

FINANCIAL REVIEW

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

- the changes in our earnings from 1999 to 2000 and from 1998 to 1999;
- the effects of regulatory agreements on our results and outlook;
- our capital needs and resources;
- 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 retail and wholesale electric service to the entire state with the exception of Tucson and about one-half of the Phoenix area. APS also generates and, directly or through our power marketing division, sells and delivers electricity to wholesale customers in the western United States.

Our other major subsidiaries are:

- Pinnacle West Energy, through which we intend to conduct our unregulated generation operations;
- APS Energy Services, which sells energy and energy-related products and services in competitive retail markets in the western United States;
- SunCor, which is a developer of residential, commercial, and industrial real estate projects in Arizona, New Mexico, and Utah; and
- El Dorado, which is primarily a venture capital and investment firm.

OUR BUSINESS STRATEGIES

Our business strategies are linked to the strong growth characteristics of Arizona and the western regional market. We are committed to the West and are pursuing the following primary strategies:

- Continuing focus on customer value provided by APS, our regulated "energy delivery" company;
- Expanding our interests in competitively efficient generation assets in the West through Pinnacle West Energy by developing new plants, increasing our ownership share of plants that we already operate and partially own, and buying plants from other utilities;
- Aggressively managing costs, with an emphasis on the reduction of variable costs per generating unit (fuel, operations, and maintenance expenses) and on increased productivity through technological efficiencies; and

- Managing energy activities, including:
 - continuing expansion of wholesale operations;
 - managing commodity price risk; and
 - providing sufficient capacity, energy, and ancillary services to reliability meet obligations to our regulated service customers.

BUSINESS SEGMENTS

As we discuss below in greater detail, APS' 1999 Settlement Agreement with the Arizona Corporation Commission (ACC) authorizes APS to transfer its competitive generation assets and services to one or more corporate affiliates no later than December 31, 2002. We have internally organized our operations into the following two principal business segments, determined by products, services, and regulatory environment:

- The electricity delivery business segment, which consists of the transmission and distribution of electricity and wholesale activities; and
- The generation business segment, which consists of our generation activities.

See "Business Segments" in Note 18 for more information about our business segments. In general, we have structured our discussion below based on existing legal entities rather than the operating segments defined by the new organizational structure because we continue to analyze these matters internally by legal entity. The "Results of Operations," for example, primarily reflect the results of APS' operations because APS currently owns substantially all of our assets and produces substantially all of our profits.

Throughout this Financial Review, we refer to specific "Notes" in the Notes to Consolidated Financial Statements that begin on page 35. These Notes add further details to the discussion.

RESULTS OF OPERATIONS

The following is a summary of net income for 2000, 1999, and 1998:

(dollars in millions)	<i>2000</i>	<i>1999</i>	<i>1998</i>
APS	\$ 307	\$ 267	\$ 246
Pinnacle West Energy	(2)	—	—
APS Energy Services	(13)	(9)	—
SunCor	11	6	45
El Dorado	2	11	5
Parent Company	(3)	(5)	(53)
Income from Continuing Operations	302	270	243
Income Tax Benefit from Discontinued Operations	—	38	—
Extraordinary Charge – Net of Income Taxes of \$94	—	(140)	—
Net Income	\$ 302	\$ 168	\$ 243

2000 Compared with 1999

Our 2000 consolidated net income was \$302 million compared with \$168 million in 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 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 increased \$32 million, or 12%, over 1999 primarily because of increases in wholesale and retail electric sales and in real estate profits. These positive factors more than offset decreases resulting from the completion of investment tax credit (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.

In 2000, electric operating revenues increased \$1.2 billion primarily because of:

- increased wholesale revenues (\$1.1 billion);
- increases in the number of retail electricity customers and the average amount of electricity used by customers (\$97 million); and
- weather impacts (\$33 million).

As mentioned above, these positive factors were partially offset by the effects of reductions in retail electricity prices (\$28 million).

The increase in wholesale revenues resulted primarily from higher prices and increased activity in western United States wholesale power markets. These revenues were accompanied by increases in purchased power and fuel expense of \$1.0 billion.

Fuel and purchased power expenses were also higher because of higher retail sales volumes and increased prices.

The increase in real estate profits resulted from increases in sales of land and homes by SunCor.

The increase in operations and maintenance expenses, which primarily related to customer growth, was substantially offset by \$20 million of non-recurring items recorded in 1999.

Net other income and expense decreased \$11 million primarily because of a decrease 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.

1999 Compared with 1998

Our 1999 consolidated net income was \$168 million compared with \$243 million in 1998. Our 1999 net income decreased \$75 million from 1998 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 decrease in our 1999 net income was partially offset by 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 increased \$27 million, or 11%, over 1998 primarily because of increases in retail electricity revenues and lower financing costs. These positive factors more than offset the effects of retail electricity price reductions and higher utility operations and maintenance expense. See “Regulatory Agreements” below and Note 3 for additional information about the price reductions.

In 1999, electric operating revenues increased \$287 million primarily because of:

- increased wholesale revenues (\$219 million);
- increases in retail electricity customers and the average amount of electricity used by customers (\$81 million); and
- miscellaneous factors (\$9 million).

As mentioned above, these positive factors were partially offset by the effects of reductions in retail prices (\$22 million).

The increase in wholesale revenues resulted from higher prices and increased activity in western United States wholesale markets. The revenues were accompanied by an increase in purchased power expenses. Although these activities contributed positively to earnings in both periods, the contribution in 1999 was lower than in 1998.

Operations and maintenance expenses increased \$27 million primarily because of \$20 million of non-recurring items recorded in 1999, including a provision for certain environmental costs. Other increases primarily related to customer growth were partially offset by lower employee benefit costs.

Net other income and expense increased \$10 million primarily because of an increase 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, full offer 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 now 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 annual 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).

CAPITAL NEEDS AND RESOURCES

Capital Expenditure Requirements

The following table summarizes the actual capital expenditures for the period ended December 31, 2000 and estimated capital expenditures for the next three years:

	(actual)		(estimated)	
(dollars in millions)	2000	2001	2002	2003
APS				
Delivery	\$ 285	\$ 337	\$ 293	\$ 294
Existing Generation (a)	187	118	108	—
	472	455	401	294
Pinnacle West Energy (b)				
Generation Expansion	193	659	129	132
Existing Generation (a)	—	—	—	122
	193	659	129	254
SunCor (c)	50	75	23	14
Other (d)	—	21	9	9
Total	\$ 715	\$1,210	\$ 562	\$ 571

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

(b) Does not include the Southern California Edison (SCE) purchase agreements. See Note 12 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.

(d) Primarily APS Energy Services.

Capital Resources and Cash Requirements

Pinnacle West (Parent Company)

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

- dividends to our shareholders;
- equity infusions into our subsidiaries, including \$200 million invested in APS from 1996 through 1999 as part of the 1996 regulatory agreement (see Note 3) and \$193 million invested in Pinnacle West Energy for 2000 capital expenditures;
- interest payments; and
- optional and mandatory repayment of principal on our long-term debt.

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

Our primary sources of cash are dividends from our subsidiaries and external financing. For the years 1998 through 2000, total dividends from subsidiaries were \$596 million which included \$510 million from APS, \$50 million from SunCor, and \$36 million from El Dorado.

Our long-term debt at December 31, 2000 was \$238 million compared to \$106 million at December 31, 1999. We have a \$250 million line of credit, under which we had \$188 million of borrowings outstanding at December 31, 2000. Our debt repayment requirements for the next three years are approximately: \$213 million in 2001, zero in 2002, and \$25 million in 2003.

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.

During the period from 1998 through 2000, APS paid for substantially all of its capital expenditures with cash from operations. APS expects to do so in 2001 through 2003, as well.

See the table above for actual capital expenditures in 2000 and projected capital expenditures for the next three years. In general, most of APS' projected capital expenditures are for:

- expanding transmission and distribution capabilities to serve growing customer needs;
- upgrading existing utility property; and
- environmental purposes.

During 2000, APS redeemed approximately \$357 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: \$380 million in 2001; \$125

million in 2002; and zero in 2003. APS made optional redemptions of about \$13 million of long-term debt in February 2001. Based on market conditions and optional call provisions, APS may make optional redemptions of long-term debt from time to time.

As of December 31, 2000, 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 2000, APS had about \$82 million of commercial paper and no long-term bank borrowings outstanding.

APS' long-term debt was \$2.1 billion at December 31, 2000 and 1999.

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

Pinnacle West Energy

Pinnacle West Energy has announced plans to build up to 2,800 megawatts (MW) of generating capacity from 2001-2006 at an estimated cost of about \$1.3 billion.

Site	MW
West Phoenix 4	120
West Phoenix 5	530
Redhawk 1	530
Redhawk 2	530
Redhawk 3	530
Redhawk 4	530
TOTAL	2,770

As discussed in greater detail below, Pinnacle West Energy has also announced plans to purchase Nevada Power Company's (NPC) Harry Allen Power Station and SCE's interest in the Palo Verde Nuclear Generating Station (Palo Verde).

Pinnacle West Energy is also considering additional expansion, which may result in additional expenditures.

Pinnacle West Energy expects to fund its capital requirements through internally generated cash, debt issued directly by Pinnacle West Energy, and capital infusions from the parent company's internally generated cash and external financing.

Pinnacle West Energy is currently planning a 650 MW expansion of the West Phoenix Power Plant and the construction of a natural gas-fired electric generating station of up to four, 530 MW units, near Palo Verde, called Redhawk. Construction on the 120 MW West Phoenix Unit 4 began in June 2000, with commercial operation of the unit expected in the summer of 2001. Pinnacle West Energy expects construction to begin on the 530 MW West Phoenix Unit 5

in the fall of 2001, with commercial operation beginning in mid-2003. Construction began on the first two units of Redhawk in December 2000, and commercial operation is currently scheduled for the summer of 2002.

Pinnacle West Energy has entered into an agreement with NPC to purchase NPC's 72 MW gas-fired Harry Allen Power Station about 30 miles northeast of Las Vegas, Nevada, for a net purchase price, after adjustments for purchased power commitments, of approximately \$65.2 million. The purchase is subject to filing with and/or approval of various regulatory agencies, including the Federal Energy Regulatory Commission (FERC) and the Nevada Public Utility Commission (NPUC). The filing with the NPUC was made in February 2001. NPC will have the right, but not the obligation, to purchase the output from the Harry Allen plant at market rates, subject to a floor and a cap. As demand grows in the region during the next five years, Pinnacle West Energy expects to add a 480 MW gas-fired, combined cycle unit to the site. The Governor of Nevada recently requested that the NPUC reexamine NPC's divestiture of generation assets. The timing and result of any action by the NPUC is not yet known.

On April 27, 2000, Pinnacle West Energy entered into two separate agreements with SCE to purchase SCE's 15.8% ownership interest in Palo Verde and its 48% ownership interest in the Four Corners Power Plant. Consistent with the agreements, on January 5, 2001, Pinnacle West Energy informed SCE that it would not match a competing bid that SCE received for its Four Corners ownership interest. Therefore, Pinnacle West Energy will not purchase SCE's Four Corners interest under the April 2000 agreement unless the Palo Verde transaction closes, the competing Four Corners transaction does not close, and Pinnacle West Energy acquires the Four Corners interest at the original \$300 million purchase price as a standby purchaser. SCE did not receive any qualified competing bids for its Palo Verde ownership interest, which Pinnacle West Energy agreed to purchase for \$250 million. However, recently-enacted California legislation provides that "no facility for the generation of electricity owned by a public utility may be disposed of prior to January 1, 2006." Unless this California law is amended, Pinnacle West Energy would not be able to acquire SCE's Palo Verde ownership interest pursuant to the original April 2000 agreement.

Other Subsidiaries

During the past three years, SunCor and El Dorado each funded all of their cash requirements with cash from operations and, in the case of SunCor, its own external financings. APS Energy Services funded its cash requirements with cash infusions from the parent company.

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 2000 and projected capital expenditures for the next three years. SunCor expects to fund its capital requirements from internally generated cash and external financings.

As of December 31, 2000, SunCor had a \$120 million line of credit, under which \$110 million of borrowings were outstanding. SunCor's debt repayment obligations for the next three years are approximately: zero in 2001; \$37 million in 2002; and \$74 million in 2003.

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

APS Energy Services' capital expenditures and other cash requirements will be funded from cash invested by the parent company.

ACCOUNTING MATTERS

We adopted a new standard on accounting for derivatives in 2001. As a result, in January 2001 we recognized a \$3 million after-tax loss in net income as a cumulative effect of a change in accounting principles and a \$64 million after-tax gain reflected in equity (as a component of other comprehensive income). The gain resulted from unrealized gains on cash flow hedges. There are still several unresolved issues related to the application of certain provisions of this new standard as it relates to the electric utility industry. The ultimate resolution of these issues by the Financial Accounting Standards Board (FASB) could result in a material impact to our financial statements and increased volatility in future net income and comprehensive income. See Note 2 for further information. Also, see Note 2 for a description of a proposed standard on accounting for certain liabilities related to closure or removal of long-lived assets.

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 our 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 income statement. See Note 1 for additional information on regulatory accounting and Note 3 for additional information on the 1999 Settlement Agreement.

BUSINESS OUTLOOK

This section describes several major factors affecting our financial outlook.

Competition and Industry Restructuring

Electric Competition (Wholesale)

The National Energy Policy Act of 1992 (1992 Energy Act) and the FERC's subsequent rulemaking activities have established the regulatory framework to open the wholesale electricity market to competition. The 1992 Energy Act amended provisions of the Public Utility Holding Company Act of 1935 and the Federal Power Act to remove certain barriers to a competitive wholesale market. The 1992 Energy Act permits utilities to participate in the development of independent electric generating plants for electricity sales to wholesale customers, and also permits the FERC to order transmission access for third parties to transmission facilities owned by another entity. The 1992 Energy Act does not, however, permit the FERC to issue an order requiring transmission access to retail customers. Open-access transmission for wholesale customers as defined by the FERC's final rules provides energy suppliers, including us, with opportunities to sell and deliver electricity at market-based prices.

Electric Competition (Retail)

On September 21, 1999, the ACC voted to approve the rules that provide a framework for the introduction of retail electric competition in Arizona (the Rules). Among other things, the Rules require most utilities, including APS, to transfer all competitive generation assets and services either to an unaffiliated party or to a separate corporate affiliate. The Rules require the transfer to take place by January 1, 2001, absent a waiver. APS received a waiver in the 1999 Settlement Agreement to allow the transfer of its competitive generation assets and services to affiliates no later than December 31, 2002. Accordingly, we plan to complete the move of such assets and services from APS to the parent company or to Pinnacle West Energy by the end of 2002, as required.

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 customers under rates that have been approved by the ACC. These rates are fixed 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 wholesale market vary and, during the course of the last year, have been volatile. At various times prices in the spot wholesale market have significantly exceeded the amount included in APS' current retail rates. APS expects these market conditions to continue in 2001. We believe we have adequately supplemented our current generation portfolio with power purchased through contracts and hedging

techniques that limit exposure to the volatile spot wholesale power market. However, 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.

As discussed in Note 3, the 1999 Settlement Agreement authorizes APS to transfer its competitive generation assets and services to one or more corporate affiliates no later than December 31, 2002. APS intends to move its generation assets to Pinnacle West Energy within that timeframe. Following its receipt of these generation assets, Pinnacle West Energy expects to sell its power at wholesale to our power marketing division (Power Marketing). Power Marketing, in turn, is expected to sell power to APS and to non-affiliated power purchasers. APS is expected to meet fifty percent of its energy needs under a power purchase agreement with Power Marketing. As required by the Rules, APS will acquire the remaining fifty percent of its energy needs through a competitive bid process in which Power Marketing may participate. We believe that these arrangements will allow us to manage APS' exposure to the wholesale power market during the period within which APS' rates are fixed, as discussed in the preceding paragraph.

Under the 1999 Settlement Agreement, the Rules are to be interpreted and applied, to the greatest extent possible, in a manner consistent with the 1999 Settlement Agreement. If the two cannot be reconciled, APS must seek, and the other parties to the 1999 Settlement Agreement must support, a waiver of the Rules in favor of the 1999 Settlement Agreement. Several rural electric cooperatives and the Arizona Consumers Council, a private non-profit public interest group (represented by the Arizona Center for Law in the Public Interest, also a private non-profit public interest organization) have filed court challenges to the Rules. Although these actions do not directly challenge the divestiture provisions of the Rules, they do raise fundamental constitutional issues concerning the ability of the ACC to permit the forces of competition to determine retail electric prices.

On November 27, 2000, a Maricopa County, Arizona, Superior Court judge issued a final judgment holding that the Rules are unconstitutional and unlawful in their entirety due to failure to establish a fair value rate base for competitive electric service providers and because certain of the Rules were not submitted to the Arizona Attorney General for certification. The judgment also invalidates all ACC orders authorizing competitive electric service providers, including APS Energy Services, in Arizona. We do not believe the ruling affects the 1999 Settlement Agreement.

The 1999 Settlement Agreement was not at issue in the consolidated cases before the judge. Further, the ACC made findings related to the fair value of APS' property in the order approving the 1999 Settlement Agreement. The ACC and other parties aligned with the ACC have appealed the ruling to the Court of Appeals, as a result of which the ruling is automatically stayed pending further judicial review.

On December 13, 1999, two parties filed lawsuits challenging the ACC's approval of the 1999 Settlement Agreement. Each party bringing the lawsuits appealed the ACC's order approving the APS 1999 Settlement Agreement directly to the Arizona Court of Appeals, as provided by Arizona law. In one of the appeals, on December 26, 2000, the Arizona Court of Appeals affirmed the ACC's approval of the 1999 Settlement Agreement. A decision is still pending on the other appeal, which raises a number of different issues.

Neither party challenging the 1999 Settlement Agreement has raised issues regarding the 1999 Settlement Agreement that could not be remedied by the ACC if the Arizona Court of Appeals remands the 1999 Settlement Agreement to the ACC. However, it is impossible to predict with certainty exactly what the ACC would do in the event the order approving the 1999 Settlement Agreement were invalidated, either in whole or in part. Even aside from the pending litigation, the ACC retains continuing jurisdiction over all orders issued by it and can attempt to "rescind, alter or amend" such order under appropriate circumstances and upon notice and hearing.

In May 1998, a law was enacted by the Arizona legislature to facilitate implementation of retail electric competition in the state. Additionally, legislation related to electric competition has been proposed in the United States Congress. See Note 3 for additional information about the Rules, the 1999 Settlement Agreement, the ongoing litigation related to each, and for legislative developments.

As a result of the foregoing matters, as well as energy market developments, particularly in California (see "California Energy Market Issues" below), electric utility restructuring is in a state of flux in the western United States and around the country.

Generation Expansion

See "Capital Needs and Resources – Capital Resources and Cash Requirements – Pinnacle West Energy" and Note 12 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

SCE and PG&E Corp. (PG&E) have publicly disclosed that their liquidity has been materially and adversely affected because of, among other things, their inability to pass on to ratepayers the prices each has paid for energy and ancillary services procured through the California Power Exchange (PX) and California Independent System Operator (ISO).

We are closely monitoring developments in the California energy market and the potential impact of these developments on us and our subsidiaries. We have evaluated, among other things, SCE's role as a Palo Verde and Four Corners participant; APS' transactions with the PX and the ISO; contractual relationships with SCE and PG&E; APS Energy Services' retail transactions involving SCE and PG&E; and power marketing exposures. Based upon the financial transactions to date, we do not believe the foregoing matters will have a material adverse effect on our financial position or liquidity. We cannot predict with certainty, however, the impact that any future resolution or attempted resolution, of the California energy market situation may have on us or our subsidiaries or the regional energy market in general.

See "Capital Resources and Cash Requirements – Pinnacle West Energy" above for a discussion of Pinnacle West Energy's agreement to purchase SCE's Palo Verde interest.

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 3.8% a year for the three years 1998 through 2000; we currently expect customer growth to average 3.5% to 4% a year for 2001 through 2003. We currently estimate that retail electricity sales in kilowatt-hours will grow 3.5% to 4.5% a year in 2001 through 2003, 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.

Wholesale activities will be affected by electricity prices and costs of available fuel and purchased power in the western United States, as well as competitive market conditions and regulatory and legislative changes in various state and federal jurisdictions. These factors have significantly affected our wholesale power activities and their resultant earnings contributions over the last several years. We cannot predict future contributions from wholesale activities.

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. Such activities are currently not material to our consolidated financial results.

Other Factors Affecting Future Financial Results

Fuel and purchased power costs are impacted by our electricity sales volumes, existing contracts for generation fuel and purchased power, our power plant performance, prevailing market prices, and our hedging program for managing such costs.

Operations and maintenance expenses are expected to be affected by sales mix and volumes, inflation, 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. 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 our real estate subsidiary, SunCor, is expected to remain modest over the next several years. SunCor's earnings were \$5 million (excluding the effects of a \$40 million deferred tax asset transfer) in 1998, \$6 million in 1999, and \$11 million in 2000.

El Dorado, our investment subsidiary, is affected by market conditions related to its investments. See Note 1 for a discussion of recent events affecting El Dorado's financial results and its outlook. Historical results are not necessarily indicative of future performance for El Dorado. El Dorado's

strategies focus on realization of the value of its existing investments. Any future investments are expected to be in the energy business.

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.

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.

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 13). 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,

2000 and December 31, 1999. The interest rates presented in the tables below represent the weighted average interest rates for the years ended December 31, 2000 and December 31, 1999.

EXPECTED MATURITY/PRINCIPAL REPAYMENT - DECEMBER 31, 2000

(dollars in thousands)	Short-Term		Variable Long-Term		Fixed Long-Term	
	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		\$ 82,775		\$ 1,033,023		\$ 1,391,522
Fair Value		\$ 82,775		\$ 1,033,023		\$ 1,422,014

EXPECTED MATURITY/PRINCIPAL REPAYMENT - DECEMBER 31, 1999

(dollars in thousands)	Short-Term		Variable Long-Term		Fixed Long-Term	
	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
2000	5.33%	\$ 38,300	10.25%	\$ 87	5.79%	\$ 114,711
2001	—	—	7.00%	336,117	6.70%	27,488
2002	—	—	8.47%	64,085	8.13%	125,000
2003	—	—	5.51%	50,118	6.87%	25,000
2004	—	—	10.25%	130	6.17%	205,000
Years thereafter	—	—	3.19%	479,727	7.87%	900,483
Total		\$ 38,300		\$ 930,264		\$ 1,397,682
Fair Value		\$ 38,300		\$ 930,264		\$ 1,366,968

Commodity Price Risk

Pinnacle West's Energy Risk Management Committee (the ERMC) has established risk management guidelines to monitor and manage commodity price risks. The ERMC is chaired by Pinnacle West's Vice President of Finance and is comprised of senior executives.

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/credits. In addition, subject to specified risk parameters established by the Board of Directors and monitored by the ERMC, 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 wholesale activities and are reflected in the wholesale revenues and expenses.

As of December 31, 2000, a hypothetical adverse price movement of 10% in the market price of our commodity derivative portfolio would have decreased the fair market value of these contracts by approximately \$29 million compared to a \$6 million decrease that would have been realized as of December 31, 1999. The increase in this exposure over 1999 is a result of the increased volume of hedge positions and increased prices in this portfolio. This analysis does not include the favorable impact this same hypothetical price move would have had on certain underlying physical exposures being hedged with the commodity derivative portfolio.

We are exposed to losses in the event of non-performance or non-payment by counterparties. We use a risk management process to assess and monitor the financial exposure of counterparties. Despite the fact that the great majority of trading counterparties are rated as investment grade by the credit rating agencies, there is still a possibility that one or more of these companies could default, resulting in a material impact on earnings for a given period.

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; the outcome of the regulatory proceedings relating to the restructuring; regional economic and market conditions, including the California energy situation, 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; 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 stock market (particularly the technology sector in which El Dorado is currently invested) and 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.