

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

INTRODUCTION

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

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

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

BUSINESS OVERVIEW

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

Our other major subsidiaries are:

- Pinnacle West Energy, through which we conduct our competitive electricity generation operations;
- APS Energy Services, which provides competitive commodity-related energy services (such as direct access commodity contracts, energy procurement and energy supply consultation) and energy-related products and services (such as energy master planning, energy use

consultation and facility audits, cogeneration analysis and installation and project management) to commercial, industrial and institutional retail customers in the western United States;

- SunCor, a developer of residential, commercial, and industrial real estate projects in Arizona, New Mexico, and Utah; and
- El Dorado, which owns a majority interest in NAC (specializing in spent nuclear fuel technology) and holds miscellaneous small investments, including interests in Arizona community-based ventures.

SUMMARY OF KEY FACTORS AFFECTING OUR FINANCIAL OUTLOOK

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

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

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

EARNINGS CONTRIBUTIONS BY SUBSIDIARY AND BUSINESS SEGMENT

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

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

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

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

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

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

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

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

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

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

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

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

RESULTS OF OPERATIONS

General

Throughout the following explanations of our results of operations, we refer to "gross margin." With respect to our regulated electricity segment and marketing and trading segment, gross margin refers to electric operating revenues less purchased power and fuel costs. Our real estate segment gross margin refers to real estate revenues less real estate operations costs of SunCor. Other gross margin refers to other operating revenues less other operating expenses, which includes El Dorado's investment in NAC, which we began consolidating in our financial statements in July 2002 (see Note 22). Other gross margin also includes amounts related to APS Energy Services' energy consulting services.

2002 Compared with 2001

Our consolidated net income for the year ended December 31, 2002 was \$149 million compared with \$312 million for the prior year. We recognized a \$66 million after-tax charge in 2002 for the cumulative effect of a change in accounting for trading activities for the early adoption of EITF 02-3 on October 1, 2002 (see Note 18). In 2001, we recognized a \$15 million after-tax charge for the cumulative effect of a change in accounting for derivatives, as required by SFAS No. 133 (see Note 18).

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

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

The above decreases were partially offset by:

- increased earnings contributions from our regulated electricity activities, reflecting lower replacement power costs for power plant outages,

retail customer growth and higher average usage per customer, partially offset by the effects of milder weather, retail electricity price decreases and higher costs for purchased power and gas due to higher hedged gas and power prices; and

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

For additional details, see the following discussion.

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

(dollars in millions)	Increase (Decrease)
Regulated electricity segment gross margin:	
Lower replacement power costs for plant outages due to lower market prices and fewer unplanned outages	\$ 127
Increased purchased power and fuel costs due to higher hedged gas and power prices, partially offset by improved hedge management, net of mark-to-market reversals	(9)
Higher retail sales volumes due to customer growth and higher average usage, excluding weather effects	38
2001 charges related to purchased power contracts with Enron and its affiliates	13
Retail price reductions effective July 1, 2001 and July 1, 2002	(28)
Effects of milder weather on retail sales	(27)
Miscellaneous factors, net	(2)
Net increase in regulated electricity segment gross margin	112
Marketing and trading segment gross margin:	
Decrease in generation sales other than Native Load due to lower market prices partially offset by higher sales volumes	(66)
Lower realized wholesale margins net of related mark-to-market reversals due to lower prices and volumes	(91)
Higher competitive retail sales in California by APS Energy Services	32
2001 write-off of prior period mark-to-market value related to trading with Enron and its affiliates	8
Lower mark-to-market reversals due to the adoption of EITF 02-3	8
Lower mark-to-market gains for future delivery due to lower market liquidity and lower price volatility	(76)
Net decrease in marketing and trading segment gross margin	(185)
Net decrease in regulated electricity and marketing and trading segments' gross margins	(73)
Higher real estate segment gross margin primarily due to increased sales activities	16
Lower other gross margin primarily related to NAC losses	(44)
Higher operations and maintenance expense related to a \$47 million write-off of Redhawk Units 3 and 4 and 2002 severance costs of approximately \$36 million, partially offset by lower generation reliability costs	(54)
Higher taxes other than income taxes	(7)
Lower other income primarily due to a 2001 insurance recovery of environmental remediation costs	(11)
Higher net interest expense primarily due to higher debt balances and lower capitalized interest	(16)
Miscellaneous factors, net	2
Net decrease in income before income taxes	(187)
Lower income taxes primarily due to lower income	75
Net decrease in income before accounting change	\$ (112)

REGULATED ELECTRICITY SEGMENT GROSS MARGIN

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

- decreased revenues related to traditional wholesale sales as a result of lower sales volumes and lower prices (\$64 million);
- decreased revenues related to retail load hedge management wholesale sales, primarily as a result of lower prices and lower sales volumes (\$455 million);
- decreased retail revenues related to milder weather (\$60 million);
- increased retail revenues related to customer growth and higher average usage, excluding weather effects (\$69 million);

- decreased retail revenues related to reductions in retail electricity prices (\$28 million); and
- other miscellaneous factors (\$11 million net decrease).

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

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

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

MARKETING AND TRADING SEGMENT GROSS MARGIN

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

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

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

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

OTHER INCOME STATEMENT ITEMS

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

The decrease in other gross margin of \$44 million was primarily due to losses on El Dorado's investment in NAC (see further discussion in Note

22). These losses for 2002 totaled approximately \$59 million on a pretax basis and were primarily related to NAC contracts with two customers (\$51 million was recorded in other gross margin and \$8 million was recorded in other expense). We believe we have reserved our exposure with respect to these contracts in all material respects and, as a result, we consider these charges to be non-recurring.

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

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

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

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

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

2001 Compared with 2000

Our consolidated net income for the year ended December 31, 2001 was \$312 million compared with \$302 million for the prior year. In 2001, we recognized a \$15 million after-tax charge for the cumulative effect of a change in accounting for derivatives, as required by SFAS No. 133 (see Note 18).

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

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

The above increases were partially offset by:

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

For additional details, see the following discussion.

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

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

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

REGULATED ELECTRICITY SEGMENT GROSS MARGIN

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

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

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

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

MARKETING AND TRADING SEGMENT GROSS MARGIN

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

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

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

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

OTHER INCOME STATEMENT ITEMS

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

The increase in operations and maintenance expenses of \$80 million primarily related to the 2001 generation summer reliability program (the addition of generating capability to enhance reliability for the summer of 2001 (\$42 million)) and increased employee benefit costs, plant outage and maintenance and other costs (\$38 million). The comparison reflects Pinnacle West's \$10 million provision for our credit exposure related to the California energy situation, \$5 million of which was recorded in the fourth quarter of 2000 and \$5 million of which was recorded in the first quarter of 2001.

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

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

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

LIQUIDITY AND CAPITAL RESOURCES

Capital Needs and Resources

CAPITAL EXPENDITURE REQUIREMENTS

The following table summarizes the actual capital expenditures for the year ended December 31, 2002 and estimated capital expenditures for the next three years.

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

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

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

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

Delivery capital expenditures are comprised of T&D infrastructure additions and upgrades, capital replacements, new customer construction and related information systems and facility costs. Examples of the types of projects included in the forecast include T&D lines and substations, line extensions to new residential and commercial developments and upgrades to customer information systems. In addition, APS began several major transmission projects in 2001. These projects are periodic in nature and are driven by strong regional customer growth. APS expects to spend about \$105 million on major transmission projects during the 2003 to 2005 time frame, and these amounts are included in "APS-Delivery" in the table above.

Generation capital expenditures are comprised of various improvements for APS' existing fossil and nuclear plants and the replacement of Palo Verde steam generators. Examples of the types of projects included in this category are additions, upgrades and capital replacements of various power plant equipment such as turbines, boilers and environmental equipment. Generation also contains nuclear fuel expenditures of approximately \$30 million annually for 2003 to 2005.

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

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

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

Contractual Obligations

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

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

Off-Balance Sheet Arrangements

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

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

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

Guarantees

We and certain of our subsidiaries have issued guarantees in support of our unregulated businesses. We have also obtained surety bonds on behalf of APS Energy Services. We have not recorded any liability on our Consolidated Balance Sheets with respect to these obligations. See Note 23 for additional information regarding guarantees.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of March 28, 2003 are shown below and are considered to be "investment-grade" ratings. The ratings reflect the respective views of the rating agencies, from which an explanation of the significance of their ratings may be obtained. There is no assurance that these ratings will continue for any given period of time. The ratings may be revised or withdrawn entirely by the rating agencies, if, in their respective judgments, circumstances so warrant. Any downward revision or withdrawal may adversely affect the market price of Pinnacle West's or APS' securities and serve to increase those companies' cost of and access to capital.

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

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

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

Debt Provisions

Pinnacle West's and APS' significant debt covenants related to their respective financing arrangements include debt-to-total-capitalization ratio and an interest coverage test. Pinnacle West and APS are in compliance with such covenants and each anticipates it will continue to meet all the significant covenant requirement levels. The ratio of debt to total capitalization cannot exceed 65% for both the Company and APS. At December 31, 2002, the ratios are approximately 54% and 48% for the parent company and APS, respectively. The provisions regarding interest coverage require a minimum cash coverage of two times the interest requirements for both the Company and APS. The coverages are approximately 4 times for the parent company, 5 times for the APS bank agreements and 15 times for the APS mortgage indenture. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants.

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

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

Pinnacle West (Parent Company)

Our primary cash needs are for dividends to our shareholders; equity infusions into our subsidiaries, primarily Pinnacle West Energy; and interest payments and optional and mandatory repayments of principal on our long-term debt (see the table above for our contractual requirements, including our debt repayment obligations, but excluding optional repayments). On October 23, 2002, our board of directors increased the common stock dividend to an indicated annual rate of \$1.70 per share from \$1.60 per share, effective with the December 1, 2002 dividend payment. The level of our common dividends and future dividend growth will be dependent on a number of factors including, but not limited to, payout ratio trends, free cash flow and financial market conditions.

Our primary sources of cash are dividends from APS, external financings, and cash distributions from our other subsidiaries, primarily SunCor. For the years 2000 through 2002, total dividends from APS were \$510 million and total distributions from SunCor were \$33 million. For the year ended December 31, 2002, dividends from APS were approximately \$170 million and distributions from SunCor were approximately \$13 million. We expect SunCor to make cash distributions to the parent company of \$80 million to \$100 million annually in 2003 through 2005 due to anticipated accelerated asset sales activity.

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

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

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

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

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

As part of a multi-employer pension plan sponsored by Pinnacle West, we contribute at least the minimum amount required under IRS regulations, but no more than the maximum tax-deductible amount. The minimum required funding takes into consideration the value of the fund assets and our pension obligation. We elected to contribute cash to our pension plan in each of the last five years; our minimum required contributions during each of those years was zero. Specifically, we contributed \$27 million for 2002, \$24 million for 2001, \$44 million for 2000, \$25 million for 1999 and \$14 million for 1998. APS and other subsidiaries fund their share of the pension contribution, of which APS represents approximately 90% of the total funding amounts described above. The assets in the plan are mostly domestic common stocks, bonds and real estate. We currently forecast a pension contribution in 2003 of approximately \$50 million, all or part of which may be required. If the fund performance continues to decline as a result of a continued decline in equity markets, larger contributions may be required in future years.

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

APS

APS' capital requirements consist primarily of capital expenditures and optional and mandatory redemptions of long-term debt. See "Factors Affecting Our Financial Outlook – Regulatory Matters" below and Note 3 for discussion of the \$500 million financing arrangement between APS and Pinnacle West Energy recently approved by the ACC. See "Pinnacle West (Parent Company)" above and Note 3 for discussion of a \$125 million financing arrangement between APS and Pinnacle West.

APS pays for its capital requirements with cash from operations and, to the extent necessary, external financings. APS has historically paid for its dividends to Pinnacle West with cash from operations.

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

APS' outstanding debt was approximately \$2.2 billion at December 31, 2002. At December 31, 2002, APS had credit commitments from various banks totaling about \$250 million, which were available either

to support the issuance of commercial paper or to be used as bank borrowings. At December 31, 2002, APS had no outstanding commercial paper or bank borrowings.

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

Pinnacle West Energy

The costs of Pinnacle West Energy's construction of generating capacity from 2000 through 2004 are expected to be about \$1.4 billion. This does not reflect an expected reimbursement in 2004 by SNWA of about \$100 million of Pinnacle West Energy's cumulative capital expenditures in the Silverhawk project assuming SNWA exercises its option to purchase a 25% interest in the project. Pinnacle West Energy is currently funding its capital requirements through capital infusions from Pinnacle West, which finances those infusions through debt and equity financings and internally-generated cash. See the capital expenditures table above for actual capital expenditures in 2002 and projected capital expenditures for the next three years.

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

Other Subsidiaries

During the past three years, SunCor funded its cash requirements with cash from operations and its own external financings. SunCor's capital needs consist primarily of capital expenditures for land development and retail and office building construction. See the capital expenditures table above for actual capital expenditures in 2002 and projected capital expenditures for the next three years. SunCor expects to fund its capital requirements with cash from operations and external financings.

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

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

We expect SunCor to make cash distributions to the parent company of \$80 to \$100 million annually in 2003 through 2005 due to anticipated accelerated asset sales activity.

El Dorado funded its cash requirements during the past three years, primarily for NAC in 2002, with cash infused by the parent company and with cash from operations. El Dorado expects minimal capital requirements over the next three years and intends to focus on prudently realizing the value of its existing investments. El Dorado's long-term debt was approximately \$3 million at December 31, 2002 and it had no long-term debt outstanding at December 31, 2001. El Dorado's long-term debt increased primarily due to its consolidation of NAC for financial reporting purposes (see Notes 6 and 22).

APS Energy Services' cash requirements during the past three years were funded with cash infusions from the parent company. APS Energy Services' capital expenditures and other cash requirements are increasingly funded by operations, with some funding from cash infused by Pinnacle West. See the capital expenditures table above regarding APS Energy Services' actual capital expenditures for 2002 and projected capital expenditures for the next three years.

CRITICAL ACCOUNTING POLICIES

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

- **Regulatory Accounting** – Regulatory accounting allows for the actions of regulators, such as the ACC and the FERC, to be reflected in the financial statements. Their actions may cause us to capitalize costs that would otherwise be included as an expense in the current period by unregulated companies.
- **Pensions and Other Postretirement Benefit Accounting** – Changes in our actuarial assumptions used in calculating our pension and other postretirement benefit liability and expense can have a significant impact on our earnings and financial position. The most relevant actuarial assumptions are the discount rate used to measure our liability and the expected long-term rate of return on plan assets used to estimate earnings on invested funds over the long-term.
- **Derivative Accounting** – Derivative accounting requires evaluation of rules that are complex and subject to varying interpretations. Our evaluation of these rules, as they apply to our contracts, will determine whether we use accrual accounting or fair value (mark-to-market) accounting. Mark-to-market accounting requires that changes in fair value be recorded in earnings or, if certain hedge accounting criteria are met, in other comprehensive income.
- **Mark-to-Market Accounting** – The market value of our derivative contracts is not always readily determinable. In some cases, we use models and other valuation techniques to determine fair value. The

use of these models and valuation techniques sometimes requires subjective and complex judgment. Actual results could differ from the results estimated through application of these methods. Our marketing and trading portfolio consists of structured activities hedged with a portfolio of forward purchases that protects the economic value of the sales transactions.

See the discussion below for further details on our critical accounting policies.

Regulatory Accounting

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

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

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

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

Pensions and Other Postretirement Benefit Accounting

We sponsor a qualified defined benefit pension plan and a non-qualified supplemental excess benefit retirement plan for our employees and employees of our subsidiaries. Our reported costs of providing defined pension and other postretirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. Pension and other postretirement benefit costs, for

example, are impacted by actual employee demographics (including age, compensation levels and employment periods), the level of contributions we make to the plans and earnings on plan assets. Changes made to the provisions of the plans may also impact current and future pension and other postretirement benefit costs. Pension and other postretirement benefit costs may also be significantly affected by changes in key actuarial assumptions, including the expected long-term rate of return on plan assets and the discount rates used in determining the projected benefit obligation and pension and other postretirement benefit costs.

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

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

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

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

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

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

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

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

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

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

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

In selecting the pretax expected long-term rate of return on plan assets, we consider past performance and economic forecasts for the types of investments held by the plan. The market value of the plan assets has been affected by sharp declines in the equity markets. For 2003, we decreased our pretax expected long-term rate of return on plan assets from 10% to 9%, as a result of continued declines in general equity and bond market returns.

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

Derivative Accounting

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

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

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

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

Mark-to-Market Accounting

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

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

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

For options, long-term contracts and other contracts for which price quotes are not available, we use models and other valuation methods. The valuation models we employ utilize spot prices, forward prices, historical market data and other factors to forecast future prices. The

primary valuation technique we use to calculate the fair value of contracts where price quotes are not available is based on the extrapolation of forward pricing curves using observable market data for more liquid delivery points in the same region and actual transactions at the more illiquid delivery points. We also value option contracts using a variation of the Black-Scholes option-pricing model.

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

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

The use of models and other valuation methods to determine fair market value often requires subjective and complex judgment. Actual results could differ from the results estimated through application of these methods. Our marketing and trading portfolio includes structured activities hedged with a portfolio of forward purchases that protects the economic value of the sales transactions. To illustrate, as presented in the "Factors Affecting our Financial Outlook – Market Risks – Commodity Price Risk" section below, a 10% increase in the price of trading commodities would result in only a \$2 million decrease in pretax income. Our practice is to hedge within timeframes established by the ERM.

OTHER ACCOUNTING MATTERS

Accounting for Derivative and Trading Activities

During 2002, the EITF discussed EITF 02-3 and reached a consensus on certain issues. EITF 02-3 rescinded EITF 98-10 and was effective October 25, 2002 for any new contracts, and on January 1, 2003 for existing contracts, with early adoption permitted. We adopted the EITF 02-3 guidance for all contracts in the fourth quarter of 2002. We recorded a \$66 million after-tax charge in net income as a cumulative effect adjustment for the previously recorded accumulated unrealized

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

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

In 2001, we adopted SFAS No. 133 and recorded a \$15 million after-tax charge in net income and a \$72 million after-tax credit in common stock equity (as a component of other comprehensive income), both as a cumulative effect of a change in accounting for derivatives. See Notes 1 and 18 for further information on accounting for derivatives under SFAS No. 133.

Asset Retirement Obligations

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

We determined that we have asset retirement obligations for our nuclear facilities (nuclear decommissioning) and certain other generation, transmission and distribution assets. On January 1, 2003 we recorded a liability of \$219 million for our asset retirement obligations including the accretion impacts; a \$67 million increase in the carrying amount of the associated assets; and a net reduction of \$192 million in accumulated depreciation related primarily to the reversal of previously recorded accumulated decommissioning and other removal costs related to these

obligations. Additionally, we recorded a regulatory liability of \$40 million for our asset retirement obligations related to our regulated utility. This regulatory liability represents the difference between the amount currently being recovered in regulated rates and the amount calculated under SFAS No. 143. We believe we can recover in regulated rates the transition costs and ongoing current period costs calculated in accordance with SFAS No. 143.

Stock-Based Compensation

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

Variable Interest Entities

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

Other

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

FACTORS AFFECTING OUR FINANCIAL OUTLOOK

Regulatory Matters

GENERAL

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

1999 SETTLEMENT AGREEMENT

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

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

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

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

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

APS FINANCING APPLICATION

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

TRACK A ORDER

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

COMPETITIVE PROCUREMENT PROCESS

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

for about 2,500 MW of capacity and about 4,600 gigawatt-hours of energy, or approximately 20% of APS' total retail energy requirements. The bid amounts are expected to increase in 2004 and 2005 based largely on growth in APS' retail load and APS' retail energy sales. The Track B Order also confirmed that it was "not intended to change the current rate base status of [APS'] existing assets." The order recognizes APS' right to reject any bids that are unreasonable, uneconomical or unreliable.

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

APS GENERAL RATE CASE

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

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

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

WHOLESALE POWER MARKET CONDITIONS

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

GENERATION CONSTRUCTION

See "Capital Needs and Resources – Pinnacle West Energy" above and Note 11 for information regarding Pinnacle West Energy's generation construction program. The planned additional generation is expected to increase revenues, fuel expenses, operating expenses and financing costs.

FACTORS AFFECTING OPERATING REVENUES

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

Customer Growth Customer growth in APS' service territory averaged about 3.6% a year for the three years 2000 through 2002; we currently expect customer growth to average about 3.5% per year from 2003 to 2005. We currently estimate that retail electricity sales in kilowatt-hours will grow 3.5% to 5.5% a year in 2003 through 2005, before the retail effects of weather variations. The customer growth and sales growth referred to in this paragraph applies to energy delivery customers. As previously noted, under the 1999 Settlement Agreement, we agreed to retail electricity price reductions of 1.5% annually through July 1, 2003 (see Note 3).

OTHER FACTORS AFFECTING FUTURE FINANCIAL RESULTS

Purchased Power and Fuel Costs Purchased power and fuel costs are impacted by our electricity sales volumes, existing contracts for purchased power and generation fuel, our power plant performance, prevailing market prices, new generating plants being placed in service and our hedging program for managing such costs.

Operations and Maintenance Expenses Operations and maintenance expenses are expected to be affected by sales mix and volumes, power plant additions and operations, inflation, outages, higher trending pension and other postretirement benefit costs and other factors. In July 2002, we implemented a voluntary workforce reduction as part of our cost reduction program. We recorded \$36 million before taxes in voluntary severance costs in the second half of 2002. In addition, we are expecting to produce annual operating expense savings of approximately \$30 million beginning in 2003 as a result of this workforce reduction.

Depreciation and Amortization Expenses Depreciation and amortization expenses are expected to be affected by net additions to existing utility plant and other property, changes in regulatory asset amortization and our generation construction program. West Phoenix Unit 4 was placed in service in June 2001. Redhawk Units 1 and 2 and the new Saguaro Unit 3 began commercial operations in July 2002. West Phoenix Unit 5 is expected to be on line in mid-2003 and Silverhawk is expected to be in service in mid-2004 (see Note 11 for further details about our generation construction program). The regulatory assets to be recovered under the 1999 Settlement Agreement are currently being amortized as follows (dollars in millions):

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

Property Taxes Taxes other than income taxes consist primarily of property taxes, which are affected by tax rates and the value of property in-service and under construction. The average property tax rate for APS, which currently owns the majority of our property, was 9.7% of assessed value for 2002 and 9.3% for 2001. We expect property taxes to increase primarily due to our generation construction program and our additions to existing facilities.

Interest Expense Interest expense is affected by the amount of debt outstanding and the interest rates on that debt. The primary factors affecting borrowing levels in the next several years are expected to be our capital requirements and our internally-generated cash flow. Capitalized interest offsets a portion of interest expense while capital projects are under construction. We stop recording capitalized interest on a project when it is placed in commercial operation. As noted above, we have placed new power plants in commercial operation in 2001 and 2002 and we expect to bring additional plants on-line in 2003 and 2004. We are continuing to evaluate our generation construction program. Interest expense is affected by interest rates on variable-rate debt and interest rates on the refinancing of the Company's future liquidity needs.

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

Subsidiaries In the case of SunCor, we are undertaking an aggressive effort to accelerate asset sales activities to approximately double SunCor's

annual earnings in 2003 to 2005 compared to the \$19 million in earnings recorded in 2002. A portion of these sales could be reported as discontinued operations on the Consolidated Statements of Income.

The annual earnings contribution from APS Energy Services is expected to be positive over the next several years due primarily to a number of retail electricity contracts in California. APS Energy Services had pretax earnings of \$28 million in 2002.

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

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

Market Risks

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

INTEREST RATE AND EQUITY RISK

Our major financial market risk exposure is changing interest rates. Changing interest rates will affect interest paid on variable-rate debt and interest earned by our pension plan (see Note 8) and nuclear decommissioning trust fund (see Note 12). Our policy is to manage interest rates through the use of a combination of fixed-rate and floating-rate debt. The pension plan and nuclear decommissioning fund also have risks associated with changing market values of equity investments. Pension (APS only) and nuclear decommissioning costs are recovered in regulated electricity prices. See "Critical Accounting Policies – Pension and Other Postretirement Benefit Accounting" for a sensitivity analysis on the long-term rate of return on plan assets.

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

EXPECTED MATURITY/PRINCIPAL REPAYMENT (dollars in thousands)

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

EXPECTED MATURITY/PRINCIPAL REPAYMENT (dollars in thousands)

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

COMMODITY PRICE RISK

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

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

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

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

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

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

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

	System	Marketing and Trading
Mark-to-market of net positions at December 31, 2001	\$ (107)	\$ 138
Cumulative effect adjustment due to adoption of EITF 02-3	-	(109)
Change in mark-to-market gains for future period deliveries	(13)	47
Changes in cash flow hedges recorded in OCI	57	16
Ineffective portion of changes in fair value recorded in earnings	11	-
Mark-to-market losses/(gains) realized during the year	3	(38)
Change in valuation techniques	-	3
Mark-to-market of net positions at December 31, 2002	\$ (49)	\$ 57

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

The Company no longer reports non-derivative energy contracts or physical inventories at fair value. Since July 1, 2002, the Company has not recognized a dealer profit or unrealized gain or loss at the inception of a derivative unless the fair value of that instrument (in its entirety) is

evidenced by quoted market prices or current market transactions.

Prior to the change in our policy, we recorded net gains at inception of \$10 million in 2002 and \$3 million in 2001. These amounts included a reasonable marketing margin.

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

SYSTEM

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

MARKETING AND TRADING

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

The table below shows the impact hypothetical price movements of 10% would have on the market value of our risk management and trading assets and liabilities included on the Consolidated Balance Sheets at December 31, 2002 and 2001 (dollars in millions).

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

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

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

CREDIT RISK

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

FORWARD-LOOKING STATEMENTS

The above discussion contains forward-looking statements based on current expectations and we assume no obligation to update these statements or make any further statements on any of these issues, except as required by applicable laws. Because actual results may differ materially

from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from results or outcomes currently expected or sought by us. These factors include the ongoing restructuring of the electric industry, including the introduction of retail electric competition in Arizona and decisions impacting wholesale competition; the outcome of regulatory and legislative proceedings relating to the restructuring; state and federal regulatory and legislative decisions and actions, including price caps and other market constraints imposed by the FERC; regional economic and market conditions, including the California energy situation and completion of generation and transmission construction in the region, which could affect customer growth and the cost of power supplies; the cost of debt and equity capital and access to capital markets; weather variations affecting local and regional customer energy usage; the effect of conservation programs on energy usage; power plant performance; the successful completion of our generation construction program; regulatory issues associated with generation construction, such as permitting and licensing; our ability to compete successfully outside traditional regulated markets (including the wholesale market); our ability to manage our marketing and trading activities and the use of derivative contracts in our business; technological developments in the electric industry; the performance of the stock market, which affects the amount of our required contributions to our pension plan and nuclear decommissioning trust funds; the strength of the real estate market in SunCor's market areas, which include Arizona, New Mexico and Utah; and other uncertainties, all of which are difficult to predict and many of which are beyond our control.