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

INTRODUCTION

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

OVERVIEW

Pinnacle West owns all of the outstanding common stock of APS. APS is a vertically-integrated electric utility that provides retail and wholesale electric service to most of the state of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona. APS has historically accounted for a substantial part of our revenues and earnings, and is expected to continue to do so. Customer growth in APS' service territory is about three times the national average and remains a fundamental driver of our revenues and earnings.

The ACC regulates APS' retail electric rates. The key issue affecting Pinnacle West's and APS' financial outlook is the satisfactory resolution of APS' retail rate proceedings pending before the ACC. As discussed in greater detail in Note 3, these proceedings consist of:

- a general retail rate case pursuant to which APS is requesting a 20.4%, or \$434.6 million, increase in its annual retail electricity revenues;
- an application for a temporary rate increase of approximately 1.9%, through a PSA surcharge, to recover \$45 million in retail fuel and purchased power costs relating to Palo Verde's 2005 unplanned outages that were deferred by APS in 2005 under the PSA and are subject to the ACC's completion of an inquiry regarding the outages (this matter is now being addressed in the general retail rate case); and
- the ACC's prudence review of amounts collected through the May 2, 2006 interim PSA adjustor (see "Interim Rate Increase" in Note 3) related to unplanned 2006 Palo Verde outages. The related PSA deferrals were approximately \$79 million in 2006.

SunCor, our real estate development subsidiary, has been and is expected to be an important source of earnings. See discussion below in "Factors Affecting our Financial Outlook – Subsidiaries." Our subsidiary, APS Energy Services, provides competitive commodity-related energy services and energy-related products and services to commercial and industrial

retail customers in the western United States. El Dorado, our investment subsidiary, owns minority interests in several energy-related investments and Arizona community-based ventures.

Pinnacle West Energy was a subsidiary that owned and operated unregulated generating plants. Pursuant to the ACC's April 7, 2005 order in APS' retail rate settlement, on July 29, 2005, Pinnacle West Energy transferred the PWEC Dedicated Assets to APS. Pinnacle West Energy sold its 75% interest in Silverhawk to NPC on January 10, 2006. See Note 22 for a discussion of discontinued operations. As a result, Pinnacle West Energy no longer owned any generating plants and was dissolved as of August 31, 2006.

We continue to focus on solid operational performance in our electricity generation and delivery activities. In the delivery area, we focus on superior reliability and customer satisfaction. We plan to expand long-term resources and our transmission and distribution systems to meet the electricity needs of our growing retail customers and sustain reliability.

See "Factors Affecting Our Financial Outlook" below for a discussion of several factors that could affect our future financial results.

EARNINGS CONTRIBUTION BY BUSINESS SEGMENT

Pinnacle West's two principal business segments are:

- our regulated electricity segment, which consists of traditional regulated retail and wholesale electricity businesses (primarily electric service to Native Load customers) and related activities and includes electricity generation, transmission and distribution; and
- our real estate segment, which consists of SunCor's real estate development and investment activities.

Our reportable business segments reflect a change from the previously reported information. As of December 31, 2006, our marketing and trading activities are no longer considered a segment requiring separate reporting or disclosure. The marketing and trading activities consist of our competitive energy business, including wholesale marketing and trading and retail commodity-related energy services. These activities have decreased as a result of fewer market opportunities and the Company's intention to de-emphasize that part of our business. These activities

are now reported as part of the “Other” category in the table below. The corresponding information for earlier periods has been reclassified.

The following table summarizes income from continuing operations by segment for December 31, 2006, 2005 and 2004 and reconciles to net income in total (dollars in millions):

	2006	2005	2004
	-----	-----	-----
Regulated electricity (a)	\$ 259	\$ 167	\$ 152
Real estate	50	35	40
Other (b)	8	21	55
Income from continuing operations	<u>317</u>	<u>223</u>	<u>247</u>
Discontinued operations			
– net of tax:			
Real estate (c)	10	17	4
Sale of Silverhawk (d)	1	(67)	(12)
Sale of NAC	(1)	3	4
Net income	<u>\$ 327</u>	<u>\$ 176</u>	<u>\$ 243</u>

(a) Includes an \$84 million after-tax regulatory disallowance of plant costs in 2005 in accordance with APS’ 2003 general retail rate case settlement.

(b) Primarily marketing and trading activity.

(c) Primarily relates to sales of commercial properties.

(d) See Note 22.

RESULTS OF OPERATIONS

General

Throughout the following explanations of our results of operations, we refer to “gross margin.” With respect to our regulated electricity segment and our marketing and trading contributions, gross margin refers to operating revenues less fuel and purchased power costs. “Gross margin” is a “non-GAAP financial measure,” as defined in accordance with SEC rules. The charts on pages 86-87 reconcile this non-GAAP financial measure to operating income, which is the most directly comparable financial measure calculated and presented in accordance with accounting principles generally accepted in the United States (GAAP). We view gross margin as an important performance measure of the core profitability of our operations. This measure is a key component of our internal financial reporting and is used by our management in analyzing our business segments. We believe that investors benefit from having access to the same financial measures that our management uses.

Deferred Fuel and Purchased Power Costs

Our subsidiary, APS, settled its 2003 general retail rate case effective April 1, 2005. As part of the settlement,

the ACC approved the PSA, which permits APS to defer for recovery or refund fluctuations in retail fuel and purchased power costs, subject to specified parameters. In accordance with the PSA, APS defers for future rate recovery 90% of the difference between actual retail fuel and purchased power costs and the amount of such costs currently included in base rates. APS’ recovery of PSA deferrals from its customers is subject to the ACC’s approval of annual PSA adjustments and periodic surcharge applications. See “Power Supply Adjustor” in Note 3.

Since the inception of the PSA, APS has incurred substantially higher fuel and purchased power costs than those authorized for recovery through APS’ current base rates primarily due to the use of higher cost resources and has deferred those cost differences in accordance with the PSA. The balance of APS’ PSA deferrals at December 31, 2006 was approximately \$160 million. The recovery of PSA deferrals through ACC approved adjustors and surcharges recorded as revenue is offset dollar-for-dollar by the amortization of those deferred expenses recorded as fuel and purchased power.

APS operated Palo Verde Unit 1 at reduced power levels from December 25, 2005 until March 18, 2006 due to vibration levels in one of the Unit’s shutdown cooling lines. During an outage at Unit 1 from March 18, 2006 to July 7, 2006, APS performed the necessary work and modifications to remedy the situation. APS estimates that incremental replacement power costs resulting from these and other unplanned Palo Verde outages and reduced power levels were approximately \$88 million during 2006. The related impact on the PSA deferrals was an increase of approximately \$79 million. These Palo Verde replacement power costs were partially offset by \$42 million of lower than expected replacement power costs related to APS’ other generating units during 2006, which decreased PSA deferrals by \$38 million.

The PSA deferral balance at December 31, 2006 includes (a) \$45 million related to replacement power costs associated with unplanned 2005 Palo Verde outages and (b) \$79 million related to replacement power costs associated with unplanned 2006 outages or reduced power operations at Palo Verde. The PSA deferrals associated with these unplanned Palo

Verde outages and reduced power operations are the subject of ACC prudence reviews. The ACC staff has recommended disallowance of \$17 million of the 2005 costs. The recommendation will be considered as part of APS' general rate case currently before the ACC. See "PSA Deferrals Related to Unplanned Palo Verde Outages" in Note 3. The ACC staff recommendation does not change management's belief that the expenses in question were prudently incurred and, therefore, are recoverable. See Note 3.

2006 Compared with 2005

Our consolidated net income for 2006 was \$327 million compared with \$176 million for the comparable prior-year period. The prior year included a net loss from discontinued operations of \$47 million, which was related to the sale and operations of Silverhawk, partially offset by income from sales of real estate commercial properties at SunCor. Income from continuing operations increased \$94 million in the period-to-period comparison, reflecting the following changes in earnings by segment:

- Regulated Electricity Segment – Income from continuing operations increased approximately \$92 million primarily due to an \$84 million after-tax regulatory disallowance of plant costs recorded in 2005. Income also increased due to higher retail sales volumes due to customer growth; income tax credits related to prior years resolved in 2006; and increased
 - Real Estate Segment – Income from continuing operations increased approximately \$15 million primarily due to increased margins on residential sales and the sale of certain joint venture assets, partially offset by higher general and administrative expenses. Income from discontinued operations decreased \$7 million due to lower commercial property sales.
 - Other – Income from continuing operations decreased approximately \$13 million primarily due to lower mark-to-market gains, partially offset by higher unit margins on wholesale sales and competitive retail sales in California.
- other income due to higher interest income on higher investment balances. These positive factors were partially offset by higher operations and maintenance expense related to generation and customer service; and higher depreciation and amortization primarily due to increased plant asset balances, partially offset by lower depreciation rates. In addition, higher fuel and purchased power costs of \$74 million after-tax were partially offset by the deferral of \$45 million after-tax of costs in accordance with the PSA. See discussion – "Deferred Fuel and Purchased Power Costs" above.

Additional details on the major factors that increased (decreased) net income are contained in the following table (dollars in millions):

	INCREASE (DECREASE)	
	----- PRETAX	----- AFTER TAX
Regulated electricity segment gross margin:		
Higher fuel and purchased power costs (see “Deferred Fuel and Purchased Power Costs” above)	\$ (121)	\$ (74)
Increased deferred fuel and purchased power costs (deferrals began April 1, 2005)	73	45
Higher retail sales volumes due to customer growth, excluding weather effects	87	53
Miscellaneous items, net	(7)	(4)
Net increase in regulated electricity segment gross margin	32	20
Lower marketing and trading gross margin primarily related to lower mark-to-market gains, partially offset by higher unit margins on wholesale sales and competitive retail sales in California	(18)	(11)
Higher real estate segment contribution primarily related to increased margins on residential sales and the sale of certain joint venture assets	25	15
Regulatory disallowance of plant costs in 2005, in accordance with APS’ 2003 general retail rate case settlement	139	84
Operations and maintenance increases primarily due to:		
Generation costs, including increased maintenance and overhauls	(41)	(25)
Customer service costs, including regulatory demand-side management programs and planned maintenance	(16)	(10)
Miscellaneous items, net	2	1
Higher depreciation and amortization primarily due to increased plant asset balances partially offset by lower depreciation rates	(11)	(7)
Higher other income, net of expense, primarily due to miscellaneous asset sales and increased interest income on higher investment balances	12	7
Income tax credits related to prior years resolved in 2006	-	14
Miscellaneous items, net	-	6
Net increase in income from continuing operations	<u>\$ 124</u>	94
Discontinued operations:		
Silverhawk loss in 2005		68
Lower commercial property real estate sales		(7)
Sale of NAC International Inc.		(4)
Net increase in net income		<u>\$ 151</u>

Regulated Electricity Segment Revenues

Regulated electricity segment revenues were \$398 million higher for 2006 compared with the prior-year period primarily as a result of:

- a \$265 million increase in revenues related to recovery of PSA deferrals, which had no earnings effect because of amortization of the same amount recorded as fuel and purchased power expense (see “Deferred Fuel and Purchased Power Costs” above);
- a \$124 million increase in retail revenues related to customer growth, excluding weather effects;
- a \$6 million increase in Off-System Sales primarily resulting from \$12 million of sales previously reported in marketing and trading that were classified

beginning in April 2005 as sales in the regulated electricity segment in accordance with APS’ 2003 general retail rate case settlement, partially offset by \$6 million of lower Off-System Sales in 2006; and

- a \$3 million increase due to miscellaneous factors.

Real Estate Segment Revenues

Real estate segment revenues were \$62 million higher for 2006 compared with the prior-year period primarily as a result of:

- a \$55 million increase in residential sales due to higher prices and volumes; and
- a \$7 million increase in commercial real estate sales.

Other Revenues

Other revenues were \$25 million lower for 2006 compared with the prior-year period primarily as a result of decreased sales-related products and services by APS Energy Services.

Marketing and trading revenues were \$21 million lower for 2006 compared with the prior-year period primarily as a result of:

- a \$20 million decrease in mark-to-market gains on contracts for future delivery due to changes in forward prices;
- a \$12 million decrease in Off-System Sales due to the absence of sales previously reported in marketing and trading that were classified beginning in April 2005 as sales in the regulated electricity segment in accordance with APS' 2003 general retail rate case settlement;
- a \$23 million increase from higher prices on competitive retail sales in California; and
- a \$12 million decrease due to miscellaneous factors.

2005 Compared with 2004

Our consolidated net income for 2005 was \$176 million compared with \$243 million for the prior year. The 2005 net income included an after-tax net loss from discontinued operations of \$47 million compared with a \$4 million after-tax loss in the prior year, which for both years is related primarily to the sale and operations of Silverhawk, partially offset by sales of commercial properties at SunCor. Income from continuing operations decreased \$24 million in the period-to-period comparison, reflecting the following changes in earnings by segment:

- **Regulated Electricity Segment** – Income from continuing operations increased approximately \$15 million primarily due to deferred fuel and purchased power costs; a retail price increase effective April 1, 2005; higher retail sales volumes due to customer growth; lower depreciation due to lower depreciation rates; lower regulatory asset amortization; and effects of weather on retail sales. These positive factors were partially offset by the regulatory disallowance of plant costs in accordance with the APS retail rate case settlement; higher fuel and purchased power costs primarily due to higher prices and more plant outage days; higher operations and maintenance expense related to generation and customer service; and higher property taxes due to increased plant in service.
- **Real Estate Segment** – Income from continuing operations decreased approximately \$5 million primarily due to decreased parcel sales, partially offset by increased margins on home sales. Income from discontinued real estate operations increased \$13 million due to higher commercial property sales.
- **Other** – Income from continuing operations decreased approximately \$34 million primarily due to an after-tax gain related to the sale of a limited partnership interest in the Phoenix Suns recorded in 2004 and due to lower unit margins on competitive retail sales in California.

Additional details on the major factors that increased (decreased) net income are contained in the following table (dollars in millions):

	INCREASE (DECREASE)	
	PRETAX	AFTER TAX
Regulated electricity segment gross margin:		
Deferred fuel and purchased power costs (see "Deferred Fuel and Purchased Costs" above)	\$ 171	\$ 104
Retail price increase effective April 1, 2005	65	40
Higher retail sales volumes due to customer growth, excluding weather effects	58	35
Effects of weather on retail sales	14	9
Higher fuel and purchased power costs primarily due to higher prices and more plant outage days	(126)	(77)
Miscellaneous items, net	(8)	(5)
Net increase in regulated electricity segment gross margin	174	106
Lower real estate segment contribution primarily related to decreased parcel sales, partially offset by increased margins on home sales	(8)	(5)
Lower marketing and trading gross margin primarily due to lower unit margins on competitive retail sales in California	(21)	(13)
Regulatory disallowance, in accordance with the APS retail rate case settlement	(139)	(84)
Lower other income primarily due to sale of limited partnership interest in Phoenix Suns recorded in the prior year, partially offset by higher interest income	(30)	(18)
Operations and maintenance increases primarily due to:		
Generation costs, including maintenance and overhauls	(20)	(12)
Customer service costs, including regulatory demand-side management programs and planned maintenance	(20)	(12)
Miscellaneous items, net	(4)	(2)
Depreciation and amortization decreases primarily due to:		
Lower regulatory asset amortization	22	13
Lower depreciation rates, partially offset by increased depreciable assets	22	13
Higher property taxes primarily due to increased plant in service	(11)	(7)
Miscellaneous items, net	2	(3)
Net decrease in income from continuing operations	\$ (33)	(24)
Discontinued operations related to:		
Sale of Silverhawk		(56)
Sales of real estate assets and other		13
Net decrease in net income		\$ (67)

Regulated Electricity Segment Revenues

Regulated electricity segment revenues were \$202 million higher for 2005 compared with the prior year primarily as a result of:

- an \$81 million increase in retail revenues related to customer growth, excluding weather effects;
- a \$65 million increase in retail revenues due to a price increase effective April 1, 2005;
- a \$40 million increase in Off-System Sales primarily resulting from sales previously reported as marketing and trading revenues that were classified beginning in April 2005 as sales in the regulated electricity

segment in accordance with the APS retail rate case settlement;

- an \$11 million increase in retail revenues related to weather; and
- a \$5 million increase due to miscellaneous factors.

Real Estate Segment Revenues

Real estate segment revenues were \$12 million lower for 2005 compared with the prior year primarily due to decreased parcel sales, partially offset by increased home sales at SunCor.

Other Revenues

Other revenues were \$31 million lower for 2005 compared with the prior year primarily as a result of:

- a \$40 million decrease in Off-System Sales due to the absence of sales previously reported as marketing and trading revenues that were classified beginning in April 2005 as sales in the regulated electricity

segment in accordance with the APS retail rate case settlement;

- an \$18 million increase due to increased sales of energy-related products and services by APS Energy Services; and
- a \$9 million decrease due to miscellaneous factors.

LIQUIDITY AND CAPITAL RESOURCES

Capital Needs and Resources

CAPITAL EXPENDITURE REQUIREMENTS

The following table summarizes the actual capital expenditures for the year ended 2006 and estimated capital expenditures for the next three years (dollars in millions):

	ACTUAL 2006	2007	2008	ESTIMATED 2009
APS				
Distribution	\$ 357	\$ 361	\$ 414	\$ 459
Transmission	113	173	195	288
Generation	176	333	304	313
Other (a)	16	26	37	40
Subtotal	662	893	950	1,100
SunCor (b)	201	131	101	100
Other	7	13	19	11
Total	\$ 870	\$ 1,037	\$ 1,070	\$ 1,211

(a) Primarily information systems and facilities projects.

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

Distribution and transmission capital expenditures are comprised of 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 lines, substations, line extensions to new residential and commercial developments and upgrades to customer information systems. Major transmission projects are driven by strong regional customer growth.

Generation capital expenditures are comprised of various improvements to APS' existing fossil and nuclear plants and the replacement of Palo Verde steam generators (see below). 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. Environmental expenditures

are estimated at approximately \$80 million to \$100 million per year for 2007, 2008 and 2009. Generation also includes nuclear fuel expenditures of approximately \$50 million for 2007, and approximately \$75 million per year for 2008 and 2009.

The Palo Verde owners have approved the manufacture of one additional set of steam generators. These generators will be installed in Unit 3 and are scheduled for completion in the Fall of 2007 at an approximate cost of \$70 million (APS' share). Approximately \$30 million of the Unit 3 steam generator costs have been incurred through December 31, 2006, with the remaining \$40 million included in the capital expenditures table above. Capital expenditures will be funded with internally generated cash and/or external financings.

CONTRACTUAL OBLIGATIONS

The following table summarizes Pinnacle West's consolidated contractual requirements as of December 31, 2006 (dollars in millions):

	2007	2008-2009	2010-2011	THEREAFTER	TOTAL
Long-term debt payments, including interest: (a)					
APS	\$ 158	\$ 316	\$ 929	\$ 3,600	\$ 5,003
Pinnacle West	10	20	188	–	218
SunCor	14	185	6	–	205
Total long-term debt payments, including interest	182	521	1,123	3,600	5,426
Short-term debt payments, including interest (b)	36	–	–	–	36
Capital lease payments	1	2	2	1	6
Operating lease payments	79	148	133	253	613
Minimum pension funding requirement (c)	24	–	–	–	24
Purchased power and fuel commitments (d)	366	500	412	1,310	2,588
Purchase obligations (e)	44	11	1	80	136
Nuclear decommissioning funding requirements	21	43	48	234	346
Total contractual commitments	\$ 753	\$ 1,225	\$ 1,719	\$ 5,478	\$ 9,175

(a) The long-term debt matures at various dates through 2036 and bears interest principally at fixed rates. Interest on variable-rate long-term debt is determined by using the rates at December 31, 2006 (see Note 6).

(b) The short-term debt is primarily related to commercial paper at Pinnacle West (see Note 5).

(c) Future pension contributions are not determinable for time periods after 2007.

(d) Our fuel and purchased power commitments include purchases of coal, electricity, natural gas and nuclear fuel (see Note 11).

(e) These contractual obligations include commitments for capital expenditures and other obligations.

OFF-BALANCE SHEET ARRANGEMENTS

In 1986, APS entered into agreements with three separate VIE lessors in order to sell and lease back interests in Palo Verde Unit 2. The leases are accounted for as operating leases in accordance with GAAP. We are not the primary beneficiary of the Palo Verde VIEs and, accordingly, do not consolidate them.

APS is exposed to losses under the Palo Verde sale leaseback agreements upon the occurrence of certain events that APS does not consider to be reasonably likely to occur. Under certain circumstances (for example, the NRC issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), APS would be required to assume the debt associated with the transactions, make specified payments to the equity participants, and take title to the leased Unit 2 interests, which, if appropriate, may be required to be written down in value. If such an event had occurred as of December 31, 2006, APS would have been required to assume approximately \$214 million of debt and pay the equity participants approximately \$177 million.

GUARANTEES AND LETTERS OF CREDIT

We and certain of our subsidiaries have issued guarantees and letters of credit in support of our unregulated businesses. We have also obtained surety

bonds on behalf of APS Energy Services. We have not recorded any liability on our Consolidated Balance Sheets with respect to these obligations. We generally agree to indemnification provisions related to liabilities arising from or related to certain of our agreements, with limited exceptions depending on the particular agreement. See Note 21 for additional information regarding guarantees and letters of credit.

CREDIT RATINGS

The ratings of securities of Pinnacle West and APS as of February 28, 2007 are shown below. The ratings reflect the respective views of the rating agencies, from which an explanation of the significance of their ratings may be obtained. There is no assurance that these ratings will continue for any given period of time. The ratings may be revised or withdrawn entirely by the rating agencies, if, in their respective judgments, circumstances so warrant. Any downward revision or withdrawal may adversely affect the market price of Pinnacle West's or APS' securities and serve to increase the cost of and access to capital. It may also require additional collateral related to certain derivative instruments (see Note 18).

	MOODY'S -----	STANDARD & POOR'S -----	FITCH -----
PINNACLE WEST			
Senior unsecured (a)	Baa3(P)	BB+ (prelim)	N/A
Commercial paper	P-3	A-3	F-3
Outlook	Negative	Stable	Stable
APS			
Senior unsecured	Baa2	BBB-	BBB
Secured lease obligation bonds	Baa2	BBB-	BBB-
Commercial paper	P-2	A-3	F-2
Outlook	Negative	Stable	Stable

(a) Pinnacle West has a shelf registration under SEC Rule 415. Pinnacle West currently has no outstanding, rated senior unsecured securities. However, Moody's assigns a provisional (P) rating and Standard & Poor's assigns a preliminary (prelim) rating to the senior unsecured securities under such shelf registrations.

DEBT PROVISIONS

Pinnacle West's and APS' debt covenants related to their respective bank financing arrangements include debt to capitalization ratios. Certain of APS' bank financing arrangements also include an interest coverage test. Pinnacle West and APS comply with these covenants and each anticipates it will continue to meet these and other significant covenant requirements. For both Pinnacle West and APS, these covenants require that the ratio of consolidated debt to total consolidated capitalization not exceed 65%. At December 31, 2006, the ratio was approximately 48% for Pinnacle West and 46% for APS. The provisions regarding interest coverage require a minimum cash coverage of two times the interest requirements for APS. The interest coverage was approximately 4.7 times under APS' bank financing agreements as of December 31, 2006. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants and could cross-default other debt. See further discussion of "cross-default" provisions below.

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

All of Pinnacle West's loan agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under these loan agreements if Pinnacle West or APS were to default under certain other material agreements. All of APS' bank agreements contain cross-default provisions that would result in defaults and the potential acceleration of payment under these bank agreements if APS were to default under certain other material agreements. Pinnacle West and APS do not have a material adverse change restriction for revolver borrowings.

See Note 6 for further discussions.

Capital Needs and Resources

PINNACLE WEST (PARENT COMPANY)

Our primary cash needs are for dividends to our shareholders and principal and interest payments on our long-term debt. On October 18, 2006, our Board of Directors increased the common stock dividend to an indicated annual rate of \$2.10 per share from \$2.00 per share, effective with the December 1, 2006 dividend payment. The level of our common stock dividends and future dividend growth will be dependent on a number of factors including, but not limited to, payout ratio trends, free cash flow and financial market conditions.

Our primary sources of cash are dividends from APS, external financings and cash distributions from our other subsidiaries, primarily SunCor. For the years 2004 through 2006, total dividends from APS were \$510 million and total distributions from SunCor were \$145 million. For 2006, cash contributions from APS were \$170 million and distributions from SunCor were

\$10 million. An existing ACC order requires APS to maintain a common equity ratio of at least 40% and prohibits APS from paying common stock dividends if the payment would reduce its common equity below that threshold. As defined in the ACC order, the common equity ratio is common equity divided by the sum of common equity and long-term debt, including current maturities of long-term debt. At December 31, 2006, APS' common equity ratio, as defined, was approximately 53%.

At December 31, 2006, Pinnacle West's outstanding long-term debt, including current maturities, was \$175 million. Pinnacle West has a \$300 million revolving credit facility that terminates in December 2010. This line of credit is available to support the issuance of up to \$250 million in commercial paper or to be used as bank borrowings, including issuances of letters of credit. At December 31, 2006, we had \$28 million of commercial paper outstanding.

Pinnacle West sponsors a qualified defined benefit and account balance pension plan and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and its subsidiaries. IRS regulations require us to contribute a minimum amount to the qualified plan. We contribute at least the minimum amount required under IRS regulations, but no more than the maximum tax-deductible amount. The minimum required funding takes into consideration the value of plan assets and our pension obligation. The assets in the plan are comprised of common stocks, bonds, fixed-income securities and domestic equity securities and short-term investments. Future year contribution amounts are dependent on fund performance and plan asset valuation assumptions. We contributed approximately \$47 million in 2006. The contribution to our pension plan in 2007 is estimated to be approximately \$24 million. The expected contribution to our other postretirement benefit plans in 2007 is estimated to be approximately \$25 million. APS and other subsidiaries fund their share of the contributions. APS' share is approximately 97% of both plans.

In January 2006, Pinnacle West infused into APS \$210 million of the proceeds from the sale of Silverhawk. See "Equity Infusions" in Note 3 for more information.

On February 28, 2006, Pinnacle West entered into an Uncommitted Master Shelf Agreement with Prudential Investment Management, Inc. ("Prudential") and certain of its affiliates. The agreement provides the terms under which Pinnacle West may offer up to \$200 million of its senior notes for purchase by Prudential affiliates at any time prior to December 31, 2007. The maturity of notes issued under the agreement cannot exceed five years. Pursuant to the agreement, on February 28, 2006, Pinnacle West issued and sold to Prudential affiliates \$175 million of its 5.91% Senior Notes, Series A, due February 28, 2011 (the "Series A Notes").

On April 3, 2006, Pinnacle West repaid \$300 million of its 6.40% Senior Notes due April 2006. Pinnacle West used the proceeds of the Series A Notes, cash on hand and commercial paper proceeds to repay these notes.

On January 4, 2007, the FERC issued an order permitting Pinnacle West to transfer its market based rate tariff and wholesale power sales agreements to a newly-created Pinnacle West subsidiary, Pinnacle West Marketing & Trading. Pinnacle West completed the transfer on February 1, 2007, which resulted in Pinnacle West no longer being a public utility under the Federal Power Act. As a result, Pinnacle West is no longer subject to FERC jurisdiction in connection with its issuance of securities or its incurrence of long-term debt.

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

Although provisions in APS' articles of incorporation and ACC financing orders establish maximum amounts of preferred stock and debt that APS may issue, APS

does not expect any of these provisions to limit its ability to meet its capital requirements. On December 15, 2006, APS filed a financing application with the ACC requesting an increase in APS' current long-term debt authorization (approximately \$3.2 billion) to approximately \$4.2 billion in light of the projected growth of APS and its customer base and the resulting projected future financing needed to fund APS' capital expenditure and maintenance program and other cash requirements.

On August 3, 2006, APS issued \$400 million of debt as follows: \$250 million of its 6.25% Notes due 2016 and \$150 million of its 6.875% Notes due 2036. A portion of the proceeds was used to pay at maturity approximately \$84 million of APS' 6.75% Senior Notes due November 15, 2006. The remainder may be used to fund its construction program and other general corporate purposes.

On September 28, 2006, APS put in place an additional \$500 million revolving credit facility that terminates in September 2011. APS may increase the amount of the facility up to a maximum facility of \$600 million upon the satisfaction of certain conditions. APS will use the facility for general corporate purposes. The facility can also be used for the issuance of letters of credit. Interest rates are based on APS' senior unsecured debt credit ratings.

See "Deferred Fuel and Purchased Power Costs" above and "Power Supply Adjustor" in Note 3 for information regarding the PSA approved by the ACC. Although APS defers actual retail fuel and purchased power costs on a current basis, APS' recovery of the deferrals from its ratepayers is subject to the ACC's approval of annual PSA adjustments and periodic surcharge applications. During 2006, APS recovered approximately \$265 million of PSA deferrals, which provided cash flow but had no effect on earnings because of amortization of the same amount recorded as fuel and purchased power expense.

APS' outstanding debt was approximately \$2.9 billion at December 31, 2006. APS has two committed lines of credit totaling \$900 million that are available either to support the issuance of up to \$250 million in commercial paper or to be used for bank borrowings, including issuances of letters of credit. The \$400 million line terminates in December 2010 and the \$500 million

line terminates in September 2011. At December 31, 2006, APS had no outstanding commercial paper or bank borrowings. APS ended 2006 in an invested cash position.

See "Cash Flow Hedges" in Note 18 for information related to decreased collateral provided to us by counterparties and the change in our margin account.

OTHER SUBSIDIARIES

During the past three years, SunCor funded its cash requirements with cash from operations and its own external financings. SunCor's capital needs consist primarily of capital expenditures for land development and retail and office building construction. See the capital expenditures table above for actual capital expenditures during 2006 and projected capital expenditures for the next three years. SunCor expects to fund its future capital requirements with cash from operations and external financings.

SunCor's total outstanding debt was approximately \$189 million as of December 31, 2006, including \$118 million of debt classified as long-term debt under a \$170 million line of credit. SunCor's long-term debt, including current maturities, was \$181 million and total short-term debt was \$8 million at December 31, 2006. See Note 6.

See Note 22 for a discussion of the sale of Pinnacle West Energy's 75% ownership interest in Silverhawk.

El Dorado expects minimal capital requirements over the next three years and intends to focus on prudently realizing the value of its existing investments.

APS Energy Services and Pinnacle West Marketing & Trading expect minimal capital expenditures over the next three years.

CRITICAL ACCOUNTING POLICIES

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

Regulatory Accounting

Regulatory accounting allows for the actions of regulators, such as the ACC and the FERC, to be reflected in our financial statements. Their actions may cause us to capitalize costs that would otherwise be included as an expense in the current period by unregulated companies. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings. A major component of our regulatory assets is the retail fuel and power costs deferred under the PSA. APS defers for future rate recovery 90% of the difference between actual retail fuel and power costs and the amount of such costs currently included in base rates. We had \$846 million, including \$160 million related to the PSA, of regulatory assets on the Consolidated Balance Sheets at December 31, 2006. Included in the \$160 million is approximately \$45 million related to the 2005 unplanned Palo Verde outages and \$79 million related to the 2006 unplanned outages, which currently are the subject of inquiry by the ACC.

At December 31, 2006, APS recorded a regulatory asset of \$473 million in accordance with SFAS No. 158 for pension and other postretirement benefits. This regulatory asset represents the future recovery of these costs through retail rates as these amounts are charged to earnings. If these costs are disallowed by the ACC this regulatory asset would be charged to OCI.

In addition, we had \$635 million of regulatory liabilities on the Consolidated Balance Sheets at December 31, 2006, which primarily are related to removal costs. See Notes 1, 3 and 8 for more information about regulatory assets, APS' general rate case and the PSA.

Pensions and Other Postretirement Benefit Accounting

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

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the December 31, 2006 reported pension liability on the Consolidated Balance Sheets and our 2006 reported pension expense, after consideration of amounts capitalized or billed to electric plant participants, on Pinnacle West's Consolidated Statements of Income (dollars in millions):

ACTUARIAL ASSUMPTION (a)	INCREASE (DECREASE)	
	IMPACT ON PENSION LIABILITY	IMPACT ON PENSION EXPENSE
Discount rate:		
Increase 1%	\$ (217)	\$ (9)
Decrease 1%	249	9
Expected long-term rate of return on plan assets:		
Increase 1%	-	(5)
Decrease 1%	-	5

(a) Each fluctuation assumes that the other assumptions of the calculation are held constant while the rates are changed by one percentage point.

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the December 31, 2006 reported other postretirement benefit obligation on the Consolidated Balance Sheets and our 2006 reported other postretirement benefit expense, after consideration of amounts capitalized or billed to electric plant participants, on Pinnacle West's Consolidated Statements of Income (dollars in millions):

ACTUARIAL ASSUMPTION (a)	INCREASE (DECREASE)	
	IMPACT ON OTHER POSTRETIREMENT BENEFIT OBLIGATION	IMPACT ON OTHER POSTRETIREMENT BENEFIT EXPENSE
Discount rate:		
Increase 1%	\$ (92)	\$ (5)
Decrease 1%	108	5
Health care cost trend rate (b):		
Increase 1%	105	8
Decrease 1%	(87)	(7)
Expected long-term rate of return on plan assets - pretax:		
Increase 1%	-	(2)
Decrease 1%	-	2

(a) Each fluctuation assumes that the other assumptions of the calculation are held constant while the rates are changed by one percentage point.

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

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

Derivative Accounting

Derivative accounting requires evaluation of rules that are complex and subject to varying interpretations. Our evaluation of these rules, as they apply to our contracts, determines whether we use accrual accounting (for contracts designated as normal) or fair value (mark-to-market) accounting. Mark-to-market accounting requires that changes in the fair value are recognized periodically in income unless certain hedge criteria are met. For fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item associated with the hedged risk are recognized in earnings. For cash flow hedges, the effective portion of changes in the fair value of the derivative are recognized in common stock equity (as a component of other comprehensive income (loss)).

The fair value of our derivative contracts is not always readily determinable. In some cases, we use models and other valuation techniques to determine fair value. The use of these models and valuation techniques sometimes requires subjective and complex judgment. Actual results could differ from the results estimated through application of these methods. Our marketing and trading portfolio consists of structured activities hedged with a portfolio of forward purchases that protects the economic value of the sales transactions. See “Market Risks – Commodity Price Risk” below for quantitative analysis. See Note 1 for discussion on accounting policies and Note 18 for a further discussion on derivative and energy trading accounting.

OTHER ACCOUNTING MATTERS

In June 2006, the FASB issued FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109.” This guidance requires us to recognize the tax benefits of an uncertain tax position if it is more likely than not that the benefit will be sustained upon examination by the taxing authority. A tax position that meets the more-likely-than-not recognition threshold must be recognized in the financial statements at the largest amount of benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement. The Interpretation is effective for fiscal years beginning after December 15, 2006. We are currently evaluating this new guidance and believe it will not have a material impact on retained earnings.

In September 2006, the FASB issued SFAS No. 157, “Fair Value Measurements.” This guidance establishes a framework for measuring fair value and expands disclosures about fair value measurements. The Statement is effective for fiscal years beginning after November 15, 2007. We are currently evaluating this new guidance.

In February 2007, the FASB issued SFAS No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities.” SFAS No. 159 provides companies with an option to report selected financial assets and liabilities at fair value. SFAS No. 159 is effective for us on January 1, 2008. We are currently evaluating the impact of this new standard.

See the following Notes for information about new accounting standards:

- See Note 8 for a discussion of SFAS No. 158 on pension and other postretirement plans.
- See Note 16 for a discussion of the accounting standard (SFAS No. 123(R)) on stock-based compensation.

FACTORS AFFECTING OUR FINANCIAL OUTLOOK

Factors Affecting Operating Revenues, Fuel and Purchased Power Costs

GENERAL Electric operating revenues are derived from sales of electricity in regulated retail markets in Arizona and from competitive retail and wholesale power markets in the western United States. For the years 2004 through 2006, retail electric revenues comprised approximately 82% of our total electric operating revenues. Our electric operating revenues are affected by electricity sales volumes related to customer mix, customer growth, average usage per customer, electricity rates and tariffs, variations in weather from period to period, and amortization of PSA deferrals. Competitive retail sales of energy and energy-related products and services are made by APS Energy Services in certain western states that have opened to competition. Off-system sales of excess generation output, purchased power and natural gas are included in regulated electricity segment revenues and related fuel and purchased power because the gross margin is credited to APS’ retail customers through the PSA (see Note 3). These revenue transactions are affected by the availability of excess generation or other energy resources and wholesale market conditions, including demand and

prices. Competitive wholesale transactions are made by the marketing and trading group through structured trading opportunities involving matched sales and purchases of commodities.

RETAIL RATE PROCEEDINGS The key issue affecting Pinnacle West's and APS' financial outlook is the satisfactory resolution of APS' retail rate proceedings pending before the ACC, which are discussed in greater detail in Note 3. The most significant pending retail rate proceedings are APS' general rate case request and an application for a 1.9% PSA surcharge, or temporary rate increase, related to incremental replacement power costs incurred by APS in 2005 in connection with unplanned outages at Palo Verde, which is subject to the ACC's review of the unplanned outages. These matters have been consolidated procedurally and a decision on them by the ACC is expected in the second quarter of 2007. In addition, the ACC staff is conducting a review of the prudence of approximately \$79 million in PSA deferrals related to 2006 unplanned outages at Palo Verde.

FUEL AND PURCHASED POWER COSTS Fuel and purchased power costs included on our income statements are impacted by our electricity sales volumes, existing contracts for purchased power and generation fuel, our power plant performance, transmission availability or constraints, prevailing market prices, new generating plants being placed in service in our market areas, our hedging program for managing such costs and, since April 1, 2005, PSA deferrals and amortization thereof. See "Power Supply Adjustor" in Note 3 for information regarding the PSA, including PSA deferrals related to Palo Verde unplanned outages and reduced power operations that are the subject of ACC prudence reviews. See "Natural Gas Supply" in Note 11 for more information on fuel costs. APS' recovery of PSA deferrals from its ratepayers is subject to the ACC's approval of annual PSA adjustments and periodic surcharge applications.

CUSTOMER AND SALES GROWTH The customer and sales growth referred to in this paragraph applies to Native Load customers and sales to them. Customer growth in APS' service territory was 4.4% during 2006. Such growth averaged 4.1% a year for the three years from 2004 through 2006; and we currently expect customer growth to average about 4.0% per year from 2007 to

2009. For the three years 2004 through 2006, APS' actual retail electricity sales in kilowatt-hours grew at an average rate of 4.2%; adjusted to exclude effects of weather variations, such retail sales growth averaged 4.6% a year. We currently estimate that total retail electricity sales in kilowatt-hours will grow 3.2% on average, from 2007 through 2009, before the effects of weather variations. We currently expect our retail sales growth in 2007 to be below average because of potential effects on customer usage from the retail rate increases proposed by APS (see Note 3).

Actual sales growth, excluding weather-related variations, may differ from our projections as a result of numerous factors, such as economic conditions, customer growth, usage patterns and responses to retail price changes. Our experience indicates that a reasonable range of variation in our kilowatt-hour sales projection attributable to such economic factors can result in increases or decreases in annual net income of up to \$10 million.

WEATHER In forecasting retail sales growth, we assume normal weather patterns based on historical data. Historical extreme weather variations have resulted in annual variations in net income in excess of \$20 million. However, our experience indicates that the more typical variations from normal weather can result in increases or decreases in annual net income of up to \$10 million.

WHOLESALE MARKET CONDITIONS The marketing and trading group focuses primarily on managing APS' risks relating to fuel and purchased power costs in connection with its costs of serving Native Load customer demand. The marketing and trading group, subject to specified parameters, markets, hedges and trades in electricity, fuels and emission allowances and credits.

Other Factors Affecting Financial Results

OPERATIONS AND MAINTENANCE EXPENSES Operations and maintenance expenses are impacted by growth, power plant additions and operations, inflation, outages, higher-trending pension and other postretirement benefit costs and other factors.

DEPRECIATION AND AMORTIZATION EXPENSES Depreciation and amortization expenses are impacted by net additions to utility plant and other property, which include generation construction, changes in depreciation and amortization rates, and changes in regulatory asset amortization.

PROPERTY TAXES Taxes other than income taxes consist primarily of property taxes, which are affected by the value of property in service and under construction, assessed valuation ratios, and tax rates. The average property tax rate for APS, which currently owns the majority of our property, was 8.9% of assessed value for 2006 and 9.2% for 2005 and 2004. We expect property taxes to increase as new power plants (including the Sundance Plant acquired in 2005) and additions to our transmission and distribution facilities are included in the property tax base.

INTEREST EXPENSE Interest expense is affected by the amount of debt outstanding and the interest rates on that debt. The primary factors affecting borrowing levels are expected to be our capital expenditures, long-term debt maturities, and internally generated cash flow. Capitalized interest offsets a portion of interest expense while capital projects are under construction. We stop accruing capitalized interest on a project when it is placed in commercial operation.

RETAIL COMPETITION Although some very limited retail competition existed in Arizona in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to APS' customers. We cannot predict when, and the extent to which, additional competitors will re-enter APS' service territory.

SUBSIDIARIES SunCor's net income was \$61 million in 2006, \$56 million in 2005, and \$45 million in 2004. See Note 22 for further discussion. We currently expect SunCor's net income in 2007 will be between \$30 million and \$35 million. This estimate reflects a slow-down in the western United States residential real estate markets.

APS Energy Services' and El Dorado's historical results are not indicative of future performance.

GENERAL Our financial results may be affected by a number of broad factors. See "Forward-Looking Statements" 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 our nuclear decommissioning trust fund.

INTEREST RATE AND EQUITY RISK

We have exposure to changing interest rates. Changing interest rates will affect interest paid on variable-rate debt and the market value of fixed income securities held by our nuclear decommissioning trust fund (see Note 12). The nuclear decommissioning trust fund also has risks associated with the changing market value of its investments. Nuclear decommissioning costs are recovered in regulated electricity prices.

The tables below present contractual balances of our consolidated long-term and short-term debt at the expected maturity dates as well as the fair value of those instruments on December 31, 2006 and 2005. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2006 and 2005 (dollars in thousands):

	SHORT-TERM DEBT		VARIABLE-RATE LONG-TERM DEBT		FIXED-RATE LONG-TERM DEBT	
	INTEREST RATES	AMOUNT	INTEREST RATES	AMOUNT	INTEREST RATES	AMOUNT
2006						
2007	6.26%	\$ 35,750	10.25%	\$ 112	5.78%	\$ 1,549
2008	-	-	7.26%	161,356	5.39%	7,810
2009	-	-	9.37%	2,500	6.23%	5,371
2010	-	-	-	-	6.24%	6,455
2011	-	-	-	-	6.24%	576,320
Years thereafter	-	-	3.77%	565,855	5.81%	1,916,758
Total		<u>\$ 35,750</u>		<u>\$ 729,823</u>		<u>\$ 2,514,263</u>
Fair value		<u>\$ 35,750</u>		<u>\$ 729,823</u>		<u>\$ 2,480,605</u>

	SHORT-TERM DEBT		VARIABLE-RATE LONG-TERM DEBT		FIXED-RATE LONG-TERM DEBT	
	INTEREST RATES	AMOUNT	INTEREST RATES	AMOUNT	INTEREST RATES	AMOUNT
2005						
2006	7.11%	\$ 15,673	5.38%	\$ 350	6.47%	\$ 386,624
2007	-	-	5.38%	350	5.90%	1,271
2008	-	-	5.93%	128,178	5.85%	1,318
2009	-	-	-	-	5.73%	1,014
2010	-	-	-	-	5.69%	1,077
Years thereafter	-	-	3.25%	565,855	5.79%	1,918,026
Total		<u>\$ 15,673</u>		<u>\$ 694,733</u>		<u>\$ 2,309,330</u>
Fair value		<u>\$ 15,673</u>		<u>\$ 694,733</u>		<u>\$ 2,326,235</u>

The tables below present contractual balances of APS' long-term debt at the expected maturity dates as well as the fair value of those instruments on December 31, 2006 and 2005. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2006 and 2005 (dollars in thousands):

2006	VARIABLE-RATE LONG-TERM DEBT		FIXED-RATE LONG-TERM DEBT	
	INTEREST RATES	AMOUNT	INTEREST RATES	AMOUNT
2007	-	\$ -	6.18%	\$ 1,033
2008	-	-	6.18%	1,230
2009	-	-	6.17%	1,020
2010	-	-	6.17%	1,111
2011	-	-	6.38%	401,320
Years thereafter	3.77%	565,855	5.81%	1,916,758
Total		<u>\$ 565,855</u>		<u>\$ 2,322,472</u>
Fair value		<u>\$ 565,855</u>		<u>\$ 2,288,814</u>

2005	VARIABLE-RATE LONG-TERM DEBT		FIXED-RATE LONG-TERM DEBT	
	INTEREST RATES	AMOUNT	INTEREST RATES	AMOUNT
2006	-	\$ -	6.71%	\$ 86,165
2007	-	-	5.76%	1,075
2008	-	-	5.74%	1,271
2009	-	-	5.70%	1,005
2010	-	-	5.69%	1,077
Years thereafter	3.25%	565,855	5.79%	1,918,026
Total		<u>\$ 565,855</u>		<u>\$ 2,008,619</u>
Fair value		<u>\$ 565,855</u>		<u>\$ 2,025,001</u>

COMMODITY PRICE RISK

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal and emissions allowances. We manage risks associated with these market fluctuations by utilizing various commodity instruments that qualify as derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. Our ERM, consisting of officers and key management personnel, oversees company-wide energy risk management activities and monitors the results of marketing and trading activities to ensure compliance with our stated energy risk management and trading policies. As part of our risk management program, we use such instruments to hedge purchases and sales of electricity, fuels and emissions allowances and credits. The changes in market value of such contracts have a high correlation to price changes in the hedged

commodities. In addition, subject to specified risk parameters monitored by the ERM, we engage in marketing and trading activities intended to profit from market price movements.

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

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

The following tables show the pretax changes in mark-to-market of our non-trading and trading derivative positions in 2006 and 2005 (dollars in millions):

	2006		2005	
	REGULATED ELECTRICITY	MARKETING AND TRADING	REGULATED ELECTRICITY	MARKETING AND TRADING
Mark-to-market of net positions at beginning of period	\$ 335	\$ 181	\$ 33	\$ 107
Recognized in earnings:				
Change in mark-to-market gains (losses) for future period deliveries	(12)	(15)	14	20
Mark-to-market gains realized including ineffectiveness during the period	(3)	—	(8)	(14)
Deferred as a regulatory liability (asset)	(93)	—	31	—
Recognized in OCI:				
Changes in mark-to-market gains (losses) for future period deliveries (a)	(285)	(67)	359	102
Mark-to-market gains realized during the period	(4)	(22)	(94)	(34)
Change in valuation techniques	—	—	—	—
Mark-to-market of net positions at end of period	\$ (62)	\$ 77	\$ 335	\$ 181

(a) The change in regulated mark-to-market recorded in OCI is due primarily to changes in forward natural gas prices.

The tables below show the fair value of maturities of our non-trading and trading derivative contracts (dollars in millions) at December 31, 2006 by maturities and by the type of valuation that is performed to calculate the fair values. See Note 1, "Derivative Accounting," for more discussion of our valuation methods.

Regulated Electricity

SOURCE OF FAIR VALUE	2007	2008	2009	2010	2011	YEARS THEREAFTER	TOTAL FAIR VALUE
	-----	-----	-----	-----	-----	-----	-----
Prices actively quoted	\$ (34)	\$ (6)	\$ (10)	\$ —	\$ —	\$ —	\$ (50)
Prices provided by other external sources	13	(3)	(1)	—	—	—	9
Prices based on models and other valuation methods	(3)	(2)	(2)	(3)	(2)	(9)	(21)
Total by maturity	\$ (24)	\$ (11)	\$ (13)	\$ (3)	\$ (2)	\$ (9)	\$ (62)

Marketing and Trading

SOURCE OF FAIR VALUE	2007	2008	2009	2010	2011	TOTAL FAIR VALUE
	-----	-----	-----	-----	-----	-----
Prices actively quoted	\$ 9	\$ —	\$ —	\$ —	\$ —	\$ 9
Prices provided by other external sources	40	17	—	—	2	59
Prices based on models and other valuation methods	(5)	17	(1)	(1)	(1)	9
Total by maturity	\$ 44	\$ 34	\$ (1)	\$ (1)	\$ 1	\$ 77

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 Pinnacle West's Consolidated Balance Sheets at December 31, 2006 and 2005 (dollars in millions).

COMMODITY	DECEMBER 31, 2006		DECEMBER 31, 2005	
	PRICE UP 10%	PRICE DOWN 10%	PRICE UP 10%	PRICE DOWN 10%
Mark-to-market changes reported in OCI (a):				
Electricity	\$ 38	\$ (38)	\$ 66	\$ (66)
Natural gas	80	(80)	103	(103)
Total	\$ 118	\$ (118)	\$ 169	\$ (169)

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

CREDIT RISK

We are exposed to losses in the event of non-performance or non-payment by counterparties. See Note 1, "Derivative Accounting" for a discussion of our credit valuation adjustment policy. See Note 18 for further discussion of credit risk.

FORWARD-LOOKING STATEMENTS

This document contains forward-looking statements based on current expectations, and Pinnacle West assumes no obligation to update these statements or make any further statements on any of these issues, except as required by applicable law. These forward-looking statements are often identified by words such as "estimate," "predict," "hope," "may," "believe," "anticipate," "plan," "expect," "require," "intend," "assume" and similar words. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from results or outcomes currently expected or sought by Pinnacle West. In addition to the Risk Factors described in Item 1A of the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2006, these factors include, but are not limited to:

- state and federal regulatory and legislative decisions and actions, including the outcome and timing of APS' retail rate proceedings pending before the ACC;

- the timely recovery of PSA deferrals, including such deferrals in 2005 and 2006 associated with unplanned Palo Verde outages and reduced power operations that are the subject of ACC prudence reviews;
- the ongoing restructuring of the electric industry, including the introduction of retail electric competition in Arizona and decisions impacting wholesale competition;
- the outcome of regulatory, legislative and judicial proceedings, both current and future, relating to the restructuring;
- market prices for electricity and natural gas;
- power plant performance and outages;
- transmission outages and constraints;
- weather variations affecting local and regional customer energy usage;
- customer growth and energy usage;
- regional economic and market conditions, including the results of litigation and other proceedings resulting from the California energy situation, volatile fuel and purchased power costs and the completion of generation and transmission construction in the region, which could affect customer growth and the cost of power supplies;
- the cost of debt and equity capital and access to capital markets;
- current credit ratings remaining in effect for any given period of time;
- our ability to compete successfully outside traditional regulated markets (including the wholesale market);

- the performance of our marketing and trading activities due to volatile market liquidity and any deteriorating counterparty credit and the use of derivative contracts in our business (including the interpretation of the subjective and complex accounting rules related to these contracts);
- changes in accounting principles generally accepted in the United States of America and the interpretation of those principles;
- the performance of the stock market and the changing interest rate environment, which affect the value of our nuclear decommissioning trust, pension, and other postretirement benefit plan assets, the amount of required contributions to Pinnacle West's pension plan and contributions to APS' nuclear decommissioning trust funds, as well as the reported costs of providing pension and other postretirement benefits;
- technological developments in the electric industry;
- the strength of the real estate market in SunCor's market areas, which include Arizona, Idaho, New Mexico and Utah; and
- other uncertainties, all of which are difficult to predict and many of which are beyond the control of Pinnacle West and APS.