales exception and are not reflected on the balance sheet at fair value. Certain of our non-trading electricity purchase and sales agreements qualify as normal purchases and sales and are exempted from recognition in the financial statements until the electricity is delivered. Derivatives associated with trading activities are adjusted to fair value through income.

EITF 02-3 requires that derivatives held for trading purposes, whether settled financially or physically, be reported in the income statement on a net basis. Previous guidance under EITF 98-10 permitted physically-settled energy trading contracts to be reported either gross or net in the income statement. Beginning in the third quarter of 2002, we netted all of our energy trading activities on the Consolidated Statements of Income and restated prior year amounts for all periods presented. Reclassification of such trading activity to a net basis of reporting resulted in reductions in both revenues and purchased power and fuel costs, but did not have any impact on our financial condition, net income or cash flows.

We adopted EITF 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not 'Held for Trading Purposes' As Defined in Issue No. 02-3," effective October 1, 2003. EITF 03-11 provided guidance on whether realized gains and losses on physically settled derivative contracts not held for trading purposes should be reported on a net or gross basis and concluded such classification is a matter of judgment that depends on the relevant facts and circumstances. 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 netted these book-outs reducing both revenues and purchased power and fuel costs in 2003, 2002 and 2001, but this did not impact our financial condition, net income or cash flows. Following are the net reclassifications to our previously reported amounts (dollars in thousands):

Year Ended December 31,	2003	2002	2001
Regulated Electricity	$ 40,069	$ 122,632	$ 577,783
Marketing and Trading	184,298	39,052	181,447
Total	$ 224,367	$ 161,684	$ 759,230

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 changes the criteria for the normal purchases and sales scope exception for electricity contracts. We do not expect this guidance to have a material impact on our financial statements.

In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." This statement amends and clarifies financial accounting and reporting for derivative instruments and for hedging activities under SFAS No. 133. The provisions of SFAS No. 149 that relate to previously issued SFAS No. 133 derivatives implementation guidance should continue to be applied in accordance with the effective dates of the original implementation guidance. In general, other provisions are applied prospectively to contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. The impact of this standard was immaterial to our financial statements.

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

Year Ended December 31,	2003	2002
Gains on the ineffective portion of derivatives qualifying for hedge accounting	$ 8,237	$ 13,682
Gains/(losses) from the change in options' time value excluded from measurement of effectiveness	181	(2,484)
Losses from the discontinuance of cash flow hedges	–	(8,820)

As of December 31, 2003, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted transactions is approximately five years. During the year ending December 31, 2004, we estimate that a net gain of $8 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, 2003 and 2002 (dollars in thousands):

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	$ 97,630	$ 138,946	$ (92,755)	$ (82,730)	$ 61,091

December 31, 2002	Current Assets	Investments	Current Liabilities	Other Liabilities	Net Asset/ (Liability)
Regulated Electricity:					
Mark-to-Market	$ 41,522	$ 6,971	$ (60,819)	$ (36,678)	$ (49,004)
Options	–	24,651	–	–	24,651
Marketing and Trading:					
Mark-to-Market	61,142	121,189	(50,510)	(74,841)	56,980
Emission allowances – at cost	–	38,943	–	(36,381)	2,562
Total	$ 102,664	$ 191,754	$ (111,329)	$ (147,900)	$ 35,189

Cash or collateral 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, 2003 and $5 million at December 31, 2002, and is included in investments and other assets on the Consolidated Balance Sheet. Collateral provided to us by counterparties is $12 million at December 31, 2003 and $22 million at December 31, 2002, and is included in other deferred credits on the Consolidated Balance Sheet.

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 37% of our $237 million of risk management and trading assets as of December 31, 2003. 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 and local distribution companies. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition.

In many contracts, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties. See Note 1 “Mark-to-Market 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, 2003, 2002 and 2001 (dollars in thousands):

Year Ended December 31,	2003	2002	2001
Other income:			
SunCor joint venture earnings (a)	$ 24,740	$ 7,355	$ 3,687
Interest income	4,412	4,332	6,763
Investment gains	3,649	–	–
Environmental insurance recovery	–	–	12,349
Miscellaneous	2,762	3,223	3,617
Total other income	$ 35,563	$ 14,910	$ 26,416
Other expense:			
Non-operating costs (b)	$ (16,481)	$ (19,430)	$ (16,807)
Investment losses (c)	–	(10,439)	(5,126)
Non-operating costs – SunCor	–	–	(7,000)
Miscellaneous	(4,093)	(3,786)	(4,644)
Total other expense	$ (20,574)	$ (33,655)	$ (33,577)

(a) 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.

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

(c) Primarily related to El Dorado’s investment losses in NAC prior to consolidation in the third quarter of 2002.

20. VARIABLE INTEREST ENTITIES

In 2003, we adopted FIN No. 46R, "Consolidation of Variable Interest Entities," as it applies to special-purpose entities. FIN No. 46R requires that we consolidate a VIE if we have a majority of the risk of loss from the VIE's activities or we are entitled to receive a majority of the VIE's residual returns or both. A VIE is a corporation, partnership, trust or any other legal structure that either does not have equity investors with voting rights or has equity investors that do not provide sufficient financial resources for the entity to support its activities. In 1986, APS entered into agreements with three separate SPE lessors in order to sell and lease back interests in Palo Verde Unit 2. The leases are accounted for as operating leases in accordance with GAAP. See Note 9 for further information about the sale leaseback transactions. Based on our assessment of FIN No. 46R, we are not required to consolidate the Palo Verde VIEs. Certain provisions of FIN No. 46R have a future effective date. We do not expect these provisions to have a material impact on our financial statements.

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, 2003, APS would have been required to assume approximately $268 million of debt and pay the equity participants approximately $200 million.

21. GUARANTEES

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

We have issued parental guarantees and letters of credit and obtained surety bonds on behalf of our unregulated subsidiaries. Our parental guarantees related to Pinnacle West Energy consist of equipment and performance guarantees related to our generation construction program, transmission service guarantees for West Phoenix Units 4 and 5 and long-term service agreement guarantees for new power plants. Our credit support instruments enable APS Energy Services to offer commodity energy and energy-related products and enable El Dorado to support the activities of NAC. Non-performance or payment under the original contract by our unregulated subsidiaries would require us to perform under the guarantee or surety bond. No liability is currently recorded on the Consolidated Balance Sheets related to Pinnacle West's guarantees on behalf of its subsidiaries. Our guarantees have no recourse (except NAC) or collateral provisions to allow us to recover amounts paid under the guarantee. The amounts and approximate terms of our guarantees and surety bonds for each subsidiary at December 31, 2003 are as follows (dollars in millions):

	Guarantees		Surety Bonds	
	Amount	Term (in years)	Amount	Term (in years)
Parental:				
Pinnacle West Energy	$ 86	1 to 2	$ –	–
APS Energy Services	16	1 to 2	35	2
El Dorado (NAC)	40	1 to 3	–	–
Total	$ 142		$ 35	

At December 31, 2003, we had entered into approximately $41 million of letters of credit which support various construction agreements. These letters of credit expire in 2004 and 2005. 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, 2003, Pinnacle West has approximately $4 million of letters of credit related to workers' compensation expiring in 2004.

APS has entered into various agreements that require letters of credit for financial assurance purposes. At December 31, 2003, 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. These letters of credit have expiration dates in 2004 and 2005. APS has also entered into approximately $109 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 2004. 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 and therefore no related liability has been recorded.

22. REAL ESTATE ACTIVITIES – DISCONTINUED OPERATIONS

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 our 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. We adopted SFAS No. 144 effective January 1, 2002 and determined that activities that would have required discontinued operations reporting in 2002 and 2001 were immaterial.

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 our Consolidated Statements of Income. The amounts related to 2001 were immaterial for reclassification.

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 pre-tax) 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. The amounts related to 2001 were immaterial for reclassification.

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 our Consolidated Statements of Income. There were no prior-year operations related to this retail center. The amounts related to 2001 were immaterial for reclassification.

The following table provides SunCor's revenue and income before income taxes related to properties classified as discontinued operations on our consolidated statements of income for the years ended December 31, 2003 and 2002 (dollars in thousands):

	2003	2002
Revenue	$ 70,580	$ 35,307
Income before taxes	$ 16,532	$ 14,827

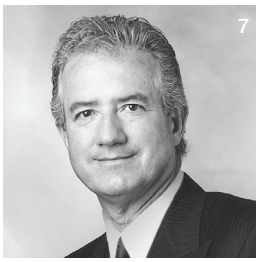
The following tables provide the amounts related to properties of discontinued operations which were reclassified to assets and liabilities held for sale on the Consolidated Balance Sheets at December 31, 2003 and 2002 (dollars in thousands):

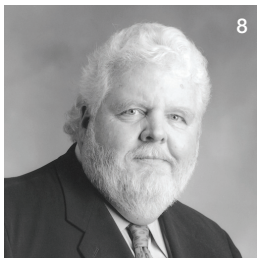
	2003	2002
Real estate investments – net	$ –	$ 39,849
Other	–	2,490
Real estate assets held for sale	$ –	$ 42,339

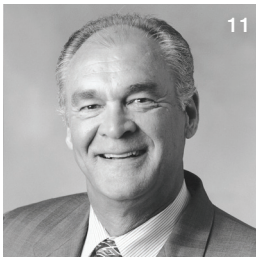
	2003	2002
Customer deposits	$ –	$ 13,648
Long-term debt less current maturities	–	12,454
Other	–	2,753
Real estate liabilities held for sale	$ –	$ 28,855

See Note 17 for information related to the real estate segment.

Board of Directors







1_PAMELA GRANT, (65) 1980* Civic Leader COMMITTEES: *Human Resources, Chairman; Audit; Corporate Governance*

2_MARTHA O. HESSE, (61) 1991 Former CEO, Hesse Gas Company COMMITTEES: *Audit, Chairman; Finance and Operating; Corporate Governance*

3_THE REV. BILL JAMIESON, JR., (60) 1991 President, Institute for Servant Leadership of Asheville, North Carolina COMMITTEES: *Human Resources; Corporate Governance*

4_ROY A. HERBERGER, JR., (61) 1992 President, Thunderbird, The American Graduate School of International Management COMMITTEES: *Finance and Operating, Chairman; Human Resources; Corporate Governance*

5_ROBERT G. MATLOCK, (70) 1993 Management Consultant, R.G. Matlock & Associates, Inc. COMMITTEES: *Human Resources; Corporate Governance*

6_WILLIAM J. POST, (53) 1994 Chairman of the Board & Chief Executive Officer COMMITTEE: *Finance and Operating*

7_HUMBERTO S. LOPEZ, (58) 1995 President, HSL Properties, Inc. COMMITTEES: *Audit; Corporate Governance*

8_MICHAEL L. GALLAGHER, (59) 1997 Chairman Emeritus, Gallagher & Kennedy, P.A. COMMITTEES: *Human Resources; Corporate Governance, Chairman*

9_BRUCE J. NORDSTROM, (54) 1997 Certified Public Accountant, Nordstrom and Associates, P.C. COMMITTEES: *Audit; Corporate Governance*

10_JACK E. DAVIS, (57) 1998 President & Chief Operating Officer COMMITTEE: *Finance and Operating*

11_WILLIAM L. STEWART, (60) 1998 COMMITTEE: *Finance and Operating*

12_EDDIE BASHA, (66) 1999 Chairman of the Board, Bashas' COMMITTEES: *Audit; Corporate Governance*

13_KATHRYN L. MUNRO, (55) 1999 Principal, BridgeWest L.L.C. COMMITTEES: *Finance and Operating; Corporate Governance*

* The year in which the individual first joined the Board of a Pinnacle West company.

Officers

PINNACLE WEST

William J. Post (53) 1973*
Chairman of the Board
& Chief Executive Officer

Jack E. Davis (57) 1973
President
& Chief Operating Officer

Donald E. Brandt (49) 2002
Executive Vice President
& Chief Financial Officer

Robert S. Aiken (47) 1986
Vice President, Federal Affairs

Barbara M. Gomez (49) 1978
Vice President & Treasurer

Nancy C. Loftin (50) 1985
Vice President, General Counsel
& Secretary

Martin L. Shultz (59) 1979
Vice President,
Government Affairs

ARIZONA PUBLIC SERVICE

William J. Post
Chairman of the Board

Jack E. Davis
President
& Chief Executive Officer

Donald E. Brandt
Executive Vice President
& Chief Financial Officer

Armando B. Flores (60) 1991
Executive Vice President,
Corporate Business Services

James M. Levine (54) 1989
Executive Vice President,
Generation

Steven M. Wheeler (55) 2001
Executive Vice President,
Customer Service & Regulation

Gregg R. Overbeck (57) 1990
Senior Vice President,
Nuclear Generation

Jan H. Bennett (56) 1967
Vice President,
Customer Service

Ajit P. Bhatti (58) 1973
Vice President,
Resource Planning

Dennis L. Brown (53) 1973
Vice President
& Chief Information Officer

John R. Denman (61) 1964
Vice President,
Fossil Generation

Edward Z. Fox (50) 1995
Vice President,
Communications,
Environment & Safety

Chris N. Froggatt (46) 1986
Vice President & Controller

Barbara M. Gomez
Vice President & Treasurer

David A. Hansen (44) 1980
Vice President,
Power Marketing & Trading

Nancy C. Loftin
Vice President, General
Counsel & Secretary

David Mauldin (54) 1990
Vice President,
Nuclear Engineering

Donald G. Robinson (50) 1978
Vice President, Planning

PINNACLE WEST ENERGY

James M. Levine
President
& Chief Executive Officer

Donald E. Brandt
Chief Financial Officer

Ajoy K. Banerjee (58) 1999
Vice President,
Construction & Operations

Warren C. Kotzmann (54) 1989
Vice President, Business
& Corporate Services

SUNCOR DEVELOPMENT

William J. Post
Chairman of the Board

John C. Ogden (58) 1972
President
& Chief Executive Officer

Geoffrey L. Appleyard (50) 1987
Vice President
& Chief Financial Officer

Duane S. Black (51) 1989
Vice President
& Chief Operating Officer

Jay T. Ellingson (55) 1992
Vice President,
Development – Palm Valley

Steven Gervais (48) 1987
Vice President
& General Counsel

Margaret E. Kirch (54) 1988
Vice President
Commercial Development

Thomas A. Patrick (50) 1995
Vice President, Golf Operations

APS ENERGY SERVICES

Vicki G. Sandler (47) 1982
President, APS Energy Services

EL DORADO INVESTMENT

William J. Post
Chairman of the Board,
President
& Chief Executive Officer

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

Shareholder Information

CORPORATE HEADQUARTERS
400 North 5th Street
P.O. Box 53999
Phoenix, Arizona 85004

Main telephone number: (602) 250-1000

ANNUAL MEETING OF SHAREHOLDERS
Wednesday, May 19, 2004
10:30 a.m.
The Herberger Theater Center
222 East Monroe Street
Phoenix, Arizona 85004

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

FORM 10-K
Pinnacle West's Annual Report to the Securities and Exchange Commission on Form 10-K will be available (after March 15, 2004) to shareholders upon written request, without charge.
Write: Office of the Secretary.

INVESTORS ADVANTAGE PLAN
Pinnacle West offers a direct stock purchase plan. Any interested investor may purchase Pinnacle West common stock through the Investors Advantage Plan. Features of the Plan include a variety of options for reinvesting dividends, direct deposit of cash dividends, automatic monthly investment, certificate safekeeping, reduced brokerage commissions and more. An Investors Advantage Plan prospectus and enrollment materials may be obtained by calling the Company at (800) 457-2983, at the corporate Web site – www.pinnaclewest.com, or by writing to:

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

CORPORATE WEB SITE
www.pinnaclewest.com

TRANSFER AGENTS AND REGISTRAR
Common Stock
Pinnacle West Capital Corporation
Stock Transfer Department
P.O. Box 52134
Phoenix, Arizona 85072-2134
Or:
400 North 5th Street
Phoenix, Arizona 85004
Telephone: (602) 250-5505

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

STATISTICAL REPORT
A detailed Statistical Report for Financial Analysis for 1998-2003 will be available in April on the Company's Web site or by writing to the Investor Relations Department.

INVESTOR RELATIONS CONTACTS
Rebecca L. Hickman, Director, Investor Relations
Lisa Malagon, Manager
P.O. Box 53999 Station 9998
Phoenix, Arizona 85072-3999
Telephone: (602) 250-5668
Fax: (602) 250-2789

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

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

ENVIRONMENTAL, HEALTH AND SAFETY REPORT
To view the APS Environmental, Health and Safety Report please visit www.aps.com, or to receive a printed summary report, call (602) 250-3259.

printed on recycled paper.

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

Campbell Fisher Design www.cfd2k.com

PINNACLE WEST
CAPITAL CORPORATION