

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

In this section, we explain the results of operations, general financial condition, and outlook for Pinnacle West Capital Corporation and our subsidiaries: Arizona Public Service Company (APS), Pinnacle West Energy Corporation (Pinnacle West Energy), APS Energy Services Company, Inc. (APSES), SunCor Development Company (SunCor), and El Dorado Investment Company (El Dorado) including:

- the changes in our earnings from 2000 to 2001 and from 1999 to 2000;
- our capital needs, liquidity and capital resources;
- our marketing and trading activities;
- our financial outlook;
- our critical accounting policies
- major factors that affect our financial outlook; and
- our management of market risks.

### OVERVIEW OF OUR BUSINESS

Pinnacle West owns all of the outstanding common stock of APS. APS is Arizona's largest electric utility and provides either retail or wholesale electric service to substantially all of the state, with the major exceptions of the Tucson metropolitan area and about one-half of the Phoenix metropolitan area. APS also generates and, through our marketing and trading division, sells and delivers electricity to wholesale customers in the western United States.

Our other major subsidiaries are:

- Pinnacle West Energy, through which we conduct our unregulated electricity generation operations;
- APSES, which provides commodity energy and energy-related products to key customers in competitive markets 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, an investment firm.

Pinnacle West's marketing and trading division sells in the wholesale market APS and Pinnacle West Energy generation production output that is not needed for APS' native load, which includes loads for retail customers and traditional cost-of-service wholesale customers. Subject to specified risk parameters established by our Board of Directors, the marketing and trading division also engages in activities to hedge purchases and sales of electricity, fuels, and emissions allowance and credits and to profit from market price movements. We explain in detail below the historical and prospective contribution of marketing and trading activities to our financial results.

APS is required to transfer its competitive electric assets and services to one or more corporate affiliates no later than December 31, 2002. Consistent with that requirement, APS has been addressing the legal and regulatory requirements necessary to complete the transfer of its generation assets to Pinnacle West Energy before that date. As we discuss in greater detail below under "Business Outlook – Other Factors

Affecting Our Financial Outlook," recent Arizona regulatory developments have raised uncertainty about the status and pace of retail electric competition in Arizona, including APS' transfer of generation assets to Pinnacle West Energy.

### BUSINESS SEGMENTS

We have two principal business segments (determined by products, services and regulatory environment), which consist of regulated retail electricity business and related activities (retail business segment) and competitive business activities (marketing and trading segment). Our retail business segment currently includes activities related to electricity transmission and distribution, as well as electricity generation. Our marketing and trading segment currently includes activities related to wholesale marketing and trading, and APSES' competitive energy services.

These reportable segments reflect a change in the reporting of our segment information. Before the fourth quarter of 2001, we had two segments (generation and delivery). The "generation segment" information combined our marketing and trading activities with our generation of electricity activities. The "delivery segment" included transmission and distribution activities.

In the fourth quarter, APS filed with the ACC a request for a proposed rule variance and approval of a purchase power agreement (see Note 3) that inherently views our business in the new reportable segments described as presented herein. Internal management reporting has been changed to reflect this alignment. See "Business Segments" in Note 16 for more information about our business segments.

The following is a summary of net income by business segment for 2001, 2000, and 1999:

(dollars in millions)	2001	2000	1999
Retail	\$ 152	\$ 225	\$ 246
Marketing and trading	172	63	5
Other	3	14	19
Income from continuing operations	327	302	270
Income tax benefit from discontinued operations	–	–	38
Extraordinary charge – net of income taxes	–	–	(140)
Cumulative effect of change in accounting – net of income taxes	(15)	–	–
<b>Net Income</b>	<b>\$ 312</b>	<b>\$ 302</b>	<b>\$ 168</b>

Throughout this section, we refer to specific "Notes" in the Notes to Consolidated Financial Statements that begin on page 38. These Notes add further details to the discussion.

## RESULTS OF OPERATIONS

The following is a summary of our net income by legal entity for 2001, 2000, and 1999:

(dollars in millions)	2001	2000	1999
APS	\$ 281	\$ 307	\$ 267
Pinnacle West Energy	18	(2)	–
APSES	(10)	(13)	(9)
SunCor	3	11	6
El Dorado	–	2	11
Parent company (a)	35	(3)	(5)
Income from continuing operations	327	302	270
Income tax benefit from discontinued operations	–	–	38
Extraordinary charge – net of income taxes	–	–	(140)
Cumulative effect of change in accounting – net of income taxes	(15)	–	–
<b>Net income</b>	<b>\$ 312</b>	<b>\$ 302</b>	<b>\$ 168</b>

(a) The 2001 amount primarily includes marketing and trading activities. APS also includes some marketing and trading activities. (see Note 16 for further discussion of our business segments.)

## 2001 Compared With 2000

Our consolidated net income for the year ended December 31, 2001 was \$312 million compared with \$302 million for the year ended December 31, 2000. In 2001, we recognized a \$15 million after-tax loss in net income as a cumulative effect of a change in accounting for derivatives. See Note 17 for further discussion on accounting for derivatives.

Income from continuing operations for the year ended December 31, 2001 was \$327 million compared with \$302 million for the year ended December 31, 2000. The year-to-year comparison benefited from strong marketing and trading results, including significant benefits in the 2001 third quarter from structured trading activities, and retail customer growth. These factors were partially offset by higher purchased power and fuel costs, due in part to increased power plant maintenance; generation reliability measures; continuing retail electricity price decreases; and a charge related to Enron and its affiliates.

The major factors that increased (decreased) income from continuing operations were as follows:

(dollars in millions)	INCREASE (DECREASE)
Increases (decreases) in electric revenues, net of purchased power and fuel expense due to:	
Marketing and trading activities:	
Increase from generation sales other than native load due to higher market prices	\$ 25
Increase in other realized marketing and trading in current period primarily due to more transactions	45
Change in prior year period mark-to-market value for losses transferred to realized margin in current period	16 (a)
Change in prior period mark-to-market value related to trading with Enron and its affiliates	(8)(b)
Increase in mark-to-market value related to future periods	113 (a)
Net increase in marketing and trading	191
Higher replacement power costs for plant outages related to higher market prices	(70)
Retail price reductions (see Note 3)	(27)
Charges related to purchased power contracts with Enron and its affiliates	(13)(b)
Higher retail sales primarily related to customer growth	35
Miscellaneous revenues	3
Total increase in revenues, net of purchased power and fuel expense	119
Decrease in real estate 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	(5)
Miscellaneous items, net	1
Net increase in income from continuing operations before income taxes	44
Higher income taxes primarily due to higher income	(19)
<b>Net increase in income from continuing operations</b>	<b>\$ 25</b>

(a) Essentially all of our marketing and trading activities are structured activities. This means our portfolio of forward sales positions is hedged with a portfolio of forward purchases that protects the economic value of the sales transactions.

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

Electric operating revenues increased approximately \$850 million because of:

- changes in marketing and trading revenues (\$827 million, net increase):
  - increased revenues related to generation sales other than native load as a result of higher average market prices (\$32 million);
  - increased realized revenues related to other marketing and trading in current period primarily due to more transactions (\$681 million);
  - decreased prior period mark-to-market value related to trading with Enron and its affiliates (\$8 million);
  - increased prior period mark-to-market value for losses transferred to realized margin in current period (\$9 million);
  - increased mark-to-market value for future periods primarily as a result of more forward sales volumes (\$113 million);
- decreased revenues related to other wholesale sales and miscellaneous revenues as a result of 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).

Purchased power and fuel expenses increased approximately \$731 million primarily because of:

- changes in marketing and trading purchased power and fuel costs (\$636 million, net increase) due to:
  - increased fuel costs related to generation sales other than native load as a result of higher fuel prices (\$7 million);
  - increased fuel and purchased power costs related to other realized marketing and trading in current period primarily due to more transactions (\$636 million);
  - decreased mark-to-market fuel costs related to accounting for derivatives (\$7 million) (see Note 17)
- 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).

The decrease in real estate profits of \$8 million resulted primarily from decreases in 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 \$5 million primarily because of a change in the market value of El Dorado's investment in a technology-related venture capital partnership in 2000 (see Note 1) and other non-operating costs partially offset by an insurance recovery of environmental remediation costs.

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

#### **2000 Compared With 1999**

Our consolidated net income for the year ended December 31, 2000 was \$302 million compared with \$168 million for the year ended December 31, 1999. Our 2000 net income increased \$134 million over 1999 primarily because of a \$140 million after-tax extraordinary charge that we recorded in 1999. This charge reflected a regulatory disallowance resulting from an ACC-approved Settlement Agreement related to the implementation of retail electric competition. The resulting increase in our 2000 net income was partially offset by the absence of a \$38 million income tax benefit from discontinued operations that we also recorded in 1999. See "Regulatory Agreements" below and Notes 1 and 3 for additional information about the 1999 Settlement Agreement and the resulting regulatory disallowance. See Note 4 for additional information about the income tax benefit from discontinued operations.

Income from continuing operations for the year ended December 31, 2000 was \$302 million compared with \$270 million for the year ended December 31, 1999. The year-to-year comparison benefited from strong wholesale and retail electric sales and real estate profits. These positive factors more than offset decreases resulting from the completion of ITC amortization in 1999, reductions in retail electricity prices, lower earnings from El Dorado, and miscellaneous factors. See "Regulatory Agreements" below and Note 3 for information on the price reductions. See "Regulatory Agreements" below and Note 4 for additional information about ITC amortization.

The major factors that increased (decreased) income from continuing operations were as follows:

(dollars in millions)	INCREASE (DECREASE)
Increases (decreases) in electric revenues, net of purchased power and fuel expense due to:	
Marketing and trading activities:	
Increase from generation sales other than native load due to higher market prices	\$ 47
Increase in other realized marketing and trading in current period primarily due to more transactions	51
Change in prior year period mark-to-market value for gains transferred to realized margin in current period	(2)(a)
Increase in mark-to-market value related to future periods	13 (a)
Net increase in marketing and trading	109
Retail price reductions (see Note 3)	(28)
Higher retail sales primarily related to customer growth	9
Miscellaneous revenues	10
Total increase in revenues, net of purchased power and fuel expense	100
Increase in real estate contributions	13
Higher operations and maintenance expense related primarily to customer growth substantially offset by \$20 million of other items recorded in 1999	(4)
Higher other net expense primarily related to El Dorado	(10)
Higher depreciation and amortization expense	(11)
Miscellaneous items, net	(3)
Net increase in income from continuing operations before income taxes	85
Higher income taxes due to higher income in 2000 and higher ITC amortization in 1999	(53)
Net increase in income from continuing operations	\$ 32

(a) Essentially all of our marketing and trading activities are structured activities. This means our portfolio of forward sales positions is hedged with a portfolio of forward purchases that protects the economic value of the sales transactions.

Electric operating revenues increased approximately \$1.24 billion because of:

- changes in marketing and trading revenues (\$616 million, net increase):
  - increased revenues related to generation sales other than native load as a result of higher market prices (\$86 million);
  - increased realized revenues related to other marketing and trading in current period primarily due to more transactions and higher market prices (\$519 million);
  - decreased prior period mark-to-market value for gains transferred to realized margin in current period (\$2 million);
  - increased mark-to-market value for future periods primarily as a result of more forward sales volumes (\$13 million);
- increased revenues related to increased volumes and higher market prices for other wholesale sales resulting from retail load hedging activities and miscellaneous revenues (\$523 million);
- increased retail revenues primarily related to higher sales volumes due to customer growth (\$127 million); and
- decreased retail revenues related to reductions in retail electricity prices (\$28 million).

Purchased power and fuel expenses increased approximately \$1.14 billion primarily due to:

- changes in marketing and trading purchased power and fuel costs (\$507 million, increase) due to:

- increased fuel costs related to generation sales other than native load as a result of higher fuel prices (\$39 million);
- increased fuel and purchased power costs related to other realized marketing and trading in current period primarily due to more transactions (\$468 million);
- increased costs related to increased volumes and higher market prices for wholesale sales resulting from retail hedging activities (\$513 million); and
- higher costs related to retail sales volumes due to customer growth and increased fuel and purchased power prices (\$118 million).

The increase in real estate profits of \$13 million resulted primarily from increases in sales of land and homes by SunCor.

The increase in operations and maintenance expenses of \$4 million primarily related to customer growth was substantially offset by \$20 million of other items recorded in 1999.

The increase in depreciation and amortization of \$11 million primarily related to higher plant in service balances offset by lower regulatory asset amortization.

Net other expense decreased \$10 million primarily because of changes in 2000 in the market value of El Dorado's investment in a technology-related venture capital partnership. See Note 1 for additional information about the valuation of El Dorado's investments.

## Regulatory Agreements

Regulatory agreements approved by the ACC affect the results of APS' operations. The following discussion focuses on three agreements approved by the ACC, each of which included retail electricity price reductions:

- The 1999 Settlement Agreement to implement retail electric competition;
- A 1996 agreement that accelerated the amortization of APS' regulatory assets; and
- A 1994 settlement that accelerated the amortization of APS' deferred ITCs.

### 1999 Settlement Agreement

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%. The first reduction of approximately \$24 million (\$14 million after income taxes) included the July 1, 1999 retail price decrease required by the 1996 regulatory agreement (see below). For customers having loads three megawatts or greater, standard-offer rates will be reduced in annual increments that total 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 income statement.

Under the 1996 regulatory agreement, APS was recovering substantially all of its regulatory assets through accelerated amortization over an eight-year period that would have ended June 30, 2004. For more details, see Note 1. 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	1/1- 6/30 2004	TOTAL
\$164	\$158	\$145	\$115	\$86	\$18	\$686

See Note 3 and "Business Outlook – Electric Competition (Retail)" below for additional information regarding the 1999 Settlement Agreement.

### 1996 Regulatory Agreement

As part of the 1996 regulatory agreement, APS reduced its retail electricity prices by 3.4% effective July 1, 1996. This reduction decreased electric revenue by about \$49 million annually (\$29 million after income taxes). APS also agreed to share future cost savings with its customers during the term of this agreement, which resulted in the following additional retail price reductions:

- \$18 million annually (\$11 million after income taxes), or 1.2%, effective July 1, 1997;
- \$17 million annually (\$10 million after income taxes), or 1.1%, effective July 1, 1998; and

- \$11 million annually (\$7 million after income taxes), or 0.7%, effective July 1, 1999 (as noted above, this reduction was included in the July 1, 1999 price reduction under the 1999 Settlement Agreement).

### 1994 Rate Settlement

As part of a 1994 rate settlement, APS accelerated amortization of substantially all of its ITCs over a five-year period that ended on December 31, 1999. The amortization of ITCs decreased annual consolidated income tax expense by about \$24 million. Beginning in 2000, no further benefits were reflected in income tax expense related to the acceleration of the ITCs (see Note 4).

## 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, 2001 and estimated capital expenditures for the next three years.

(dollars in millions)	(ACTUAL)		(ESTIMATED)	
	2001	2002	2003	2004
APS				
Delivery	\$ 354	\$ 349	\$ 271	\$ 280
Existing generation (a)	117	149	–	–
Subtotal	471	498	271	280
Pinnacle West Energy (b)				
Generation expansion	533	411	255	113(e)
Existing generation(a)	–	–	107	99
Subtotal	533	411	362	212
SunCor (c)	80	79	48	52
Other (d)	45	35	15	16
Total	\$1,129	\$ 1,023	\$ 696	\$ 560

(a) Pursuant to the 1999 Settlement Agreement, APS is required to transfer its competitive electric assets and services no later than December 31, 2002.

(b) See Note 10 for further discussion of Pinnacle West Energy's generation expansion program and "Capital Resources and Cash Requirements – Pinnacle West Energy" below.

(c) Consists primarily of capital expenditures for land development and retail and office building construction reflected in the "Increase in real estate investments" in the consolidated statements of cash flows.

(d) Primarily Pinnacle West and APSES.

(e) This amount does not include an expected reimbursement by Southern Nevada Water Authority (SNWA) of \$100 million of these costs in 2004 in exchange for SNWA's purchase of a 25% interest in the Silverhawk project at that time.

APS and the other Palo Verde participants are currently considering issues related to replacement of the steam generators in Units 1 and 3. Although a final determination of whether Units 1 and 3 will require steam generator replacement to operate over their current full licensed lives has not yet been made, APS and the other participants have approved an expenditure in 2002 to procure long lead-time materials for fabrication of a spare set of steam generators for either Unit 1 or 3. APS' portion of this expenditure is approximately \$7 million and is included in the estimated expenditures above.

This action will provide the Palo Verde participants an option to replace the steam generators at either Unit 1 or 3 as early as fall 2005 should they ultimately choose to do so. If the participants decide to proceed with steam generator replacement at both Units 1 and 3, APS has estimated that its portion of the fabrication and installation costs and associated power uprate modifications would be approximately \$130 million over the next seven years, which will be funded with internally generated cash or external financings.

Existing generation capital expenditures are comprised of multiple improvements for our existing fossil and nuclear plants. 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. The increase in this category in 2002 is due primarily to Four Corners and various gas-fired units. The increased work on equipment is due to higher use of the units and also a stack replacement project for Four Corners Units 1 and 2. The existing generation also contains nuclear fuel expenditures of approximately \$30 million annually in 2002, 2003 and 2004.

Delivery capital expenditures are comprised of transmission and distribution (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, we began several major transmission projects in 2001. These projects are periodic in nature and are driven by strong regional customer growth. We expect to spend about \$150 million on major transmission projects during the 2002-2004 time frame.

### Capital Resources and Cash Requirements

The following table summarizes cash commitments for the year ended December 31, 2001 and estimated commitments for the next three years:

(dollars in millions)	(ACTUAL)		(ESTIMATED)	
	2001	2002	2003	2004
Long-term debt payments (see Note 6)				
APS	\$ 384	\$ 247	\$ -	\$ 205
Pinnacle West	213	-	276	216
SunCor	24	-	42	86
Total long-term debt payments	621	247	318	507
Operating leases payments (see Note 8)	67	68	66	65
Fuel and purchase power commitments (see Note 10)	374	270	124	80
Total cash commitments	\$ 1,062	\$ 585	\$ 508	\$ 652

Pinnacle West had available lines of credit in the amount of \$250 million at December 31, 2001. APS had lines of credit available in the amount of \$250 million at December 31, 2001. There was no outstanding balance on either the Pinnacle West or APS lines of credit at December 31, 2001. Pinnacle West and APS project that these lines of credit will be available over the next three years. The lines of credit are anticipated to be renewed at their expiration dates. See Note 5 for further information on Pinnacle West's and APS' lines of credit.

SunCor had an available line of credit at December 31, 2001 in the amount of \$140 million. This line of credit had an outstanding balance at December 31, 2001 of \$128 million. SunCor projects that this line of credit will be available over the next three years. SunCor also anticipates renewing the line of credit at its expiration date. See Note 5 for further details on SunCor's line of credit.

The parent company has issued parental guarantees and obtained surety bonds on behalf of its unregulated subsidiaries, primarily for Pinnacle West Energy's expansion plans, which are reflected in the capital expenditure table above, and APSES' retail and energy business.

APS has obtained approximately \$500 million in letters of credit primarily to provide credit support for its variable rate tax-exempt bonds and its Palo Verde sale-leaseback transactions. Pinnacle West has obtained approximately \$40 million in letters of credit to provide credit support for Pinnacle West Energy's generation expansion plans.

Pinnacle West and APS do not have ratings triggers in any of their debt agreements. Ratings triggers are provisions that would result in the acceleration of repayment obligations based upon a credit rating agency downgrade. Although those rating triggers appear in certain power marketing and trading agreements, their financial impacts are not expected to be significant.

APS' first mortgage bondholders share a lien on substantially all utility plant assets (other than nuclear fuel, transportation equipment and other excluded assets). The mortgage bond indenture restricts the payment of common stock dividends under certain conditions. These conditions did not exist at December 31, 2001.

See the Company's consolidated debt structure in Note 6. The parent company and our subsidiaries' capital needs and resources are described as follows.

### *Pinnacle West (Parent Company)*

During the past three years, our primary cash needs were for:

- dividends to our shareholders;
- equity infusions into our subsidiaries;
- interest payments; and
- optional and mandatory repayment of principal on our long-term debt.

The equity infusions into our subsidiaries during the past three years included \$50 million invested in APS in 1999.

This investment completed the funding of Pinnacle West's commitment under the 1996 regulatory agreement (see Note 3) to infuse \$50 million a year into APS (\$200 million total) from 1996 through 1999. The investments into Pinnacle West Energy were \$484 million in 2001 and \$193 million in 2000 to fund portions of its capital expenditures for its generation expansion program.

Over the next three years, we anticipate that our cash needs will fall into these same categories. We expect our equity infusions into Pinnacle West Energy to continue as it invests in additional generating facilities (see Note 10) until it begins to finance its own construction needs.

Our primary sources of cash are dividends from APS, our marketing and trading operations, and external financing. For the years 1999 through 2001, total dividends from APS were \$510 million.

Our long-term debt at December 31, 2001 was \$576 million compared with \$238 million at December 31, 2000. We had \$235 million of borrowings outstanding on our commercial paper at December 31, 2001. Our debt repayment requirements for the parent company for the next three years are approximately: zero in 2002, \$276 million in 2003, and \$216 million in 2004.

On February 8, 2002, we issued \$215 million of our 4.5% Notes due 2004.

### **APS**

APS' capital requirements consist primarily of capital expenditures and optional and mandatory redemptions of long-term debt. APS pays for its capital requirements with cash from operations and, to the extent necessary, external financing. APS pays for its dividends to Pinnacle West with cash from operations.

During the period from 1999 through 2001, APS paid for substantially all of its capital expenditures with cash from operations. APS expects to do so in 2002 through 2004 with cash from operations and its own debt issuances.

See the capital expenditure table above for additional information regarding actual capital expenditures in 2001 and projected capital expenditures for the next three years.

During 2001, APS redeemed approximately \$384 million of long-term debt, including premiums, with cash from operations and from the issuance of long- and short-term debt. APS' long-term debt redemption requirements for the next three years are approximately: \$247 million in 2002; zero in 2003; and \$205 million in 2004. Based on market conditions and call provisions, APS may make optional redemptions of long-term debt from time to time.

As of December 31, 2001, 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 the end of 2001, APS had about \$171 million of commercial paper outstanding and no bank borrowings.

APS' long-term debt was approximately \$2.1 billion at December 31, 2001 and 2000 (see Note 6).

Although ACC financing orders establish maximum amounts of additional debt that APS may issue, APS does not expect these orders to limit its ability to meet its capital requirements.

On March 1, 2002, APS issued \$375 million of 6.50% Notes due 2012. On March 15, 2002, APS announced the redemption on April 15, 2002 of approximately \$125 million of its First Mortgage Bonds, 8.75% series due 2024.

### ***Pinnacle West Energy***

See Note 10 for a discussion of Pinnacle West Energy's generation expansion plans. Pinnacle West Energy is currently funding its capital requirements through capital infusions from the parent. We finance those infusions through debt financing and internally generated cash, as Pinnacle West Energy develops and obtains additional generation assets. Pinnacle West Energy also expects to fund its capital requirements through internally generated cash and its own debt issuances. See the Capital Expenditures Table above for actual capital expenditures in 2001 and projected capital expenditures for the next three years.

### ***Other Subsidiaries***

During the past three years, both SunCor and El Dorado funded all of their cash requirements with cash from operations and, in the case of SunCor, its own external financings. APSES funded its cash requirements with cash infusions from Pinnacle West.

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 2001 and projected capital expenditures for the next three years. SunCor expects to fund its capital requirements with cash from operations and external financings.

As of December 31, 2001, SunCor had a \$140 million line of credit, under which \$128 million of borrowings were outstanding. SunCor's debt repayment obligations for the next three years are approximately: zero in 2002; \$42 million in 2003; and \$86 million in 2004.

El Dorado does not have any capital requirements over the next three years. El Dorado intends to focus on prudently realizing the value of its existing investments. El Dorado's future investments are expected to be related to the energy sector.

APSES 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 APSES' capital expenditures.

See Notes 5 and 6 for additional information about outstanding lines of credit and long-term debt obligations.

### CRITICAL ACCOUNTING POLICIES

In preparing the financial statements in accordance with generally accepted accounting principles (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 judgements can be subjective and complex, and actual results could differ from those estimates. Our most critical accounting policies include the determination of the appropriate accounting for our derivative instruments, mark-to-market accounting and the impacts of regulatory accounting on our financial statements. See Note 1 for a discussion of these critical accounting policies.

### OTHER ACCOUNTING MATTERS

We prepare our financial statements in accordance with Statement of Financial Accounting Standards (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 of the 1999 Settlement Agreement (see "Regulatory Agreements" above and Note 3), we discontinued the application of SFAS No. 71 for our generation operations. As a result, we tested the generation assets for impairment and determined that the generation assets were not impaired. Pursuant to the 1999 Settlement Agreement, we reported a regulatory disallowance (\$140 million after income taxes) as an extraordinary charge on the 1999 consolidated income statement. See Note 1 for additional information on regulatory accounting and Note 3 for additional information on the 1999 Settlement Agreement.

Effective January 1, 2001, we adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 requires that entities recognize all derivatives as either assets or liabilities on the balance sheets and measure those instruments at fair value. Changes in the fair value of derivative financial instruments are either recognized periodically in income or stockholders' equity (as a component of other comprehensive income), depending on whether or not the derivative meets specific hedge accounting criteria. Hedge effectiveness is measured based on the relative changes in fair value between the derivative contract and the hedged commodity over time. Any change in the fair value resulting from ineffectiveness is recognized immediately in net income. This new standard may result in additional volatility in our net income and other comprehensive income.

As a result of adopting SFAS No. 133 in 2001, we recorded a \$15 million after-tax loss in consolidated net income and a \$72 million after-tax gain in equity (as a component of other comprehensive income), both as a cumulative effect of a change in accounting principle. The loss primarily resulted from electricity options contracts. The gain resulted

from unrealized gains on cash flow hedges. See Note 17 for further information on accounting for derivatives under SFAS No. 133, including discussion on new guidance effective on April 1, 2002.

In July 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets." This Statement addresses financial accounting and reporting for acquired goodwill and other intangible assets and supersedes Accounting Principles Board Opinion No. 17, "Intangible Assets." This standard is effective for the year beginning January 1, 2002. We have no goodwill recorded in our consolidated balance sheets. The impacts of this new standard are not material to our consolidated financial statements.

The FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" in August 2001. The standard requires the estimated present value of the cost of decommissioning and certain other removal costs to be recorded as a liability, along with an offsetting plant asset when a decommissioning or other removal obligation is incurred. We are currently evaluating the impacts of the new standard, which is effective for the year beginning January 1, 2003.

In October 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." This statement supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of," and the accounting and reporting provisions for the disposal of a segment of a business. SFAS No. 144 is effective for the year beginning January 1, 2002. This standard does not impact our financial statements at adoption.

In 2001, the American Institute of Certified Public Accountants (AICPA) issued an exposure draft of a proposed Statement of Position (SOP), "Accounting for Certain Costs Related to Property, Plant and Equipment (PP&E)." This proposed SOP would create a project timeline framework for capitalizing costs related to PP&E construction, require that PP&E assets be accounted for at the component level and require administrative and general cost incurred in support of capital projects to be expensed in the current period. The AICPA plans to issue the final SOP in the fourth quarter of 2002. We are currently evaluating the impacts of the proposed SOP.

In 1986, APS entered into agreements with three separate special purpose entity (SPE) lessors in order to sell and lease back interests in Palo Verde Unit 2 (See Note 8). The leases are accounted for as operating leases in accordance with GAAP. In February 2002, the FASB discussed issues related to special purpose entities. It is expected that FASB will issue additional guidance on accounting for SPEs later this year. As a result of future FASB actions, we may be required to consolidate the Palo Verde SPEs in our financial statements. If consolidation is required, the assets and liabilities of the SPEs that relate to the sale-leaseback transactions would be reflected on our consolidated balance sheets. The SPE debt that is not reflected on our consolidated balance

sheets is approximately \$300 million at December 31, 2001. Rating agencies have already considered this debt when evaluating our credit ratings.

## **BUSINESS OUTLOOK**

### **Financial Outlook**

We currently believe that it will be a challenge for us in 2002 to repeat our 2001 earnings. For 2001, our reported income from continuing operations was \$327 million, or \$3.85 per diluted share of common stock, and included charges totaling \$21 million before income taxes, or \$0.15 per diluted share, that we do not expect to recur related to our exposure to Enron and its affiliates. Our earnings in 2002 are expected to be negatively affected by a significant decrease in the earnings contribution from our marketing and trading activities and retail electricity price decreases. These negative factors are expected to be substantially offset in 2002 by the absence of significant expenses for reliability and power plant outages that we incurred in 2001 that we do not expect to recur in 2002 and by retail customer growth, although the pace of growth is expected to be slower than in the past. These factors are described in more detail below.

In 2001, our marketing and trading activities contributed about one-half of our income from continuing operations before the Enron related charges. These activities are currently expected to provide about one-fourth of our earnings in 2002. The drivers of such reduced earnings contributions from our marketing and trading activities in 2002 are significant reductions in: wholesale market prices for electricity that occurred during 2001; wholesale market liquidity, which affects our ability to buy and resell electricity; and market volatility, which affects our ability to capture profitable structured trading activities. These reductions in regional market factors were due, in large part, to conservation measures in California and throughout the West; more generating plants in service in the West; lower natural gas prices; and the price mitigation plan that took effect in June 2001 as mandated by the FERC.

During 2001, in order to meet highest customer demand in APS' history, we incurred significant expenses for our summer reliability program and for higher replacement power costs related to power plant outages. These efforts cost approximately \$140 million before income taxes, which is not expected to be repeated in 2002. See "Results of Operations – 2001 Compared with 2000" above.

We estimate our retail customer growth in 2002 to be 3.2%, which is slower than the pace of growth in recent years, although still about three times the national average. Our customer growth in 2001 was 3.7%. We expect the customer growth rate to be weak in the first two quarters of 2002, then begin a rebound. Our current estimate for customer growth in 2003 and 2004 is between 3.5% and 4.0% annually.

The retail price decreases are described above in "Results of Operations – Regulatory Agreements."

As of December 31, 2001, the indicated annual dividend rate on our common stock was \$1.60 per share. Since 1994, we have increased the dividend on our common stock ten cents per share per year. We currently plan to continue annual dividend increases of relatively consistent amounts, which would continue dividend growth at a pace above the industry average.

The foregoing discussion of future expectations is forward-looking information. Actual results may differ materially from expectations. See "Forward-Looking Statements" below.

### **Other Factors Affecting Our Financial Outlook**

#### ***Competition and Industry Restructuring***

##### **Electric Competition (Wholesale)**

The FERC regulates rates for wholesale power sales and transmission services. Our marketing and trading division sells in the wholesale market APS and Pinnacle West Energy generation production output that is not needed for APS' native load and, in doing so, competes with other utilities, power marketers, and independent power producers. Wholesale market prices significantly fell during 2001 and remain low for the reasons discussed under "Financial Outlook" above. We cannot predict whether these lower prices will continue, or whether changes in various factors that affect demand and capacity, including regulatory actions, will cause the market prices to rise during 2002 or thereafter.

##### **Electric Competition (Retail)**

On September 21, 1999, the ACC approved Rules that provide a framework for the introduction of retail electric competition in Arizona. A Maricopa County, Arizona, Superior Court later found the Rules unlawful and unconstitutional; however, the Rules remain in effect pending the outcome of appeals. See "Retail Electric Competition Rules" in Note 3 for additional information about the Rules and the outstanding legal challenges to the Rules.

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

On September 23, 1999, the ACC approved a comprehensive 1999 Settlement Agreement among APS and various parties related to the implementation of retail electric competition in Arizona. See “1999 Settlement Agreement” in Note 3 for additional information about the 1999 Settlement Agreement, including the recent resolution of legal challenges to the 1999 Settlement Agreement.

Under the Rules, as modified by the 1999 Settlement Agreement, APS is required to transfer all of its competitive electric assets and services either to an unaffiliated party or to a separate corporate affiliate no later than December 31, 2002. Consistent with that requirement, APS has 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. In anticipation of APS’ transfer of generation assets, Pinnacle West Energy has completed, and is in the process of developing and planning, various generation expansion projects so that APS can reliably meet the energy requirements of its Arizona customers.

Following APS’ transfer of its fossil-fueled generation assets and the receipt of certain regulatory approvals, Pinnacle West Energy expects to sell its power at wholesale to our marketing and trading division, which, in turn, is expected to sell power to APS and to non-affiliated power purchasers. In a filing with the ACC on October 18, 2001, APS requested the ACC to:

- grant APS a partial variance from an ACC Rule that would obligate APS to acquire all of its customers’ standard-offer generation requirements from the competitive market (with at least 50% of those requirements coming from a “competitive bidding” process) starting in 2003; and
- approve as just and reasonable a long-term purchase power agreement between APS and Pinnacle West.

APS requested these ACC actions to ensure ongoing reliable service to APS standard-offer, full-service customers in a volatile generation market and to recognize Pinnacle West Energy’s significant investment to serve APS load. See “Proposed Rule Variance and Purchase Power Agreement” in Note 3 for additional information about APS’ October 2001 ACC filing.

On February 8, 2002, the ACC’s Chief ALJ issued a procedural order which consolidated the ACC docket relating to APS’ October, 2001 filing with several other pending ACC dockets, including a “generic” docket request by the ACC Chairman to “determine if changed circumstances require the [ACC] to take another look at restructuring in Arizona.” Although the order consolidates several dockets, it states that a hearing on the APS matter will commence on April 29, 2002. The order went on to state that, contrary to APS’ position, the ALJ was construing the October, 2001 filing as a request by APS to amend the 1999 ACC order that approved the 1999 Settlement Agreement.

On March 22, 2002, the ACC Staff issued a report to the ACC recommending that the ACC address the following issues in the generic docket:

- The extent and manner of the ACC’s involvement in monitoring market conditions and/or mitigating the development of market power for generation and transmission;
- The lack of guidance in the Rules regarding the mechanics of the “competitive bidding process” referenced above;
- The consideration of alternatives to the transfer of generation assets required by the Rules (the ACC Staff stated that such transfers would be “unwise” at the present time and recommended that “all transfer and separation of utilities’ assets be stayed pending the completion of the generic docket”);
- The consideration of transmission constraints that could impact the development of the wholesale power market;
- The reassessment of adjustor mechanisms for standard-offer rates in light of problems with the development of a wholesale power market; and
- The adequacy of customer “shopping credits” in the context of the development of a competitive retail market (a shopping credit is the cost a customer does not pay to a utility distribution company if the customer obtains generation from another party).

Although not a specific ACC Staff recommendation, the report was also critical of certain aspects of the proposed purchase power agreement between APS and Pinnacle West.

A modification to the Rules or the 1999 Settlement Agreement as a result of the consolidated docket could, among other things, adversely affect APS’ ability to transfer its generation assets to Pinnacle West Energy by December 31, 2002. We cannot predict the outcome of the consolidated docket or its effect on the specific requests in APS’ October 2001 filing, the existing Arizona electric competition rules, or the 1999 Settlement Agreement.

As a result of the foregoing matters, as well as energy market developments, including those relating to California’s failed deregulation efforts and to Enron’s recent bankruptcy filing, electric utility restructuring is in a state of flux in the western United States, including Arizona, and around the country.

### **Generation Expansion**

See Note 10 for information regarding our generation expansion plans. The planned additional generation is expected to increase revenues, fuel expenses, operating expenses, and financing costs.

### **California Energy Market Issues**

See Note 10 for information regarding California energy market issues.

### **Factors Affecting Operating Revenues**

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.

In APS' regulated retail market area, APS will provide electricity services to standard-offer, full-service customers and to energy delivery customers who have chosen another provider for their electricity commodity needs (unbundled customers). Customer growth in APS' service territory averaged about 4% a year for the three years 1999 through 2001; we currently expect customer growth to be about 3.2% in 2002 and between 3.5% and 4.0% a year in 2003 and 2004. We currently estimate that retail electricity sales in kilowatt-hours will grow 3.5% to 5.5% a year in 2002 through 2004, before the retail effects of weather variations. The customer growth and sales growth referred to in this paragraph apply to energy delivery customers. As industry restructuring evolves in the regulated market area, we cannot predict the number of APS' standard-offer customers that will switch to unbundled service. As previously noted, under the 1999 Settlement Agreement, we have annual retail electricity price reductions of 1.5% through July 1, 2003 (see Note 3).

Competitive sales of energy and energy-related products and services are made by APSES in western states that have opened to competitive supply. Such activities currently are not material to our consolidated financial results.

#### **Other Factors Affecting Future Financial Results**

Purchased power and fuel costs are impacted by our electricity sales volumes, existing contracts for generation fuel and purchased power, 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 are expected to be affected by sales mix and volumes, power plant operations, inflation, outages and other factors.

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 expansion program. See Note 1 for the regulatory asset amortization that is being recorded in 1999 through 2004 pursuant to the 1999 Settlement Agreement. Also, see Note 1 regarding current depreciation rates.

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 9.32% for 2001 and 9.16% for 2000. We expect property taxes to increase primarily due to our generation expansion program and our additions to existing facilities.

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 generation expansion program and our internally-generated cash flow.

The annual earnings contribution from APSES is expected to be modest, yet positive, over the next several years due primarily to a number of retail electricity contracts in California. APSES' pretax losses were \$10 million in 2001 and \$13 million in 2000.

The annual earnings contribution from SunCor is expected to remain modest over the next several years. SunCor's earnings were \$3 million in 2001, \$11 million in 2000 and \$6 million in 1999.

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. Any future investments are expected to be related to the energy sector. See Note 1 for additional information regarding El Dorado.

We cannot accurately predict the impact of full retail competition on our financial position, cash flows, results of operations, or liquidity. As competition in the electric industry continues to evolve, we will continue to evaluate strategies and alternatives that will position us to compete effectively in a restructured industry.

Our financial results may be affected by the application of SFAS No. 133. See "Critical Accounting Policies" above and Note 17 for further information.

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.

#### **Interest Rate and Equity Risk**

Our major financial market risk exposure is changing interest rates. Changing interest rates will affect interest paid on variable-rate debt and interest earned by our nuclear decommissioning trust fund (see Note 11). Our policy is to manage interest rates through the use of a combination of fixed-rate and floating-rate debt. The nuclear decommissioning fund also has risks associated with changing market values of equity investments. Nuclear decommissioning costs are recovered in regulated electricity prices.

The tables below present contractual balances of our long-term debt and commercial paper at the expected maturity dates as well as the fair value of those instruments on

December 31, 2001 and 2000. The interest rates presented in the tables below represent the weighted average interest rates for the years ended December 31, 2001 and 2000.

#### 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		<u>\$ 405,762</u>		<u>\$ 862,772</u>		<u>\$ 1,941,712</u>
Fair Value		<u>\$ 405,762</u>		<u>\$ 862,772</u>		<u>\$ 1,963,389</u>

#### EXPECTED MATURITY/PRINCIPAL REPAYMENT (dollars in thousands)

December 31, 2000	SHORT-TERM DEBT		VARIABLE-RATE LONG-TERM DEBT		FIXED-RATE LONG-TERM DEBT	
	INTEREST RATES	AMOUNT	INTEREST RATES	AMOUNT	INTEREST RATES	AMOUNT
2001	6.64%	\$ 82,775	7.23%	\$ 438,203	6.63%	\$ 25,266
2002		—	8.62%	36,890	8.13%	125,000
2003		—	8.61%	73,578	6.89%	25,443
2004		—	8.87%	268	6.17%	205,000
2005		—	8.89%	294	7.28%	400,000
Years thereafter		—	4.13%	483,790	7.47%	610,813
Total		<u>\$ 82,775</u>		<u>\$ 1,033,023</u>		<u>\$ 1,391,522</u>
Fair Value		<u>\$ 82,775</u>		<u>\$ 1,033,023</u>		<u>\$ 1,422,014</u>

#### Commodity Price Risk

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal, and emissions allowances. We employ established procedures to manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange-traded futures and options and over-the-counter forwards, options, and swaps. As part of our overall risk management program, we enter into derivative transactions to hedge purchases and sales of electricity, fuels, and emissions allowances and credits. The changes in market value of such contracts have a high correlation to price changes in the hedged commodity.

In addition, subject to specified risk parameters established by the Board of Directors and monitored by the Energy Risk Management Committee, we engage in trading activities intended to profit from market price movements. In accordance with Emerging Issues Task Force (EITF) 98-10, "Accounting For Contracts Involved in Energy Trading and Risk Management Activities," such trading positions are marked-to-market. These trading activities are part of our marketing and trading activities and are reflected in the marketing and trading revenues and expenses.

The following schedule shows the changes in mark-to-market of our trading positions during the years ended December 31, 2001 and 2000:

(dollars in millions)	2001	2000
Mark-to-market of net trading positions at beginning of year	\$ 12	\$ —
Prior period marked-to-market gains realized during the year	(1)	(2)
Change in marked-to-market gains for future period deliveries	127	14
Mark-to-market of net trading positions at end of year	\$ 138	\$ 12

Net gains at inception include a reasonable marketing margin and were approximately \$3 million in 2001 and \$2 million in 2000. See Note 17 for disclosure of risk management activities recorded on the consolidated balance sheets.

The table below shows the maturities of our trading positions as of December 31, 2001 in millions of dollars by the type of valuation that is performed to calculate the fair value of the contract. In addition, see Note 1 for more discussion on our valuation methods.

SOURCE OF FAIR VALUE	2002	2003-2004	2005-2006	YEARS THEREAFTER	TOTAL FAIR VALUE
Prices actively quoted	\$ (13)	\$ 4	\$ 2	\$ -	\$ (7)
Prices provided by other external sources	(12)	(8)	(4)	-	(24)
Prices based on models and other valuation methods	68	50	39	12	169
<b>Total by maturity</b>	<b>\$ 43</b>	<b>\$ 46</b>	<b>\$ 37</b>	<b>\$ 12</b>	<b>\$ 138</b>

The table below shows the impact that hypothetical price movements of 10% would have on the market value of our

risk management and trading assets and liabilities included on the consolidated balance sheets at December 31, 2001 and 2000.

(dollars in millions) COMMODITY	DECEMBER 31, 2001 GAIN / (LOSS)		DECEMBER 31, 2000 GAIN / (LOSS)	
	PRICE UP 10%	PRICE DOWN 10%	PRICE UP 10%	PRICE DOWN 10%
Trading (a):				
Electric	\$ (3)	\$ 3	\$ 2	\$ (2)
Natural gas	(1)	1	(1)	1
Other	-	2	-	-
System (b):				
Natural gas hedges	23	(23)	28	(28)
<b>Total</b>	<b>\$ 19</b>	<b>\$ (17)</b>	<b>\$ 29</b>	<b>\$ (29)</b>

(a) Essentially all of our marketing and trading activities are structured activities. This means our portfolio of forward sales positions is 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. 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.

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 one counterparty for which a worst case exposure represents approximately 50% of our \$267 million of risk management and trading assets as of December 31, 2001. We use a risk management process to assess and monitor the financial exposure of this 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 counterparty noted above, there is still a possibility that one or more of these companies could default, resulting in a material impact on consolidated earnings for a given period. Counterparties in the portfolio consist principally of major energy companies, municipalities, and local distribution companies. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. In many contracts, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Credit reserves are established representing our estimated credit losses on our overall exposure to counterparties. See Note 1 for a discussion of our credit reserve policy.

#### FORWARD-LOOKING STATEMENTS

The above discussion contains forward-looking statements based on current expectations and we assume no obligation to update these statements. 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 APS' October 2001 ACC filing; the outcome of regulatory and legislative proceedings relating to the restructuring; state and federal regulatory and legislative decisions and actions, including the price mitigation plan adopted by the FERC in June 2001; regional economic and market conditions, including the California energy situation and completion of generation construction in the region, which could affect customer growth and the cost of power supplies; the cost of debt and equity capital; weather variations affecting local and regional customer energy usage; conservation programs; power plant performance; the successful completion of our generation expansion program; regulatory issues associated with generation expansion, such as permitting and licensing; our ability to compete successfully outside traditional regulated markets (including the wholesale market); technological developments in the electric industry; and the strength of the real estate market in SunCor's market areas, which include Arizona, New Mexico and Utah.

These factors and the other matters discussed above may cause future results to differ materially from historical results, or from results or outcomes we currently expect or seek.