

2003 Consolidated
Financial Information

16_SELECTED CONSOLIDATED FINANCIAL DATA

17_GLOSSARY

18_MANAGEMENT'S DISCUSSION AND
ANALYSIS OF FINANCIAL CONDITION
AND RESULTS OF OPERATIONS

34_MANAGEMENT'S REPORT ON INTERNAL
CONTROL OVER FINANCIAL REPORTING

35_INDEPENDENT ACCOUNTANTS' REPORT

36_INDEPENDENT AUDITORS' REPORT

37_CONSOLIDATED STATEMENTS OF INCOME

38_CONSOLIDATED BALANCE SHEETS

40_CONSOLIDATED STATEMENTS
OF CASH FLOWS

41_CONSOLIDATED STATEMENTS OF
CHANGES IN COMMON STOCK EQUITY

42_NOTES TO CONSOLIDATED
FINANCIAL STATEMENTS

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

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

(a) Includes reclassifications of revenues in 2003, 2002 and 2001 for the adoption of EITF 03-11. See Note 18 of Notes to Consolidated Financial Statements.

(b) Tax benefit stemming from the resolution of income tax matters related to a former subsidiary, MeraBank, A Federal Savings Bank in 1999.

(c) Real estate discontinued operations in 2003 and 2002. See Note 22 of Notes to Consolidated Financial Statements.

(d) Charges associated with a regulatory disallowance. See "Regulatory Accounting" in Note 1 of Notes to Consolidated Financial Statements.

(e) Change in accounting standards related to derivatives in 2001. See Note 18 of Notes to Consolidated Financial Statements.

(f) Change in accounting standards related to energy trading activities in 2002. See Note 18 of Notes to Consolidated Financial Statements.

QUARTERLY STOCK PRICES AND DIVIDENDS PER SHARE Stock Symbol: PNW

2003	High	Low	Close	Dividends Per Share	2002	High	Low	Close	Dividends Per Share
1st Quarter	\$ 37.13	\$ 28.34	\$ 33.24	\$ 0.425	1st Quarter	\$ 45.60	\$ 39.36	\$ 45.35	\$ 0.400
2nd Quarter	39.59	31.35	37.45	0.425	2nd Quarter	46.68	37.08	39.50	0.400
3rd Quarter	38.03	32.87	35.50	0.425	3rd Quarter	39.72	25.82	27.76	0.400
4th Quarter	40.48	34.91	40.02	0.450	4th Quarter	34.36	21.70	34.09	0.425

GLOSSARY

- ACC** – Arizona Corporation Commission
- ADEQ** – Arizona Department of Environmental Quality
- AFUDC** – allowance for funds used during construction
- ALJ** – Administrative Law Judge
- ANPP** – Arizona Nuclear Power Project, also known as Palo Verde
- APS** – Arizona Public Service Company, a subsidiary of the Company
- APS Energy Services** – APS Energy Services Company, Inc., a subsidiary of the Company
- CC&N** – Certificate of Convenience and Necessity
- Cholla** – Cholla Power Plant
- Citizens** – Citizens Communications Company
- Clean Air Act** – the Clean Air Act, as amended
- Company** – Pinnacle West Capital Corporation
- CPUC** – California Public Utility Commission
- DOE** – United States Department of Energy
- EITF** – the FASB’s Emerging Issues Task Force
- El Dorado** – El Dorado Investment Company, a subsidiary of the Company
- EPA** – United States Environmental Protection Agency
- ERMIC** – the Company’s Energy Risk Management Committee
- FASB** – Financial Accounting Standards Board
- FERC** – United States Federal Energy Regulatory Commission
- FIN** – FASB Interpretation
- Financing Order** – ACC Order that authorized APS’ \$500 million loan to Pinnacle West Energy in May 2003
- Four Corners** – Four Corners Power Plant
- GAAP** – accounting principles generally accepted in the United States of America
- IRS** – United States Internal Revenue Service
- ISO** – California Independent System Operator
- kW** – kilowatt, one thousand watts
- kWh** – kilowatt-hour, one thousand watts per hour
- Moody’s** – Moody’s Investors Service
- MW** – megawatt, one million watts
- MWh** – megawatt-hours, one million watts per hour
- NAC** – NAC International Inc., a subsidiary of El Dorado
- Native Load** – retail and wholesale sales supplied under traditional cost-based rate regulation
- 1999 Settlement Agreement** – comprehensive settlement agreement related to the implementation of retail electric competition
- NRC** – United States Nuclear Regulatory Commission
- Nuclear Waste Act** – Nuclear Waste Policy Act of 1982, as amended
- OCI** – other comprehensive income
- Palo Verde** – Palo Verde Nuclear Generating Station
- PCAOB** – Public Company Accounting Oversight Board
- PG&E** – PG&E Corp.
- Pinnacle West** – Pinnacle West Capital Corporation, the Company
- Pinnacle West Energy** – Pinnacle West Energy Corporation, a subsidiary of the Company
- PWEC Dedicated Assets** – the following Pinnacle West Energy power plants, each of which is dedicated to serving APS’ customers: Redhawk Units 1 and 2, West Phoenix Units 4 and 5 and Saguaro Unit 3
- PX** – California Power Exchange
- Rules** – ACC retail electric competition rules
- Salt River Project** – Salt River Project Agricultural Improvement and Power District
- SCE** – Southern California Edison Company
- SEC** – United States Securities and Exchange Commission
- SFAS** – Statement of Financial Accounting Standards
- SNWA** – Southern Nevada Water Authority
- SPE** – special-purpose entity
- Standard & Poor’s** – Standard & Poor’s Corporation
- SunCor** – SunCor Development Company, a subsidiary of the Company
- T&D** – transmission and distribution
- Track A Order** – ACC order dated September 10, 2002 regarding generation asset transfers and related issues
- Track B Order** – ACC order dated March 14, 2003 regarding competitive solicitation requirements for power purchases by Arizona’s investor-owned electric utilities
- Trading** – energy-related activities entered into with the objective of generating profits on changes in market prices
- VIE** – variable interest entity

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

INTRODUCTION

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

OVERVIEW

We own all of the outstanding common stock of APS. APS is a vertically integrated electric utility that provides either retail or wholesale electric service to substantially all of the state of Arizona, with the major exceptions of the Tucson metropolitan area and about one-half of the Phoenix metropolitan area. Through its marketing and trading division, APS also generates, sells and delivers electricity to wholesale customers in the western United States. APS has historically accounted for a substantial part of our revenues and earnings. Growth in APS' service territory is about three times the national average and remains a fundamental driver of our revenues and earnings.

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

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

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

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

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

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

EARNINGS CONTRIBUTIONS BY SUBSIDIARY AND BUSINESS SEGMENTS

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

- our regulated electricity segment, which consists of traditional regulated retail and wholesale electricity businesses and related activities and includes electricity generation, transmission and distribution;

- our marketing and trading segment, which consists of our competitive energy business activities, including wholesale marketing and trading and APS Energy Services' commodity-related energy services. In early 2003, we moved our marketing and trading activities to APS from Pinnacle West (existing wholesale contracts

remained at Pinnacle West) as a result of the ACC's Track A Order prohibiting the previously required transfer of APS' generating assets to Pinnacle West Energy; and

- our real estate segment, which consists of SunCor's real estate development and investment activities.

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

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

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

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

(a) See Note 22, "Real Estate Activities – Discontinued Operations."

(b) The "Other" segment primarily includes activities related to El Dorado's investment in NAC. We recorded pretax losses of \$59 million in 2002, primarily related to NAC contracts with three customers.

- (c) Consistent with APS' October 2001 ACC filing, APS entered into contracts with its affiliates to buy power through June 2003. The contracts reflected prices based on the fully-dispatchable dedication of the PWEC Dedicated Assets to APS' Native Load customers (customers receiving power under traditional cost-based rate regulation). Beginning July 1, 2003, under the ACC Track B Order, APS was required to solicit bids for certain estimated capacity and energy requirements. Pinnacle West Energy bid and entered into a contract to supply most of these purchase power requirements in summer months through September 2006. See "Track B Order" in Note 3 for more information.
- (d) APS Energy Services' net income prior to 2003 and El Dorado's net income (loss) are primarily reported before income taxes. The income tax expense or benefit for these subsidiaries is recorded at the parent company.
- (e) In the fourth quarter of 2002 Pinnacle West Energy recorded a charge related to the cancellation of Redhawk Units 3 and 4 of approximately \$30 million after income taxes (\$49 million pretax).
- (f) As of October 1, 2002, we recorded a \$66 million after-tax charge for the cumulative effect of a change in accounting for trading activities, for the early adoption of EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." See Note 18.
- (g) APS recorded a \$15 million after-tax charge in 2001 for the cumulative effect of a change in accounting for derivatives related to the adoption of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." See Note 18.

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

RESULTS OF OPERATIONS

General

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

2003 Compared with 2002

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

- Regulated Electricity Segment – Net income was flat when comparing the two years, due to offsetting factors. Net income in 2003 was negatively impacted by higher purchased power and

fuel costs resulting from higher prices for hedged gas and purchased power; higher costs related to new power plants, net of purchased power savings; higher replacement power costs from plant outages due to higher market prices and more unplanned outages (Unit 3 of the Cholla Power Plant experienced an unplanned outage from August 3, 2003 through November, 2003 and Units 1 and 2 of the Redhawk Power Plant were substantially restricted for almost one-half of the fourth quarter to correct an equipment design defect); higher operations and maintenance costs related to increased pension and other benefits; two retail electricity price reductions; and higher depreciation expense related to increased delivery and other assets. These negative factors were offset by higher retail sales primarily due to customer growth and favorable weather; the absence of the 2002 write-off of Redhawk Units 3 and 4; lower operating costs primarily related to severance costs recorded in 2002; lower regulatory asset amortization; tax credits and favorable income tax adjustments related to prior years resolved in 2003; and higher income related to APS' return to the AFUDC method of capitalizing construction finance costs.

- Marketing and Trading Segment – Income from continuing operations decreased approximately \$49 million primarily due to lower market liquidity and deteriorating counterparty credit in the wholesale power markets in the western United States.
- Real Estate Segment – Net income improved approximately \$36 million primarily due to increased asset, land and home sales.
- Other Segment – Net income increased approximately \$39 million primarily due to NAC losses recognized in 2002.

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

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

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

Regulated Electricity Segment Revenues

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

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

Marketing and Trading Segment Revenues

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

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

Real Estate Segment Revenues

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

Other Revenues

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

2002 Compared with 2001

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

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

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

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

Regulated Electricity Segment Revenues

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

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

Marketing and Trading Segment Revenues

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

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

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

Real Estate Segment Revenues

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

Other Revenues

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

LIQUIDITY AND CAPITAL RESOURCES

Capital Needs and Resources

Capital Expenditure Requirements

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

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

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

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

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

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

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

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

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

Contractual Obligations

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

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

- (a) The long-term debt matures at various dates through fiscal year 2034 and bears interest principally at fixed rates. Interest on variable long-term debt is set at the December 31, 2003 rates. The short-term debt matures within 12 months. The weighted-average interest rate of the short-term debt is 4.26% at December 31, 2003.
- (b) The short-term debt matures within 12 months. The weighted-average interest rate of the short-term debt is 4.26% at December 31, 2003.
- (c) If currently pending legislation is enacted, our required pension contribution in 2004 would decrease to the \$25 to \$50 million range. Future pension contributions are not determinable for time periods after 2004.
- (d) Our purchase power and fuel commitments include purchases of coal, electricity, natural gas and nuclear fuel (see Note 11).
- (e) These contractual obligations include commitments for capital expenditures and other obligations.

Off-Balance Sheet Arrangements

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

APS is exposed to losses under the Palo Verde sale leaseback agreements upon the occurrence of certain events that APS does not consider to be reasonably likely to occur. Under certain circumstances (for example, the NRC issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), APS would be required to assume the debt associated with the transactions, make specified payments to the equity participants, and take title to the leased Unit 2 interests, which, if appropriate, may be required to be written down in value. If such an event had occurred as of December 31, 2003, APS would have been required to assume approximately \$268 million of debt and pay the equity participants approximately \$200 million.

Guarantees and Letters of Credit

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

Credit Ratings

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

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

Debt Provisions

Pinnacle West's and APS' debt covenants related to their respective financing arrangements include a debt-to-total-capitalization ratio and an interest coverage test. Pinnacle West and APS comply with these covenants and each anticipates it will continue to meet the covenant requirement levels. The ratio of debt to total capitalization cannot exceed 65% for each of the Company and APS individually. At December 31, 2003, the ratio was approximately 54% for Pinnacle West. At December 31, 2003, the ratio was approximately 53% for APS. The provisions regarding interest coverage require a minimum cash coverage of two times the interest requirements for each of the Company and APS. Based on 2003 results, the coverages were approximately 4 times for the Company, 4 times for the APS bank financing agreements and 15 times for the APS mortgage indenture. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants.

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

All of Pinnacle West's bank agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under these loan agreements if Pinnacle West or APS were to default under other agreements. All of APS' bank agreements contain cross-default provisions that would result in defaults and the potential acceleration of payment under these bank agreements if APS were to default under other agreements. Pinnacle West's and APS' credit agreements generally contain provisions under which the lenders could refuse to advance loans in the event of a material adverse change in financial condition or financial prospects.

Capital Needs and Resources by Company

Pinnacle West (Parent Company)

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

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

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

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

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

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

APS

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

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

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

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

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

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

Pinnacle West Energy

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

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

Other Subsidiaries

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

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

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

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

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

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

CRITICAL ACCOUNTING POLICIES

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

Regulatory Accounting

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

Pensions and Other Postretirement Benefit Accounting

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

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

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

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

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

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

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

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

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

Derivative Accounting

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

Mark-to-Market Accounting

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

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

OTHER ACCOUNTING MATTERS

Accounting for Derivative and Trading Activities

We adopted EITF 03-11 effective October 1, 2003. EITF 03-11 provides guidance on whether realized gains and losses on physically settled derivative contracts not held for trading purposes should be reported on a net or gross basis and concluded such classification is a matter of judgment that depends on the relevant facts and circumstances. In the electricity business, some contracts to purchase energy are netted against other contracts to sell energy. This is called “book-out” and usually occurs in contracts that have the same terms (quantities and delivery points) and for which power does not flow. We netted these book-outs reducing both revenues and purchased power and fuel costs in 2003, 2002 and 2001, but this did not impact our financial condition, net income or cash flows.

We adopted EITF 02-3 in the fourth quarter of 2002. We recorded a \$66 million after-tax charge in net income as a cumulative effect adjustment for the previously recorded accumulated unrealized mark-to-market on energy trading contracts that did not meet the accounting definition of a derivative. Our energy trading contracts that are derivatives are accounted for at fair value under SFAS No. 133. Contracts that do not meet the definition of a derivative are now accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received.

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

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

Asset Retirement Obligations

On January 1, 2003, we adopted SFAS No. 143, “Accounting for Asset Retirement Obligations.” The standard requires the fair value of asset retirement obligations to be recorded as a liability, along with an offsetting plant asset, when the obligation is incurred. Accretion of the liability due to the passage of time is an operating expense and the capitalized cost is depreciated over the useful life

of the long-lived asset. (See Note 1 for more information regarding our previous accounting for removal costs.)

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

Variable Interest Entities

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

FACTORS AFFECTING OUR FINANCIAL OUTLOOK

APS General Rate Case

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

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

Wholesale Power Market Conditions

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

Generation Construction Program

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

Factors Affecting Operating Revenues

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

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

Retail Rate Changes As part of the 1999 Settlement Agreement, APS agreed to a series of annual retail electricity price reductions of 1.5% on July 1 for each of the years 1999 to 2003 for a total of 7.5%. The final price reduction was implemented July 1, 2003. See "1999 Settlement Agreement" in Note 3 for further information. In addition, the Company has requested a 9.8% retail rate increase to be effective July 1, 2004. See "APS General Rate Case and Retail Rate Adjustment Mechanisms" in Note 3 for further information.

Other Factors Affecting Future Financial Results

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

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

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

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

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

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

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

Retail Competition The regulatory developments and legal challenges to the Rules discussed in Note 3 have raised considerable uncertainty about the status and pace of retail electric competition and of electric restructuring in Arizona. Although some very limited retail competition existed in APS' service area in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to APS' customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter APS' service territory.

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

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

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

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

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

Market Risks

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

Interest Rate and Equity Risk

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

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

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

Commodity Price Risk

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

instruments that qualify as derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. Our ERM, consisting of officers and key management personnel, oversees company-wide energy risk management activities and monitors the results of marketing and trading

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

The mark-to-market value of derivative instruments related to our risk management and trading activities are presented in two categories consistent with our business segments:

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

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

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

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

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

Regulated Electricity

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

Marketing and Trading

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

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

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

(a) These contracts are primarily structured sales activities hedged with a portfolio of forward purchases that protects the economic value of the sales transactions.

(b) These contracts are hedges of our forecasted purchases of natural gas and electricity. The impact of these hypothetical price movements would substantially offset the impact that these same price movements would have on the physical exposures being hedged.

Credit Risk

We are exposed to losses in the event of nonperformance or non-payment by counterparties. We have risk management and trading contracts with many counterparties, including two counterparties for which a worst case exposure represents approximately 37% of our \$237 million of risk management and trading assets as of December 31, 2003. See Note 1, “Mark-to-Market Accounting” for a discussion of our credit valuation adjustment policy. See Note 18 for further discussion of credit risk.

Forward-Looking Statements

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

- state and federal regulatory and legislative decisions and actions, including the outcome of the rate case APS filed with the ACC on June 27, 2003 and the wholesale electric price mitigation plan adopted by the FERC;

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

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

- Management is responsible for establishing and maintaining effective internal control over financial reporting of Pinnacle West Capital Corporation and Subsidiaries (the "Company"). The internal control contains monitoring mechanisms, and actions are taken to correct deficiencies identified.

- There are inherent limitations in the effectiveness of any internal control, including the possibility of human error and the circumvention or overriding of controls. Accordingly, even effective internal controls can provide only reasonable assurance with respect to financial statement preparation. Further, because of changes in conditions, the effectiveness of internal control may vary over time.
- Management evaluated the Company's internal control over financial reporting as of December 31, 2003. This assessment was based on criteria for effective internal control over financial reporting described in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2003.

March 11, 2004

INDEPENDENT ACCOUNTANTS' REPORT

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

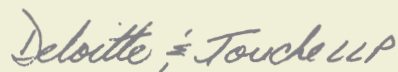
We have examined the accompanying management's assertion that Pinnacle West Capital Corporation and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2003, based on the criteria established in *Internal Control-Integrated Framework* issued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

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

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

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

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



DELOITTE & TOUCHE LLP
Phoenix, Arizona
March 11, 2004

INDEPENDENT AUDITORS' REPORT

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

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

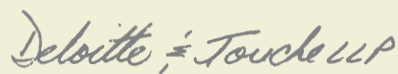
We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining,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

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

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

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

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

The logo for Deloitte & Touche LLP, featuring the company name in a stylized, cursive script font.

DELOITTE & TOUCHE LLP
Phoenix, Arizona
March 11, 2004

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

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

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS (dollars in thousands)

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

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS (dollars in thousands)

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

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS (dollars in thousands)

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

See Notes to Consolidated Financial Statements.

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

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

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Consolidation and Nature of Operations

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

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

Accounting Records and Use of Estimates

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

Derivative Accounting

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal and emissions allowances. We manage risks associated with these market fluctuations by utilizing various commodity instruments that qualify as derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. As part of our overall risk management program, we use such

instruments to hedge purchases and sales of electricity, fuels, and emissions allowances and credits. In addition, subject to specified risk parameters monitored by the ERM, we engage in marketing and trading activities intended to profit from market price movements.

We account for our derivative contracts in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 requires that entities recognize all derivatives as either assets or liabilities on the balance sheet and measure those instruments at fair value. Changes in the fair value of derivative instruments are either recognized periodically in income or, if hedge criteria are met, in common stock equity (as a component of other comprehensive income (loss)). SFAS No. 133 provides a scope exception for contracts that meet the normal purchases and sales criteria specified in the standard.

Prior to the fourth quarter of 2002, we accounted for our trading activity at fair value, with changes in fair value reported in earnings as required by EITF 98-10 "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." In the fourth quarter of 2002, we adopted EITF 02-3 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," which rescinded EITF 98-10. We recorded a \$66 million after-tax charge in net income as a cumulative effect adjustment for the previously recorded accumulated unrealized mark-to-market on energy trading contracts that did not meet the accounting definition of a derivative. Our energy trading contracts that are derivatives are accounted for at fair value under SFAS No. 133. Energy trading contracts that do not meet the definition of a derivative are now accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received.

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

Mark-to-Market Accounting

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

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

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

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

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

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

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

Regulatory Accounting

APS is regulated by the ACC and the FERC. The accompanying financial statements reflect the rate-making policies of these commissions. For regulated operations, we prepare our financial statements in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in its financial statements. As a result, we capitalize certain costs that would be included as expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent the recovery of expected future costs in current customer rates.

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

As part of the 1999 Settlement Agreement with the ACC (see Note 3), we continue to amortize certain regulatory assets over an eight-year period as follows (dollars in millions):

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

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

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

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

(b) See "Reacquired Debt Costs" below.

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

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

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

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

Rate Synchronization Cost Deferrals

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

Utility Plant and Depreciation

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

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

We expense the costs of plant outages, major maintenance and routine maintenance as incurred. We charge retired utility plant to accumulated depreciation. Prior to 2003, we charged removal costs, less salvage, to accumulated depreciation. Effective January 1, 2003, we applied the provisions of SFAS 143 (see Note 12).

We record depreciation on utility plant on a straight-line basis over the remaining useful life of the related assets. The approximate remaining average useful lives of our utility property at December 31, 2003 were as follows:

- Fossil plant – 23 years;
- Nuclear plant – 20 years;
- Other generation – 29 years;
- Transmission – 36 years;

- Distribution – 23 years; and
- Other – 9 years.

For the years 2001 through 2003, the depreciation rates, as prescribed by our regulators, ranged from a low of 1.51% to a high of 12.5%. The weighted-average rate was 3.35% for 2003, 3.35% for 2002 and 3.40% for 2001. We depreciate non-utility property and equipment over the estimated useful lives of the related assets, ranging from 3 to 30 years.

El Dorado Investments

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

Capitalized Interest

Capitalized interest represents the cost of debt funds used to finance construction projects. Plant construction costs, including capitalized interest, are expensed through depreciation when completed projects are placed into commercial operation. The rate used to calculate capitalized interest was a composite rate of 4.55% for 2003, 4.80% for 2002 and 6.13% for 2001. Capitalized interest ceases to accrue when construction is complete.

Allowance for Funds Used During Construction

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

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

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

Electric Revenues

We derive electric revenues from sales of electricity to our regulated Native Load customers and sales to other parties from our marketing and trading activities. Revenues related to the sale of

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

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

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

SunCor

SunCor recognizes revenue from land, home and qualifying commercial operating assets sales in full, provided (a) the income is determinable, that is, the collectibility of the sales price is reasonably assured or the amount that will not be collectible can be estimated, and (b) the earnings process is virtually complete, that is, SunCor is not obligated to perform significant activities after the sale to earn the income. Unless both conditions exist, recognition of all or part of the income is postponed. SunCor recognizes income only after the assets' title has passed. A single method of recognizing income is applied to all sales transactions within an entire home, land or commercial development project. Commercial property and management revenues are recorded over the term of the lease or period in which services are provided. In addition, see Note 22 – Real Estate Activities – Discontinued Operations.

Percentage of Completion – NAC

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

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

Cash and Cash Equivalents

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

Nuclear Fuel

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

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

Income Taxes

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

Board of Directors

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Officers

PINNACLE WEST

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

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

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

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

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

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

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

ARIZONA PUBLIC SERVICE

William J. Post
Chairman of the Board

Jack E. Davis
President
& Chief Executive Officer

Donald E. Brandt
Executive Vice President
& Chief Financial Officer

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

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

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

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

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

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

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

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

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

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

Barbara M. Gomez
Vice President & Treasurer

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

Nancy C. Loftin
Vice President, General
Counsel & Secretary

David Mauldin (54) 1990
Vice President,
Nuclear Engineering

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

PINNACLE WEST ENERGY

James M. Levine
President
& Chief Executive Officer

Donald E. Brandt
Chief Financial Officer

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

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

SUNCOR DEVELOPMENT

William J. Post
Chairman of the Board

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

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

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

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

Steven Gervais (48) 1987
Vice President
& General Counsel

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

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

APS ENERGY SERVICES

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

EL DORADO INVESTMENT

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

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

Shareholder Information

CORPORATE HEADQUARTERS

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

Main telephone number: (602) 250-1000

ANNUAL MEETING OF SHAREHOLDERS

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

STOCK LISTING

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

FORM 10-K

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

INVESTORS ADVANTAGE PLAN

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

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

CORPORATE WEB SITE

www.pinnaclewest.com

TRANSFER AGENTS AND REGISTRAR

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

SHAREHOLDER ACCOUNT AND ADMINISTRATIVE INFORMATION

Shareholder Department telephone number (toll-free): (800) 457-2983

STATISTICAL REPORT

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

INVESTOR RELATIONS CONTACTS

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

STATEWIDE ASSOCIATION FOR UTILITY INVESTORS

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

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

ENVIRONMENTAL, HEALTH AND SAFETY REPORT

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

 printed on recycled paper.

IMPORTANT NOTICE TO SHAREHOLDERS:

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

