In Our Element

Pinnacle West Capital Corporation
2002 ANNUAL REPORT

Pinnacle West is a Phoenix-based company with consolidated assets of approximately $8.4 billion and consolidated revenues of $2.6 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 projects.

THIS YEAR'S ANNUAL REPORT

Throughout this Annual Report, you'll see examples of the unique plants, animals and cultures found in Arizona. Each highlighted example thrives in Arizona's diverse climate by relying on characteristics such as agility, resourcefulness, durability, discipline and adaptability. These are also characteristics of Pinnacle West.

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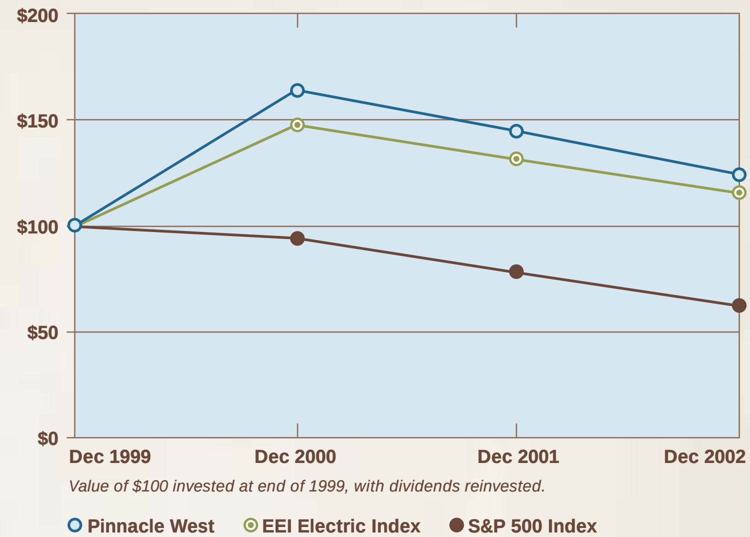
STOCK PERFORMANCE COMPARISON

A $100 investment in Pinnacle West in December 1999 (with dividends reinvested) would have been worth $125 at the end of 2002. By comparison, the same $100 would have been worth $115 if invested in the EEI Electric Index, and $62 if invested in the S&P 500 Index.



Value of $100 invested at end of 1999, with dividends reinvested.

CORE STRATEGIC OBJECTIVES

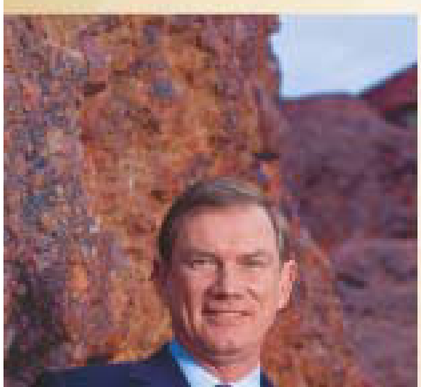
Focus on superior long-term total returns for shareholders · Provide Arizona electricity customers with reliable energy at stable prices · Capture growth opportunities in our electricity markets · Actively manage our costs and business risks · Maximize the long-term value of our assets · Maintain a disciplined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

FINANCIAL HIGHLIGHTS

(dollars in thousands, except per share amounts)

year ended December 31,	2002	2001	2000	Growth Rate 2002 VS. 2001	Growth Rate 2001 VS. 2000
INCOME HIGHLIGHTS					
Operating revenues	**$ 2,637,279**	$ 3,393,998	$ 3,119,522	(22.3%)	8.8%
Income before accounting change	**$ 215,153**	$ 327,367	$ 302,332	(34.3%)	8.3%
BALANCE SHEET HIGHLIGHTS					
Total assets – year-end	**$ 8,425,806**	$ 7,939,399	$ 7,122,667	6.1%	11.5%
Common stock equity – year-end	**$ 2,686,153**	$ 2,499,323	$ 2,382,714	7.5%	4.9%
PER SHARE HIGHLIGHTS					
Earnings per share before accounting change – diluted	**$ 2.53**	$ 3.85	$ 3.56	(34.3%)	8.1%
Indicated annual dividend – year-end	**$ 1.70**	$ 1.60	$ 1.50	6.3%	6.7%
Book value per share – year-end	**$ 29.40**	$ 29.46	$ 28.09	(0.2%)	4.9%
STOCK PERFORMANCE					
Stock price per share – year-end	**$ 34.09**	$ 41.85	$ 47.63		
Stock price appreciation	**(18.5%)**	(12.1%)	55.8%		
Total return	**(14.8%)**	(9.0%)	61.8%		
Market capitalization – year-end	**$ 3,115,142**	$ 3,549,924	$ 4,039,788	(12.2%)	(12.1%)

To Our Shareholders



WILLIAM J. POST, CHAIRMAN

Last year the economy didn't perform. Our company did.

Still, our earnings were down. In 2002, net income dropped due to a depressed electric wholesale market and non-recurring charges. However, earnings from our core operations remained relatively strong as a result of outstanding operational performance.

Despite punishing markets and a slack economy over the last two years, we continued to improve reliability and customer satisfaction, and took extraordinary steps to meet customer demand. In this challenging environment, flexibility and agility remain essential to our success.

We continued an unprecedented series of price reductions, insulated customers from volatile wholesale markets and added new generation capacity to meet Arizona Public Service (APS) electricity demand not met by existing APS generation. Our power plant performance set records. We saw significant earnings improvement from unregulated subsidiaries SunCor and APS Energy Services.

Going forward, our story will include a large component of state regulation. We know the regulatory environment and have shown the ability to adjust to its changes. This is a challenge, but it's familiar.

There is no place we'd rather do business than here in Arizona. This is a unique and dynamic state. Our growth has been robust, and has slowed little through the current economic downturn. We're still adding customers at about three times the national average. When economic growth and business investment return to historical norms, our strong fundamentals will, again, support earnings growth. Excellent performance has softened the blow of a weak economy and changing regulation. We've been through a turbulent year, and we won't attempt to minimize its impact. In coming years, the overall picture looks brighter.

Throughout these pages you'll see images of our state. Those that survive and thrive here possess unique adaptive abilities, hard-earned experience and the flexibility to adjust to change. I see a lot of our company in these examples.

WE ARE ADAPTABLE

If you're a long-time owner of our company, you know we emphasized agility, long-term growth and adaptability as we prepared for competition. We knew changes would come. This approach has served us well. For example, we didn't sell our generating plants, even though we felt the same pressure to sell as other utilities. We also didn't over-commit to competitive markets. We built new generation, primarily in Arizona, to match the growing needs of APS customers.

After preparing for deregulation for nearly a decade, we neared completion of that process in 2002. Under the 1999 regulatory settlement agreement with the Arizona Corporation Commission (ACC), we were to transfer APS' generation to Pinnacle West Energy by the end of 2002. The competition and affiliate rules adopted by the ACC kept APS from adding new generation to serve its needs, while requiring APS to remain the provider of last resort.

To meet APS' growing demand for power, Pinnacle West Energy built state-of-the-art, gas-fired combined-cycle power plants, financed with temporary "bridge" debt. This temporary financing was to be converted to permanent financing when the APS generation assets were consolidated with Pinnacle West Energy's new plants as required by the 1999 settlement. Meanwhile, our company and the ACC recognized market conditions were radically different than envisioned in 1999. Serious structural flaws in the wholesale market were painfully apparent. In response, the ACC reversed course in August of 2002 and prohibited the transfer of APS generation to Pinnacle West Energy.

Prior to that, in the fall of 2001, we proposed a different solution in response to the same market weaknesses. The company and the ACC each sought to protect Arizona customers from a competitive debacle that could have mirrored the California disaster.

When the ACC changed its policy on competitive generation, however, it did not address the treatment of our plants built since 1999 to serve APS customers. Our request for financial treatment of the plants followed, and recognizing that the debt markets are essentially closed to unregulated generation companies, the ACC acted quickly on our application to allow APS to extend Pinnacle West a $125 million line of credit. Then, in March of 2003, the ACC also approved a $500 million loan from APS to Pinnacle West Energy. The loan will provide sufficient liquidity while the ACC decides the long-term rate treatment of these plants.

As required by the 1999 settlement agreement, we will file a full general rate case in 2003 – our first in well over a decade – to update our cost of service and address issues arising from the change in direction by the ACC. These issues include folding Pinnacle West Energy's Arizona plants into rates, reversal of the $234 million write-off we took as part of the 1999 settlement agreement, and consideration of the costs incurred preparing to transfer APS' generation to Pinnacle West Energy. We face a hefty regulatory agenda, but it's an agenda we will continue to address to the benefit of our customers and shareholders. We have anticipated the issues and are resolving them before they turn into greater problems. We believe the ACC recognizes the importance of this agenda.

WE MANAGE CONFLICTING AGENDAS

When California wanted more natural gas at the expense of our transportation contract (and the contracts of other southwestern companies) with El Paso Natural Gas, we went to the Federal Energy Regulatory Commission (FERC) and fought against erosion of this "full requirements" contract. Erosion of the El Paso gas contract would increase our costs and make for a less stable supply. We expect resolution by mid-2003 without material cost increases.

We have actively sought a workable transmission structure for the Southwest by forming an independent transmission group known as WestConnect. In 2002, the FERC granted conditional approval of WestConnect, its for-profit structure and its departures from the current standard model. A for-profit structure will provide incentive for new investment in the transmission grid, which is needed in the West. We've said for years, without a robust transmission system, there can be no robust wholesale market. Without a robust wholesale market, we can't have broad retail competition. In fact, the current path is leading to more regulation, not competition.

The growth of APS customers implies a strong core business that will drive future financial performance.

In the West, we believe the FERC must spend more effort addressing the real barriers to competition – insufficient transmission capacity and the inability to incorporate public power into the competitive structure. Municipal and federal agencies control large chunks of transmission, making tight coordination of scarce capacity even more difficult. Patchwork rules only result in disorder. Without a set of common protocols and full participation by all parties, western wholesale market development is problematic.

There are other unique issues in the West that must be respected. We have long geographic distances between load centers, typically with only one or two transmission lines. Our systems are not "networked" to the degree of denser East Coast systems. The West has large amounts of hydro capacity that often cannot be scheduled a day ahead.

The mantra of competition will continue to be the catalyst for greater state and federal regulatory involvement. Competition, regulation and the physics of a western electric system will coexist, inconsistencies aside. With the FERC continuing to push for generation deregulation and the ACC maintaining vertical integration, we must deal with incompatibilities and live in different universes at the same time. Business opportunities have and will continue to develop from these apparently colliding forces. We plan to capitalize on them by remaining agile and versatile enough to occupy the ground between these two, while always remaining focused on the ultimate best interests of our customers and shareholders.

OUR BUSINESS STRATEGY IS SOLID

Pinnacle West and APS occupy a solid niche in the business landscape. We'll continue to concentrate primarily on our core business in an area our employees know well – Arizona and the western U.S. power markets – with a combination of customer focus, exceptional operational performance and financial strength.

We have worked hard to shape this landscape. We avoided price increases by keeping control of our power plants. We didn't sell our generation. We brought in temporary generating resources and built new permanent plants to protect our customers. When prices reached hundreds of dollars per megawatt-hour in 2000 and 2001, we had "hedged" our market position – with financial instruments as well as short-term power contracts – to insulate customers from price volatility, ensure reliability and protect our shareholders' returns.

This risk management expertise has served us well. We learned to manage purchased power and fuel price risks, then market risk. Even in today's battered wholesale market, our Power Marketing group has produced positive results, and we expect they will continue to do so in the future.

By July of 2003, we will have decreased our electricity prices 16 percent over the last decade while significantly improving customer satisfaction. That's customer value. Our employees – the "we" I've referred to throughout this letter – will continue our tenacious focus on efficiency and operational excellence.

As we work through the implications of our change in course – the 1999 regulatory write-off, the expense of creating a generation subsidiary, the rate treatment of plants built to serve APS customers and the many issues that affect a traditional rate case – we will not accept inferior outcomes. We acted responsibly in protecting our customers during the power market debacle. We avoided the blackouts, price spikes and bankruptcies that afflicted other states. We honored the terms of our 1999 settlement agreement and the ACC's competition rules. We expect to achieve a regulatory solution that is fair to our customers and shareholders.

Despite major regulatory shifts, our business strategy has seen little fundamental change. Our core strategic objectives – outlined on page one of this report – still lock together, allowing us to occupy a rewarding business niche, positioning us well to provide solid shareholder returns.

WE ARE FOCUSED ON DELIVERING VALUE

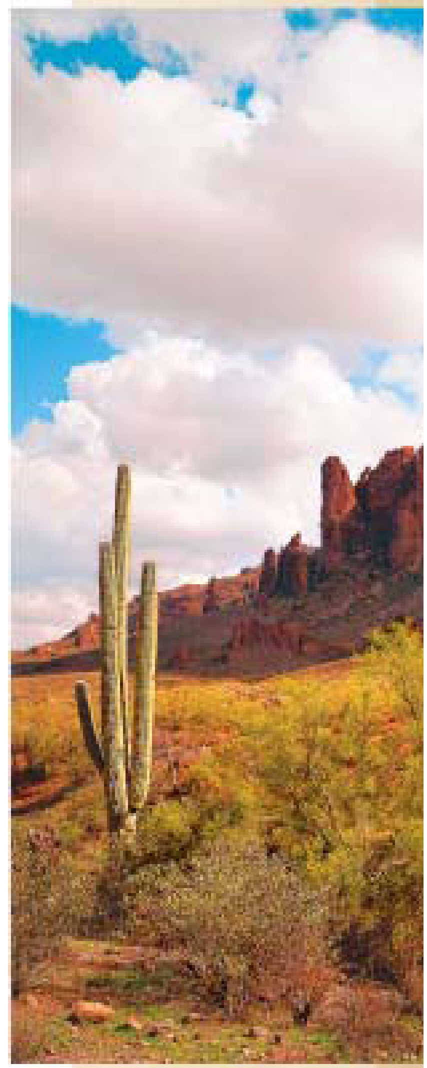
For our shareholders, our performance is judged by the delivery of returns in the form of share appreciation and dividends over time. In 2002, the convergence of regulatory change, financial and credit market fears, a weak economy, wholesale electric market declines and our own non-recurring charges contributed to a lower stock price. Although our stock performance for the year mirrored the industry, we are not satisfied with relative industry performance, let alone a decline.

Steps taken in 2002 to reposition our regulatory structure, improve efficiency, reduce staffing, realign our generation portfolio and improve our liquidity, place us well for the future. Although 2003 continues to be a transition year as we work through regulatory and other issues, our operations and market base are strong. We expect debt ratios to improve as we complete our current power plant projects, and even now we have a sound liquidity position, significantly exceeding our cash requirements. The growth of APS customers – both in number and energy usage – implies a strong core business that will drive future financial performance. Meanwhile, we will continue to emphasize dividends for our shareholders tied to factors such as our cash flow, dividend payout trends and financial market conditions.

Our company, and others in our industry, moved in one direction for nearly a decade – toward a new competitive industry. In 2002, that direction reversed. Such sudden change is not easy, and it caused disruptions. But everything that makes us a good company and a good investment remains intact. Our customer growth is powerful and customer satisfaction has never been higher. Our power plants and wires networks are operating beyond our previous high performance. We know this region and the opportunities it holds.

Our course is set. Arizona – with its intense climate, aesthetic beauty and nearly limitless potential – has never seemed more attractive. This is our home. This is our future. This is our element. •

William J. Post



Arizona's elk spend summers in the world's largest ponderosa pine forest, feeding on plentiful grass in northern Arizona's high country. As autumn comes, the elk adapt to the changing temperature and availability of food and migrate to the state's lower grasslands to spend the winter.

In an evolving climate, those that are agile and adaptable survive. Those that combine these traits with a solid strategic core thrive. We are such a company.

· After approximately a decade of preparing for retail electric competition, in mid-2002, the Arizona Corporation Commission changed its generation divestiture policy, resulting in APS remaining a vertically integrated utility. We quickly adapted to this reversal of direction and demonstrated our ability to remain agile in the face of changing regulatory and marketplace climates.

· We continue to meet the changing needs of our customers. Since 1999, our peak load has grown 18 percent, while we have continued to improve our reliability measurements.

· Streamlined processes and a more productive workforce allow us to do more with less. In 1998, we served approximately 775,000 retail electric customers with about 5,900 employees*. In 2002, we served more than 900,000 customers with approximately 6,100 employees.

· Process and workforce improvements also enable us to keep generation production costs low. In 2002, our nuclear and coal production costs averaged 1.68 cents per kilowatt-hour, well below expected national averages.

· We continue to have a diverse generation mix. By 2004, our estimated generation mix will consist of roughly 43 percent coal, 31 percent nuclear and 26 percent natural gas. This diversity will allow us to continue effectively managing risk in the face of changing wholesale markets and fuel prices.

· We continue to offer customers greater flexibility, and reduce our operating costs through our utility Web site – APS.com. In recognition of these efforts, APS.com was named Best Energy Site for 2002 by the Web Marketing Association, a national organization made up of Internet marketing, advertising, public relations and design professionals.

**Employee counts reflect workforce serving retail electric business*

Our region continues to grow rapidly. Growth is our future and we will manage it to benefit our customers, our shareholders, our employees and our state.

· APS experienced 3.1 percent customer growth (nearly 30,000 new customers) in 2002 – about three times the national average. Our customer base is projected to continue to grow about 3.5 percent annually in the next three years.

· Much of this growth occurs in the heart of our service territory – the greater Phoenix area. The Phoenix metro area issued nearly 41,000 building permits in 2002 – ranking second among the 10 largest metropolitan areas in the United States in building permits per 1,000 residents.

· As our customer base grows, we also are expanding our power resources. By bringing on line two new gas-fired units at the Redhawk Power Plant and a new unit at the Saguaro Power Plant, we added more than 1,000 megawatts of new generating capacity in 2002. In addition, a 530-megawatt unit at the West Phoenix Power Plant is expected to be completed in summer 2003, and the 570-megawatt Silverhawk Plant in summer 2004.

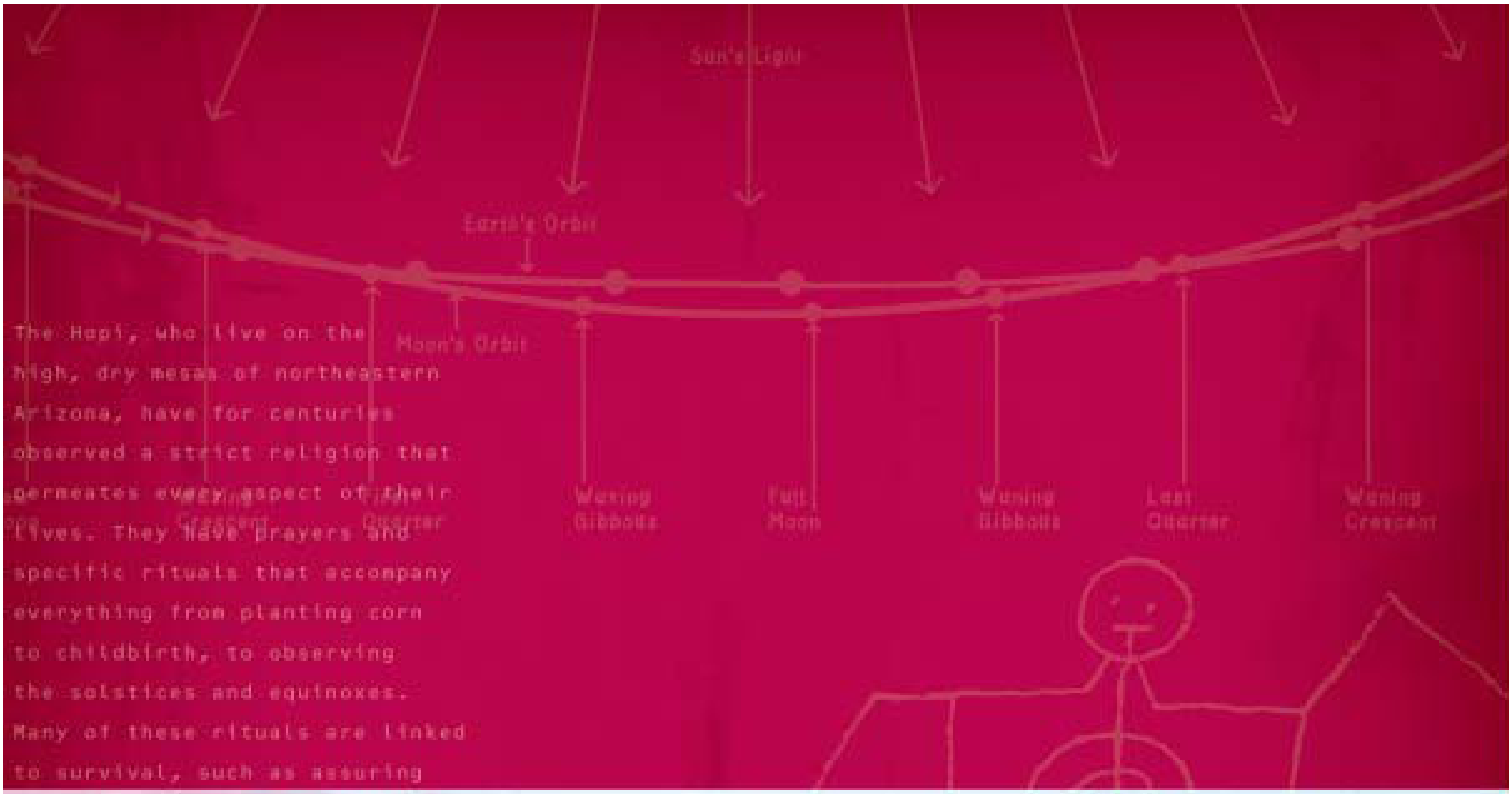
· As an internationally recognized leader in the research and development of solar technology, we are dedicated to finding renewable energy solutions for future generations. In 2002, APS began construction of the Prescott (Ariz.) Airport Solar Power Plant, which, when completed, should be the largest photovoltaic solar plant in the world. Completion of the solar plant is expected in the next five years, when the facility's capacity will reach 5 megawatts.

· We expanded our transmission and distribution system in 2002, adding nearly 800 miles of wires. On average, a new substation was completed every seven-and-a-half weeks. We also began construction on a 500-kilovolt transmission line that, when completed in mid-2003, will bring needed transmission capacity to support the continued growth of the greater Phoenix area.

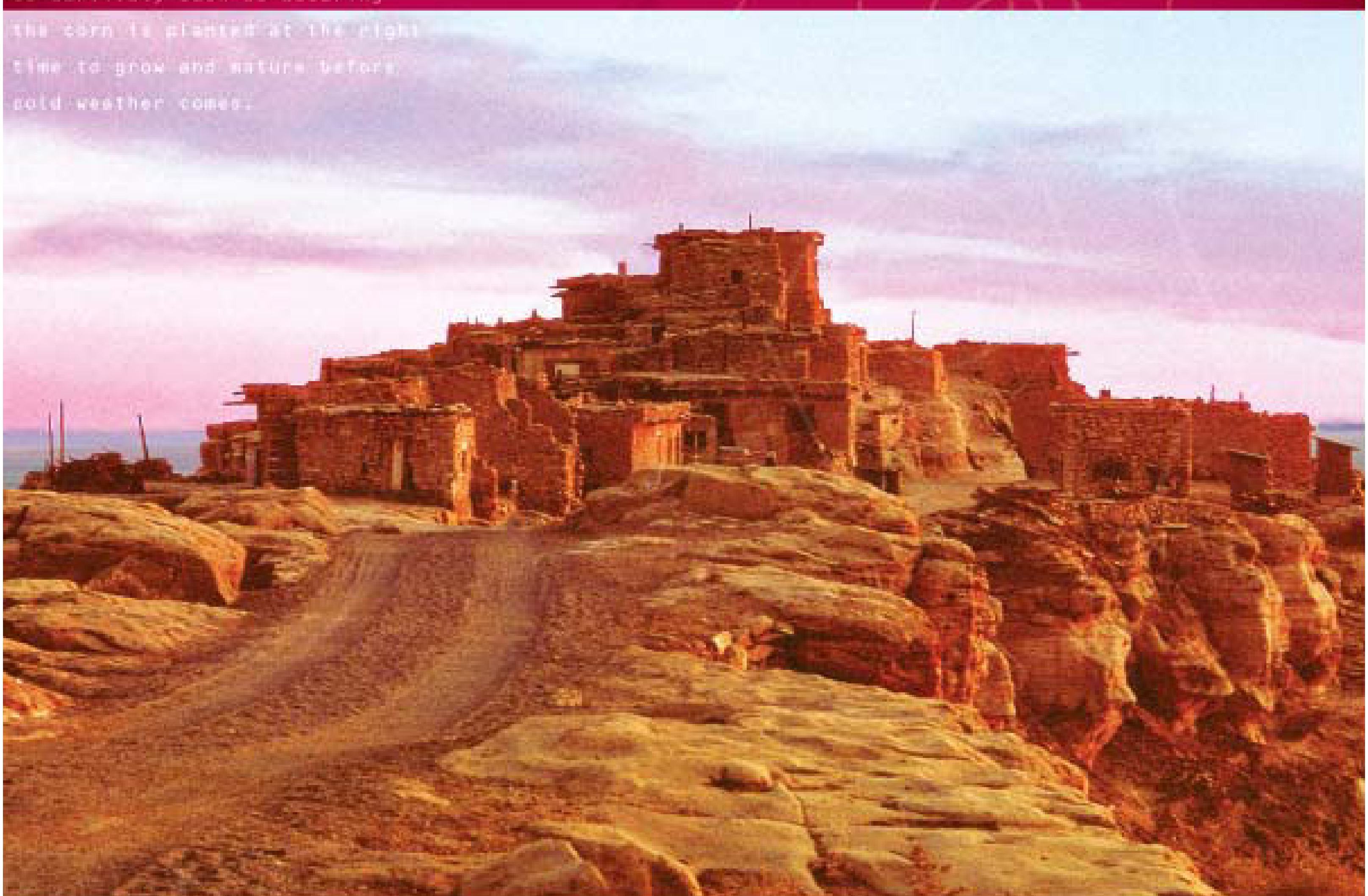
The seeds of desert wildflowers lie dormant in the soil for all but a few weeks each spring. Then, if autumn and winter rains have fallen at the right times and in the right amounts, Arizona's desert explodes in a riot of growth and color. Rushing to take advantage of the short period when moisture and temperature are optimal, desert wildflowers germinate, grow to maturity and bloom in a matter of days. The speed of their growth, the varied colors and the abundance of flowers are startling.

AVERAGE YEARLY PRECIPITATION
(Rain, Melted Snow, and Other Moisture)

Inches	Centimeters
24 to 32	61 to 81
16 to 24	41 to 61
8 to 16	20 to 41



The Hopi, who live on the high, dry mesas of northeastern Arizona, have for centuries observed a strict religion that permeates every aspect of their lives. They have prayers and specific rituals that accompany everything from planting corn to childbirth, to observing the solstices and equinoxes. Many of these rituals are linked to survival, such as assuring the corn is planted at the right time to grow and mature before cold weather comes.



© photographed by Jerry Jacka

A strong plan is important. Execution of that plan is vital. Our people continue to perform and raise the standards by which we measure success.

· Our fossil power plants operated at high levels throughout 2002. The five coal-fired Four Corners units achieved a combined capacity factor of 83 percent, placing the site in the top 20 percent in the nation. Our Cholla coal plant and the combined gas and oil plants at Ocotillo, Saguaro, West Phoenix, Yucca and Douglas had availabilities of more than 90 percent.

· In 2002, the Palo Verde Nuclear Generating Station produced a national record 30.8 billion kilowatt-hours of electricity, breaking its own record of 30.4 billion kilowatt-hours set in 1999 and repeated in 2000.

· Palo Verde also operated at a best-ever 94.4 percent capacity factor and marked its eleventh consecutive year as the number one power producer of any kind in the United States. This focus on efficient plant production continues to be exceeded only by our intense focus on plant safety.

· We continue to believe areas such as safety, financial integrity, business practices, community involvement and environmental stewardship are key ingredients in creating shareholder value. We emphasize continuous improvement in our safety record and again reduced our number of preventable recordable injuries.

· We grew our common dividend 6.3 percent in 2002. Our dividend growth over the past five years averaged 7.2 percent per year and ranked number one among U.S. electric utilities.

· Pinnacle West again earned the top rating (AAA) for environmental, economic and social performance from Innovest, an international investment advisory firm. The firm ranked us number two out of the 28 electric utilities included in the S&P 500. We also were presented the Better Business Bureau of Central and Northern Arizona's Business Ethics Award.

Our roots run deep in Arizona and the West. We've been here for 116 years. We know the landscape. We know the people. We know the opportunities.

· APS has reduced customer electricity prices 14.5 percent since 1993. This number will reach 16 percent in mid-2003 and represents the largest cumulative price decrease among investor-owned utilities nationwide in that time period. These reductions have saved our customers more than a billion dollars.

· In the 2002 electric utility customer satisfaction studies conducted by J.D. Power and Associates, APS residential and midsize business customers rated us higher than any other investor-owned utility in the western region.

· In a year of low wholesale energy prices and a market in which most industry power marketing functions lost millions, our Power Marketing group effectively managed wholesale risk and contributed more than $100 million of pretax gross margin to our company.

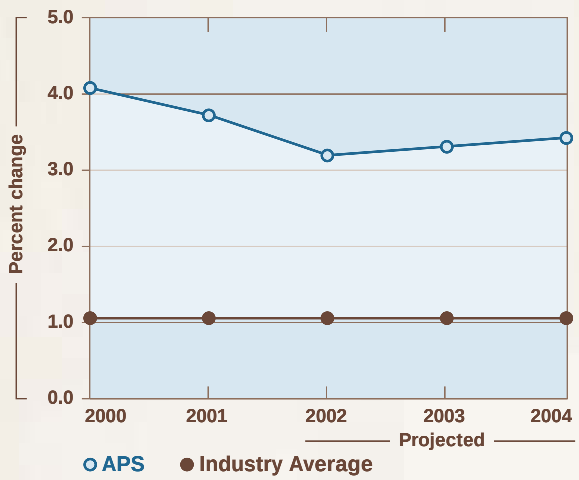
· In its fourth year of operation, APS Energy Services, our competitive retail energy services company, continued to carve a profitable niche for itself by providing integrated solutions from commodity energy to energy efficiency-related products and services. In 2002, APS Energy Services began $40 million worth of energy efficiency work for Arizona's three major universities, continued adding commercial and industrial commodity customers in the West and contributed more than $28 million to pretax earnings.

· SunCor, our real estate development company and one of Arizona's premier home-builders, had a strong financial year as well, contributing $19 million to earnings. SunCor is also expected to make cash distributions to Pinnacle West of $80 million to $100 million annually from 2003 to 2005 from matured asset sales. In 2002, the company opened its newest development, the 1,850-acre StoneRidge golf community in Prescott Valley, Ariz. Nearly 140 homes and 20 custom home sites had been sold at StoneRidge by the end of 2002.

Scientists think the creosote bush, which thrives in Arizona's deserts, may be the oldest living plant in the world. These desert shrubs grow and send out a root system that is wide and deep. Additional plants sprout from the roots some distance away, and as the original plant dies, the shrubs that sprouted from the root (essentially the same plant) live on. The creosote provides more food and shelter for desert animals than any other plant species.

We continue to experience unique customer growth – about three times the industry average…

APS CUSTOMER GROWTH



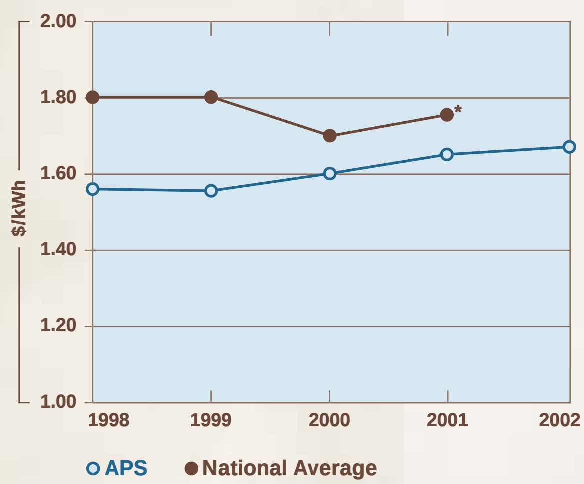
Though we're rapidly adding customers, increasingly efficient operations have helped keep workforce increases minimal…

CUMULATIVE PERCENT INCREASE OF CUSTOMERS AND EMPLOYEES SINCE 1999

Employee counts reflect workforce serving retail electric business

These efficiencies have also allowed us to keep power plant production costs below national averages…

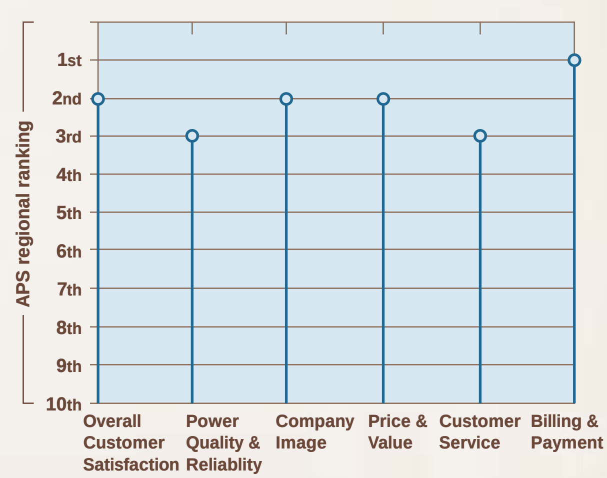
COAL AND NUCLEAR PRODUCTION COST



**2002 national average not available at press time*

And our customer satisfaction scores continue to improve, ranking at or near the top of the western region.

CUSTOMER SATISFACTION RANKING



Source: J.D. Power & Associates
2002 Midsize Business Customer Satisfaction Survey

2002 Consolidated Financial Statements

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

	2002	2001	2000	1999	1998
OPERATING RESULTS					
Operating revenues:					
Regulated electricity segment	$ 2,013,023	$ 2,562,089	$ 2,538,752	$ 1,915,108	$ 1,741,148
Marketing and trading segment	325,931	651,230	418,532	154,125	180,145
Real estate segment	236,388	168,908	158,365	130,169	124,188
Other revenues	61,937	11,771	3,873	439	–
Income from continuing operations	$ 215,153	$ 327,367	$ 302,332	$ 269,772	$ 242,892
Discontinued operations (a)	–	–	–	38,000	–
Extraordinary charge – net of income taxes (b)	–	–	–	(139,885)	–
Cumulative effect of change in accounting – net of income taxes (c)(d)	(65,745)	(15,201)	–	–	–
Net income	$ 149,408	$ 312,166	$ 302,332	$ 167,887	$ 242,892
COMMON STOCK DATA					
Book value per share – year-end	$ 29.40	$ 29.46	$ 28.09	$ 26.00	$ 25.50
Earnings (loss) per weighted average common share outstanding:					
Continuing operations – basic	$ 2.53	$ 3.86	$ 3.57	$ 3.18	$ 2.87
Discontinued operations	–	–	–	0.45	–
Extraordinary charge	–	–	–	(1.65)	–
Cumulative effect of change in accounting	(0.77)	(0.18)	–	–	–
Net income – basic	$ 1.76	$ 3.68	$ 3.57	$ 1.98	$ 2.87
Continuing operations – diluted	$ 2.53	$ 3.85	$ 3.56	$ 3.17	$ 2.85
Net income – diluted	$ 1.76	$ 3.68	$ 3.56	$ 1.97	$ 2.85
Dividends declared per share	$ 1.625	$ 1.525	$ 1.425	$ 1.325	$ 1.225
Indicated annual dividend rate per share – year-end	$ 1.70	$ 1.60	$ 1.50	$ 1.40	$ 1.30
Weighted-average common shares outstanding – basic	84,902,946	84,717,649	84,732,544	84,717,135	84,774,218
Weighted-average common shares outstanding – diluted	84,963,921	84,930,140	84,935,282	85,008,527	85,345,946
BALANCE SHEET DATA					
Total assets	$ 8,425,806	$ 7,939,399	$ 7,122,667	$ 6,571,023	$ 6,789,975
Liabilities and equity:					
Long-term debt less current maturities	$ 2,881,695	$ 2,673,078	$ 1,955,083	$ 2,206,052	$ 2,048,961
Other liabilities	2,857,958	2,766,998	2,784,870	2,159,238	2,482,422
Total liabilities	5,739,653	5,440,076	4,739,953	4,365,290	4,531,383
Minority interests:					
Non-redeemable preferred stock of APS	–	–	–	–	85,840
Redeemable preferred stock of APS	–	–	–	–	9,401
Common stock equity	2,686,153	2,499,323	2,382,714	2,205,733	2,163,351
Total liabilities and equity	$ 8,425,806	$ 7,939,399	$ 7,122,667	$ 6,571,023	$ 6,789,975

(a) Tax benefit stemming from the resolution of income tax matters related to a former subsidiary MeraBank, A Federal Savings Bank.
(b) Charges associated with a regulatory disallowance. See “Regulatory Accounting” in Note 1.
(c) Change in accounting standards related to derivatives in 2001. See Note 18.
(d) Change in accounting standards related to trading activities in 2002. See Note 18.

SELECTED CONSOLIDATED FINANCIAL DATA (CONTINUED) (dollars in thousands)

	2002	2001	2000	1999	1998
REGULATED ELECTRICITY AND MARKETING AND TRADING SEGMENTS' REVENUES					
Regulated electricity segment:					
Residential – retail	**$ 906,069**	$ 914,711	$ 880,468	$ 805,173	$ 766,378
Business – retail	**927,773**	952,627	935,214	911,449	889,244
Total retail	**1,833,842**	1,867,338	1,815,682	1,716,622	1,655,622
Wholesale revenue on delivered electricity:					
Traditional contracts	**8,616**	73,305	120,618	60,486	58,184
Retail load hedge management (a)	**122,630**	577,784	560,493	108,153	–
Transmission for others	**29,803**	25,971	14,765	11,348	11,058
Other miscellaneous services	**18,132**	17,691	27,194	18,499	16,284
Total regulated electricity revenue	**2,013,023**	2,562,089	2,538,752	1,915,108	1,741,148
Marketing and trading segment:					
Delivered marketing and trading:					
Generation sales other than Native Load (a)	**50,364**	148,316	115,476	29,551	–
Realized margin on electricity trading	**47,897**	62,067	55,910	8,565	2,157
Other delivered electricity (a)	**207,810**	328,972	244,183	112,551	170,796
Total delivered marketing and trading	**306,071**	539,355	415,569	150,667	172,953
Other marketing and trading:					
Realized margins on delivered commodities other than electricity	**7,771**	(13,646)	(8,789)	2,483	7,192
Prior period mark-to-market gains on contracts delivered during current period	**(40,072)**	(1,059)	(2,079)	–	–
Change in mark-to-market for future period deliveries	**52,161**	126,580	13,831	975	–
Total other marketing and trading	**19,860**	111,875	2,963	3,458	7,192
Total marketing and trading revenue	**325,931**	651,230	418,532	154,125	180,145
Total regulated electricity and marketing and trading segments' revenues	**$ 2,338,954**	$ 3,213,319	$ 2,957,284	$ 2,069,233	$ 1,921,293
ELECTRIC SALES (MWh)					
Regulated electricity segment:					
Residential – retail	**10,443,820**	10,334,860	9,780,680	8,774,822	8,310,689
Business – retail	**12,917,935**	13,064,152	12,753,844	12,299,748	12,152,394
Total retail	**23,361,755**	23,399,012	22,534,524	21,074,570	20,463,083
Wholesale electricity delivered:					
Traditional contracts	**473,699**	1,213,704	1,610,032	1,421,522	1,410,392
Retail load hedge management (a)	**2,641,714**	3,039,905	6,673,658	630,945	–
Total regulated electricity	**26,477,168**	27,652,621	30,818,214	23,127,037	21,873,475
Delivered marketing and trading:					
Generation sales other than Native Load (a)	**1,791,319**	1,387,860	1,494,299	1,267,349	–
Electricity trading	**16,924,509**	12,031,055	9,259,054	5,679,023	846,864
Other delivered electricity (a)	**4,138,055**	2,581,942	2,960,314	6,694,995	8,060,135
Total delivered marketing and trading	**22,853,883**	16,000,857	13,713,667	13,641,367	8,906,999
Total regulated electricity and marketing and trading sales	**49,331,051**	43,653,478	44,531,881	36,768,404	30,780,474
ELECTRIC CUSTOMERS – AVERAGE					
Retail:					
Residential	**801,801**	776,339	749,285	719,774	689,871
Business	**100,228**	98,198	94,128	90,496	87,831
Total retail	**902,029**	874,537	843,413	810,270	777,702
Wholesale	**67**	66	67	69	60
Total average electric customers	**902,096**	874,603	843,480	810,339	777,762

(a) The break-out of retail load hedge management and generation sales other than Native Load is not available for 1998. These amounts are included in other delivered electricity in the marketing and trading segment for 1998.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations" for a discussion of certain information in the tables above.

QUARTERLY STOCK PRICES AND DIVIDENDS PER SHARE

Stock Symbol: PNW

2002	High	Low	Close	Dividends Per Share	2001	High	Low	Close	Dividends Per Share
1st Quarter	$ 45.60	$ 39.36	$ 45.35	$0.400	1st Quarter	$ 47.96	$ 39.06	$ 45.87	$ 0.375
2nd Quarter	46.68	37.08	39.50	0.400	2nd Quarter	50.70	45.20	47.40	0.375
3rd Quarter	39.72	25.82	27.76	0.400	3rd Quarter	49.93	37.65	39.70	0.375
4th Quarter	34.36	21.70	34.09	0.425	4th Quarter	43.50	38.00	41.85	0.400

GLOSSARY

ACC – Arizona Corporation Commission

ACC Staff – Staff of the Arizona Corporation Commission

ADEQ – Arizona Department of Environmental Quality

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

ERMC – the Company's Energy Risk Management Committee

FASB – Financial Accounting Standards Board

FERC – United States Federal Energy Regulatory Commission

FIN – FASB Interpretation

Financing Application – APS application filed with the ACC on September 16, 2002

Fitch – Fitch, Inc.

Four Corners – Four Corners Power Plant

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

Interim Financing Application – APS application filed with the ACC on November 8, 2002

IRS – United States Internal Revenue Service

ISO – California Independent System Operator

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

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

PX – California Power Exchange

Rules – ACC retail electric competition rules

SCE – Southern California Edison Company

SFAS – Statement of Financial Accounting Standards

SMD – standard market design

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

System – non-trading energy related activities

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

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

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

- the changes in our earnings from 2001 to 2002 and from 2000 to 2001;
- our capital needs, liquidity and capital resources;
- our critical accounting policies;
- our business outlook and major factors that affect our financial outlook; and
- our management of market risks.

Throughout this section, we refer to specific "Notes" in the Notes to Consolidated Financial Statements in this report. These Notes add further details to the discussion.

BUSINESS OVERVIEW

The Company owns all of the outstanding common stock of APS. APS is an electric utility that provides either retail or wholesale electric service to substantially all of the state of Arizona, with the major exceptions of the Tucson metropolitan area and about one-half of the Phoenix metropolitan area. Electricity is delivered through a distribution system owned by APS. APS also generates, sells and delivers electricity to wholesale customers in the western United States. The marketing and trading division sells, in the wholesale market, APS and Pinnacle West Energy generation output that is not needed for APS' Native Load, which includes loads for retail customers and traditional cost-of-service wholesale customers. APS does not distribute any products.

Our other major subsidiaries are:

- Pinnacle West Energy, through which we conduct our competitive electricity generation operations;
- APS Energy Services, which provides competitive commodity-related energy services (such as direct access commodity contracts, energy procurement and energy supply consultation) and energy-related products and services (such as energy master planning, energy use consultation and facility audits, cogeneration analysis and installation and project management) to commercial, industrial and institutional retail customers in the western United States;
- SunCor, a developer of residential, commercial, and industrial real estate projects in Arizona, New Mexico, and Utah; and
- El Dorado, which owns a majority interest in NAC (specializing in spent nuclear fuel technology) and holds miscellaneous small investments, including interests in Arizona community-based ventures.

SUMMARY OF KEY FACTORS AFFECTING OUR FINANCIAL OUTLOOK

We believe the following are among the key factors affecting our financial outlook:

- The following ACC regulatory matters:
  - APS' $500 million financing application which the ACC approved on March 27, 2003;
  - the implementation of the ACC-mandated process by which APS must competitively procure energy; and
  - APS' general rate case to be filed in 2003.
- Wholesale power market conditions in the western United States.

We discuss each of these, and other factors in detail below in the section entitled "Factors Affecting Our Financial Outlook."

EARNINGS CONTRIBUTIONS BY SUBSIDIARY AND BUSINESS SEGMENT

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

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

The following tables summarize net income and segment details for the years ended December 31, 2002, 2001 and 2000 for Pinnacle West and each of our subsidiaries:

(dollars in millions)	TOTAL	Regulated Electricity	Marketing and Trading	Real Estate	Other (a)
2002					
APS (b)	$ 199	$ 198	$ 1	$ –	$ –
Pinnacle West Energy (b)	(19)	(21)	2	–	–
APS Energy Services (c)	28	–	23	–	5
SunCor	19	–	–	19	–
El Dorado (principally NAC) (c)	(55)	–	–	–	(55)
Parent company (c)	43	(7)	32	–	18
Income (loss) before accounting change	215	170	58	19	(32)
Cumulative effect of change in accounting – net of income taxes (d)	(66)	–	(66)	–	–
Net income (loss)	$ 149	$ 170	$ (8)	$ 19	$ (32)

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

(dollars in millions)	TOTAL	Regulated Electricity	Marketing and Trading	Real Estate	Other
2000					
APS	$ 307	$ 228	$ 79	$ –	$ –
Pinnacle West Energy	(2)	(2)	–	–	–
APS Energy Services (c)	(13)	–	(16)	–	3
SunCor	11	–	–	11	–
El Dorado	2	–	–	–	2
Parent company	(3)	(5)	2	–	–
Net income	$ 302	$ 221	$ 65	$ 11	$ 5

(a) Primarily includes activities related to El Dorado, principally NAC. See Note 22.

(b) Consistent with APS' October 2001 ACC filing, APS entered into agreements with its affiliates to buy power. The agreements reflected a price based on the fully-dispatchable dedication of the Pinnacle West Energy generating assets to APS' Native Load customers. In 2002, Pinnacle West Energy recorded a $49 million pretax write-off related to the cancellation of Redhawk Units 3 and 4.

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

(d) We recorded 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, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," as of October 1, 2002. See Note 18.

(e) 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 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 includes El Dorado's investment in NAC, which we began consolidating in our financial statements in July 2002 (see Note 22). Other gross margin also includes amounts related to APS Energy Services' energy consulting services.

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).

Our income before accounting change for the year ended December 31, 2002 was $215 million compared with $327 million for the prior year. The period-to-period comparison was lower due to:

- lower earnings contributions from our marketing and trading activities, reflecting lower liquidity and lower price volatility in the wholesale power markets in the western United States;
- pretax losses of $59 million related to our investment in NAC;
- a $49 million pretax write-off related to the cancellation of Redhawk Units 3 and 4, of which $47 million was recorded in operations and maintenance expense and $2 million was recorded in capitalized interest; and
- severance costs of approximately $36 million pretax recorded in the second half of 2002 relating to a voluntary workforce reduction.

The above decreases were partially offset by:

- increased earnings contributions from our regulated electricity activities, reflecting lower replacement power costs for power plant outages, retail customer growth and higher average usage per customer, partially offset by the effects of milder weather, retail electricity price decreases and higher costs for purchased power and gas due to higher hedged gas and power prices; and

- increased earnings contributions from real estate operations, primarily as a result of increased sales activities.

For additional details, see the following discussion.

The major factors that increased (decreased) income before accounting change were as follows:

(dollars in millions)	Increase (Decrease)
Regulated electricity segment gross margin:	
Lower replacement power costs for plant outages due to lower market prices and fewer unplanned outages	$ 127
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)
Higher retail sales volumes due to customer growth and higher average usage, excluding weather effects	38
2001 charges related to purchased power contracts with Enron and its affiliates	13
Retail price reductions effective July 1, 2001 and July 1, 2002	(28)
Effects of milder weather on retail sales	(27)
Miscellaneous factors, net	(2)
Net increase in regulated electricity segment gross margin	112
Marketing and trading segment gross margin:	
Decrease in generation sales other than Native Load due to lower market prices partially offset by higher sales volumes	(66)
Lower realized wholesale margins net of related mark-to-market reversals due to lower prices and volumes	(91)
Higher competitive retail sales in California by APS Energy Services	32
2001 write-off of prior period mark-to-market value related to trading with Enron and its affiliates	8
Lower mark-to-market reversals due to the adoption of EITF 02-3	8
Lower mark-to-market gains for future delivery due to lower market liquidity and lower price volatility	(76)
Net decrease in marketing and trading segment gross margin	(185)
Net decrease in regulated electricity and marketing and trading segments' gross margins	(73)
Higher real estate segment gross margin primarily due to increased sales activities	16
Lower other gross margin primarily related to NAC losses	(44)
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)
Higher taxes other than income taxes	(7)
Lower other income primarily due to a 2001 insurance recovery of environmental remediation costs	(11)
Higher net interest expense primarily due to higher debt balances and lower capitalized interest	(16)
Miscellaneous factors, net	2
Net decrease in income before income taxes	(187)
Lower income taxes primarily due to lower income	75
Net decrease in income before accounting change	$ (112)

REGULATED ELECTRICITY SEGMENT GROSS MARGIN

Regulated electricity segment revenues related to our regulated retail and wholesale electricity businesses were $549 million lower in the year ended December 31, 2002, compared with the prior year as a result of:

- decreased revenues related to traditional wholesale sales as a result of lower sales volumes and lower prices ($64 million);
- decreased revenues related to retail load hedge management wholesale sales, primarily as a result of lower prices and lower sales volumes ($455 million);
- decreased retail revenues related to milder weather ($60 million);
- increased retail revenues related to customer growth and higher average usage, excluding weather effects ($69 million);
- decreased retail revenues related to reductions in retail electricity prices ($28 million); and
- other miscellaneous factors ($11 million net decrease).

Regulated electricity segment purchased power and fuel costs were $661 million lower in the year ended December 31, 2002, compared with the prior year as a result of:

- decreased costs related to traditional wholesale sales as a result of lower sales volumes and lower prices ($64 million);
- decreased costs related to retail load hedge management wholesale sales, primarily as a result of lower prices and lower sales volumes ($460 million);

- increased costs related to higher prices for hedged natural gas and purchased power, net of mark-to-market reversals ($14 million);
- decreased costs related to the effects of milder weather on retail sales ($33 million);
- increased costs related to retail sales growth, excluding weather effects ($31 million);
- charges in 2001 related to purchased power contracts with Enron and its affiliates ($13 million net decrease);
- decreased replacement power costs for power plant outages due to lower market prices and fewer unplanned outages ($127 million); and
- miscellaneous factors ($9 million net decrease).

MARKETING AND TRADING SEGMENT GROSS MARGIN

Marketing and trading segment revenues were $325 million lower in the year ended December 31, 2002, compared with the prior year as a result of:

- decreased revenues from generation sales other than Native Load primarily due to lower market prices partially offset by higher sales volumes ($98 million);
- lower realized wholesale revenues net of related mark-to-market reversals primarily due to lower prices partially offset by higher volumes ($273 million);
- increased revenues from higher competitive retail sales in California by APS Energy Services ($105 million);
- 2001 write-off of prior period mark-to-market value related to trading with Enron and its affiliates ($8 million increase);
- higher revenues related to the adoption of EITF 02-3 ($8 million); and
- lower mark-to-market gains for future delivery primarily as a result of lower market liquidity and lower price volatility, resulting in lower volumes ($75 million).

Marketing and trading segment purchased power and fuel costs were $140 million lower in the year ended December 31, 2002, compared to the prior year as a result of:

- decreased fuel costs related to generation sales other than Native Load primarily because of lower natural gas prices partially offset by higher sales volumes ($32 million);
- decreased purchased power costs related to other realized marketing activities in the current period primarily due to lower prices partially offset by higher volumes ($182 million);
- increased purchased power costs related to higher competitive retail sales in California by APS Energy Services ($73 million); and
- change in mark-to-market fuel costs for future delivery ($1 million increase).

OTHER INCOME STATEMENT ITEMS

The increase in real estate segment gross margin of $16 million was primarily due to increased sales activities.

The decrease in other gross margin of $44 million was primarily due to losses on El Dorado's investment in NAC (see further discussion in Note 22). These losses for 2002 totaled approximately $59 million on a pretax basis and were primarily related to NAC contracts with two customers ($51 million was recorded in other gross margin and $8 million was recorded in other expense). We believe we have reserved our exposure with respect to these contracts in all material respects and, as a result, we consider these charges to be non-recurring.

The increase in operations and maintenance expense of $54 million was due to a $47 million write-off related to the cancellation of Redhawk Units 3 and 4, severance costs of $36 million related to a 2002 voluntary workforce reduction and other costs of $9 million, partially offset by lower costs related to generation reliability, plant outages and maintenance costs of $38 million.

The increase in taxes other than income taxes of $7 million is primarily due to increased property taxes on higher property balances.

Other income decreased $11 million primarily due to an insurance recovery recorded in 2001 related to environmental remediation costs and other costs (see Note 19).

Other expense was comparable with the prior year primarily due to losses recorded related to El Dorado's investment in NAC of approximately $8 million (see further discussion in Note 22) offset by $8 million of lower miscellaneous non-operating costs (see Note 19).

Net interest expense increased $16 million primarily because of higher debt balances related to our generation construction program and lower capitalized interest on our generation construction program due to completion of Redhawk Units 1 and 2 in mid-2002.

2001 Compared with 2000

Our consolidated net income for the year ended December 31, 2001 was $312 million compared with $302 million for the prior year. 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).

Our income before accounting change for the year ended December 31, 2001 was $327 million compared with $302 million for the prior year. The period-to-period comparison benefited from:

- strong marketing and trading results, including significant benefits recognized in the third quarter of 2001 from structured trading activities; and
- retail customer growth.

The above increases were partially offset by:

- lower earnings contributions from our regulated electricity activities, reflecting higher purchased power and fuel costs, due in part to increased power plant maintenance, generation reliability measures and continuing retail electricity price decreases; and
- 2001 charges related to Enron and its affiliates.

For additional details, see the following discussion.

The major factors that increased (decreased) income before accounting change were as follows:

(dollars in millions)	Increase (Decrease)
Regulated electricity segment gross margin:	
Higher replacement power costs for plant outages related to higher market prices	$ (70)
Retail price reductions effective July 1, 2001 and July 1, 2000	(27)
Charges related to purchased power contracts with Enron and its affiliates	(13) (a)
Higher retail sales primarily related to customer growth	35
Miscellaneous revenues	3
Net decrease in regulated electricity segment gross margin	(72)
Marketing and trading segment gross margin:	
Increase from generation sales other than Native Load due to higher market prices	25
Higher realized wholesale margin net of related mark-to-market reversals	61
Change in prior period mark-to-market value related to trading with Enron and its affiliates	(8) (a)
Increase in mark-to-market value related to future periods	113
Net increase in marketing and trading segment gross margin	191
Net increase in regulated electricity and marketing and trading segments' gross margins	119
Decrease in real estate segment contributions	(8)
Higher operations and maintenance expense related to 2001 generation reliability program	(42)
Higher operations and maintenance expense related primarily to employee benefits, plant outage and maintenance and other costs	(38)
Lower net interest expense primarily due to higher capitalized interest	17
Higher other net expense	(4)
Net increase in income before income taxes	44
Higher income taxes primarily due to higher income	(19)
Net increase in income before accounting change	$ 25

(a) We recorded charges totaling $21 million before income taxes for exposure to Enron and its affiliates in the fourth quarter of 2001.

REGULATED ELECTRICITY SEGMENT GROSS MARGIN

Regulated electricity segment revenues related to our regulated retail and wholesale electricity businesses were $23 million higher in the year ended December 31, 2001 compared to the prior year as a result of:

- decreased revenues related to other wholesale sales and miscellaneous revenues as a result of lower sales volumes ($28 million);
- increased retail revenues primarily related to higher sales volumes primarily due to customer growth ($78 million); and
- decreased retail revenues related to reductions in retail electricity prices ($27 million).

Regulated electricity segment purchased power and fuel costs were $95 million higher in the year ended December 31, 2001 compared to the prior year as a result of:

- decreased costs related to other wholesale sales as a result of lower volumes ($31 million);
- higher replacement power costs primarily due to higher market prices and increased plant outages ($70 million), including costs of $12 million related to a Palo Verde outage extension to replace fuel control element assemblies;
- higher costs related to retail sales volumes due to customer growth ($43 million); and
- charges related to purchased power contracts with Enron and its affiliates ($13 million).

MARKETING AND TRADING SEGMENT GROSS MARGIN

Marketing and trading segment revenues were $233 million higher in the year ended December 31, 2001 compared with the prior year as a result of:

- increased revenues related to generation sales other than Native Load as a result of higher average market prices ($32 million);
- increased realized wholesale revenues net of related mark-to-market reversals primarily due to more transactions ($96 million);
- decreased prior period mark-to-market value related to trading with Enron and its affiliates ($8 million); and
- increased mark-to-market value for future periods primarily as a result of more forward sales volumes ($113 million).

Marketing and trading segment purchased power and fuel costs were $42 million higher in the year ended December 31, 2001 compared to the prior year as a result of:

- increased fuel costs related to generation sales other than Native Load as a result of higher fuel prices ($7 million); and
- increased purchased power and fuel costs net of related mark-to-market reversals primarily due to more transactions ($35 million).

OTHER INCOME STATEMENT ITEMS

The decrease in real estate segment profits of $8 million resulted primarily from reduced sales of land and homes by SunCor.

The increase in operations and maintenance expenses of $80 million primarily related to the 2001 generation summer reliability program (the addition of generating capability to enhance reliability for the summer of 2001 ($42 million)) and increased employee benefit costs, plant outage and maintenance and other costs ($38 million). The comparison reflects Pinnacle West's $10 million provision 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.

Net other expense increased $4 million primarily because of a change in the market value of El Dorado's investment in a technology-related venture capital partnership in 2000 and other nonoperating costs partially offset by an insurance recovery of environmental remediation costs (see Note 19).

Interest expense decreased by $17 million primarily because of increased capitalized interest resulting from our generation construction plan partially offset with higher interest expense due to higher debt balances.

See "Regulatory Matters – 1999 Settlement Agreement" in Note 3 for a discussion of the 1999 Settlement Agreement under which, among other things, APS agreed to five annual retail electricity price reductions of 1.5% with the last decrease to take effect July 1, 2003.

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, 2002 and estimated capital expenditures for the next three years.

	Estimated		
	2003	2004	2005
	$ 273	$ 275	$ 329
	123	99	164
	5	5	5
	401	379	498
	268	31	20
	64	23	20
	17	13	14
	$ 750	$ 446	$ 552

(a) As discussed below under "Factors Affecting Our Financial Outlook," as part of its 2003 general rate case, APS intends to seek rate-base treatment of certain power plants in Arizona currently owned by Pinnacle West Energy (specifically, Redhawk Units 1 and 2, West Phoenix Units 4 and 5 and Saguaro Unit 3).

(b) See Note 11 for further discussion of Pinnacle West Energy's generation construction program and "Capital Resources and Cash Requirements – Pinnacle West Energy" below. These amounts do not include an expected reimbursement in 2004 by SNWA of about $100 million, assuming SNWA exercises its option to purchase a 25% interest in the Silverhawk project at that time.

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

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

(e) The other amounts relate to capital expenditures for our marketing and trading segment. These costs were in the parent company for 2002.

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. In addition, APS began several major transmission projects in 2001. These projects are periodic in nature and are driven by strong regional customer growth. APS expects to spend about $105 million on major transmission projects during the 2003 to 2005 time frame, and these amounts are included in "APS-Delivery" in the table above.

Generation capital expenditures are comprised of various improvements for 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 contains nuclear fuel expenditures of approximately $30 million annually for 2003 to 2005.

Replacement of the steam generators in Palo Verde Unit 2 is presently scheduled for completion during the fall outage of 2003. The Palo Verde owners have approved the manufacture of two additional sets of steam generators. We expect that these generators will be installed in Units 1 and 3 in the 2005 to 2008 time frame. Our portion of steam generator expenditures for Units 1, 2 and 3 is approximately $145 million, which will be spent from 2003 through 2008. In 2003 through 2005, $94 million of the costs are included in the generation capital expenditures table above and would be funded with internally-generated cash or external financings.

Contractual Obligations

The following table summarizes actual contractual requirements for the year ended December 31, 2002 and estimated contractual commitments for the next five years and thereafter:

(dollars in millions)	Actual 2002	Estimated 2003	2004	2005	2006	2007	Thereafter
Long-term debt payments:							
APS	$ 337	$ –	$ 205	$ 400	$ 84	$ –	$ 1,518
Pinnacle West	–	275	215	–	300	–	–
SunCor	3	–	126	–	3	–	15
El Dorado	13	1	1	1	–	–	–
Total long-term debt payments	353	276	547	401	387	–	1,533
Capital lease payments	1	5	5	4	3	3	6
Operating lease payments	69	70	66	64	63	63	478
Purchase power and fuel commitments	338	173	82	28	31	17	162
Total contractual commitments	$ 761	$ 524	$ 700	$ 497	$ 484	$ 83	$ 2,179

Off-Balance Sheet Arrangements

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

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

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

Guarantees

We and certain of our subsidiaries have issued guarantees 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 23 for additional information regarding guarantees.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of March 28, 2003 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.

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

On November 4, 2002, Standard & Poor's affirmed the APS debt ratings in the above chart, but lowered Pinnacle West's senior unsecured debt rating from BBB to BBB- "because of the structural subordination of this debt as compared to the unsecured debt at APS." On that same date, Standard & Poor's lowered APS' corporate credit rating from BBB+ to BBB and affirmed the BBB corporate credit rating of Pinnacle West. Standard & Poor's assigned a stable outlook to the ratings. All of Pinnacle West's and APS' credit ratings remain investment grade. In December 2002, Fitch placed certain of our debt and that of APS on Ratings Watch Negative. The ratings watch affects our senior unsecured debt and commercial paper ratings. It also affects all of APS' debt ratings, with the exception of its commercial paper rating.

On December 31, 2002, Moody's affirmed the ratings set forth above.

Debt Provisions

Pinnacle West's and APS' significant debt covenants related to their respective financing arrangements include debt-to-total-capitalization ratio and an interest coverage test. Pinnacle West and APS are in compliance with such covenants and each anticipates it will continue to meet all the significant covenant requirement levels. The ratio of debt to total capitalization cannot exceed 65% for both the Company and APS. At December 31, 2002, the ratios are approximately 54% and 48% for the parent company and APS, respectively. The provisions regarding interest coverage require a minimum cash coverage of two times the interest requirements for both the Company and APS. The coverages are approximately 4 times for the parent company, 5 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.

Pinnacle West (Parent Company)

Our primary cash needs are for dividends to our shareholders; equity infusions into our subsidiaries, primarily Pinnacle West Energy; and 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). On October 23, 2002, our board of directors increased the common stock dividend to an indicated annual rate of $1.70 per share from $1.60 per share, effective with the December 1, 2002 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 2000 through 2002, total dividends from APS were $510 million and total distributions from SunCor were $33 million. For the year ended December 31, 2002, dividends from APS were approximately $170 million and distributions from SunCor were approximately $13 million. We expect SunCor to make cash distributions to the parent company of $80 million to $100 million annually in 2003 through 2005 due to anticipated accelerated asset sales activity.

On December 23, 2002, we issued 6,555,000 shares of common stock, no par value, which resulted in net proceeds of $199 million. See Note 7.

We have financed Pinnacle West Energy's generation construction program premised upon Pinnacle West Energy's receipt of APS' generation assets by the end of 2002. On November 22, 2002, the ACC approved APS' request (Interim Financing Application) to permit APS to (a) make short-term advances to Pinnacle West in the form of an inter-affiliate line of credit in the amount of $125 million, or (b) guarantee $125 million of Pinnacle West's short-term debt, subject to certain conditions. As of December 31, 2002, there were no borrowings outstanding under this financing arrangement. On March 27, 2003, the ACC authorized APS to lend up to $500 million to Pinnacle West Energy, guarantee up to $500 million of Pinnacle West Energy debt, or a combination of both, not to exceed $500 million in the aggregate. See "Factors Affecting our Financial Outlook – Regulatory Matters" and "ACC Applications" in Note 3 for additional information.

In 2002, the parent company issued $215 million in long-term debt and had no repayments of long-term debt (see Note 6).

The parent company's outstanding long and short-term debt was approximately $887 million at December 31, 2002. At December 31, 2002, our commitments totaled $475 million, which were available to support the issuance of commercial paper or to be used as bank borrowings. At December 31, 2002, we had about $24 million of commercial paper outstanding and $72 million of short-term borrowings. Our long-term debt including current maturities totaled $791 million at December 31, 2002.

In mid-2003, we will need to refinance approximately $475 million of parent company indebtedness, including a total of $225 million we expect to borrow under an existing credit facility. We expect that this indebtedness will be repaid through funds borrowed by Pinnacle West Energy from APS under the $500 million financing arrangement recently approved by the ACC.

As part of a multi-employer pension plan sponsored by Pinnacle West, 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 $27 million for 2002, $24 million for 2001, $44 million for 2000, $25 million for 1999 and $14 million for 1998. APS and other subsidiaries fund their share of the pension contribution, of which APS represents approximately 90% of the total funding amounts described above. The assets in the plan are mostly domestic common stocks, bonds and real estate. We currently forecast a pension contribution in 2003 of approximately $50 million, all or part of which may be required. If the fund performance continues to decline as a result of a continued decline in equity markets, larger contributions may be required in future years.

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

APS

APS' capital requirements consist primarily of capital expenditures and optional and mandatory redemptions of long-term debt. See "Factors Affecting Our Financial Outlook – Regulatory Matters" below and Note 3 for discussion of the $500 million financing arrangement between APS and Pinnacle West Energy recently approved by the ACC. See "Pinnacle West (Parent Company)" above and Note 3 for 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.

In 2002, APS issued $375 million in long-term debt, refinanced $90 million in long-term debt and redeemed approximately $247 million in long-term debt (see Note 6). On April 7, 2003, APS will redeem $33 million of its first mortgage bonds.

APS' outstanding debt was approximately $2.2 billion at December 31, 2002. At December 31, 2002, APS had 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, 2002, APS had no outstanding commercial paper or bank borrowings.

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 generating capacity from 2000 through 2004 are expected to be about $1.4 billion. This does not reflect an expected reimbursement in 2004 by SNWA of about $100 million of Pinnacle West Energy's cumulative capital expenditures in the Silverhawk project assuming SNWA exercises its option to purchase a 25% interest in the project. Pinnacle West Energy is currently funding its capital requirements 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 2002 and projected capital expenditures for the next three years.

See "Factors Affecting Our Financial Outlook – Regulatory Matters" below and Note 3 for discussion of the $500 million.

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 2002 and projected capital expenditures for the next three years. SunCor expects to fund its capital requirements with cash from operations and external financings.

In 2002, SunCor issued $50 million in long-term debt, and redeemed, refinanced or repaid $53 million in long-term debt (see Note 6).

SunCor's outstanding long and short-term debt was approximately $153 million as of December 31, 2002. As of December 31, 2002, SunCor had a $140 million line of credit, under which $126 million of borrowings were outstanding. SunCor's short-term debt was $6 million and other long-term debt, including current maturities, totaled $21 million at December 31, 2002.

We expect SunCor to make cash distributions to the parent company of $80 to $100 million annually in 2003 through 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. El Dorado's long-term debt was approximately $3 million at December 31, 2002 and it had no long-term debt outstanding at December 31, 2001. El Dorado's long-term debt increased primarily due to its consolidation of NAC for financial reporting purposes (see Notes 6 and 22).

APS Energy Services' cash requirements during the past three years were funded with cash infusions from the parent company. APS Energy Services' capital expenditures and other cash requirements are increasingly funded by operations, with some funding from cash infused by Pinnacle West. See the capital expenditures table above regarding APS Energy Services' actual capital expenditures for 2002 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 the 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.
- 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 the expected long-term rate of return on plan assets used to estimate earnings on invested funds over the long-term.
- 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 other comprehensive income.
- 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 the discussion below for further details on our critical accounting policies.

Regulatory Accounting

For our regulated operations, we prepare our financial statements in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in its financial statements. As a result, we capitalize certain costs that would be included as expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections of costs not likely to be incurred.

We are required to discontinue applying SFAS No. 71 when deregulatory legislation is passed or a rate order is issued that contains sufficient detail to determine its effect on the portion of the business being deregulated. In 1999, we discontinued the application of SFAS No. 71 for APS' generation operations due to the 1999 Settlement Agreement with the ACC. See Note 3 for a discussion of the 1999 Settlement Agreement.

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

Management continually assesses whether our regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes and recent rate orders to other regulated entities in the same jurisdiction. This determination reflects the current political and regulatory climate in the state and is subject to change in the future. If future recovery of costs ceases to be probable, the assets would be written off as a charge to current period earnings. We had $241 million of regulatory assets included on the Consolidated Balance Sheets at December 31, 2002. See Notes 1 and 3 for more information.

Pensions and Other Postretirement Benefit Accounting

We sponsor a qualified defined benefit pension plan and a non-qualified supplemental excess benefit retirement plan for our employees and employees of our subsidiaries. Our reported costs of providing defined pension and other postretirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. Pension and other postretirement benefit costs, for example, are impacted by actual employee demographics (including age, compensation levels and employment periods), the level of contributions we make to the plans and earnings on plan assets. Changes made to the provisions of the plans may also impact current and future pension and other postretirement benefit costs. Pension and other postretirement benefit costs may also be significantly affected by changes in key actuarial assumptions, including the expected long-term rate of return on plan assets and the discount rates used in determining the projected benefit obligation and pension and other postretirement benefit costs.

Pinnacle West's pension and other postretirement plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity market returns as well as changes in general interest rates may result in increased or decreased pension and other postretirement benefit costs in future periods. Likewise, changes in assumptions regarding current discount rates and the expected long-term rate of return on plan assets could also increase or decrease recorded pension and other postretirement benefit costs.

We account for our defined benefit pension plans in accordance with SFAS No. 87, "Employers' Accounting for Pensions," which requires amounts recognized in our financial statements to be determined on an actuarial basis. Changes in pension obligations associated with these factors may not be immediately recognized as pension costs on the income statement, but generally are recognized in future years over the remaining average service period of plan participants. As such, significant portions of pension costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants.

The following chart reflects the sensitivities associated with a one percent increase or decrease in certain actuarial assumptions related to our defined benefit pension plans. Each sensitivity below reflects the impact of changing only that assumption. The chart shows the increase (decrease) each change in assumption would have on the 2002 projected benefit obligation, our 2002 reported pension liability on the Consolidated Balance Sheets and our 2002 reported annual pension expense, after consideration of amounts capitalized or billed to electric plant participants, on the Consolidated Statements of Income (dollars in millions).

	Increase/(Decrease)		
Actuarial Assumption	**Impact on Projected Benefit Obligation**	**Impact on Pension Liability**	**Impact on Pension Expense**
Discount rate:			
Increase 1%	$ (143)	$ (107)	$ (4)
Decrease 1%	177	130	9
Expected long-term rate of return on plan assets:			
Increase 1%	–	–	(4)
Decrease 1%	–	–	4

At the end of each year, we determine the discount rate to be used to calculate the present value of plan liabilities. The discount rate is an estimate of the current interest rate at which the pension liabilities could be effectively settled at the end of the year. The discount rate is selected by comparison to current yields on high-quality, long-term bonds. We changed our discount rate assumption from 7.5% at December 31, 2001 to 6.75% at December 31, 2002.

In 2002, we assumed that the expected long-term rate of return on plan assets would be 10%. However, the plan assets have earned a rate of return substantially less than 10% in the last three years due to sharp declines in the equity markets. For 2003, we decreased our expected long-term rate of return on plan assets to 9%, as a result of continued declines in general equity and bond market returns.

The following chart reflects the sensitivities associated with a one percent increase or decrease in certain actuarial assumptions related to our other postretirement benefit plans. Each sensitivity below reflects the impact of changing only that assumption. The chart shows the increase (decrease) each change in assumption would have on the 2002 accumulated other postretirement benefit obligation and our 2002 reported other postretirement benefit expense, after consideration of amounts capitalized or billed to electric plant participants, on the Consolidated Statements of Income (dollars in millions).

	Increase/(Decrease)	
Actuarial Assumption	**Impact on Accumulated Postretirement Benefit Obligation**	**Impact on Other Postretirement Benefit Expense**
Discount rate:		
Increase 1%	$ (38)	$ (2)
Decrease 1%	43	2
Health care cost trend rate (a):		
Increase 1%	54	5
Decrease 1%	(43)	(4)
Expected long-term rate of return on plan assets – pretax:		
Increase 1%	–	(1)
Decrease 1%	–	1

(a) This assumes a 1% change in the initial and ultimate health care cost trend rate.

The discount rate is selected by comparison to current yields on high-quality, long-term bonds. We changed our discount rate assumption from 7.5% at December 31, 2001 to 6.75% at December 31, 2002.

In selecting our health care cost trend rate, we consider past performance and forecasts of health care costs. In 2002, we increased our initial health care cost trend rate to 8% from 7% based on an analysis of our actual plan experience. We also assume an ultimate health care cost trend rate of 5% is reached in 2007.

In selecting the pretax expected long-term rate of return on plan assets, we consider past performance and economic forecasts for the types of investments held by the plan. The market value of the plan assets has been affected by sharp declines in the equity markets. For 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 returns.

Pension and other postretirement benefit costs and cash funding requirements may increase in future years without a substantial recovery in the equity markets. Due to the actual investment performance of our pension and other postretirement benefit funds and the changes in the actuarial assumptions discussed above, we expect an increase of approximately $29 million before income taxes in 2003 expense over 2002. See Note 8 for further details about our pension and other postretirement benefit plans.

Derivative Accounting

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

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

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

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

Mark-to-Market Accounting

Under mark-to-market accounting, the purchase or sale of energy commodities is reflected at fair market value, net of valuation adjustments, with resulting unrealized gains and losses recorded as assets and liabilities from risk management and trading activities in the Consolidated Balance Sheets.

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

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

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

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

A credit valuation adjustment is also recorded to represent estimated credit losses on our overall exposure to counterparties, taking into account netting arrangements; expected default experience for the credit rating of the counterparties; and the overall diversification of the portfolio. Counterparties in the portfolio consist principally of major energy companies, municipalities and local distribution companies. We maintain credit policies that management believes minimize overall credit risk. Determination of the credit quality of counterparties is based upon a number of factors, including credit ratings, financial condition, project economics and collateral requirements. When applicable, we employ standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. See "Factors Affecting our Financial Outlook – Market Risks – Commodity Price Risk" below and 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. To illustrate, as presented in the "Factors Affecting our Financial Outlook – Market Risks – Commodity Price Risk" section below, a 10% increase in the price of trading commodities would result in only a $2 million decrease in pretax income. Our practice is to hedge within timeframes established by the ERMC.

OTHER ACCOUNTING MATTERS

Accounting for Derivative and Trading Activities

During 2002, the EITF discussed EITF 02-3 and reached a consensus on certain issues. EITF 02-3 rescinded EITF 98-10 and was effective October 25, 2002 for any new contracts, and on January 1, 2003 for existing contracts, with early adoption permitted. We adopted the EITF 02-3 guidance for all contracts in the fourth quarter of 2002. We recorded a $66 million after-tax charge in net income as a cumulative effect adjustment for the previously recorded accumulated unrealized mark-to-market on energy trading contracts that did not meet the accounting definition of a derivative. As a result, our energy trading contracts that are derivatives continue to be accounted for at fair value under SFAS No. 133. Contracts that were previously marked-to-market as trading activities under EITF 98-10 that do not meet the definition of a derivative are now accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received. Additionally, all gains and losses (realized and unrealized) on energy trading contracts that qualify as derivatives are included in marketing and trading segment revenues on the Consolidated Statements of Income on a net basis. The rescission of EITF 98-10 has no effect on the accounting for derivative instruments used for non-trading activities, which continue to be accounted for in accordance with SFAS No. 133.

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, results of operations or cash flows.

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 under SFAS No. 133.

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 will be an operating expense and the capitalized cost is depreciated over the useful life of the long-lived asset. (See Note 1 for more information regarding our previous accounting for removal costs.)

We determined that we have asset retirement obligations for our nuclear facilities (nuclear decommissioning) and certain other 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. 143.

Stock-Based Compensation

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, "Accounting for Stock-Based Compensation." We recorded approximately $500,000 in stock option expense before income taxes in our Consolidated Statements of Income for 2002. See Notes 1 and 16 for further information on the impacts of adopting the fair value method provided in SFAS No. 123.

Variable Interest Entities

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

Other

See Note 2 for discussion of other new accounting standards that are not expected to have a material impact on the Company.

FACTORS AFFECTING OUR FINANCIAL OUTLOOK

Regulatory Matters

GENERAL

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

1999 SETTLEMENT AGREEMENT

The 1999 Settlement Agreement has affected, and will affect, our results of operations. As part of the 1999 Settlement Agreement, APS agreed to reduce retail electricity prices for standard-offer, full-service customers with loads less than three megawatts in a series of annual decreases of 1.5% on July 1, 1999 through July 1, 2003, for a total of 7.5%. For customers with loads three megawatts or greater, standard-offer rates were reduced in annual increments totaling 5% in the years 1999 through 2002.

The 1999 Settlement Agreement also removed, as a regulatory disallowance, $234 million before income taxes ($183 million net present value) from ongoing regulatory cash flows. APS recorded this regulatory disallowance as a net reduction of regulatory assets and reported it as a $140 million after-tax extraordinary charge on the 1999 Consolidated Statement of Income. As discussed under "APS General Rate Case" below, APS intends to seek recovery of this $234 million write-off in its next general rate case.

Prior to the 1999 Settlement Agreement, the ACC accelerated the amortization of substantially all of APS' regulatory assets to an eight-year period that would have ended June 30, 2004. The regulatory assets to be recovered under the 1999 Settlement Agreement are currently being amortized as follows (dollars in millions):

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

See Note 3 for additional information regarding the 1999 Settlement Agreement.

APS FINANCING APPLICATION

On September 16, 2002, APS filed an application with the ACC requesting the ACC to allow APS to borrow up to $500 million and to lend the proceeds to Pinnacle West Energy or to the Company; to guarantee up to $500 million of Pinnacle West Energy's or the Company's debt; or a combination of both, not to exceed $500 million in the aggregate. In its application, APS stated that the ACC's reversal of the generation asset transfer requirement and the resulting bifurcation of generation assets between APS and Pinnacle West Energy under different regulatory regimes result in Pinnacle West Energy being unable to attain investment-grade credit ratings. This, in turn, precludes Pinnacle West Energy from accessing capital markets to refinance the bridge financing that we provided to fund the construction of Pinnacle West Energy generation assets or from effectively competing in the wholesale markets. On March 27, 2003, the ACC authorized APS to lend up to $500 million to Pinnacle West Energy, guarantee up to $500 million of Pinnacle West Energy debt, or a combination of both, not to exceed $500 million in the aggregate. See "ACC Applications" in Note 3 for further discussion of the approval and related conditions.

TRACK A ORDER

On September 10, 2002, the ACC issued the Track A Order. See "Track A Order" in Note 3.

COMPETITIVE PROCUREMENT PROCESS

On September 10, 2002, the ACC issued an order that, among other things, established a requirement that APS competitively procure certain power requirements. On March 14, 2003, the ACC issued the Track B Order which documented the decision made by the ACC at its open meeting on February 27, 2003 addressing this requirement. Under the ACC's Track B Order, APS will be required to solicit bids for certain estimated capacity and energy requirements for periods beginning July 1, 2003. For 2003, APS will be required to solicit competitive bids for about 2,500 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.

APS expects to issue requests for proposals in March 2003 and to complete the selection process by June 1, 2003. Pinnacle West Energy will be eligible to bid to supply APS' electricity requirements. See "Track B Order" in Note 3 for additional information.

APS GENERAL RATE CASE

As required by the 1999 Settlement Agreement, on or before June 30, 2003, APS will file a general rate case with the ACC. In this rate case, APS will update its cost of service and rate design. In addition, APS expects to seek:

- rate base treatment of certain power plants currently owned by Pinnacle West Energy (specifically, Redhawk Units 1 and 2, West Phoenix Units 4 and 5 and Saguaro Unit 3);
- recovery of the $234 million pretax asset write-off recorded by APS as part of the 1999 Settlement Agreement ($140 million extraordinary charge recorded on the 1999 Consolidated Statement of Income); and
- recovery of costs incurred by APS in preparation for the previously required transfer of generation assets to Pinnacle West Energy.

We assume that the ACC will make a decision in this general rate case by the end of 2004.

WHOLESALE POWER MARKET CONDITIONS

The marketing and trading division, which we moved to APS in early 2003 for future marketing and trading activities (existing wholesale contracts will remain at Pinnacle West) as a result of the ACC's Track A Order prohibiting APS' transfer of generating assets to Pinnacle West Energy, focuses primarily on managing APS' purchased power and fuel risks in connection with its costs of serving retail customer demand. Additionally, the marketing and trading division, subject to specified parameters, markets, hedges and trades in electricity, fuels and emission allowances and credits. Earnings contributions from our marketing and trading division were lower in 2002 compared to 2001 due to weak wholesale power market conditions in the western United States, which included a lack of market liquidity, fewer creditworthy counterparties, lower wholesale market prices and resulting decreases in sales volumes. Our 2003 earnings will be affected by the strength (or weakness) of the wholesale power market.

GENERATION CONSTRUCTION

See "Capital Needs and Resources – Pinnacle West Energy" above and Note 11 for information regarding Pinnacle West Energy's generation construction program. The planned 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 bulk 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 3.6% a year for the three years 2000 through 2002; we currently expect customer growth to average about 3.5% per year from 2003 to 2005. We currently estimate that retail electricity sales in kilowatt-hours will grow 3.5% to 5.5% a year in 2003 through 2005, before the retail effects of weather variations. The customer growth and sales growth referred to in this paragraph applies to energy delivery customers. As previously noted, under the 1999 Settlement Agreement, we agreed to retail electricity price reductions of 1.5% annually through July 1, 2003 (see Note 3).

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.

Operations and Maintenance Expenses Operations and maintenance expenses are expected to be affected by sales mix and volumes, power plant additions and operations, inflation, outages, higher trending pension and other postretirement benefit costs and other factors. 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 the second half of 2002. In addition, we are expecting to produce annual operating expense savings of approximately $30 million beginning in 2003 as a result of this workforce reduction.

Depreciation and Amortization Expenses Depreciation and amortization expenses are expected to be affected 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 is expected to be on line in mid-2003 and Silverhawk is expected to be in service in mid-2004 (see Note 11 for further details about our generation construction program). 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 9.7% of assessed value for 2002 and 9.3% for 2001. We expect property taxes to increase primarily due to our generation construction program 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 recording capitalized interest on a project when it is placed in commercial operation. As noted above, we have placed new power plants in commercial operation in 2001 and 2002 and we expect to bring additional plants on-line in 2003 and 2004. We are continuing to evaluate our generation construction program. Interest expense is affected by interest rates on variable-rate debt and interest rates on the refinancing of the Company's future liquidity needs.

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 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, we are undertaking an aggressive effort to accelerate asset sales activities to approximately double SunCor's annual earnings in 2003 to 2005 compared to the $19 million in earnings recorded in 2002. A portion of these sales could be reported as discontinued operations on the Consolidated Statements of Income.

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 pretax earnings of $28 million in 2002.

El Dorado's historical results are not necessarily indicative of future performance for El Dorado. El Dorado's strategies focus on prudently realizing the value of its existing investments.

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 pension plan (see Note 8) and 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. The pension plan and nuclear decommissioning fund also have risks associated with changing market values of equity investments. Pension (APS only) and nuclear decommissioning costs are recovered in regulated electricity prices. See "Critical Accounting Policies – Pension and Other Postretirement Benefit Accounting" for a sensitivity analysis on the long-term rate of return on plan assets.

The tables below present contractual balances of our consolidated long-term debt and commercial paper at the expected maturity dates as well as the fair value of those instruments on December 31, 2002 and 2001. The interest rates presented in the tables below represent the weighted-average interest rates for the years ended December 31, 2002 and 2001.

EXPECTED MATURITY/PRINCIPAL REPAYMENT (dollars in thousands)

	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
December 31, 2002	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
2003	2.59%	$ 102,183	2.68%	$ 250,800	6.73%	$ 30,223
2004	–	–	3.76%	126,813	5.32%	424,697
2005	–	–	3.39%	1,294	7.27%	403,931
2006	–	–	10.10%	2,954	6.47%	387,018
2007	–	–	8.00%	209	6.04%	2,738
Years thereafter	–	–	2.00%	390,537	6.08%	1,148,371
Total		$ 102,183		$ 772,607		$ 2,396,978
Fair Value		$ 102,183		$ 772,607		$ 2,501,073

EXPECTED MATURITY/PRINCIPAL REPAYMENT (dollars in thousands)

	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
December 31, 2001	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
2002	4.01%	$ 405,762	7.76%	$ 207	8.10%	$ 125,933
2003	–	–	4.75%	292,912	6.87%	25,829
2004	–	–	5.32%	85,601	6.08%	205,677
2005	–	–	7.70%	294	7.59%	400,380
2006	–	–	7.30%	3,018	6.48%	384,085
Years thereafter	–	–	2.63%	480,740	6.73%	799,808
Total		$ 405,762		$ 862,772		$ 1,941,712
Fair Value		$ 405,762		$ 862,772		$ 1,963,389

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 derivatives, including exchange-traded futures and options, and over-the-counter forwards, options and swaps. The ERMC, consisting of senior officers, 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 enter into derivative transactions to hedge purchases and sales of electricity, fuels and emissions allowances and credits. The changes in market value of such contracts have a high correlation to price changes in the hedged commodities. In addition, subject to specified risk parameters monitored by the ERMC, we engage in marketing and trading activities intended to profit from market price movements.

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

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

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

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

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

The following tables show the changes in mark-to-market of our system and marketing and trading derivative positions in 2002 and 2001 (dollars in millions):

	System	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 gains for future period deliveries	(13)	47
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	(38)
Change in valuation techniques	–	3
Mark-to-market of net positions at December 31, 2002	$ (49)	$ 57

	System	Marketing and Trading
Mark-to-market of net positions at December 31, 2000	$ –	$ 12
Cumulative effect adjustment due to adoption of SFAS No. 133	95	–
Change in mark-to-market (losses)/gains for future period deliveries	(12)	203
Changes in cash flow hedges recorded in OCI	(166)	–
Ineffective portion of changes in fair value recorded in earnings	(6)	–
Mark-to-market gains realized during the year	(18)	(77)
Change in valuation techniques	–	–
Mark-to-market of net positions at December 31, 2001	$ (107)	$ 138

The Company no longer reports non-derivative energy contracts or physical inventories at fair value. Since July 1, 2002, the Company has not recognized a dealer profit or unrealized gain or loss at the inception of a derivative unless the fair value of that instrument (in its entirety) is evidenced by quoted market prices or current market transactions. Prior to the change in our policy, we recorded net gains at inception of $10 million in 2002 and $3 million in 2001. These amounts included a reasonable marketing margin.

The tables below show the maturities of our system and marketing and trading derivative positions at December 31, 2002 by the type of valuation that is performed to calculate the fair value of the contract (dollars in millions). See "Critical Accounting Policies – Mark-to-Market Accounting" above for more discussion on our valuation methods.

SYSTEM

Source of Fair Value	2003	2004	2005	2006	2007	Years Thereafter	Total Fair Value
Prices actively quoted	$ (23)	$ (10)	$ –	$ –	$ –	$ –	$ (33)
Prices provided by other external sources	(1)	(12)	–	–	–	–	(13)
Prices based on models and other valuation methods	(1)	(2)	–	–	–	–	(3)
Total by maturity	$ (25)	$ (24)	$ –	$ –	$ –	$ –	$ (49)

MARKETING AND TRADING

Source of Fair Value	2003	2004	2005	2006	2007	Years Thereafter	Total Fair Value
Prices actively quoted	$ (1)	$ 5	$ 6	$ 3	$ 3	$ 7	$ 23
Prices provided by other external sources	2	8	9	12	–	–	31
Prices based on models and other valuation methods	6	3	(3)	(4)	5	(4)	3
Total by maturity	$ 7	$ 16	$ 12	$ 11	$ 8	$ 3	$ 57

The table below shows the impact 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, 2002 and 2001 (dollars in millions).

	December 31, 2002 Gain (Loss)		December 31, 2001 Gain (Loss)	
Commodity	Price Up 10%	Price Down 10%	Price Up 10%	Price Down 10%
Mark-to-market changes reported in earnings (a):				
Electricity	$ (2)	$ 3	$ (3)	$ 3
Natural gas	(4)	4	(1)	1
Other	1	–	–	2
Mark-to-market changes reported in OCI (b):				
Electricity	32	(32)	–	–
Natural gas	18	(16)	23	(23)
Total	$ 45	$ (41)	$ 19	$ (17)

(a) These contracts are 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 33% of our $181 million of risk management and trading assets as of December 31, 2002. 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 "Critical Accounting Policies – Mark-to-Market Accounting" above for a discussion of our credit valuation adjustment policy.

FORWARD-LOOKING STATEMENTS

The above discussion 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 laws. 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 the ongoing restructuring of the electric industry, including the introduction of retail electric competition in Arizona and decisions impacting wholesale competition; the outcome of regulatory and legislative proceedings relating to the restructuring; state and federal regulatory and legislative decisions and actions, including price caps and other market constraints imposed by the FERC; regional economic and market conditions, including the California energy situation and 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; weather variations affecting local and regional customer energy usage; the effect of conservation programs on energy usage; power plant performance; the successful completion of our generation construction program; regulatory issues associated with generation construction, such as permitting and licensing; our ability to compete successfully outside traditional regulated markets (including the wholesale market); our ability to manage our marketing and trading activities and the use of derivative contracts in our business; technological developments in the electric industry; the performance of the stock market, which affects the amount of our required contributions to our pension plan and nuclear decommissioning trust funds; the strength of the real estate market in SunCor's market areas, which include Arizona, New Mexico and Utah; and other uncertainties, all of which are difficult to predict and many of which are beyond our control.

INDEPENDENT AUDITORS' REPORT

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

We have audited the accompanying consolidated balance sheets of Pinnacle West Capital Corporation and subsidiaries ("the Corporation") as of December 31, 2002 and 2001 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, 2002. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the 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, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 18 to the consolidated financial statements, in 2002 Pinnacle West Capital Corporation changed its method of accounting for trading activities in order to comply with the provisions of Emerging Issues Task Force Issue 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 Pinnacle West Capital Corporation 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
February 3, 2003 (March 4, 14, 26, and 27, 2003 as to Note 24)

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

year ended December 31,	2002	2001	2000
OPERATING REVENUES			
Regulated electricity segment	$ 2,013,023	$ 2,562,089	$ 2,538,752
Marketing and trading segment	325,931	651,230	418,532
Real estate segment	236,388	168,908	158,365
Other revenues	61,937	11,771	3,873
Total	2,637,279	3,393,998	3,119,522
OPERATING EXPENSES			
Regulated electricity segment purchased power and fuel	499,543	1,160,863	1,065,597
Marketing and trading segment purchased power and fuel	194,039	334,209	292,669
Operations and maintenance	584,538	530,095	450,205
Real estate operations segment	205,315	153,462	134,422
Depreciation and amortization	424,886	427,903	431,229
Taxes other than income taxes	107,952	101,068	99,780
Other expenses	104,959	10,375	782
Total	2,121,232	2,717,975	2,474,684
OPERATING INCOME	516,047	676,023	644,838
OTHER			
Other income	15,104	26,416	21,832
Other expenses	(33,655)	(33,577)	(25,329)
Total	(18,551)	(7,161)	(3,497)
INTEREST EXPENSE			
Interest charges	188,353	175,822	166,447
Capitalized interest	(44,110)	(47,862)	(21,638)
Total	144,243	127,960	144,809
INCOME BEFORE INCOME TAXES	353,253	540,902	496,532
INCOME TAXES	138,100	213,535	194,200
INCOME BEFORE ACCOUNTING CHANGE	215,153	327,367	302,332
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	$ 149,408	$ 312,166	$ 302,332
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING – BASIC	84,903	84,718	84,733
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING – DILUTED	84,964	84,930	84,935
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING			
Income before accounting change – basic	$ 2.53	$ 3.86	$ 3.57
Net income – basic	1.76	3.68	3.57
Income before accounting change – diluted	2.53	3.85	3.56
Net income – diluted	1.76	3.68	3.56
DIVIDENDS DECLARED PER SHARE	$ 1.625	$ 1.525	$ 1.425

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS (dollars in thousands)

December 31,	2002	2001
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 77,707	$ 28,619
Customer and other receivables – net	374,995	367,241
Accrued utility revenues	72,915	76,131
Materials and supplies (at average cost)	91,652	81,215
Fossil fuel (at average cost)	28,185	27,023
Deferred income taxes (Note 4)	4,094	–
Assets from risk management and trading activities (Note 18)	59,162	66,973
Other current assets	103,978	80,203
Total current assets	812,688	727,405
INVESTMENTS AND OTHER ASSETS		
Real estate investments – net (Notes 1 and 6)	425,331	418,673
Assets from risk management and trading activities – long-term (Note 18)	122,336	200,351
Other assets	229,891	304,453
Total investments and other assets	777,558	923,477
PROPERTY, PLANT AND EQUIPMENT (NOTES 1, 6, 9 AND 10)		
Plant in service and held for future use	9,058,900	8,030,847
Less accumulated depreciation and amortization	3,474,325	3,290,097
Total	5,584,575	4,740,750
Construction work in progress	777,542	1,047,072
Intangible assets, net of accumulated amortization (Note 21)	109,815	86,782
Nuclear fuel, net of accumulated amortization of $102,821 and $99,185	7,466	6,933
Net property, plant and equipment	6,479,398	5,881,537
DEFERRED DEBITS		
Regulatory assets (Notes 1, 3 and 4)	241,045	342,383
Other deferred debits	115,117	64,597
Total deferred debits	356,162	406,980
TOTAL ASSETS	$ 8,425,806	$ 7,939,399

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS (dollars in thousands)

December 31,	2002	2001
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 356,305	$ 269,124
Accrued taxes	71,109	96,729
Accrued interest	53,018	48,806
Short-term borrowings (Note 5)	102,183	405,762
Current maturities of long-term debt (Note 6)	281,023	126,140
Customer deposits	55,838	30,232
Deferred income taxes (Note 4)	–	3,244
Liabilities from risk management and trading activities (Note 18)	70,667	35,994
Other current liabilities	64,972	69,475
Total current liabilities	1,055,115	1,085,506
LONG-TERM DEBT LESS CURRENT MATURITIES (NOTE 6)	2,881,695	2,673,078
DEFERRED CREDITS AND OTHER		
Liabilities from risk management and trading activities – long-term (Note 18)	75,642	207,576
Deferred income taxes (Note 4)	1,209,074	1,064,993
Unamortized gain – sale of utility plant (Note 9)	59,484	64,060
Pension liability (Note 8)	183,880	49,032
Other	274,763	295,831
Total deferred credits and other	1,802,843	1,681,492
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 2002 and 84,824,947 at end of 2001	1,737,258	1,536,924
Treasury stock; 124,830 shares at end of 2002 and 101,307 shares at end of 2001	(4,358)	(5,886)
Total common stock	1,732,900	1,531,038
Accumulated other comprehensive loss:		
Minimum pension liability adjustment	(71,264)	(966)
Derivative instruments	(20,020)	(63,599)
Total accumulated other comprehensive loss	(91,284)	(64,565)
Retained earnings	1,044,537	1,032,850
Total common stock equity	2,686,153	2,499,323
TOTAL LIABILITIES AND EQUITY	$ 8,425,806	$ 7,939,399

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS (dollars in thousands)

year ended December 31,	2002	2001	2000
CASH FLOWS FROM OPERATING ACTIVITIES			
Income before accounting change	$ 215,153	$ 327,367	$ 302,332
Items not requiring cash:			
Depreciation and amortization	424,886	427,903	431,229
Nuclear fuel amortization	31,185	28,362	30,083
Deferred income taxes	196,324	(17,203)	(37,885)
Change in mark-to-market	(18,146)	(133,573)	(11,752)
Redhawk Units 3 and 4 cancellation	49,192	–	–
Changes in current assets and liabilities:			
Customer and other receivables	18,615	146,581	(269,223)
Materials, supplies and fossil fuel	(11,599)	(16,867)	475
Other current assets	(9,784)	(1,276)	(39,083)
Accounts payable	74,833	(127,782)	193,502
Accrued taxes	(36,039)	7,483	18,736
Accrued interest	4,212	5,852	9,701
Other current liabilities	17,489	5,260	98,493
Change in real estate investments	(6,112)	(44,173)	(25,937)
Increase in regulatory assets	(11,029)	(17,516)	(14,138)
Change in risk management and trading – assets	(11,700)	(51,894)	–
Changes in risk management and trading – liabilities	(22,783)	45,330	13,834
Change in customer advances	(23,780)	28,599	2,544
Change in pension liability	(1,571)	(28,347)	(16,575)
Change in long-term assets	(16,918)	13,874	54,829
Change in long-term liabilities	8,346	(26,937)	(27,771)
Net cash flow provided by operating activities	870,774	571,043	713,394
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(895,522)	(1,055,574)	(658,608)
Capitalized interest	(44,110)	(47,862)	(21,638)
Other	36,635	(16,481)	(55,595)
Net cash flow used for investing activities	(902,997)	(1,119,917)	(735,841)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	725,419	995,447	651,000
Short-term borrowings and payments – net	(303,579)	322,987	44,475
Dividends paid on common stock	(137,721)	(129,199)	(120,733)
Repayment of long-term debt	(404,670)	(621,057)	(558,019)
Common stock equity issuance	199,238	–	–
Other	2,624	(1,048)	(4,618)
Net cash flow provided by financing activities	81,311	567,130	12,105
NET CASH FLOW	49,088	18,256	(10,342)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	28,619	10,363	20,705
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 77,707	$ 28,619	$ 10,363
Supplemental disclosure of cash flow information			
Cash paid during the period for:			
Income taxes paid/(refunded) (Note 4)	$ (17,918)	$ 223,037	$ 219,411
Interest paid, net of amounts capitalized	$ 126,322	$ 115,276	$ 132,434

See Notes to Consolidated Financial Statements.

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

for the years ended December 31,	2002	2001	2000
COMMON STOCK (NOTE 7)			
Balance of beginning of year	$ 1,536,924	$ 1,537,920	$ 1,540,197
Issuance of common stock	199,238	–	–
Other	1,096	(996)	(2,277)
Balance at end of year	1,737,258	1,536,924	1,537,920
TREASURY STOCK (NOTE 7)			
Balance at beginning of year	(5,886)	(5,089)	(2,748)
Purchase of treasury stock	(5,971)	(16,393)	(12,968)
Reissuance of treasury stock used for stock compensation, net	7,499	15,596	10,627
Balance at end of year	(4,358)	(5,886)	(5,089)
RETAINED EARNINGS			
Balance at beginning of year	1,032,850	849,883	668,284
Net income	149,408	312,166	302,332
Common stock dividends	(137,721)	(129,199)	(120,733)
Balance at end of year	1,044,537	1,032,850	849,883
ACCUMULATED OTHER COMPREHENSIVE LOSS			
Balance at beginning of year	(64,565)	–	–
Minimum pension liability adjustment, net of tax of $46,109 and $634	(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 $28,820 and $71,720	43,939	(109,346)	–
Reclassification of realized gain to income, net of tax of $237 and $17,399	(360)	(26,527)	–
Balance at end of year	(91,284)	(64,565)	–
TOTAL COMMON STOCK EQUITY	$ 2,686,153	$ 2,499,323	$ 2,382,714
COMPREHENSIVE INCOME			
Net income	$ 149,408	$ 312,166	$ 302,332
Other comprehensive loss	(26,719)	(64,565)	–
Comprehensive income	$ 122,689	$ 247,601	$ 302,332

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Consolidation and Nature of Operations

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

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

Accounting Records and Use of Estimates

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

Derivative Accounting

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

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

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

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

Mark-to-Market Accounting

Under mark-to-market accounting, the purchase or sale of energy commodities is reflected at fair market value, net of valuation adjustments, with resulting unrealized gains and losses recorded as assets and liabilities from risk management and trading activities in the Consolidated Balance Sheets.

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

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

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

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

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

The use of models and other valuation methods to determine fair market value often requires subjective and complex judgment. Actual results could differ from the results estimated through application of these methods. Our marketing and trading portfolio includes structured activities hedged with a portfolio of forward purchases that protects the economic value of the sales transactions. Our practice is to hedge within timeframes established by the 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 obligations to make refunds to customers for previous collections of costs not likely to be incurred.

We are required to discontinue applying SFAS No. 71 when deregulatory legislation is passed or a rate order is issued that contains sufficient detail to determine its effect on the portion of the business being deregulated. In 1999, we discontinued the application of SFAS No. 71 for APS' generation operations due to the 1999 Settlement Agreement with the ACC. See Note 3 for a discussion of the 1999 Settlement Agreement.

As a result, we tested the generation assets for impairment and determined the generation assets were not impaired. Pursuant to the 1999 Settlement Agreement, a regulatory disallowance removed $234 million pretax ($183 million net present value) from ongoing regulatory cash flows and was recorded as a net reduction of regulatory assets. This reduction ($140 million after income taxes) was reported as an extraordinary charge on the 1999 Consolidated Statement of Income.

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

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

Prior to the 1999 Settlement Agreement, the ACC accelerated the amortization of substantially all of APS' regulatory assets to an eight-year period that would have ended June 30, 2004. The regulatory assets to be recovered under the 1999 Settlement Agreement are currently being amortized as follows (dollars in millions):

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

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

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

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

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

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

Rate Synchronization Cost Deferrals

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

Utility Plant and Depreciation

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

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

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

We record depreciation on utility property on a straight-line basis over the remaining useful life of the related assets. The approximate remaining average useful lives of our utility property at December 31, 2002 were as follows:

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

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

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. See Note 22 for further details on El Dorado's investment in NAC.

Capitalized Interest

Capitalized interest represents the cost of debt funds used to finance construction projects. Plant construction costs, including capitalized interest, are expensed through depreciation when completed projects are placed into commercial operation. Capitalized interest does not represent current cash earnings. The rate used to calculate capitalized interest was a composite rate of 4.80% for 2002, 6.13% for 2001 and 6.62% for 2000.

Electric Revenues

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

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

SunCor

SunCor recognizes revenue from land, home and qualifying commercial operating assets sales in full, provided (a) the income is determinable, that is, the collectibility of the sales price is reasonably assured or the amount that will not be collectible can be estimated, and (b) the earnings process is virtually complete, that is, SunCor is not obligated to perform significant activities after the sale to earn the income. Unless both conditions exist, recognition of all or part of the income is postponed. A single method of recognizing income is applied to all sales transactions within an entire home, land or commercial development project. Commercial property and management revenues are recorded over the term of the lease or period in which services are provided.

Percentage of Completion – NAC

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

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

Cash and Cash Equivalents

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

Nuclear Fuel

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

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

Income Taxes

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

Reacquired Debt Costs

For debt related to the regulated portion of APS' business, APS amortizes those gains and losses incurred upon early retirement over the original remaining life of the debt. In accordance with the 1999 Settlement Agreement, APS is continuing to accelerate reacquired debt costs over an eight-year period that will end June 30, 2004. All regulatory asset amortization is included in depreciation and amortization expense in the Consolidated Statements of Income.

Real Estate Investments

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

Stock-Based Compensation

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

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

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

In order to calculate the fair value of the 2002 stock option grants and the pro forma information above, we calculated the fair value of each fixed stock option in the incentive plans using the Black-Scholes option-pricing model. The fair value was calculated based on the date the option was granted. The following weighted-average assumptions were also used in order to calculate the fair value of the stock options:

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

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

2. ACCOUNTING MATTERS

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

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

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

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

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

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

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

See the following Notes for other new accounting standards:

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

3. REGULATORY MATTERS

Electric Industry Restructuring

STATE

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

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

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

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

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

- APS has reduced, and will reduce, rates for standard-offer service for customers with loads less than three MW in a series of annual retail electricity price reductions of 1.5% on July 1 for each of the years 1999 to 2003 for a total of 7.5%. Based on the price reductions authorized in the 1999 Settlement Agreement, there were retail price decreases of approximately $24 million ($14 million after taxes), effective July 1, 1999; approximately $28 million ($17 million after taxes), effective July 1, 2000; approximately $27 million ($16 million after taxes), effective July 1, 2001; and approximately $28 million ($17 million after taxes), effective July 1, 2002. The final price reduction is to be implemented July 1, 2003. For customers having loads of three MW or greater, standard-offer rates have been reduced in varying annual increments that total 5% in the years 1999 through 2002.
- Unbundled rates being charged by APS for competitive direct access service (for example, distribution services) became effective upon approval of the 1999 Settlement Agreement, retroactive to July 1, 1999, and also became subject to annual reductions beginning January 1, 2000, that vary by rate class, through January 1, 2004.
- There will be a moratorium on retail price changes for standard-offer and unbundled competitive direct access services until July 1, 2004, except for the price reductions described above and certain other limited circumstances. Neither the ACC nor APS will be prevented from seeking or authorizing rate changes prior to July 1, 2004 in the event of conditions or circumstances that constitute an emergency, such as an inability to finance on reasonable terms; material changes in APS' cost of service for ACC-regulated services resulting from federal, tribal, state or local laws; regulatory requirements; or judicial decisions, actions or orders.
- APS will be permitted to defer for later recovery prudent and reasonable costs of complying with the Rules, system benefits costs in excess of the levels included in then-current (1999) rates, and costs associated with the "provider of last resort" and standard-offer obligations for service after July 1, 2004. These costs are to be recovered through an adjustment clause or clauses commencing on July 1, 2004.
- APS' distribution system opened for retail access effective September 24, 1999. Customers were eligible for retail access in accordance with the phase-in adopted by the ACC under the Rules (see "Retail Electric Competition Rules" below), including an additional 140 MW being

made available to eligible non-residential customers. APS opened its distribution system to retail access for all customers on January 1, 2001. The regulatory developments and legal challenges to the Rules discussed in this note have raised considerable uncertainty about the status and pace of electric competition in Arizona. Although some very limited retail competition existed in APS' service area in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to APS' customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter APS' service territory.

- Prior to the 1999 Settlement Agreement, APS was recovering substantially all of its regulatory assets through July 1, 2004, pursuant to a 1996 regulatory agreement. In addition, the 1999 Settlement Agreement states that APS has demonstrated that its allowable stranded costs, after mitigation and exclusive of regulatory assets, are at least $533 million net present value (in 1999 dollars). APS will not be allowed to recover $183 million net present value (in 1999 dollars) of the above amounts. The 1999 Settlement Agreement provides that APS will have the opportunity to recover $350 million net present value (in 1999 dollars) through a competitive transition charge that will remain in effect through December 31, 2004, at which time it will terminate. The costs subject to recovery under the adjustment clause described above will be decreased or increased by any over/under-recovery due to sales volume variances.
- APS will form, or cause to be formed, a separate corporate affiliate or affiliates and transfer to such affiliate(s) its competitive electric assets and services at book value as of the date of transfer, and will complete the transfers no later than December 31, 2002. APS will be allowed to defer and later collect, beginning July 1, 2004, 67% of its costs to accomplish the required transfer of generation assets to an affiliate. However, as noted above and discussed in greater detail below, in 2002 the ACC unilaterally modified this aspect of the 1999 Settlement Agreement by issuing an order preventing APS from transferring its generation assets.

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

- They apply to virtually all Arizona electric utilities regulated by the ACC, including APS.
- Effective January 1, 2001, retail access became available to all APS retail electricity customers.
- Electric service providers that get CC&N's from the ACC can supply only competitive services, including electric generation, but not electric transmission and distribution.
- Affected utilities must file ACC tariffs that unbundle rates for noncompetitive services.
- The ACC shall allow a reasonable opportunity for recovery of unmitigated stranded costs.
- Absent an ACC waiver, prior to January 1, 2001, each affected utility (except certain electric cooperatives) must transfer all competitive electric assets and services to an unaffiliated party or parties or to a separate corporate affiliate or affiliates. Under the 1999 Settlement Agreement, APS received a waiver to allow transfer of its competitive electric assets and services to affiliates no later than December 31, 2002. However, as noted above and discussed in greater detail below, in 2002 the ACC reversed its decision, as reflected in the Rules, to require APS to transfer its generation assets.

Under the 1999 Settlement Agreement, the Rules are to be interpreted and applied, to the greatest extent possible, in a manner consistent with the 1999 Settlement Agreement. If the two cannot be reconciled, APS must seek, and the other parties to the 1999 Settlement Agreement must support, a waiver of the Rules in favor of the 1999 Settlement Agreement.

On November 27, 2000, a Maricopa County, Arizona, Superior Court judge issued a final judgment holding that the Rules are unconstitutional and unlawful in their entirety due to failure to establish a fair value rate base for competitive electric service providers and because certain of the Rules were not submitted to the Arizona Attorney General for certification. The judgment also invalidates all ACC orders authorizing competitive electric service providers, including APS Energy Services, to operate in Arizona. We do not believe the ruling affects the 1999 Settlement Agreement. The 1999 Settlement Agreement was not at issue in the consolidated cases before the judge. Further, the ACC made findings related to the fair value of APS' property in the order approving the 1999 Settlement Agreement. The ACC and other parties aligned with the ACC have appealed the ruling to the Arizona Court of Appeals, as a result of which the Superior Court's ruling is automatically stayed pending further judicial review. That appeal is still pending. In a similar appeal concerning the issuance of competitive telecommunications CC&N's, the Arizona Court of Appeals invalidated rates for competitive carriers due to the ACC's failure to establish a fair value rate base for such carriers. That decision was upheld by the Arizona Supreme Court.

Provider of Last Resort Obligation Although the Rules allow retail customers to have access to competitive providers of energy and energy services, APS is the "provider of last resort" for standard-offer, full-service customers under rates that have been approved by the ACC. These rates are established until at least July 1, 2004. The 1999 Settlement Agreement allows APS to seek adjustment of these rates in the event of emergency conditions or circumstances, such as the inability to secure financing on reasonable terms; material changes in APS' cost of service for ACC-regulated services resulting from federal, tribal, state or local laws; regulatory requirements; or judicial decisions, actions or orders. Energy prices in the western wholesale market vary and, during the course of the last two years, have been volatile. At various times, prices in the spot wholesale market have significantly exceeded the amount included in APS' current retail rates. In the event of shortfalls due to unforeseen increases in load demand or generation or transmission outages, APS may need to purchase additional supplemental power in the wholesale spot market. Unless APS is able to obtain an adjustment of its rates under the emergency provisions of the 1999 Settlement Agreement, there can be no assurance that APS would be able to fully recover the costs of this power.

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

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

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

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

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

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

On November 15, 2002, APS filed appeals of the Track A Order in the Maricopa County, Arizona Superior Court and in the Arizona Court of Appeals. Arizona Public Service Company vs. Arizona Corporation Commission, CV 2002-0222 32. Arizona Public Service Company vs. Arizona Corporation Commission, 1CA CC 02-0002. On December 13, 2002, APS and the ACC staff agreed to principles for resolving certain issues raised by APS in its appeals of the Track A Order. APS and the ACC are the only parties to the Track A Order appeals. The major provisions of this document include, among other things, the following:

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

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

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

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

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

ACC Applications

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

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

- APS noted that its April 19, 2002 filing with the ACC had sought unification of "[Pinnacle West Energy] Assets" (West Phoenix Units 4 and 5, Redhawk Units 1 and 2 and Saguaro Unit 3) and APS generation assets under a common financial and regulatory regime. APS further noted that the Track A Order's language regarding the treatment of the Pinnacle West Energy Assets for Track B purposes appears to postpone a decision regarding the inclusion of the Pinnacle West Energy Assets in APS' rate base, thereby effectively precluding the consolidation of the Pinnacle West Energy Assets at APS under a common financial and regulatory regime at the present time.
- APS stated that it did not intend or desire to foreclose the possibility that it would acquire all or part of the Pinnacle West Energy Assets or that it may propose that the Pinnacle West Energy Assets be included in APS' rate base or afforded cost-of-service regulatory treatment to the extent the Pinnacle West Energy Assets are used by APS customers. APS stated that these issues would be appropriate topics in APS' 2003 general rate case and noted that the Track A Order specifically stated that the ACC would not pre-judge the eventual rate treatment of the Pinnacle West Energy Assets.
- APS stated that the Track A Order's reversal of the generation asset transfer requirement and the resulting bifurcation of generation assets between APS and Pinnacle West Energy under different regulatory regimes result in Pinnacle West Energy being unable to attain investment-grade credit ratings. This, in turn, precludes Pinnacle West Energy from accessing capital markets to refinance the bridge financing provided by the Company to fund the construction of the Pinnacle West Energy Assets or from effectively competing in the wholesale markets. APS noted that Pinnacle West Energy had previously received investment-grade credit ratings contingent upon its receipt of APS generation assets and that the Company's credit ratings could be adversely affected if Pinnacle West Energy is unable to finance its capital requirements. On November 4, 2002, Standard & Poor's lowered the Company's senior unsecured debt rating from "BBB" to "BBB–."
- APS stated that the amount of the requested loan and/or guarantee is APS' present estimate of the amount of credit support necessary through APS to restore Pinnacle West Energy and the Company to their credit status prior to the ACC's issuance of the Track A Order. APS further stated that if the requested amount proves to be inadequate, APS reserves the right to submit a second financing application seeking additional credit support.

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

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

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

- certain waivers of the ACC's affiliated interest rules previously granted to APS and its affiliates will be withdrawn and, during the term of the APS Loan, neither Pinnacle West nor Pinnacle West Energy may reorganize or restructure, acquire or divest assets, or form, buy or sell affiliates (each a "Covered Transaction"), or pledge or otherwise encumber the Pinnacle West Energy assets without prior ACC approval, expect that the foregoing restrictions will not apply to the following categories of Covered Transactions:
  - Covered Transactions less than $100 million, measured on a cumulative basis over the calendar year in which the Covered Transactions are made;
  - Covered Transactions by SunCor of less than $300 million through 2005, consistent with SunCor's anticipated accelerated asset sales activity during those years;
  - Covered Transactions related to the payment of ongoing construction costs for Pinnacle West Energy's (a) West Phoenix Unit 5, located in Phoenix, with an expected commercial operation date in mid-2003, and (b) Silverhawk plant, located near Las Vegas, with an expected commercial operation date in mid-2004; and
  - Covered Transactions related to the sale of 25% of the Silverhawk plant to SNWA if SNWA exercises its existing purchase option to do so.

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

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

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

Federal

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

On July 31, 2002, the FERC issued a Notice of Proposed Rulemaking for Standard Market Design for wholesale electric markets. Voluminous comments and reply comments were filed on virtually every aspect of the proposed rule, and the FERC has announced that it will issue an additional white paper on the proposed Standard Market Design in April 2003. We are reviewing the proposed rulemaking and cannot currently predict what, if any, impact there may be to the Company if the FERC adopts the proposed rule or any modifications proposed in the comments.

General

The regulatory developments and legal challenges to the Rules discussed in this Note have raised considerable uncertainty about the status and pace of retail electric competition in Arizona. Although some very limited retail competition existed in APS' service area in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to APS' customers.
As a result, we cannot predict when, and the extent to which, additional competitors will re-enter APS' service territory. As competition in the electric industry continues to evolve, we will continue to evaluate strategies and alternatives that will position us to compete in the new regulatory environment.

4. INCOME TAXES

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

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

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

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

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

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

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

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

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

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

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

5. LINES OF CREDIT AND SHORT-TERM BORROWINGS

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

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

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

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

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

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

6. LONG-TERM DEBT

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

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

(a) This schedule does not reflect the timing of redemptions that may occur prior to maturity.
(b) On March 15, 2002, APS redeemed at maturity $125 million of its First Mortgage Bonds, 8.125% Series due 2002.
(c) On April 15, 2002, APS redeemed $122 million of its First Mortgage Bonds, 8.75% Series due 2024.
(d) The weighted-average rate was 1.94% at December 31, 2002 and 2.55% at December 31, 2001. Changes in short-term interest rates would affect the costs associated with this debt.
(e) In November 2001, these bonds were converted to a one-year fixed rate of 3.30%. These bonds were previously adjustable rate and, from January 1, 2001 until October 31, 2001, the weighted average rate was 2.72%.
(f) On November 1, 2002, Maricopa County, Arizona Pollution Control Corporation issued $90 million of 5.05% Pollution Control Revenue Refunding Bonds (Arizona Public Service Company Palo Verde Project) 2002 Series A, due 2029, and loaned the proceeds to APS pursuant to a loan agreement. The bonds were issued to refinance $90 million of outstanding pollution control bonds. The bondholders were issued $90 million of first mortgage bonds (senior note mortgage bonds) as collateral.

(g) APS currently has outstanding $84 million of first mortgage bonds (senior note mortgage bonds) issued to the senior note trustee as collateral for the senior notes, as well as the $90 million issue discussed in footnote (f) above. The senior note mortgage bonds have the same interest rate, interest payment dates, maturity and redemption provisions as the senior notes. APS' payments of principal, premium and/or interest on the senior notes satisfy its corresponding payment obligations on the senior note mortgage bonds. As long as the senior note mortgage bonds secure the senior notes, the senior notes will effectively rank equally with the first mortgage bonds. When APS repays all of its first mortgage bonds, other than those that secure senior notes, the senior note mortgage bonds will no longer secure the senior notes and will cease to be outstanding.
(h) The weighted-average rate was 3.75% at December 31, 2002 and was 5.31% at December 31, 2001. Interest for 2002 and 2001 was based on LIBOR plus 2% or prime plus 0.5%.
(i) Multiple notes primarily with variable interest rates based mostly on the lenders' prime plus 1.75% and lenders' prime plus .25%.
(j) Includes three series of notes: $25 million at 6.87% due in 2003, $300 million at 6.4% due in 2006 and $215 million at 4.5% due in 2004 as of December 31, 2002.
(k) The weighted average rate was 2.85% at December 31, 2002 and was 4.65% at December 31, 2001. Interest for 2002 and 2001 was based on LIBOR plus 0.98%.

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

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

All of Pinnacle West's bank agreements contain "cross-default" provisions under which a default by it or APS in a specified amount under another agreement would result in a default and the potential acceleration of payment under the agreements. All of APS' bank agreements contain cross-default provisions under which a default by APS in a specified amount under another agreement would result in a default and the potential acceleration of payment under the agreements. Pinnacle West's and APS' credit agreements generally contain provisions under which the lenders could refuse to advance loans in the event of a material adverse change in the borrower's financial condition or financial prospects.

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

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

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

7. COMMON STOCK AND TREASURY STOCK

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

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

8. RETIREMENT PLANS AND OTHER BENEFITS

Pension Plans

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Employee Savings Plan Benefits

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

Other Postretirement Benefits

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

Funding is based upon actuarially determined contributions that take tax consequences into account. Plan assets consist primarily of domestic stocks and bonds. The other postretirement benefit expense after consideration of amounts capitalized or billed to electric plant participants, was:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Severance Charges

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

9. LEASES

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

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

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

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

In accordance with the 1999 Settlement Agreement and previous settlement agreements, APS is continuing to accelerate amortization of the regulatory asset for leases over an eight-year period that will end June 30, 2004 (see Note 1). All regulatory asset amortization is included in depreciation and amortization expense in the Consolidated Statements of Income. The balance of this regulatory asset at December 31, 2002 was $14 million.

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

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

10. JOINTLY-OWNED FACILITIES

APS shares ownership of some of its generating and transmission facilities with other companies. The following table shows APS' interest in those jointly-owned facilities recorded on the Consolidated Balance Sheets at December 31, 2002. APS' share of operating and maintaining these facilities is included in the Consolidated Statements of Income in operations and maintenance expense.

(dollars in thousands)	Percent Owned by APS	Plant in Service	Accumulated Depreciation	Construction Work in Progress
Generating Facilities:				
Palo Verde Nuclear Generating Station Units 1 and 3	29.1%	$ 1,829,225	$ (905,278)	$ 17,428
Palo Verde Nuclear Generating Station Unit 2 (see Note 9)	17.0%	574,745	(289,049)	68,475
Four Corners Steam Generating Station Units 4 and 5	15.0%	153,559	(82,434)	500
Navajo Steam Generating Station Units 1, 2, and 3	14.0%	235,743	(110,923)	3,010
Cholla Steam Generating Station				
Common Facilities (a)	62.8%(b)	76,322	(42,608)	1,733
Transmission Facilities:				
ANPP 500KV System	35.8%(b)	68,314	(25,655)	31
Navajo Southern System	31.4%(b)	27,129	(17,405)	664
Palo Verde – Yuma 500KV System	23.9%(b)	9,591	(4,168)	383
Four Corners Switchyards	27.5%(b)	3,071	(1,979)	–
Phoenix – Mead System	17.1%(b)	36,418	(2,906)	–
Palo Verde – Estrella 500KV System	50.0%(b)	–	–	50,450

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

11. COMMITMENTS AND CONTINGENCIES

Enron

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

Palo Verde Nuclear Generating Station

Nuclear power plant operators are required to enter into spent fuel disposal contracts with the DOE, and the DOE is required to accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by domestic power reactors. Although the Nuclear Waste Act required the DOE to develop a permanent repository for the storage and disposal of spent nuclear fuel by 1998, the DOE has announced that the repository cannot be completed before 2010 and it does not intend to begin accepting spent nuclear fuel prior to that date. In November 1997, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued a decision preventing the DOE from excusing its own delay, but refused to order the DOE to begin accepting spent nuclear fuel. Based on this decision and the DOE's delay, a number of utilities filed damages actions against the DOE in the Court of Federal Claims.

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

APS has existing fuel storage pools at Palo Verde and is in the process of completing construction of a new facility for on-site dry storage of spent nuclear fuel. With the existing storage pools and the addition of the new facility, APS believes spent nuclear fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation through the term of the operating license for each Palo Verde unit.

Although some low-level waste has been stored on-site in a low-level waste facility, APS is currently shipping low-level waste to off-site facilities. APS currently believes interim low-level waste storage methods are or will be available for use by Palo Verde to allow its continued operation and to safely store low-level waste until a permanent disposal facility is available.

APS currently estimates it will incur $115 million (in 2002 dollars) over the life of Palo Verde for its share of the costs related to the on-site interim storage of spent nuclear fuel. As of December 31, 2002, APS had spent $2 million and recorded accumulated spent nuclear fuel amortization of $44 million and a regulatory asset of $46 million for on-site interim spent nuclear fuel storage costs related to nuclear fuel burned to date.

The Palo Verde participants have insurance for public liability resulting from nuclear energy hazards to the full limit of liability under federal law. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $200 million ($300 million effective January 1, 2003) and the balance by an industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the programs exceed the accumulated funds, APS could be assessed retrospective premium adjustments. The maximum assessment per reactor under the program for each nuclear incident is approximately $88 million, subject to an annual limit of $10 million per incident. Based on APS' interest in the three Palo Verde units, APS' maximum potential assessment per incident for all three units is approximately $77 million, with an annual payment limitation of approximately $9 million.

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

Purchased Power and Fuel Commitments

APS and Pinnacle West are parties to various purchased power and fuel contracts with terms expiring from 2003 through 2025 that include required purchase provisions. We estimate the contract requirements to be approximately $173 million in 2003; $82 million in 2004; $28 million in 2005; $31 million in 2006; $17 million in 2007 and $162 million 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 nuclear fuel contracts expire in 2003 and had not been renewed as of December 31, 2002. The current take-or-pay coal contracts have terms that expire in 2007.

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

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

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

Coal Mine Reclamation Obligations

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

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

California Energy Market Issues and Refunds in the Pacific Northwest

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

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

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

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

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

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

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

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

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

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

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

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

Power Service Agreement

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

Construction Program

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

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

Pinnacle West Energy's Generation Construction

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

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

Litigation

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

12. NUCLEAR DECOMMISSIONING COSTS

APS recorded $11 million for nuclear decommissioning expense in each of the years 2002, 2001 and 2000. APS estimates it will cost approximately $1.8 billion ($528 million in 2002 dollars) to decommission its share of the three Palo Verde units. The majority of decommissioning costs are expected to be incurred over a 14-year period beginning in 2024. APS charges decommissioning costs to expense over each unit's operating license term and APS includes them in the accumulated depreciation balance until each unit is retired. Nuclear decommissioning costs are recovered in rates.

APS' current estimates are based on a 2001 site-specific study for Palo Verde that assumes the prompt removal/dismantlement method of decommissioning. An independent consultant prepared this study. APS is required by the ACC to update the study every three years.

To fund the costs APS expects to incur to decommission the plant, APS established external decommissioning trusts in accordance with NRC regulations and ACC orders. APS invests the trust funds primarily in fixed income securities and domestic stock and classifies them as available for sale. Realized and unrealized gains and losses are reflected in accumulated depreciation in accordance with industry practice. The following table shows the cost and fair value of our nuclear decommissioning trust fund assets, which were reported in investments and other assets on the Consolidated Balance Sheets at December 31, 2002 and 2001 (dollars in millions):

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

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

13. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

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

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

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

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

(b) Electric revenues are seasonal in nature, with the peak sales periods generally occurring during the summer months. Comparisons among quarters of a year may not represent overall trends and changes in operations. We have reclassified certain operating revenues to conform to the current presentation of netting energy trading contracts (see Note 18).

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

14. FAIR VALUE OF FINANCIAL INSTRUMENTS

We believe that the carrying amounts of our cash equivalents and commercial paper are reasonable estimates of their fair values at December 31, 2002 and 2001 due to their short maturities.

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

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

15. EARNINGS PER SHARE

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

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

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

Options to purchase 1,629,958 shares of common stock were outstanding at December 31, 2002 but were not included in the computation of diluted earnings per share because the options' exercise price was greater than the average market price of the common shares. Options to purchase shares of common stock that were not included in the computation of diluted earnings per share were 212,562 at December 31, 2001 and 517,614 at December 31, 2000.

16. STOCK-BASED COMPENSATION

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

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

The 1994 plan provides for the granting of new options (which may be non-qualified stock options or incentive stock options) of up to 3.5 million shares at a price per option not less than the fair market value on the date the option is granted. The 1985 plan includes outstanding options but no new options will be granted from the plan. Options vest one-third of the grant per year beginning one year after the date the option is granted and expire ten years from the date of the grant. The 1994 plan also provides for the granting of any combination of shares of restricted stock, stock appreciation rights or dividend equivalents.

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

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

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

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

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

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

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

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

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

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

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

17. BUSINESS SEGMENTS

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

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

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

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

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

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

18. DERIVATIVE AND TRADING ACCOUNTING

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal and emissions allowances. We manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. As part of our overall risk management program, we enter into derivative transactions to hedge purchases and sales of electricity, fuels, and emissions allowances and credits. The changes in market value of such contracts have a high correlation to price changes in the hedged commodities. In addition, subject to specified risk parameters monitored by the 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). We use cash flow hedges to limit our exposure to cash flow variability on forecasted transactions. Hedge effectiveness is related to the degree to which the derivative contract and the hedged item are correlated. It is measured based on the relative changes in fair value between the derivative contract and the hedged item over time. We exclude the time value of certain options from our assessment of hedge effectiveness. Any change in the fair value resulting from ineffectiveness, or the amount by which the derivative contract and the hedged commodity are not directly correlated, is recognized immediately in net income. See Note 1 for further discussion on our derivative instrument accounting policy.

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

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

During 2002, the EITF discussed EITF 02-3 and reached a consensus on certain issues. EITF 02-3 rescinded EITF 98-10 and was effective October 25, 2002 for any new contracts and on January 1, 2003 for existing contracts, with early adoption permitted. We adopted the EITF 02-3 guidance for all contracts in the fourth quarter of 2002. We recorded a $66 million after-tax charge in net income as a cumulative effect adjustment for the previously recorded accumulated unrealized mark-to-market on energy trading contracts that did not meet the accounting definition of a derivative. As a result, our energy trading contracts that are derivatives continue to be accounted for at fair value under SFAS No. 133. Contracts that were previously marked-to-market as trading activities under EITF 98-10 that do not meet the definition of a derivative are now accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received. Additionally, all gains and losses (realized and unrealized) on energy trading contracts that qualify as derivatives are included in marketing and trading segment revenues on the Consolidated Statements of Income on a net basis. The rescission of EITF 98-10 has no effect on the accounting for derivative instruments used for non-trading activities, which continue to be accounted for in accordance with SFAS No. 133.

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

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

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

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

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

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

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

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

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

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

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

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

Credit Risk

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We have risk management and trading contracts with many counterparties, including two counterparties for which a worst case exposure represents approximately 33% of our $181 million of risk management and trading assets as of December 31, 2002. We use a risk management process to assess and monitor the financial exposure of those and all other counterparties. Despite the fact that the great majority of trading counterparties are rated as investment grade by the credit rating agencies, including the counterparties noted above, there is still a possibility that one or more of these companies could default, resulting in a material impact on consolidated earnings for a given period. Counterparties in the portfolio consist principally of major energy companies, municipalities and local distribution companies. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. In many contracts, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Credit valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties. See "Mark-to-Market Accounting" in Note 1 for a discussion of our credit valuation adjustment policy.

19. OTHER INCOME AND OTHER EXPENSE

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

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

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

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

20. VARIABLE INTEREST ENTITIES

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

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

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

21. INTANGIBLE ASSETS

On January 1, 2002, we adopted SFAS No. 142, "Goodwill and Other Intangible Assets." This statement addresses financial accounting and reporting for acquired goodwill and other intangible assets and supersedes APB Opinion No. 17, "Intangible Assets." We have no goodwill recorded and have separately disclosed other intangible assets on our Consolidated Balance Sheets. The intangible assets continue to be amortized over their finite useful lives. Thus, there was no impact on our financial position as a result of the adoption of SFAS No. 142. The Company's gross intangible assets (which are primarily software) were $214 million at December 31, 2002 and $175 million at December 31, 2001. The related accumulated amortization was $104 million at December 31, 2002 and $88 million at December 31, 2001. Amortization expense was $21 million in 2002, $22 million in 2001 and $20 million in 2000. Estimated amortization expense on existing intangible assets over the next five years is $25 million in 2003, $24 million in 2004, $23 million in 2005, $21 million in 2006 and $15 million in 2007.

22. EL DORADO'S INVESTMENT IN NAC

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

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

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

23. GUARANTEES

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

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

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

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

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

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

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

24. SUBSEQUENT EVENTS

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

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

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

1. PAMELA GRANT, (64) 1980* Civic Leader COMMITTEES: *Human Resources, Chairman; Audit; Corporate Governance* **2. MARTHA O. HESSE, (60) 1991** President, Hesse Gas Company COMMITTEES: *Audit, Chairman; Finance and Operating; Corporate Governance* **3. THE REV. BILL JAMIESON, JR., (59) 1991** President, Institute for Servant Leadership of Asheville, North Carolina COMMITTEES: *Human Resources; Corporate Governance* **4. ROY A. HERBERGER, JR., (60) 1992** President, Thunderbird, The American Graduate School of International Management COMMITTEES: *Finance and Operating, Chairman; Human Resources; Corporate Governance* **5. ROBERT G. MATLOCK, (69) 1993** Management Consultant, R.G. Matlock & Associates, Inc. COMMITTEES: *Human Resources; Corporate Governance* **6. WILLIAM J. POST, (52) 1994** Chairman of the Board & Chief Executive Officer COMMITTEE: *Finance and Operating* **7. HUMBERTO S. LOPEZ, (57) 1995** President, HSL Properties, Inc. COMMITTEES: *Audit; Corporate Governance* **8. MICHAEL L. GALLAGHER, (58) 1997** Chairman Emeritus, Gallagher & Kennedy, P.A. COMMITTEES: *Human Resources; Corporate Governance, Presiding Director* **9. BRUCE J. NORDSTROM, (53) 1997** Certified Public Accountant, Nordstrom and Associates, P.C. COMMITTEES: *Audit; Corporate Governance* **10. JACK E. DAVIS, (56) 1998** President COMMITTEE: *Finance and Operating* **11. WILLIAM L. STEWART, (59) 1998**** **12. EDDIE BASHA, (65) 1999** Chairman of the Board, Bashas' COMMITTEES: *Audit; Corporate Governance* **13. KATHRYN L. MUNRO, (54) 1999** Chairman, BridgeWest L.L.C. COMMITTEES: *Finance and Operating; Corporate Governance*

Board of Directors

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

**William Stewart announced his retirement from the company effective Dec. 1, 2003. He will be transitioning his duties to other officers in the company until his retirement.

Officers

PINNACLE WEST

William J. Post (52) 1973*
Chairman of the Board
& Chief Executive Officer

Jack E. Davis (56) 1973
President

Armando B. Flores (59) 1991
Executive Vice President,
Corporate Business Services

Donald E. Brandt (48) 2002
Senior Vice President
& Chief Financial Officer

Robert S. Aiken (46) 1986
Vice President, Federal Affairs

John G. Bohon (57) 1971
Vice President, Corporate
Services & Human Resources

Dennis L. Brown (52) 1973
Vice President
& Chief Information Officer

Edward Z. Fox (49) 1995
Vice President, Communications,
Environment & Safety

Nancy C. Loftin (49) 1985
Vice President, General Counsel
& Secretary

Martin L. Shultz (58) 1979
Vice President,
Government Affairs

Barbara M. Gomez (48) 1978
Treasurer

ARIZONA PUBLIC SERVICE

William J. Post
Chairman of the Board

Jack E. Davis
President & Chief Executive
Officer

James M. Levine (53) 1989
Executive Vice President,
Generation

Donald E. Brandt
Senior Vice President
& Chief Financial Officer

Gregg R. Overbeck (56) 1990
Senior Vice President,
Nuclear Generation

Steven M. Wheeler (54) 2001
Senior Vice President,
Regulation, System Planning
& Operations

Jan H. Bennett (55) 1967
Vice President, Customer Service

Ajit P. Bhatti (57) 1973
Vice President,
Resource Planning

John R. Denman (60) 1964
Vice President, Fossil Generation

Chris N. Froggatt (45) 1986
Vice President & Controller

David A. Hansen (43) 1980
Vice President,
Power Marketing & Trading

Nancy C. Loftin
Vice President, General Counsel
& Secretary

David Mauldin (53) 1990
Vice President,
Nuclear Engineering

Donald G. Robinson (49) 1978
Vice President,
Finance & Planning

Barbara M. Gomez
Treasurer

SUNCOR DEVELOPMENT

William J. Post
Chairman of the Board

John C. Ogden (57) 1972
President
& Chief Executive Officer

Geoffrey L. Appleyard (49) 1987
Vice President
& Chief Financial Officer

Duane S. Black (50) 1989
Vice President
& Chief Operating Officer

Jay T. Ellingson (54) 1992
Vice President,
Development – Palm Valley

Steven Gervais (47) 1987
Vice President & General Counsel

Margaret E. Kirch (53) 1988
Vice President,
Commercial Development

Thomas A. Patrick (49) 1995
Vice President, Golf Operations

PINNACLE WEST ENERGY

James M. Levine
President
& Chief Executive Officer

Ajoy K. Banerjee (57) 1999
Vice President,
Construction & Operations

Warren C. Kotzmann (53) 1989
Vice President, Financial
& Corporate Services

APS ENERGY SERVICES

Vicki G. Sandler (46) 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 21, 2003
10:30 a.m.
The Herberger Theatre
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 April 1, 2003) 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) 250-5506

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

STATISTICAL REPORT
A detailed Statistical Report for Financial Analysis for 1997-2002 will be available in April on the Company's Web site or by writing to the Investor Relations Department.

INVESTOR RELATIONS CONTACT
Rebecca L. Hickman
Director, Investor Relations
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:

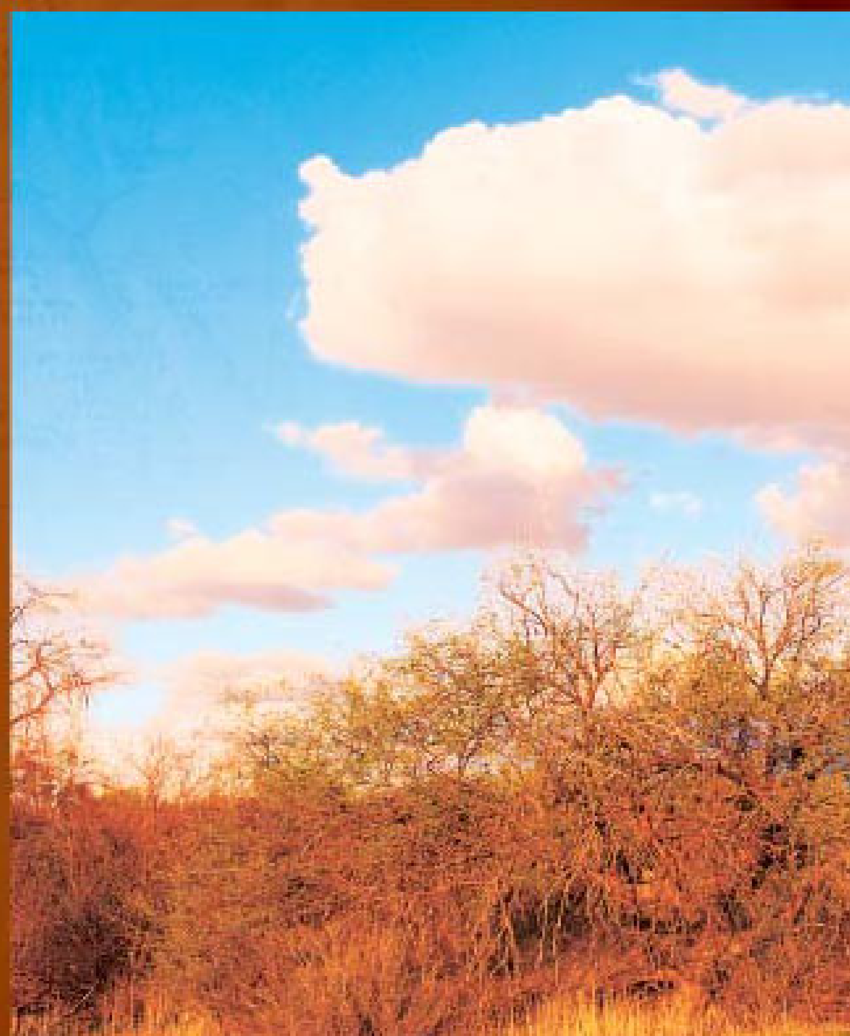
Arizona Utility Investors Association
P.O. Box 34805
Phoenix, Arizona 85067
(602) 257-9200
www.auia.org

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) 250-3282.

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

The mesquite is one of the most durable and adaptable trees in Arizona's desert regions. It thrives in dense thickets along streams and washes but, due to its long taproot, the mesquite is also able to survive in arid settings. These desert denizens are resilient and a new tree often sprouts from the stump when a mesquite is cut down.



PINNACLE WEST
CAPITAL CORPORATION

Pinnacle West Capital Corporation 2002 ANNUAL REPORT