PINNACLE WEST CAPITAL CORP

FORM 10-Q
(Quarterly Report)

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FORM 10-Q
Securities and Exchange Commission
Washington, D.C. 20549

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2002

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________ to __________

Commission file number 1-8962

PINNACLE WEST CAPITAL CORPORATION
(Exact name of registrant as specified in its charter)

Arizona (State or other jurisdiction of incorporation or organization)	86-0512431 (I.R.S. Employer Identification No.)
400 North Fifth Street, P.O. Box 53999, Phoenix, Arizona (Address of principal executive offices)	85072-3999 (Zip Code)

Registrant's telephone number, including area code: (602) 250-1000

(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes [X] No [ ]

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Number of shares of common stock, no par value, outstanding as of August 12, 2002: 84,776,489

Glossary

ACC - Arizona Corporation Commission

ACC Staff - Staff of the Arizona Corporation Commission

ALJ - administrative law judge

APS - Arizona Public Service Company, a subsidiary of the Company

APSES - APS Energy Services Company, Inc., a subsidiary of the Company

CC&N - Certificate of Convenience and Necessity

Citizens - Citizens Communications Company

Company - Pinnacle West Capital Corporation

CPUC - California Public Utility Commission

EITF - Emerging Issues Task Force

El Dorado - El Dorado Investment Company, a subsidiary of the Company

ERMC - the Company's Energy Risk Management Committee

FASB - Financial Accounting Standards Board

FERC - United States Federal Energy Regulatory Commission

Four Corners - Four Corners Power Plant

GAAP - Generally accepted accounting principles in the United States

ISO - California Independent System Operator

March 2002 10-Q - Pinnacle West Capital Corporation Quarterly Report on Form 10-Q for the fiscal quarter ended March 31, 2002

MW - megawatt, one million watts

MWh - megawatt hour

NAC - Nuclear Assurance Corporation

Native Load - retail and wholesale sales supplied under traditional cost-based rate regulation

1999 Settlement Agreement - comprehensive settlement agreement related to the implementation of retail electric competition

Palo Verde - Palo Verde Nuclear Generating Station

Pinnacle West Energy - Pinnacle West Energy Corporation, a subsidiary of the Company

PG&E - PG&E Corp.

PX - California Power Exchange

Rules - ACC retail electric competition rules

SCE - Southern California Edison

SFAS - Statement of Financial Accounting Standards

SNWA - Southern Nevada Water Authority

SPE - special-purpose entity

SunCor - SunCor Development Company, a subsidiary of the Company

System - Non-trading energy related activities

T&D - transmission and distribution

Trading - Energy related activities entered into with the objective of generating profits on changes in market prices

2001 10-K - Pinnacle West Capital Corporation Annual Report on Form 10-K for the fiscal year ended December 31, 2001

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS.

PINNACLE WEST CAPITAL CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(unaudited)

(in thousands, except per share amounts)

	Three Months Ended June 30, 2002	2001
Operating Revenues		
Electric retail segment	$ 496,840	$ 739,317
Marketing and trading segment	148,946	522,041
Real estate	69,152	32,454
Total	714,938	1,293,812
Operating Expenses		
Electric retail segment purchased power and fuel	104,590	434,822
Marketing and trading segment purchased power and fuel	129,927	423,935
Operations and maintenance	128,996	132,139
Real estate operations	56,213	32,437
Depreciation and amortization	102,087	106,129
Taxes other than income taxes	27,632	25,462
Total	549,445	1,154,924
Operating Income	165,493	138,888
Other		
Other income (Note 16)	7,073	16,016
Other expense (Note 16)	(14,766)	(12,779)
Total	(7,693)	3,237
Interest Expense		
Interest charges	46,996	43,823
Capitalized interest	(14,005)	(12,527)
Total	32,991	31,296
Income Before Income Taxes	124,809	110,829
Income Taxes	49,444	43,972
Net Income	$ 75,365	$ 66,857
Weighted-Average Common Shares Outstanding - Basic	84,794	84,744
Weighted-Average Common Shares Outstanding - Diluted	84,926	85,042
Earnings Per Weighted-Average Common Share Outstanding		
Net Income - Basic	$ 0.89	$ 0.79
Net Income - Diluted	0.89	0.79
Dividends Declared Per Share	$ 0.40	$ 0.375

See Notes to Condensed Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(unaudited)

(in thousands, except per share amounts)

	Six Months Ended June 30, 2002	Six Months Ended June 30, 2001
Operating Revenues		
Electric retail segment	$ 877,079	$ 1,152,124
Marketing and trading segment	348,479	1,015,728
Real estate	110,337	64,789
Total	1,335,895	2,232,641
Operating Expenses		
Electric retail segment purchased power and fuel	166,122	564,449
Marketing and trading segment purchased power and fuel	289,431	810,732
Operations and maintenance	246,426	257,389
Real estate operations	93,571	63,445
Depreciation and amortization	202,000	210,910
Taxes other than income taxes	54,390	50,765
Total	1,051,940	1,957,690
Operating Income	283,955	274,951
Other		
Other income (Note 16)	14,433	19,974
Other expense (Note 16)	(21,038)	(17,475)
Total	(6,605)	2,499
Interest Expense		
Interest charges	91,684	86,572
Capitalized interest	(28,128)	(22,954)
Total	63,556	63,618
Income Before Income Taxes	213,794	213,832
Income Taxes	84,672	84,770
Income Before Accounting Change	129,122	129,062
Cumulative Effect of a Change in Accounting for Derivatives - Net of Income Tax Benefit of $1,793	--	(2,755)
Net Income	$ 129,122	$ 126,307
Weighted-Average Common Shares Outstanding - Basic	84,769	84,736
Weighted-Average Common Shares Outstanding - Diluted	84,910	85,005
Earnings Per Weighted-Average Common Share Outstanding		
Income Before Accounting Change - Basic	$ 1.52	$ 1.52
Net Income - Basic	1.52	1.49
Income Before Accounting Change - Diluted	1.52	1.52
Net Income - Diluted	1.52	1.49
Dividends Declared Per Share	$ 0.80	$ 0.75

See Notes to Condensed Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(unaudited)

(in thousands, except per share amounts)

	Twelve Months Ended June 30, 2002	2001
Operating Revenues		
Electric retail segment	$ 2,287,043	$ 2,764,355
Marketing and trading segment	1,153,128	1,768,905
Real estate	214,456	144,891
Total	3,654,627	4,678,151
Operating Expenses		
Electric retail segment purchased power and fuel	762,536	1,387,776
Marketing and trading segment purchased power and fuel	982,054	1,505,521
Operations and maintenance	519,132	489,810
Real estate operations	183,588	130,473
Depreciation and amortization	418,993	430,839
Taxes other than income taxes	104,693	99,543
Total	2,970,996	4,043,962
Operating Income	683,631	634,189
Other		
Other income (Note 16)	28,700	32,099
Other expense (Note 16)	(43,569)	(58,463)
Total	(14,869)	(26,364)
Interest Expense		
Interest charges	180,934	171,418
Capitalized interest	(53,036)	(35,957)
Total	127,898	135,461
Income Before Income Taxes	540,864	472,364
Income Taxes	213,437	184,941
Income Before Accounting Change	327,427	287,423
Cumulative Effect of a Change in Accounting for Derivatives - Net of Income Tax Benefits of $8,099 and $1,793	(12,446)	(2,755)
Net Income	$ 314,981	$ 284,668
Weighted-Average Common Shares Outstanding - Basic	84,734	84,736
Weighted-Average Common Shares Outstanding - Diluted	84,888	85,007
Earnings Per Weighted-Average Common Share Outstanding		
Income Before Accounting Change - Basic	$ 3.86	$ 3.39
Net Income - Basic	3.72	3.36
Income Before Accounting Change - Diluted	3.86	3.38
Net Income - Diluted	3.71	3.35
Dividends Declared Per Share	$ 1.575	$ 1.475

See Notes to Condensed Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(dollars in thousands)

ASSETS

	June 30, 2002 (unaudited)	December 31, 2001
Current Assets		
Cash and cash equivalents	$ 13,859	$ 28,619
Customer and other receivables--net	347,079	367,241
Accrued utility revenues	110,689	76,131
Materials and supplies (at average cost)	82,300	81,215
Fossil fuel (at average cost)	31,105	27,023
Assets from risk management and trading activities	47,604	66,973
Other current assets	91,160	80,203
Total current assets	723,796	727,405
Investments and Other Assets		
Real estate investments--net	419,740	418,673
Assets from risk management and trading activities - long-term	218,910	200,351
Other assets	286,843	320,004
Total investments and other assets	925,493	939,028
Property, Plant and Equipment		
Plant in service and held for future use	8,236,570	8,030,134
Less accumulated depreciation and amortization	3,387,971	3,290,097
Total	4,848,599	4,740,037
Construction work in progress	1,225,544	1,032,234
Intangible assets, net of accumulated amortization	99,497	86,782
Nuclear fuel, net of accumulated amortization	51,661	49,282
Net property, plant and equipment	6,225,301	5,908,335
Deferred Debits		
Regulatory assets	291,473	342,383
Other deferred debits	77,166	64,597
Total deferred debits	368,639	406,980
Total Assets	$8,243,229	$7,981,748

See Notes to Condensed Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(dollars in thousands)

LIABILITIES AND EQUITY

	June 30, 2002 (unaudited)	December 31, 2001
Current Liabilities		
Accounts payable	$ 164,293	$ 269,124
Accrued taxes	171,590	96,729
Accrued interest	52,260	48,806
Short-term borrowings	374,266	405,762
Current maturities of long-term debt	1,344	126,140
Customer deposits	35,682	30,232
Deferred income taxes	3,244	3,244
Liabilities from risk management and trading activities	29,077	35,994
Other current liabilities	84,818	74,898
Total current liabilities	916,574	1,090,929
Long-Term Debt Less Current Maturities	3,124,231	2,673,078
Deferred Credits and Other		
Liabilities from risk management and trading activities - long-term	110,627	207,576
Deferred income taxes	1,052,223	1,064,993
Unamortized gain - sale of utility plant	61,772	64,060
Other	387,466	381,789
Total deferred credits and other	1,612,088	1,718,418
Commitments and contingencies (Note 12)		
Common Stock Equity		
Common stock, no par value	1,532,641	1,531,038
Retained earnings	1,094,157	1,032,850
Accumulated other comprehensive loss	(36,462)	(64,565)
Total common stock equity	2,590,336	2,499,323
Total Liabilities and Equity	$ 8,243,229	$ 7,981,748

See Notes to Condensed Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(unaudited)

(dollars in thousands)

	Six Months Ended June 30, 2002	Six Months Ended June 30, 2001
CASH FLOWS FROM OPERATING ACTIVITIES		
Income before accounting change	$ 129,122	$ 129,062
Items not requiring cash		
Depreciation and amortization	202,000	210,910
Nuclear fuel amortization	15,214	14,178
Deferred income taxes--net	(31,071)	(24,299)
Change in mark-to-market--trading	4,549	(92,990)
Change in mark-to-market--system	(6,321)	8,030
Changes in current assets and liabilities		
Customer and other receivables--net	20,162	203,147
Accrued utility revenues	(34,558)	(30,768)
Materials, supplies and fossil fuel	(5,167)	(14,090)
Other current assets	(10,957)	5,356
Accounts payable	(101,416)	(183,525)
Accrued taxes	74,861	95,428
Accrued interest	3,454	(5,225)
Other current liabilities	15,370	(63,303)
Increase in real estate investments	(547)	(25,786)
Increase in regulatory assets	(5,992)	(7,447)
Change in risk management and trading investments - at cost	(53,544)	22,541
Customer advances	1,695	30,232
Change in long term assets	(7,046)	(15,070)
Change in long term liabilities	3,145	17,022
Net Cash Flow Provided By Operating Activities	212,953	273,403
CASH FLOWS FROM INVESTING ACTIVITIES		
Trust fund for bond redemption	--	(72,370)
Capital expenditures	(454,080)	(427,062)
Capitalized interest	(28,128)	(22,954)
Other--net	28,633	14,469
Net Cash Flow Used For Investing Activities	(453,575)	(507,917)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	606,046	482,500
Short-term borrowings and payments--net	(31,496)	219,174
Dividends paid on common stock	(67,816)	(63,573)
Repayment of long-term debt	(282,475)	(396,512)
Other--net	1,603	(4,348)
Net Cash Flow Provided By Financing Activities	225,862	237,241
Net Cash Flow	(14,760)	2,727
Cash and Cash Equivalents at Beginning of Period	28,619	10,363
Cash and Cash Equivalents at End of Period	$ 13,859	$ 13,090
Supplemental Disclosure of Cash Flow Information:		
Cash paid during the period for:		
Interest, net of amounts capitalized	$ 57,935	$ 63,653
Income taxes	$ 47,274	$ 15,954

See Notes to Condensed Consolidated Financial Statements.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. The condensed consolidated financial statements include the accounts of the Company and its subsidiaries: APS, Pinnacle West Energy, APSES, SunCor, and El Dorado. All significant intercompany accounts and transactions have been eliminated. We have reclassified certain prior year amounts to conform to the current year presentation.

2. Our unaudited condensed consolidated financial statements reflect all adjustments which we believe are necessary for the fair presentation of our financial position and results of operations for the periods presented. These adjustments are of a normal recurring nature with the exception of the cumulative effect of a change in accounting for derivatives (see Note 10). We suggest that these condensed consolidated financial statements and notes to condensed consolidated financial statements be read along with the consolidated financial statements and notes to consolidated financial statements included in our 2001 10-K.

3. Weather conditions cause significant seasonal fluctuations in our revenues. In addition, trading and wholesale marketing activities can have significant impacts on our results for interim periods. Consequently, results for interim periods do not necessarily represent results to be expected for the year.

4. On February 8, 2002, Pinnacle West issued $215 million of 4.5% Notes due 2004. On March 1, 2002, APS issued $375 million, of 6.5% Notes due 2012. On April 15, 2002, APS redeemed $122 million of its First Mortgage Bonds, 8.75% Series due 2024. On March 15, 2002, APS redeemed at maturity $125 million of its First Mortgage Bonds, 8.125% Series due 2002. SunCor's long-term indebtedness decreased $15 million during the six months ended June 30, 2002. The above items represent the primary changes in capitalization for the six months ended June 30, 2002.

5. Regulatory Matters

ELECTRIC INDUSTRY RESTRUCTURING

STATE

OVERVIEW. On September 21, 1999, the ACC approved Rules that provide a framework for the introduction of retail electric competition in Arizona. On September 23, 1999, the ACC approved a comprehensive settlement agreement among APS and various parties related to the implementation of retail electric competition in Arizona. Under the Rules, as modified by the 1999 Settlement Agreement, APS is required to transfer all of its competitive electric assets and services to an unaffiliated party or parties or to a separate corporate affiliate or affiliates no later than December 31, 2002. Consistent with that requirement, APS has been addressing the legal and regulatory requirements necessary to complete the transfer of its generation assets to Pinnacle West Energy on or before that date.

In January 2002, the ACC opened a "generic" docket to "determine if changed circumstances require the [ACC] to take another look at electric restructuring in Arizona." On June 17, 2002, hearings began on various issues ("Track A

Issues") in the consolidated docket. On July 23, 2002, an ACC ALJ issued a recommended order on Track A Issues recommending, among other things, that the ability of APS to transfer its generation assets be stayed until at least July 1, 2004. On August 1, 2002, APS filed exceptions to the recommended order stating that it is unreasonable and unlawful. The ACC will hold an open meeting on August 27, 2002 to consider Track A Issues. These matters are discussed in more detail below.

1999 SETTLEMENT AGREEMENT. The following are the major provisions of the 1999 Settlement Agreement, as approved:

* APS has reduced, and will reduce, rates for standard-offer service for customers with loads less than three MW in a series of annual retail electricity price reductions of 1.5% beginning 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 a July 1, 1999 retail price decrease of approximately $11 million ($7 million after income taxes) related to a 1996 regulatory agreement. Based on the price reductions authorized in the 1999 Settlement Agreement, there were also retail price decreases of approximately $28 million ($17 million after taxes), or 1.5%, effective July 1, 2000; approximately $27 million ($16 million after taxes), or 1.5%, effective July 1, 2001; and approximately $28 million ($17 million after taxes), or 1.5%, effective July 1, 2002. For customers having loads of three MW or greater, standard-offer rates have been reduced in varying annual increments that total 5% in the years 1999 through 2002.

* Unbundled rates being charged by APS for competitive direct access service (for example, distribution services) became effective upon approval of the 1999 Settlement Agreement, retroactive to July 1, 1999, and also became subject to annual reductions beginning January 1, 2000, that vary by rate class, through January 1, 2004.

* There will be a moratorium on retail price changes for standard-offer and unbundled competitive direct access services until July 1, 2004, except for the price reductions described above and certain other limited circumstances. Neither the ACC nor APS will be prevented from seeking or authorizing rate changes prior to July 1, 2004 in the event of conditions or circumstances that constitute an emergency, such as an inability to finance on reasonable terms; material changes in APS' cost of service for ACC-regulated services resulting from federal, tribal, state or local laws; regulatory requirements; or judicial decisions, actions or orders.

* APS will be permitted to defer for later recovery prudent and reasonable costs of complying with the Rules, system benefits costs in excess of the levels included in then-current (1999) rates, and costs associated with the "provider of last resort" and standard-offer obligations for service after July 1, 2004. These costs are to be recovered through an adjustment clause or clauses commencing on July 1, 2004.

* APS' distribution system opened for retail access effective September 24, 1999. Customers were eligible for retail access in accordance with the phase-in adopted by the ACC under the Rules (see "Retail Electric

Competition Rules" below), including an additional 140 MW being made available to eligible non-residential customers. APS opened its distribution system to retail access for all customers on January 1, 2001.

* Prior to the 1999 Settlement Agreement, APS was recovering substantially all of its regulatory assets through July 1, 2004, pursuant to a 1996 regulatory agreement. In addition, the 1999 Settlement Agreement states that APS has demonstrated that its allowable stranded costs, after mitigation and exclusive of regulatory assets, are at least $533 million net present value. APS will not be allowed to recover $183 million net present value of the above amounts. The 1999 Settlement Agreement provides that APS will have the opportunity to recover $350 million net present value through a competitive transition charge that will remain in effect through December 31, 2004, at which time it will terminate. The costs subject to recovery under the adjustment clause described above will be decreased or increased by any over/under-recovery due to sales volume variances.

* APS will form, or cause to be formed, a separate corporate affiliate or affiliates and transfer to such affiliate(s) its competitive electric assets and services at book value as of the date of transfer, and will complete the transfers no later than December 31, 2002. APS will be allowed to defer and later collect, beginning July 1, 2004, sixty-seven percent of its costs to accomplish the required transfer of generation assets to an affiliate. Consistent with that requirement, APS has been addressing the legal and regulatory requirements necessary to complete the transfer of its generation assets to Pinnacle West Energy on or before that date. However, as noted above and discussed in greater detail below, an ACC ALJ has recommended that APS' ability to transfer its generation assets be stayed until at least July 1, 2004.

RETAIL ELECTRIC COMPETITION RULES. The Rules approved by the ACC include the following major provisions:

* They apply to virtually all Arizona electric utilities regulated by the ACC, including APS.

* Effective January 1, 2001, retail access became available to all APS retail electricity customers.

* Electric service providers that get CC&N's from the ACC can supply only competitive services, including electric generation, but not electric transmission and distribution.

* Affected utilities must file ACC tariffs that unbundle rates for noncompetitive services.

* The ACC shall allow a reasonable opportunity for recovery of unmitigated stranded costs.

* Absent an ACC waiver, prior to January 1, 2001, each affected utility (except certain electric cooperatives) must transfer all competitive electric assets and services to an unaffiliated party or parties or to a separate corporate affiliate or affiliates. Under the 1999 Settlement Agreement, APS received a waiver to allow transfer of its competitive electric assets and services to affiliates no later than December 31, 2002.

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.

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 APSES, to operate 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 Arizona Court of Appeals, as a result of which the Superior Court's ruling is automatically stayed pending further judicial review. In a similar appeal concerning the issuance of competitive telecommunications CC&N's, the Arizona Court of Appeals invalidated rates for competitive carriers due to the ACC's failure to establish a fair value rate base for such carriers. That decision was upheld by the Arizona Supreme Court.

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

PROPOSED RULE VARIANCE AND PURCHASE POWER AGREEMENT. Commencing on the transfer of the fossil-fueled generating assets and the receipt of certain regulatory approvals, Pinnacle West Energy expects to sell its power at wholesale to Pinnacle West's marketing and trading division, which, in turn, is expected to sell power to APS and to non-affiliated power purchasers. In a filing with the ACC on October 18, 2001, APS requested the ACC to:

* grant APS a partial variance from an ACC Rule that would obligate APS to acquire all of its customers' standard-offer, full-service generation requirements from the competitive market (with at least 50% of those requirements coming from a "competitive bidding" process) starting in 2003; and

* approve as just and reasonable a long-term purchase power agreement between APS and Pinnacle West.

APS requested these ACC actions to ensure ongoing reliable service to APS standard-offer, full-service customers in a volatile generation market and to recognize Pinnacle West Energy's significant investment to serve APS load.

GENERIC DOCKET. In January 2002, the ACC opened a "generic" docket to "determine if changed circumstances require the [ACC] to take another look at electric restructuring in Arizona." In February 2002, the ACC docket relating to APS' October 2001 filing was consolidated with several other pending ACC dockets, including the generic docket. On April 19, 2002, APS filed a motion in the consolidated docket addressing the following issues, among others:

* APS confirmed its position that whether or not the ACC approved the matters requested in its October 2001 filing, APS would proceed with the divestiture of its generation assets by the end of 2002, as legally required.

* APS also advised the ACC that whether or not the ACC approved the matters requested in its October 2001 filing, APS would implement a competitive bidding process later in 2002 to the extent legally required.

* APS noted that Pinnacle West Energy, the affiliate to which APS intends to transfer the generation assets, had committed to an investment of approximately $1 billion in generating capacity to meet APS customer needs in reliance on the 1999 Settlement Agreement. APS further noted that it had taken numerous actions in reliance on the 1999 Settlement Agreement and the ACC Rules, including writing off $234 million before income taxes of prudently incurred costs, reducing retail rates in an ongoing series of rate reductions, and incurring tens of millions of dollars in expenses related to the expected generation asset transfer. APS stated that if the ACC elects to reverse course on retail electric competition or attempts to stay the transfer of APS' generation assets, the ACC would be legally required to address just compensation to APS and Pinnacle West Energy, which would include, at a minimum:

* recognizing the transfer to APS of all assets that Pinnacle West Energy constructed to meet APS' load-serving requirements, and

subsequently including such units in APS' rate base in accordance with traditional rate-of-return regulation;

* reversing APS' $234 million pre-tax write-off and providing for the recovery of such amounts in future rates; and

* providing for the recovery of all costs incurred as a result of the transition to competition, including 100 percent of the costs incurred in preparation for divestiture (and not just the sixty-seven percent of costs permitted under the 1999 Settlement Agreement).

* APS recommended that the ACC confirm whether or not Arizona would proceed with the transition to a competitive electric market, and proposed a procedural plan in response to issues identified by the ACC Staff in a previous report.

On April 26, 2002, the ACC issued a procedural order in which the ACC stayed the previously-scheduled April 29, 2002 hearing on the matters raised in APS' October 2001 ACC filing (see "Proposed Rule Variance and Purchase Power Agreement" above). On May 2, 2002, the ACC issued a procedural order stating that hearings would begin on June 17, 2002 on various issues ("Track A Issues"), including APS' planned divestiture of generation assets to Pinnacle West Energy and associated market and affiliate issues.

The procedural order also stated that consideration of the competitive bidding process (the "Track B Issues") required by the Rules would proceed concurrently with the Track A Issues. The objectives and process of the Track B Issues would be determined in one or more meetings of affected parties with a "target completion date" of October 21, 2002.

On July 11, 2002, APS filed a letter with the ACC discussing the circumstances under which APS could support a temporary suspension or stay of certain Arizona electric competition rules. In its letter, APS stated that it could support a delay of the Rules' mandatory divestiture of generation assets and competitive procurement requirements if:

* the ACC permits APS to end the "bifurcation" of its generation resources as between itself and Pinnacle West Energy by authorizing the acquisition by APS of the Pinnacle West Energy generating facilities constructed or being constructed to serve APS;

* the ACC provides to APS any additional debt financing authorization necessary to accomplish this acquisition; and

* while these assets remain at APS serving retail customers, their inclusion in rates will be subject to ACC review as to their prudence and as to whether they are "used and useful" just as are APS' existing generating plants.

On July 23, 2002 an ACC ALJ issued a recommended order on Track A Issues in the consolidated docket. Among other things, the ALJ recommends that:

* the ability of APS to transfer its generation assets be stayed until the ACC determines that the wholesale market is "workably competitive" and until at least July 1, 2004, at which time the ACC would reassess the appropriateness and timing of divestiture;

* the current requirement that 100 percent of power purchased for standard-offer service be acquired from the competitive market, with at least 50 percent through a competitive bid process, be stayed indefinitely; and

* upon implementation of the outcome of the competitive bidding process ("Track B Issues"), APS would acquire, at a minimum, any required power not produced by its owned generation through a competitive procurement process developed in the Track B proceeding.

In addition, the ALJ recommended that if APS wishes to acquire certain generation assets from Pinnacle West Energy, as discussed in APS' July 11, 2002 letter to the ACC, APS should file appropriate applications on this matter for ACC consideration.

The ALJ also recommended that the ACC Staff open a rulemaking to review the Rules in light of the other decisions in the recommended order and that an Electric Competition Advisory Group be formed to facilitate communication among the ACC Staff, stakeholders and market participants.

On August 1, 2002, APS filed exceptions to the recommended order, stating that the recommended order, if adopted by the ACC, would be unreasonable and unlawful because, among other reasons:

* the recommended order's prohibition on APS transferring its generation assets to Pinnacle West Energy would unfairly harm APS and the Company by bifurcating generation assets between APS and Pinnacle West Energy, even though those assets are devoted to serving APS customers;

* the recommended order's prohibition on APS transferring its generation assets to Pinnacle West Energy would constitute a material breach of the 1999 Settlement Agreement, even though APS has fulfilled its obligations under the 1999 Settlement Agreement, including writing off $234 million of otherwise recoverable costs, voluntarily reducing retail rates by some $600 million (to date), and dismissing with prejudice its pending litigation against the ACC;

* the recommended order does not discuss less onerous alternatives to breaching the 1999 Settlement Agreement, such as consideration of the Purchase Power Agreement proposed by APS in its October 18, 2001 filing with the ACC or the acquisition by APS of certain Pinnacle West Energy generation assets, as outlined in APS' July 11, 2002 letter to the ACC;

* the recommended order's finding that APS has wholesale market power in certain Arizona geographical areas is not supported by the evidence or, at worst, the ACC should make no finding on the issue of market power; and

* the "generic proceedings" giving rise to the recommended order do not and have not complied with Arizona law as applicable to the amendment or rescission of the ACC order associated with the 1999 Settlement Agreement.

The ACC will hold an open meeting on August 27, 2002 to consider Track A Issues.

Pinnacle West cannot predict the outcome of the consolidated docket or its effect on the existing Rules or the 1999 Settlement Agreement.

FEDERAL

In June 2001, the FERC adopted a price mitigation plan that constrains the price of electricity in the wholesale spot electricity market in the western United States. The plan, which has a price cap of approximately $90 per MWh, remains in effect until September 30, 2002. FERC has now adopted a final price cap of $250 per MWh, which will become effective as of October 1, 2002.

On July 31, 2002, the FERC issued a Notice of Proposed Rulemaking Standard Market Design for wholesale electric markets. We are reviewing the proposed rulemaking and cannot currently predict what, if any, impact there may be to the Company if the FERC adopts the proposed rule.

GENERAL

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 in the new regulatory environment.

6. Nuclear Insurance

The Palo Verde participants have insurance for public liability resulting from nuclear energy hazards to the full limit of liability under federal law. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $200 million and the balance by an industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the programs exceed the accumulated funds, APS could be assessed retrospective premium adjustments. The maximum assessment per reactor under the program for each nuclear incident is approximately $88 million, subject to an annual limit of $10 million per incident. Based upon APS' interest in the three Palo Verde units, APS' maximum potential assessment per incident for all three units is approximately $77 million, with an annual payment limitation of approximately $9 million.

The Palo Verde participants maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.75 billion, a substantial portion of which must first be applied to stabilization and decontamination. APS has also secured insurance against portions of any increased cost of generation or purchased power and business interruption resulting from a sudden and unforeseen outage of any of the three units. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions and exclusions.

7. Business Segments

We have two principal business segments (determined by products, services and the regulatory environment), which consist of our regulated retail electricity business, regulated traditional wholesale electricity business, and related activities (electric retail business segment) and our competitive business activities (marketing and trading business segment). Our electric retail business segment includes activities related to electricity transmission and distribution, as well as electricity generation. Our marketing and trading business segment includes activities related to wholesale marketing and trading and APSES' competitive energy services. The other amounts include activities related to SunCor and El Dorado. Certain parent company costs, other than marketing and trading, are included in our electric retail segment. Financial data for the business segments follows (dollars in millions):

	Three Months Ended June 30,		Six Months Ended June 30,		Twelve Months Ended June 30,	
	2002	2001	2002	2001	2002	2001
Operating Revenues:						
Electric retail	$ 497	$ 739	$ 877	$ 1,152	$ 2,287	$ 2,764
Marketing and trading	149	522	349	1,016	1,153	1,769
Other	69	33	110	65	215	145
Total	$ 715	$ 1,294	$ 1,336	$ 2,233	$ 3,655	$ 4,678
Income Before Accounting Change:						
Electric retail	$ 61	$ 11	$ 93	$ 14	$ 231	$ 152
Marketing and trading	9	56	29	114	86	143
Other	5	--	7	1	10	(7)
Total	$ 75	$ 67	$ 129	$ 129	$ 327	$ 288

	As of June 30, 2002	As of December 31, 2001
Assets:		
Electric retail	$7,367	$7,077
Marketing and trading	393	417
Other	483	488
Total	$8,243	$7,982

8. Accounting Matters

On January 1, 2002, we adopted SFAS No. 142, "Goodwill and Other Intangible Assets." This statement addresses financial accounting and reporting for acquired goodwill and other intangible assets and supersedes APB Opinion No. 17, "Intangible Assets." We have no goodwill recorded and have separately disclosed other intangible assets in our consolidated balance sheets. This new standard has no material impact on our financial statements, and the required disclosures are provided in Note 13.

On January 1, 2002, we adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." This statement supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of," and the accounting and reporting provisions for the disposal of a segment of a business. This standard did not impact our financial statements at adoption.

In August 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations," which we will adopt January 1, 2003. The standard requires the fair value of asset retirement obligations to be recorded as a liability, along with an offsetting plant asset, when the obligation is incurred. Accretion of the liability due to the passage of time will be an operating expense and the capitalized cost will be depreciated over the useful life of the long-lived asset.

We have not yet determined the impact of the new standard on our financial statements. We determined that we have asset retirement obligations for our nuclear facilities (nuclear decommissioning) and certain other fossil generation, transmission, and distribution assets. Upon adoption, we will record the retirement obligations and the related plant assets and accumulated depreciation. The impact of these adjustments will likely be different than the removal costs currently reflected in our financial statements for assets that have an asset retirement obligation. For our non-regulated operations, the impact of adopting this new standard will be reflected in earnings as a cumulative effect of a change in accounting principle. We are currently evaluating our ability to recover the transition costs and ongoing current period costs of SFAS No. 143 in rates for our regulated operations. If such costs are expected to be recoverable in rates, we would recognize a regulatory asset or regulatory liability upon the adoption of SFAS No. 143 rather than a cumulative effect adjustment to earnings.

In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections" which supersedes previous guidance for reporting gains and losses from extinguishment of debt and accounting for leases, among other things. The portion of the statement relating to the early extinguishment of debt is effective for us beginning in 2003. We do not believe the adoption of this statement will have a material impact on our financial statements.

In July 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." The standard requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan. The guidance should be applied prospectively to exit or disposal activities initiated after December 31, 2002.

In 2001, the American Institute of Certified Public Accountants issued an exposure draft of a proposed Statement of Position, "Accounting for Certain Costs Related to Property, Plant, and Equipment." This proposed Statement of Position, which would be effective for us in 2004, would create a project timeline framework for capitalizing costs related to property, plant and equipment construction. It would require that property, plant and equipment assets be accounted for at the component level, and require administrative and general costs incurred in support of capital projects to be expensed in the current period. The American Institute of Certified Public Accountants plans to issue the final Statement of Position in the fourth quarter of 2002.

In June 2002, the FASB's EITF finalized certain guidance related to energy trading activities in EITF 02-3 "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." The new guidance, which is effective July 1, 2002, requires that all energy trading activities within the scope of EITF 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," be presented on a net basis in revenues and that prior period amounts should be restated to conform to the consensus. We will make this presentation change in the third quarter of 2002. The impact on our marketing and trading segment would result in equivalent decreases in revenues and purchased power (gross margin would not be affected) for the three, six, and twelve-month periods ended June 30, 2002 and 2001 as follows (dollars in millions before income taxes):

	Three Months Ended June 30,	Six Months Ended June 30,	Twelve Months Ended June 30,
2002	$ 99	$ 223	$ 869
2001	$ 288	$ 524	$ 999

Effective in the third quarter of 2002, we will record stock option expense on our consolidated income statement in accordance with SFAS No. 123, "Accounting For Stock-Based Compensation." We will utilize the transition adjustment as provided in SFAS No. 123 and prospectively apply SFAS No. 123 to 2002 stock grants and future stock grants. The cumulative effect of adopting this standard will be less than $1 million in 2002.

9. Off-Balance Sheet Financing

In 1986, APS entered into agreements with three separate SPE lessors in order to sell and lease back interests in Palo Verde Unit 2. The leases are accounted for as operating leases in accordance with GAAP. In July 2002, the FASB issued an exposure draft related to SPEs. It is expected that the FASB will issue final guidance on accounting for SPEs later this year with an immediate effective date for newly-created entities and for all other entities as of the beginning of the first fiscal period beginning April 1, 2003. We are currently evaluating the impacts of the exposure draft and we may be required to consolidate the Palo Verde SPEs in our financial statements. If consolidation were required, the assets and liabilities of the SPEs that relate to the sale-leaseback transactions would be reflected on our condensed consolidated balance sheet at fair value. We are also evaluating the impact of including the related fair value of assets and liabilities. The secured lease obligation bonds that are not reflected on our condensed consolidated balance sheet at June 30, 2002 are approximately $285 million. The rating agencies have already considered this debt when evaluating our credit ratings. This is our only significant off-balance sheet financing activity.

10. Derivative Instruments

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

Effective January 1, 2001, we adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 requires that entities recognize all derivatives as either assets or liabilities on the balance sheets and measure those instruments at fair value. Changes in the fair value of derivative financial instruments are either recognized periodically in income or shareholders' equity (as a component of other comprehensive income), depending on whether or not the derivative meets specific hedge accounting criteria. We use cash flow hedges to limit our exposure to cash flow variability on forecasted transactions. Hedge effectiveness is related to the degree to which the derivative contract and the hedged item are correlated. It is measured based on the relative changes in fair value between the derivative contract and the hedged item over time. We exclude the time value of certain options from our assessment of hedge effectiveness. Any change in the fair value resulting from ineffectiveness is recognized immediately in net income.

On January 1, 2001, we recorded a $3 million after-tax loss in net income and a $65 million after-tax gain in equity (as a component of other comprehensive income), both as a cumulative effect of a change in accounting principle. The gain resulted from unrealized gains on cash flow hedges.

In June 2001, the FASB issued new guidance related to electricity contracts. The effective date of this new guidance was July 1, 2001. As of July 1, 2001, we recorded an additional $12 million after-tax loss in net income and an additional $8 million after-tax gain in equity (as a component of other comprehensive income), as a result of adopting the new guidance related to electricity contracts. The loss resulted primarily from electricity options contracts. The gain resulted from unrealized gains on cash flow hedges. The impact of the new guidance is reflected in net income and other comprehensive income as a cumulative effect of a change in accounting principle.

In December 2001, the FASB issued revised guidance on the accounting for electricity contracts with option characteristics and the accounting for contracts that combine a forward contract and a purchased option contract. The effective date for the revised guidance was April 1, 2002. The impact of this guidance was immaterial to our financial statements.

The change in derivative fair value included in the condensed consolidated statements of income for the three, six and twelve months ended June 30, 2002 and 2001 are comprised of the following (dollars in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,		Twelve Months Ended June 30,	
	2002	2001	2002	2001	2002	2001
Gains (losses) on the ineffective portion of derivatives qualifying for hedge accounting	$ 4,471	$ (1,419)	$ 1,923	$ (6,184)	$ (263)	$ (6,184)
Losses from the discontinuance of cash flow hedges	(724)	(8,325)	(1,624)	(8,324)	(2,824)	(8,324)
Prior period mark-to-market losses realized upon delivery of commodities	2,209	85	6,022	6,478	25,491	6,478
Total pretax gain (loss)	$ 5,956	$ (9,659)	$ 6,321	$ (8,030)	$ 22,404	$ (8,030)

As of June 30, 2002, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted transactions is thirty months. During the twelve months ending June 30, 2003, we estimate that a net loss of $14 million before income taxes will be reclassified from accumulated other comprehensive loss as an offset to the effect on earnings of market price changes for the related hedged transactions.

The following table summarizes our assets and liabilities from risk management and trading activities related to trading and system (retail and traditional wholesale activities) as of June 30, 2002 (dollars in thousands):

	Current Assets	Investments	Current Liabilities	Other Liabilities	Net Asset/ (Liability)
Mark-to-market:					
Trading	$ 32,815	$ 118,873	$ (5,770)	$ (12,541)	$ 133,377
System	14,789	2,259	(23,307)	(46,996)	(53,255)
Cost-emission allowances and other	--	97,778(a)	--	(51,090)	46,688
Total	$ 47,604	$ 218,910	$ (29,077)	$(110,627)	$ 126,810

(a) Includes $19 million required to serve as collateral against our open positions on energy-related contracts.

11. Comprehensive Income

Components of comprehensive income for the three, six and twelve months ended June 30, 2002 and 2001, are as follows (dollars in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,		Twelve Months Ended June 30,	
	2002	2001	2002	2001	2002	2001
Net income	$ 75,365	$ 66,857	$ 129,122	$ 126,307	$ 314,981	$ 284,668
Other comprehensive income (loss):						
Minimum pension liability, net of tax	(1,835)	--	(1,835)	--	(2,801)	--
Cumulative effect of change in accounting for derivatives, net of tax	--	--	--	64,700	7,801	64,700
Unrealized gains (losses) on derivative instruments, net of tax(a)	1,386	(87,475)	24,758	(94,134)	14,108	(94,134)
Reclassification of net realized (gains) losses to income, net of tax (b)	736	(1,862)	5,180	(22,478)	(3,659)	(22,478)
Total other comprehensive income (loss)	287	(89,337)	28,103	(51,912)	15,449	(51,912)
Comprehensive income (loss)	$ 75,652	$ (22,480)	$ 157,225	$ 74,395	$ 330,430	$ 232,756

(a) These amounts primarily include unrealized gains and losses on contracts used to hedge our forecasted gas requirements to serve native load.

(b) These amounts primarily include the reclassification of unrealized gains and losses to realized for contracts that delivered during the period.

12. Commitments and Contingencies

California Energy Market Issues and Refunds in the Pacific Northwest

In July 2001, the FERC ordered an expedited fact-finding hearing to calculate refunds for spot market transactions in California during a specified time frame. This order calls for a hearing, with findings of fact due to the FERC after the ISO and PX provide necessary historical data. The FERC also ordered an evidentiary proceeding to discuss and evaluate possible refunds for the Pacific Northwest. The administrative law judge at the FERC in charge of that evidentiary proceeding made an initial finding that no refunds were appropriate. The Pacific Northwest issues will now be addressed by the FERC Commissioners. Although the FERC has not yet made a final ruling in the Pacific Northwest matter or calculated the specific refund amounts due in California, we do not expect that the resolution of these issues, as to the amounts alleged in the proceedings, will have a material adverse impact on our financial position, results of operations or liquidity.

SCE and 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 PX and the ISO. PG&E filed for bankruptcy protection in 2001.

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; APSES' retail transactions involving SCE and PG&E; and marketing and trading exposures. Based on our evaluations, we previously reserved $10 million before income taxes for our credit exposure related to the California energy situation, $5 million of which was recorded in the fourth quarter of 2000 and $5 million of which was recorded in the first quarter of 2001. Our evaluations took into consideration our range of exposure of approximately zero to $38 million before income taxes and review of likely recovery rates in bankruptcy situations. After review with legal counsel and review of bond pricing, the $10 million reserve was our best estimate of our losses.

In the first quarter of 2002, SCE paid all of its outstanding debts to APSES. In the second quarter of 2002, PG&E filed its Modified Second Amended Disclosure Statement and the CPUC filed its Alternative Plan of Reorganization. Both plans generally indicated that PG&E would, at the close of bankruptcy proceedings, be able to pay in full all outstanding, undisputed debts. As a result of these developments, the probable range of our total exposure now is approximately zero to $27 million before income taxes, and our best estimate of the probable loss is now approximately $6 million before income taxes. Consequently, we reversed $4 million of the $10 million reserve in the second quarter of 2002. 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, our subsidiaries or the regional energy market in general.

CALIFORNIA ENERGY MARKET LITIGATION. On March 19, 2002, the State of California filed a complaint with the FERC alleging that wholesale sellers of power and energy, including Pinnacle West, failed to properly file rate information at the FERC in connection with sales to California from 2000 to the present. STATE OF CALIFORNIA V. BRITISH COLUMBIA POWER EXCHANGE ET. AL., Docket No. EL02-71-000. The complaint requests the FERC to require the wholesale sellers to refund any rates that are "found to exceed just and reasonable levels." This complaint has been dismissed by FERC. In addition, the State of California and others have filed various claims, which have now been consolidated, against several power suppliers to California alleging antitrust violations. WHOLESALE ELECTRICITY ANTITRUST CASES I AND II, Superior Court in and for the County of San Diego, Proceedings Nos. 4204-00005 and 4204-00006. Two of the suppliers who were named as defendants in those matters, Reliant Energy Services, Inc. (and other Reliant entities) and Duke Energy and Trading, LLP (and other Duke entities), filed cross-claims against various other participants in the California PX and ISO markets, including APS, attempting to expand those matters to such other participants. APS has not yet filed a responsive pleading in the matter, but APS believes the claims by Reliant and Duke as they relate to APS are without merit.

APS was also named in a lawsuit regarding wholesale contracts in California. JAMES MILLAR, ET AL. V. ALLEGHENY ENERGY SUPPLY, ET AL., United
States District Court in and for the District of Northern California, Case No. C02-2855 EMC. The complaint alleges basically that the contracts entered into were the result of an unfair and unreasonable market. The California PX has filed a lawsuit against the State of California regarding the seizure of forward contracts and the State has filed a cross complaint against APS. CAL PX V. THE STATE OF CALIFORNIA Superior Court in and for the County of Sacramento, JCCP No. 4203. Various preliminary motions are being filed and we cannot currently predict the outcome of this matter. The "United States Justice Foundation" is suing numerous wholesale energy contract suppliers to California, including us, as well as the California Department of Water Resources, based upon an alleged conflict of interest arising from the activities of a consultant for Edison International who also negotiated long-term contracts for the California Department of Water Resources. MCCLINTOCK, ET AL. V. YUDHRAJA, Superior Court in and for the County of Los Angeles, Case No. GC 029447. The California Attorney General has indicated that an investigation by his office did not find evidence of improper conduct by the consultant. We believe the claims against us in the lawsuits mentioned in this paragraph are without merit and will have no material adverse impact on our financial position, results of operations or liquidity.

Power Service Agreement

By letter dated March 7, 2001, Citizens, which owns a utility in Arizona, advised APS that it believes APS has overcharged Citizens by over $50 million under a power service agreement. APS believes that its charges under the agreement were fully in accordance with the terms of the agreement. In addition, in testimony filed with the ACC on March 13, 2002, Citizens acknowledged that, based on its review, "if Citizens filed a complaint with FERC, it probably would lose the central issue in the contract interpretation dispute." APS and Citizens terminated the power service agreement effective July 15, 2001. In replacement of the power service agreement, the Company and Citizens entered into a power sale agreement under which the Company will supply Citizens with specified amounts of electricity and ancillary services through May 31, 2008. This new agreement does not address issues previously raised by Citizens with respect to charges under the original power service agreement through June 1, 2001.

13. Intangible Assets

On January 1, 2002, we adopted SFAS No. 142, "Goodwill and Other Intangible Assets." This statement addresses financial accounting and reporting for acquired goodwill and other intangible assets and supersedes APB Opinion No. 17, "Intangible Assets." The Company's gross intangible assets (which are primarily software) were $196 million at June 30, 2002 and $175 million at December 31, 2001. The related accumulated amortization was $97 million at June 30, 2002 and $88 million at December 31, 2001. Amortization expense for the three-month period ended June 30 was $5 million in 2002 and 2001. Amortization expense for the six-month period ended June 30 was $9 million in 2002 and $11 million in 2001. Amortization expense for the twelve-month period ended June 30 was $21 million in 2002 and 2001. Estimated amortization expense on existing intangible assets over the next five years is $17 million in 2002, $16 million in 2003, $15 million in 2004, $13 million in 2005 and $11 million in 2006.

14. El Dorado Investment in Nuclear Assurance Corporation

El Dorado has an equity interest in NAC. NAC develops, markets and contracts for the manufacture of spent nuclear fuel storage and transportation cask designs. El Dorado's investment in NAC is accounted for under the equity method and El Dorado's share of earnings and losses through June 2002 were recorded in other income or expense in the condensed consolidated income statement. Beginning in the third quarter of 2002, El Dorado will fully consolidate NAC's financial statements because it now has a controlling interest in NAC. As of December 31, 2001, NAC's total assets were approximately $34 million. NAC's total revenues were $74 million and its pretax net loss was $13 million for the year ended December 31, 2001. In addition, on June 26, 2002, NAC entered into a Convertible Promissory Note with El Dorado in the amount of $30 million at a rate of LIBOR plus 4.75% per annum. There was $5 million outstanding as of June 30, 2002. Pinnacle West provides guarantees for credit support related to NAC in the cumulative amount of $51 million, $8 million of which relates to NAC debt that is expected to be repaid in August 2002 with borrowings under the El Dorado Convertible Promissory Note.

15. Earnings Per Share

The following table presents earnings per weighted average common share outstanding (EPS):

	Three Months Ended June 30,		Six Months Ended June 30,		Twelve Months Ended June 30,	
	2002	2001	2002	2001	2002	2001
Basic EPS:						
Income before accounting change	$0.89	$0.79	$1.52	$1.52	$3.86	$3.39
Cumulative effect of change in accounting	--	--	--	(0.03)	(0.14)	(0.03)
Earnings per share - basic	$0.89	$0.79	$1.52	$1.49	$3.72	$3.36
Diluted EPS:						
Income before accounting change	$0.89	$0.79	$1.52	$1.52	$3.86	$3.38
Cumulative effect of change in accounting	--	--	--	(0.03)	(0.15)	(0.03)
Earnings per share - diluted	$0.89	$0.79	$1.52	$1.49	$3.71	$3.35

The following table reconciles average common shares outstanding - basic to average common shares outstanding - diluted that are used in the EPS calculation to the condensed consolidated income statement (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,		Twelve Months Ended June 30,	
	2002	2001	2002	2001	2002	2001
Average common shares outstanding - basic	84,794	84,744	84,769	84,736	84,734	84,736
Dilutive stock options	132	298	141	269	154	271
Average common shares outstanding - diluted	84,926	85,042	84,910	85,005	84,888	85,007

16. Other Income and Other Expense

The following table provides detail of other income and other expense for the three, six and twelve months ended June 30, 2002 and 2001 (dollars in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,		Twelve Months Ended June 30,	
	2002	2001	2002	2001	2002	2001
Other income:						
Environmental insurance recovery	$ --	$ 10,947	$ --	$ 10,947	$ 1,402	$ 10,947
APSES non-commodity revenues	2,881	1,252	7,157	2,620	15,974	5,552
Interest income	693	2,170	1,886	3,150	6,306	8,568
Suncor joint venture earnings	2,446	1,301	3,399	2,481	1,768	3,576
Miscellaneous	1,053	346	1,991	776	3,250	3,456
Total other income	$ 7,073	$ 16,016	$ 14,433	$ 19,974	$ 28,700	$ 32,099
Other expense:						
Investment losses - net (a)	$ (6,075)	$ (2,946)	$ (4,359)	$ (2,003)	$ (5,269)	$(27,971)
APSES non-commodity expenses	(1,669)	(133)	(4,969)	(918)	(14,097)	(1,469)
Non-operating costs - Suncor	--	(4,500)	--	(4,500)	(2,500)	(4,500)
Non-operating costs (b)	(6,156)	(2,995)	(9,163)	(6,749)	(20,537)	(16,480)
Miscellaneous	(866)	(2,205)	(2,547)	(3,305)	(1,166)	(8,043)
Total other expense	$(14,766)	$(12,779)	$(21,038)	$(17,475)	$(43,569)	$(58,463)

(a) Primarily related to El Dorado's investments.
(b) Primarily below the line utility costs.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

INTRODUCTION

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

* the changes in our earnings for the three, six and twelve months ended June 30, 2002 and 2001;

* the effects of regulatory agreements and developments on our results and outlook;

* our capital needs, liquidity and capital resources;

* our business outlook; and

* our management of market risks.

We suggest this section be read along with the 2001 10-K. Throughout this Management's Discussion and Analysis of Financial Condition and Results of Operations, we refer to specific "Notes" in the Notes to Condensed Consolidated Financial Statements in this report. These Notes add further details to the discussion. Operating statistics for the periods ended June 30, 2002 and June 30, 2001 are available on our website (www.pinnaclewest.com) and in our Current Report on Form 8-K dated June 30, 2002.

OVERVIEW OF OUR BUSINESS

The Company owns all of the outstanding common stock of APS. APS is an electric utility that provides either retail or wholesale electric service to substantially all of the state of Arizona, with the major exceptions of the Tucson metropolitan area and about one-half of the Phoenix metropolitan area. Electricity is provided through a distribution system owned by APS. APS also generates and, through our marketing and trading division, sells and delivers electricity to wholesale customers in the western United States.

Our other major subsidiaries are:

* APSES, which provides commodity-related energy services (such as direct access commodity contracts, energy procurement, and energy supply consultation) and energy-related products and services (such as energy master planning, energy use consultation and facility audits, cogeneration analysis and installation, and project management) to commercial, industrial and institutional retail customers in the western United States;

* SunCor, a developer of residential, commercial, and industrial real estate projects in Arizona, New Mexico, and Utah;

* Pinnacle West Energy, through which we conduct our unregulated electricity generation operations; and

* El Dorado, an investment firm.

Pinnacle West's marketing and trading division sells in the wholesale market, the APS and Pinnacle West Energy generation production output that is not needed for APS' Native Load, which includes loads for retail customers and traditional cost-of-service wholesale customers. Subject to specified risk parameters established by our Board of Directors, the marketing and trading division also engages in activities to hedge purchases and sales of electricity, fuels, and emissions allowances and credits and to profit from market price movements. We explain in detail the historical and prospective contribution of marketing and trading activities to our financial results. APS completed the transition of marketing and trading activities to the parent company as of the end of 2001.

APS is required to transfer its competitive electric assets and services to one or more corporate affiliates no later than December 31, 2002. Consistent with that requirement, APS has been addressing the legal and regulatory requirements necessary to complete the transfer of its generation assets to Pinnacle West Energy before that date. As we discuss in greater detail in Note 5, on July 23, 2002, an ACC ALJ issued a recommended order recommending, among other things, that the ability of APS to transfer its generation assets be stayed until at least July 1, 2004.

EARNINGS CONTRIBUTIONS BY SUBSIDIARY

The following table summarizes net income for the three, six and twelve months ended June 30, 2002 and the comparable prior-year periods for Pinnacle West and each of our subsidiaries (dollars in millions, unaudited):

	Three Months Ended June 30,		Six Months Ended June 30,		Twelve Months Ended June 30,	
	2002	2001	2002	2001	2002	2001
APS	$ 64	$ 70	$ 96	$ 134	$ 243	$ 312
APSES - pre tax	11	--	13	(7)	11	(17)
SunCor	8	--	10	--	13	6
Pinnacle West Energy	1	1	2	1	19	--
El Dorado	(3)	--	(3)	--	(3)	(14)
Parent company (a)	(6)	(4)	11	1	44	1
Income before accounting change	75	67	129	129	327	288
Cumulative effect of change in accounting - net of income taxes	--	--	--	(3)	(12)	(3)
Net income	$ 75	$ 67	$ 129	$ 126	$ 315	$ 285

(a) These amounts primarily include marketing and trading activities. APS amounts also included some marketing and trading activities in 2001, although APS completed the transition of such activities to the parent company as of the end of 2001.

BUSINESS SEGMENTS

We have two principal business segments (determined by products, services and the regulatory environment), which consist of our regulated retail electricity business, regulated traditional wholesale electricity business, and related activities (electric retail business segment) and our competitive business activities (marketing and trading business segment). Our electric retail business segment includes activities related to electricity transmission and distribution, as well as electricity generation. Our marketing and trading business segment includes activities related to wholesale marketing and trading and APSES' competitive energy services. The other amounts include activities related to SunCor and El Dorado. The parent company, other than marketing and trading, is included in our electric retail segment.

The following table summarizes net income by business segment for the three, six and twelve months ended June 30, 2002 and the comparable prior year periods (dollars in millions, unaudited):

	Three Months Ended June 30,		Six Months Ended June 30,		Twelve Months Ended June 30,	
	2002	2001	2002	2001	2002	2001
Electric retail	$ 61	$ 11	$ 93	$ 14	$ 231	$ 152
Marketing and trading	9	56	29	114	86	143
Other	5	--	7	1	10	(7)
Income before accounting change	75	67	129	129	327	288
Cumulative effect of change in accounting - net of income taxes	--	--	--	(3)	(12)	(3)
Net income	$ 75	$ 67	$ 129	$ 126	$ 315	$ 285

We recorded the cumulative effects of a change in accounting for derivatives related to our adoption in 2001 of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities."

EARNINGS VARIANCE EXPLANATIONS

Throughout these explanations, we refer to "gross margin." With respect to our electric retail segment and marketing and trading segment, gross margin refers to electric operating revenues less purchased power and fuel costs. Real estate gross margin refers to real estate revenues less real estate operations costs.

OPERATING RESULTS - THREE-MONTH PERIOD ENDED JUNE 30, 2002 COMPARED WITH THREE-MONTH PERIOD ENDED JUNE 30, 2001

Our consolidated net income for the three months ended June 30, 2002 was $75 million compared with $67 million for the same period in the prior year. The period-to-period increase was primarily the result of increased earnings contributions from our regulated retail electricity and real estate operations that were partially offset by lower earnings contributions from our marketing and trading activities. The retail comparison was favorably impacted by lower replacement costs for power plant outages, lower costs for purchased power and gas related to lower market prices, customer growth and higher average usage per customer, partially offset by the effects of milder weather. The real estate results benefited primarily from more sales activities. The comparison for marketing and trading activities reflects lower volumes and prices in the wholesale power markets in the western United States.

The major factors that increased (decreased) net income were as follows (dollars in millions):

	Increase (Decrease)
Electric retail segment gross margin:	
Lower replacement power costs for plant outages due to lower market prices and fewer unplanned outages	$ 58
Lower purchased power and fuel costs related to lower prices, net of hedge management sales	46
Effects of milder weather on retail sales	(16)
Higher retail sales volumes due to customer growth and higher average usage, excluding weather effects	12
Retail price reductions effective July 1, 2001	(7)
Miscellaneous factors - net	(5)
Net increase in electric retail segment gross margin	88
Marketing and trading segment gross margin:	
Decrease in generation sales other than native load due to lower market prices and resulting lower sales volumes	(26)
Decrease in other realized marketing and trading in the current period primarily due to lower unit margins on increased volumes	(6)(a)
Change in prior period mark-to-market gains on contracts delivered during the current period (b)	(14)(a)
Lower mark-to-market gains for future period deliveries (b)	(33)
Net decrease in marketing and trading gross margin	(79)
Total increase in the electric retail and the marketing and trading segments' gross margins	9
Higher real estate gross margin primarily due to increased sales activities	13
Lower operations and maintenance expense primarily related to lower generation reliability costs partially offset by higher other costs	3
Lower depreciation and amortization expense primarily related to lower regulatory asset amortization	4
Lower other income	(9)
Miscellaneous items, net	(6)
Increase in income before income taxes	14
Higher income taxes primarily due to higher pretax income	(6)
Increase in net income	$ 8

(a) Net marketing and trading gains (excluding the effects of generation sales other than native load) recognized for the current period decreased $20 million.

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

Electric Retail Segment Gross Margin

Revenues related to our regulated retail and wholesale electricity businesses were $242 million lower in the three-month period ended June 30, 2002, compared to the same period in the prior year as a result of:

* decreased revenues related to traditional wholesale sales as a result of lower sales volumes and lower prices ($54 million);
* decreased revenues related to retail load hedge management wholesale sales, as a result of lower sales volumes and lower prices ($171 million);
* decreased retail revenues related to milder weather ($26 million);
* increased retail revenues related to customer growth and higher average usage, excluding weather effects ($21 million);
* decreased retail revenues related to a reduction in retail electricity prices ($7 million); and
* other miscellaneous factors ($5 million net decrease).

Electric retail segment purchased power and fuel costs were $330 million lower in the three-month period ended June 30, 2002, compared to the same period in the prior year as a result of:

* decreased costs related to traditional wholesale sales as a result of lower sales volumes and lower prices ($54 million);
* decreased costs related to lower prices for hedged natural gas and purchased power ($217 million);
* decreased costs related to the effects of milder weather on retail sales ($10 million);
* increased costs related to retail sales growth excluding weather effects ($9 million); and
* decreased replacement power costs for power plant outages due to lower market prices and fewer unplanned outages ($58 million).

Marketing and Trading Segment Gross Margin

Marketing and trading segment revenues were $373 million lower in the three-month period ended June 30, 2002, compared to the same period in the prior year as a result of:

* decreased revenues from generation sales other than native load due to lower market prices and resulting lower sales volumes ($49 million);
* decreased realized revenues from other realized marketing and trading in the current period primarily due to lower prices ($277 million);
* change in prior period mark-to-market gains on contracts delivered during the current period due to higher volumes being delivered ($13 million decrease); and
* lower mark-to-market gains for future period deliveries primarily as a result of lower market liquidity and lower price volatility, resulting in lower volumes ($34 million).

Marketing and trading segment purchased power and fuel costs were $294 million lower in the three-month period ended June 30, 2002, compared to the same period in the prior year as a result of:

* decreased fuel costs related to generation sales other than native load primarily because of lower sales volumes and lower natural gas prices ($23 million); and
* decreased purchased power costs related to other realized marketing and trading in the current period primarily due to lower prices ($271 million).

The increase in real estate gross margin of $13 million was primarily due to increased sales activities.

The decrease in operations and maintenance expense of $3 million was due to lower costs related to generation reliability, plant outages and maintenance costs. Operations and maintenance expense was also lower as a result of the reversal of $4 million of a $10 million reserve for the California energy situation. These factors were partially offset with increased employee and other costs. See Note 12 for a discussion of California energy market issues.

The decrease in depreciation and amortization expense of $4 million primarily related to lower regulatory asset amortization, in accordance with APS' 1999 regulatory settlement, partially offset by increased depreciation on higher plant balances.

Other income decreased $9 million primarily due to an insurance recovery recorded in the prior period related to environmental remediation costs.

OPERATING RESULTS - SIX-MONTH PERIOD ENDED JUNE 30, 2002 COMPARED WITH SIX-MONTH PERIOD ENDED JUNE 30, 2001

Our consolidated net income for the six months ended June 30, 2002 was $129 million compared with $126 million for the same period in the prior year. We recognized a $3 million after-tax loss in the six months ended June 30, 2001 as a cumulative effect of a change in accounting for derivatives, as required by SFAS No.133.

Our income before accounting change for the six months ended June 30, 2002 and 2001 was $129 million in both periods. The period-to-period activity was the result of increased earnings contributions from our regulated retail electricity and real estate operations that were partially offset by lower earnings contributions from our marketing and trading activities. The retail comparison was favorably impacted by lower replacement costs for power plant outages, lower costs for purchased power and gas related to lower market prices, customer growth and higher average usage per customer, partially offset by the effects of milder weather and a retail electricity price decrease. The real estate results benefited primarily from more sales activities. The comparison for marketing and trading activities reflects lower volumes and prices in the wholesale power markets in the western United States.

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

	Increase (Decrease)
Electric retail segment gross margin:	
Lower replacement power costs for plant outages due to lower market prices and fewer unplanned outages	$ 108
Lower purchased power and fuel costs related to lower prices, net of hedge management sales	36
Effects of milder weather on retail sales	(22)
Higher retail sales volumes due to customer growth and higher average usage, excluding weather effects	17
Retail price reductions effective July 1, 2001	(13)
Miscellaneous factors - net	(3)
Net increase in electric retail segment gross margin	123
Marketing and trading segment gross margin:	
Decrease in generation sales other than native load due to lower market prices and resulting lower sales volumes	(71)
Increase in other realized marketing and trading in the current period primarily due to higher unit margins on increased volumes	31(a)
Change in prior period mark-to-market gains on contracts delivered during the current period (b)	(45)(a)
Lower mark-to-market gains for future period deliveries (b)	(61)
Net decrease in marketing and trading gross margin	(146)
Total decrease in the electric retail and the marketing and trading segments' gross margins	(23)
Higher real estate gross margin primarily due to increased sales activities	15
Lower operations and maintenance expense primarily related to lower generation reliability costs partially offset by higher other costs	11
Lower depreciation and amortization primarily due to lower regulatory asset amortization	9
Lower other income	(6)
Miscellaneous items, net	(6)
Change in income before income taxes	--
Change in income taxes	--
Change in income before accounting change	$ --

(a) Net marketing and trading gains (excluding the effects of generation sales other than native load) recognized for the current period decreased $14 million.

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

Electric Retail Segment Gross Margin

Revenues related to our regulated retail and wholesale electricity businesses were $275 million lower in the six-month period ended June 30, 2002, compared to the same period in the prior year as a result of:

* decreased revenues related to traditional wholesale sales as a result of lower sales volumes and lower prices ($79 million);
* decreased revenues related to retail load hedge management wholesale sales, as a result of lower sales volumes and lower prices ($174 million);
* decreased retail revenues related to milder weather ($35 million);
* increased retail revenues related to customer growth and higher average usage, excluding weather effects ($29 million);
* decreased retail revenues related to a reduction in retail electricity prices ($13 million); and
* other miscellaneous factors ($3 million net decrease).

Electric retail segment purchased power and fuel costs were $398 million lower in the six-month period ended June 30, 2002, compared to the same period in the prior year as a result of:

* decreased costs related to traditional wholesale sales as a result of lower sales volumes and lower prices ($79 million);
* decreased costs related to lower prices for hedged natural gas and purchased power ($210 million);
* decreased costs related to the effects of milder weather on retail sales ($13 million);
* increased costs related to retail sales growth, excluding weather effects ($12 million); and
* decreased replacement power costs for power plant outages due to lower market prices and fewer unplanned outages ($108 million).

Marketing and Trading Segment Gross Margin

Marketing and trading segment revenues were $667 million lower in the six-month period ended June 30, 2002, compared to the same period in the prior year as a result of:

* decreased revenues from generation sales other than native load due to lower market prices and resulting lower sales volumes ($128 million);
* decreased revenues from other realized marketing and trading in the current period primarily due to lower prices ($441 million);
* change in prior period mark-to-market gains on contracts delivered during the current period due to higher volumes being delivered ($37 million decrease); and
* lower mark-to-market gains for future period deliveries primarily as a result of lower market liquidity and lower price volatility, resulting in lower volumes ($61 million).

Marketing and trading segment purchased power and fuel costs were $521 million lower in the six-month period ended June 30, 2002, compared to the same period in the prior year as a result of:

* decreased fuel costs related to generation sales other than native load primarily because of lower sales volumes and lower natural gas prices ($57 million);
* decreased purchased power costs related to other realized marketing and trading in the current period primarily due to lower prices ($472 million); and
* change in prior period mark-to-market fuel costs for current period deliveries ($8 million net increase).

The increase in real estate gross margin of $15 million was primarily due to increased sales activities.

The decrease in operations and maintenance expense of $11 million was primarily due to lower costs related to generation reliability, plant outages and maintenance costs. Operation and maintenance expense was also lower as a result of the reversal of $4 million of a $10 million reserve recorded in the prior period for the California energy situation. These decreases were partially offset by increased employee benefit and other costs. See Note 12 for a discussion of California energy market issues.

The decrease in depreciation and amortization expense of $9 million primarily related to lower regulatory asset amortization, in accordance with APS' 1999 regulatory settlement, partially offset by increased depreciation on higher plant balances.

Other income decreased $6 million primarily due to an insurance recovery recorded in the prior period related to environmental remediation costs, partially offset by higher miscellaneous non-operating revenues in the current period.

OPERATING RESULTS - TWELVE-MONTH PERIOD ENDED JUNE 30, 2002 COMPARED WITH TWELVE-MONTH PERIOD ENDED JUNE 30, 2001

Our consolidated net income for the twelve months ended June 30, 2002 was $315 million compared with $285 million for the same period in the prior year. We recognized a $12 million after-tax loss in the twelve months ended June 30, 2002 and a $3 million after-tax loss in the twelve months ended June 30, 2001 as cumulative effects of a change in accounting for derivatives, as required by SFAS No.133.

Our income before accounting change for the twelve months ended June 30, 2002 was $327 million compared with $288 million for the same period a year earlier. The period-to-period comparison benefited from increased earnings contributions from our regulated retail electricity and real estate operations that were partially offset by lower earnings contributions from our marketing and trading activities and higher operations and maintenance expenses. The retail comparison was favorably impacted by lower replacement costs for power plant outages, lower costs for purchased power and gas related to lower market prices, customer growth and higher average usage per customer, partially offset by the effects of milder weather and a retail electricity price decrease. The real estate results benefited primarily from more sales activities. The comparison for marketing and trading activities reflects lower volumes and prices in the wholesale power markets in the western United States.

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

	Increase (Decrease)
Electric retail segment gross margin:	
Lower replacement power costs for plant outages due to lower market prices and fewer unplanned outages	$ 126
Lower purchased power and fuel costs related to lower prices, net of hedge management sales	33
Effects of milder weather on retail sales	(9)
Higher retail sales volumes due to customer growth and higher average usage, excluding weather effects	27
Retail price reductions effective July 1, 2001	(28)
Miscellaneous factors - net	(1)
Net increase in electric retail segment gross margin	148
Marketing and trading segment gross margin:	
Decrease in generation sales other than native load due to lower market prices and resulting lower sales volumes	(112)
Increase in other realized marketing and trading in the current period primarily due to higher unit margins on increased volumes	72(a)
Change in prior period mark-to-market gains on contracts delivered during the current period (b)	(88)(a)
Higher mark-to-market gains for future period deliveries (b)	36
Net decrease in marketing and trading gross margin	(92)
Total increase in the electric retail and the marketing and trading segments' gross margins	56
Higher real estate gross margin primarily due to increased sales activities	16
Higher operations and maintenance expense primarily related to higher generation reliability costs partially offset by lower other costs	(29)
Lower depreciation and amortization primarily due to lower regulatory asset amortization	12
Lower other income	(3)
Lower other expense	15
Lower net interest expense primarily due to higher capitalized interest	7
Miscellaneous items, net	(6)
Increase in income before income taxes	68
Higher income taxes primarily due to higher income	(29)
Increase in income before accounting change	$ 39

(a) Net marketing and trading gains (excluding the effects of generation sales other than native load) recognized for the current period decreased $16 million.

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

Electric Retail Segment Gross Margin

Revenues related to our regulated retail and wholesale electricity businesses were $477 million lower in the twelve-month period ended June 30, 2002, compared to the same period in the prior year as a result of:

* decreased revenues related to traditional wholesale sales as a result of lower sales volumes and lower prices ($177 million);
* decreased revenues related to wholesale sales, as a result of lower sales volumes and lower prices ($301 million);
* decreased retail revenues related to milder weather ($14 million);
* increased retail revenues related to customer growth and higher average usage, excluding weather effects ($44 million);
* decreased retail revenues related to a reduction in retail electricity prices ($28 million); and
* other miscellaneous factors ($1 million net decrease).

Electric retail segment purchased power and fuel costs were $625 million lower in the twelve-month period ended June 30, 2002, compared to the same period in the prior year as a result of:

* decreased costs related to traditional wholesale sales as a result of lower sales volumes and lower prices ($177 million);
* decreased costs related to lower prices for hedged natural gas and purchased power prices ($331 million);
* decreased costs related to the effects of milder weather on retail sales ($5 million);
* increased costs related to retail sales growth, excluding weather effects ($17 million);
* decreased replacement power costs for power plant outages due to lower market prices and fewer unplanned outages ($126 million); and
* miscellaneous factors ($3 million net decrease).

Marketing and Trading Segment Gross Margin

Marketing and trading segment revenues were $616 million lower in the twelve-month period ended June 30, 2002, compared to the same period in the prior year as a result of:

* decreased revenues from generation sales other than native load due to lower market prices and resulting lower sales volumes ($212 million);
* decreased revenues from other realized marketing and trading in the current period primarily due to lower prices ($359 million);
* change in prior period mark-to-market gains on contracts delivered during the current period due to higher volumes being delivered ($80 million decrease); and

* higher mark-to-market gains for future period deliveries primarily as a result of greater market liquidity and greater price volatility, resulting in higher volumes ($35 million).

Marketing and trading segment purchased power and fuel costs were $524 million lower in the twelve-month period ended June 30, 2002, compared to the same period in the prior year as a result of:

* decreased fuel costs related to generation sales other than native load primarily because of lower sales volumes and lower natural gas prices ($100 million);
* decreased purchased power costs related to other realized marketing and trading in the current period primarily due to lower prices ($431 million);
* change in prior period mark-to-market fuel costs for current period deliveries related to accounting for derivatives ($8 million increase); and
* other miscellaneous factors ($1 million decrease).

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

The increase in operations and maintenance expense of $29 million was primarily due to higher costs related to generation reliability, plant outages and maintenance costs. Operations and maintenance expense was also higher due to increased employee benefit and other costs. These factors were partially offset as a result of the reversal of $4 million of a $10 million reserve recorded in the prior period for the California energy situation. See Note 12 for a discussion of California energy market issues.

The decrease in depreciation and amortization expenses of $12 million primarily related to lower regulatory asset amortization, in accordance with APS' 1999 regulatory settlement, partially offset by increased depreciation on higher plant balances.

Other income decreased $3 million primarily due to the effects of an insurance recovery recorded in the prior period related to environmental remediation costs, partially offset by higher miscellaneous non-operating revenues in the current period.

Other expense decreased $15 million primarily due to lower losses recorded on El Dorado's investment in the current period, partially offset by higher miscellaneous non-operating expenses in the current period.

Net interest expense decreased $7 million primarily because of the increase in capitalized interest on our generation expansion program and the effects of lower interest rates. These reductions in net interest expense more than offset the increase in interest expense on higher debt balances primarily related to our generation expansion program.

LIQUIDITY AND CAPITAL RESOURCES

CAPITAL EXPENDITURE REQUIREMENTS

The following table summarizes the actual capital expenditures for the six months ended June 30, 2002 and estimated capital expenditures for the next three years (dollars in millions):

	Six Months Ended June 30, 2002	Estimated 2002	Estimated 2003	Estimated 2004
APS				
Delivery	$ 182	$ 347	$ 270	$ 267
Existing generation (a)	70	149	--	--
Subtotal	252	496	270	267
Pinnacle West Energy (b)				
Generation expansion	197	411	257	109(e)
Existing generation (a)	--	--	116	89
Subtotal	197	411	373	198
SunCor (c)	39	79	48	52
Other (d)	16	38	22	21
Total	$ 504	$1,024	$ 713	$ 538

(a) Pursuant to the 1999 Settlement Agreement, APS is required to transfer its competitive electric assets and services no later than December 31, 2002. As we discuss in greater detail in Note 5, on July 23, 2002, an ACC ALJ issued a recommended order recommending, among other things, that the ability of APS to transfer its generation assets be stayed until at least July 1, 2004.
(b) See further discussion below of Pinnacle West Energy's generation expansion program and "Capital Resources and Cash Requirements - Pinnacle West Energy" below.
(c) Consists primarily of capital expenditures for land development and retail and office building construction and is included in the "Increase in real estate investments" in the condensed consolidated statements of cash flows.
(d) Primarily Pinnacle West and APSES.
(e) This amount does not include an expected reimbursement by SNWA of approximately $100 million of these costs in 2004 in exchange for SNWA's option to purchase a 25% interest in the Silverhawk project at that time.

Several years ago APS and the other Palo Verde participants decided to replace Unit 2 steam generators, which replacement is presently scheduled to be completed in the fall of 2003. APS and the other Palo Verde participants are currently considering issues related to replacement of the steam generators in Units 1 and 3. Although a final determination of whether Units 1 and 3 will require steam generator replacement to operate over their current full licensed lives has not yet been made, APS and the other participants have approved fabrication of one set of spare steam generators. APS' portion of this expenditure is approximately $27 million, which will be spent from 2002 to 2005. The capital expenditure table above includes $21 million of the costs in 2002 through 2004. If the Palo Verde participants decide to proceed with steam generator replacement at both Units 1 and 3, we have estimated that our portion of the fabrication and installation costs and associated power uprate modifications would be approximately $130 million over the next seven years, which would be funded with internally-generated cash or external financings.

Existing generation capital expenditures are comprised of multiple improvements for our existing fossil and nuclear plants. Examples of the types of projects included in this category are additions, upgrades and capital replacements of various power plant equipment such as turbines, boilers, and environmental equipment. The existing generation also contains nuclear fuel expenditures of approximately $30 million annually in 2002, 2003, and 2004.

Delivery capital expenditures are comprised of T&D infrastructure additions and upgrades, capital replacements, new customer construction, and related information systems and facility costs. Examples of the types of projects included in the forecast include T&D lines and substations, line extensions to new residential and commercial developments, and upgrades to customer information systems. In addition, we began several major transmission projects in 2001. These projects are periodic in nature and are driven by strong regional customer growth. We expect to spend about $150 million on major transmission projects during the 2002-2004 time frame.

CAPITAL RESOURCES AND CASH REQUIREMENTS

The following table summarizes actual cash commitments for the six months ended June 30, 2002 and estimated commitments for the next five years and thereafter (dollars in millions):

	Six Months Ended June 30, 2002	Estimated Years Ended December 31, 2002	2003	2004	2005	2006	There -after
Long-term debt payments							
APS	$ 247	$ 247	$ --	$ 205	$ 400	$ 84	$1,518
Pinnacle West	--	1	276	216	--	300	--
SunCor	15	15	38	76	--	3	16
Total long-term debt payments	262	263	314	497	400	387	1,534
Operating leases payments	43	68	66	65	64	63	550
Fuel and purchase power commitments	102	318	132	83	65	68	170
Total cash commitments (a)	$ 407	$ 649	$ 512	$ 645	$ 529	$ 518	$2,254

(a) Total cash commitments are approximately $5.1 billion. The total net present value of these cash commitments is $2.9 billion.

Our significant debt covenants related to our financing arrangements include a debt to total capitalization ratio and interest coverage test. We are in compliance with such convenants and we anticipate that we will continue to meet all the significant covenant requirement levels. The repercussions of not meeting the covenants would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants. All of our bank agreements have cross-default provisions.

We have issued parental guarantees and obtained surety bonds on behalf of our unregulated subsidiaries. The credit support instruments enable Pinnacle West Energy to continue its generation expansion plan, enable APSES to provide commodity energy and energy-related products and enable El Dorado to support the activities of NAC. The amounts as of June 30, 2002 are listed as follows (dollars in millions):

	Guarantees	Surety Bonds
Pinnacle West Energy	$ 305	$ --
APSES	72	44
El Dorado	51	--

In addition, SunCor has provided guarantees of approximately $24 million on behalf of affiliated joint ventures.

PINNACLE WEST

The parent company's cash requirements and its ability to fund those requirements are discussed under "Capital Needs and Resources" in Management's Discussion and Analysis of Financial Condition and Results of Operation in Part II, Item 7 of the 2001 10-K.

On February 8, 2002, we issued $215 million of 4.5% Notes due 2004. See the cash commitments table above for the parent company's debt repayment requirements. The majority of these borrowings were used to fund Pinnacle West Energy capital expenditures.

On July 31, 2002, we completed a $300 million bank credit facility. The borrowings are LIBOR-based and can be drawn upon as needed, and are expected to be used primarily to fund Pinnacle West Energy capital requirements. The facility matures on July 30, 2003.

We fund our pension plan by contributing at least the minimum amount required under Internal Revenue Service regulations but no more than the maximum tax-deductible amount. The minimum required funding takes into consideration the value of the fund assets and our pension obligation. We have contributed cash to our pension plan in each of the last eight years, the last four of which were entirely voluntary (our minimum required contributions during each of those years was zero). Specifically, we contributed $24 million for 2001, $44 million for 2000, $25 million for 1999 and $14 million for 1998. We again plan to voluntarily contribute $27 million in 2002. The assets in the plan are mostly domestic common stocks, bonds and real estate. We currently forecast a pension contribution in 2003 of approximately $50 million, all or part of which may be required depending on 2002 fund performance. If the fund performance continues to decline as a result of a continued decline in equity markets, we may be required to make contributions in future years.

APS

APS' cash requirements and its ability to fund those requirements are discussed under "Capital Needs and Resources" in Management's Discussion and Analysis of Financial Condition and Results of Operation in Part II, Item 7 of the 2001 10-K.

On March 1, 2002, APS issued $375 million of 6.50% Notes due 2012.

On April 15, 2002, APS redeemed $122 million of its First Mortgage Bonds, 8.75% Series due 2024. On March 15, 2002, APS redeemed at maturity $125 million of its First Mortgage Bonds, 8.125% Series due 2002. See the cash commitments table above for APS' debt repayments. Based on market conditions and optional call provisions, APS may make optional redemptions of long-term debt from time to time.

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

PINNACLE WEST ENERGY

Pinnacle West Energy has completed or announced plans to build about 3,420 MW of natural gas-fired generating capacity from 2001 through 2007 at an estimated cost of about $1.9 billion. This does not reflect an expected reimbursement in 2004 by SNWA of approximately $100 million of Pinnacle West Energy's cumulative capital expenditures in the Silverhawk project in exchange for SNWA's option to purchase a 25% interest in the project. Our expansion plan will be sized to meet native load growth, cash flow and market conditions. Pinnacle West Energy is currently funding its capital requirements through capital infusions from Pinnacle West, which finances those infusions through debt financings and internally-generated cash. As Pinnacle West Energy develops and obtains additional generation assets, Pinnacle West Energy expects to fund its capital requirements through internally-generated cash and its own debt issuances. As we discuss in greater detail in Note 5, on July 23, 2002, an ACC ALJ issued a recommended order recommending, among other things, that the ability of APS to transfer its generating assets be stayed until at least July 1, 2004. See "Business Outlook - Other Factors Affecting Future Financial Results" below for the implications of Pinnacle West Energy funding its own capital requirements if APS is not able to transfer its generation assets to Pinnacle West Energy. See the Capital Expenditures Table above for actual capital expenditures through June 30, 2002 and projected capital expenditures for the next three years.

Pinnacle West Energy has completed or is currently planning the following projects:

* A 650 MW expansion of the West Phoenix Power Plant in Phoenix. The 120 MW West Phoenix Unit 4 began commercial operation on June 1, 2001. Construction has begun on the 530 MW West Phoenix Unit 5, with commercial operation expected to begin in mid-2003.

* The construction of a four-unit combined cycle 2,120 MW generating station near Palo Verde, called Redhawk. Construction of Units 1 and 2 began in December 2000, and commercial operation began in July 2002. Although Pinnacle West Energy currently plans to bring Units 3 and 4 on line in or before the first quarter of 2007, equipment procurement, engineering and construction plans will allow for these units to come on line as early as 2005 if warranted by market conditions.

* The construction of an 80 MW simple-cycle power plant at Saguaro in Southern Arizona. Commercial operation began in July 2002.

* Development of an electric generating station 20 miles north of Las Vegas, Nevada. Construction of the 570 MW Silverhawk combined-cycle plant began in August 2002, with an expected commercial operation date of mid-2004. Pinnacle West Energy has signed an agreement with Las Vegas-based SNWA to have an option to purchase a 25% interest in the project.

* A Pinnacle West Energy affiliate is exploring the possibility of creating an underground natural gas storage facility on Company-owned land west of Phoenix. A feasibility study is in progress to determine if the proposed acreage can support a natural gas storage cavern.

OTHER SUBSIDIARIES

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

SunCor's capital needs consist primarily of capital expenditures for land development and retail and office building construction. See the capital expenditures table above for actual capital expenditures in the six months ended June 30, 2002 and projected capital expenditures for the next three years. SunCor expects to fund its capital requirements with cash from operations and external financings. SunCor's long-term indebtedness decreased $15 million in the six months ended June 30, 2002. SunCor has provided guarantees of approximately $24 million on behalf of affiliated joint ventures.

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

APSES' capital expenditures and other cash requirements are increasingly funded by operations, with some funding from cash infused by Pinnacle West. See the capital expenditures table above regarding APSES' capital expenditures.

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. Our most critical accounting policies include the determination of the appropriate accounting for our derivative instruments, mark-to-market accounting and the impacts of regulatory accounting on our consolidated financial statements. See Note 1 in the 2001 10-K. There have been no material changes since the 2001 10-K.

BUSINESS OUTLOOK

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

In 2001, the Company reported income of $172 million from its marketing and trading activities. We expect earnings contributions from these activities will be down approximately 75% in 2002. The drivers of such reduced earnings contributions from our marketing and trading activities in 2002 are significant reductions in wholesale market prices for electricity that occurred during 2001; reduced wholesale market liquidity, which affects our ability to buy and resell electricity; and reduced market volatility, which affects our ability to capture profitable structured trading activities.

During 2001, in order to meet the highest customer demand in APS' history, we incurred significant expenses for our summer reliability program and for higher replacement power costs related to power plant outages. These efforts, which cost approximately $140 million before income taxes, are not expected to be repeated in 2002.

In July 2002, the Company announced cost-containment measures that include a voluntary workforce reduction of 500-600 positions. These reductions would be implemented in the second half of 2002 and are expected to produce annual operating expense savings of $30-35 million beginning in 2003, and a comparable one-time charge to earnings later in 2002.

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

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

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

COMPETITION AND ELECTRIC INDUSTRY RESTRUCTURING

See "Business Outlook - Competition and Industry Restructuring" in Item 7 of the 2001 10-K and Note 5 above for a discussion of developments affecting retail and wholesale electric competition.

GENERATION EXPANSION

See "Capital Resources and Cash Requirements - Pinnacle West Energy" above for information regarding our generation expansion plans. The planned additional generation is expected to increase revenues, fuel expenses, operating expenses, and financing costs.

FACTORS AFFECTING OPERATING REVENUES

Electric operating revenues are derived from sales of electricity in regulated retail markets in Arizona, and from competitive retail and wholesale bulk power markets in the western United States. These revenues are expected to be affected by electricity sales volumes related to customer mix, customer growth and average usage per customer, as well as electricity prices and variations in weather from period to period.

In APS' regulated retail market area, APS will provide electricity services to standard-offer, full-service customers and to energy delivery customers who have chosen another provider for their electricity commodity needs (unbundled customers). Customer growth in APS' service territory averaged about 4% a year for the three years 1999 through 2001; we currently expect customer growth to be about 3.2% in 2002 and between 3.5% and 4.0% a year in 2003 and 2004. We currently estimate that retail electricity sales in kilowatt-hours will grow 3.5% to 5.5% a year in 2002 through 2004, before the retail effects of weather variations. The customer growth and sales growth referred to in this paragraph apply to energy delivery customers. As industry restructuring evolves in the regulated market area, we cannot predict the number of APS' standard-offer customers that will switch to unbundled service. As previously noted, under the 1999 Settlement Agreement, we agreed to retail electricity price reductions of 1.5% annually through July 1, 2003 (see Note 5).

Competitive sales of energy and energy-related products and services are made by APSES in western states that have opened to competitive supply.

OTHER FACTORS AFFECTING FUTURE FINANCIAL RESULTS

As we discuss in greater detail in Note 5, on July 23, 2002, an ACC ALJ issued a recommended order recommending, among other things, that the ability of APS to transfer its generating assets be stayed until at least July 1, 2004. The Company has financed Pinnacle West Energy's generation expansion program premised upon Pinnacle West Energy's receipt of APS' generation assets by the end of 2002, as promised by the 1999 Settlement Agreement. Pinnacle West Energy has previously received investment grade credit ratings contingent upon its acquisition of APS' generation assets. If APS is prohibited from transferring its generation assets to Pinnacle West Energy, the Company believes that if Pinnacle West Energy is able to finance its capital requirements (including the repayment of the bridge financing provided by the Company), it would only be able to do so on commercially unattractive terms. In such a case, the Company's overall financing costs could increase. As we discuss in Note 5, APS has proposed that APS be permitted to acquire certain of Pinnacle West Energy's generating facilities if the ACC prohibits or delays APS' transfer of generation assets to Pinnacle West Energy. If APS were to acquire Pinnacle West Energy generation assets, the Company believes that APS could obtain financing for those assets and could do so on terms more favorable than those that would be otherwise available to Pinnacle West Energy.

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

Operations and maintenance expenses are expected to be affected by sales mix and volumes, power plant operations, inflation, outages, higher trending pension and other post-retirement costs and other factors. See "Business Outlook" above for information regarding Company cost-containment measures announced in July 2002.

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. As noted above, Redhawk Units 1 and 2 and the Saguaro power plant began commercial operations in July 2002.

Taxes other than income taxes consist primarily of property taxes, which are affected by tax rates and the value of property in service and under construction. The average property tax rate for APS, which currently owns the majority of our property, was 9.32% of assessed value for 2001 and 9.16% for 2000. We expect property taxes to increase primarily due to our generation expansion program and our additions to existing facilities.

Interest expense is affected by the amount of debt outstanding and the interest rates on that debt. The primary factors affecting borrowing levels in the next several years are expected to be our generation expansion program and our internally-generated cash flow. Capitalized interest offsets a portion of interest expense while capital projects are under construction. We stop recording capitalized interest on a project when it is placed in commercial operation. As noted above, Redhawk Units 1 and 2 and the Saguaro power plant began commercial operations in July 2002.

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

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

El Dorado's historical results are not necessarily indicative of future performance for El Dorado. El Dorado's strategies focus on prudently realizing the value of its existing investments. Any future investments are expected to be related to the energy sector.

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

Our financial results may be affected by the application of SFAS No. 133. See Note 10 for further information.

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

RATE MATTERS

See Note 5 for a discussion of a price reduction effective as of July 1, 2002, and for a discussion of the 1999 Settlement Agreement that will, among other things, result in five annual price reductions over a four-year period ending July 1, 2003.

FORWARD-LOOKING STATEMENTS

The above discussion contains forward-looking statements based on current expectations and we assume no obligation to update these statements, except as required by applicable laws. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from results or outcomes currently expected or sought by us. These factors include the ongoing restructuring of the electric industry, including the introduction of retail electric competition in Arizona; the outcome of regulatory and legislative proceedings relating to the restructuring; state and federal regulatory and legislative decisions and actions, including the price mitigation plan adopted by the FERC; regional economic and market conditions, including the California energy situation and completion of generation construction in the region, which could affect customer growth and the cost of power supplies; the cost of debt and equity capital; weather variations affecting local and regional customer energy usage; conservation programs; power plant performance; the successful completion of our generation expansion program; regulatory issues associated with generation expansion, such as permitting and licensing; our ability to compete successfully outside traditional regulated markets (including the wholesale market); technological developments in the electric industry; the performance of the stock market, which affects the amount of our required contributions to our pension plan; and the strength of the real estate market in SunCor's market areas, which include Arizona, New Mexico and Utah.

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

ITEM 3. 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.

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

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

The following schedule shows the changes in mark-to-market of our trading positions during the three, six and twelve months ended June 30, 2002 (dollars in millions):

	Three Months Ended June 30, 2002	Six Months Ended June 30, 2002	Twelve Months Ended June 30, 2002
Mark-to-market of net trading positions at beginning of period	$ 141	$ 138	$ 105
Prior period mark-to-market gains realized during the period	(8)	(22)	(89)
Change in mark-to-market gains for future period deliveries	--	17	117
Change in valuation techniques	--	--	--
Mark-to-Market of net trading positions at end of period	$ 133	$ 133	$ 133

Net gains at inception include a reasonable marketing margin and were approximately $1 million for the three months ended June 30, 2002, approximately $9 million for the six months ended June 30, 2002 and approximately $12 million for the twelve months ended June 30, 2002. See Note 10 for mark-to-market on system hedges and for disclosure of risk management activities recorded on the consolidated balance sheets.

The table below shows the maturities of our trading positions as of June 30, 2002, by the type of valuation that is performed to calculate the fair value of the contract (millions of dollars):

Source of Fair Value	2002	2003	2004	2005	2006	Years there-after	Total fair value
Prices actively quoted	$ (27)	$ 3	$ 4	$ 5	$ 3	$ 6	$ (6)
Prices provided by other external sources	1	(2)	(1)	1	2	(4)	(3)
Prices based on models and other valuation methods	38	27	26	20	17	14	142
Total by maturity	$ 12	$ 28	$ 29	$ 26	$ 22	$ 16	$ 133

The table below shows the impact that hypothetical price movements of 10% would have on the market value of our risk management and trading assets and liabilities included on the condensed consolidated balance sheets at June 30, 2002 (dollars in millions):

Commodity	June 30, 2002 Gain (Loss) Price Up 10%	Price Down 10%
Trading (a):		
Electric	$ (2)	$ 2
Natural gas	(1)	1
Other	2	(1)
System (b):		
Natural gas hedges	18	(16)
Total	$ 17	$(14)

(a) Essentially all of our marketing and trading activities are structured activities. This means our portfolio of forward sales positions is hedged with a portfolio of forward purchases that protects the economic value of the sales transactions.
(b) These contracts are hedges of our forecasted purchases of natural gas. The impact of these hypothetical price movements would substantially offset the impact that these same price movements would have on the physical exposures being hedged.

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We have risk management and trading contracts with many counterparties, including one counterparty for which a worst case exposure represents approximately 47% of our $267 million of risk management and trading assets as of June 30, 2002. We use a risk management process to assess and monitor the financial exposure of this and all other counterparties. Despite the fact that the great majority of trading counterparties are rated as investment grade by the credit rating agencies, including the counterparty noted above, there is still a possibility that one or more of these companies could default, resulting in a material impact on consolidated earnings for a given period. Counterparties in the portfolio consist principally of major energy companies, municipalities, and local distribution companies. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. In many contracts, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties.

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

PART II - OTHER INFORMATION

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY-HOLDERS

At our Annual Meeting of Shareholders held on May 22, 2002, the following shareholder proposal was submitted to shareholders:

	Votes For	Votes Against	Abstentions and Broker Non Votes
PROPOSAL THAT PINNACLE WEST PROVIDE SHAREHOLDERS WITH AN ENERGY REPORT	**4,395,349**	**63,512,921**	**2,197,596**

In addition, at the same annual meeting, the following management proposal was submitted to shareholders:

	Votes For	Votes Against	Abstentions and Broker Non Votes
PROPOSAL FOR APPROVAL OF A LONG-TERM INCENTIVE PLAN	65,804,188	3,394,492	907,186

Also, at the same annual meeting, the following persons were elected as directors:

	Votes For	Votes Against	Abstentions
CLASS I (TERM TO EXPIRE AT 2004 ANNUAL MEETING)			
William L. Stewart	75,953,254	140,845	--
CLASS II (TERM TO EXPIRE AT 2005 ANNUAL MEETING			
Edward N. Basha, Jr.	75,409,816	1,896,132	--
Michael L. Gallagher	75,120,087	2,203,533	--
Bruce J. Nordstrom	75,431,462	1,894,875	--
William J. Post	75,893,114	1,443,078	--

ITEM 5. OTHER INFORMATION

CONSTRUCTION AND FINANCING PROGRAMS

See "Liquidity and Capital Resources" in Part I, Item 2 of this report for a discussion of construction and financing programs of the Company and its subsidiaries.

COMPETITION AND ELECTRIC INDUSTRY RESTRUCTURING

See Note 5 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of regulatory developments regarding the introduction of retail electric competition in Arizona and related matters.

PALO VERDE NUCLEAR GENERATING STATION

In February 2002, the U. S. Secretary of Energy recommended to President Bush that the Yucca Mountain, Nevada site be developed as a permanent repository for spent nuclear fuel. The President transmitted this recommendation to Congress and the State of Nevada vetoed the President's recommendation. See "Palo Verde Nuclear Generating Station" in Part II, Item 5 of the March 2002 10-Q. Congress recently approved the Yucca Mountain site, overriding the Nevada veto. It is now expected that the U.S. Department of Energy will submit a license application to the NRC late in 2004.

NATURAL GAS SUPPLY

In a pending FERC proceeding, El Paso Natural Gas Company has proposed allocating its gas pipeline capacity in such a way that APS' (and other companies with the same contract type) gas transportation rights could be significantly impacted, and various parties, including APS and Pinnacle West Energy, have challenged this allocation. See "Generating Fuel and Purchased Power - Natural Gas Supply" in Part I, Item 1 of the 2001 10-K. The FERC conducted a public conference in April 2002 to discuss an appropriate mechanism for allocating capacity on the El Paso Natural Gas Company pipeline. On May 31, 2002 the FERC issued an order requiring the conversion of all firm, Full Requirements contracts to Contract Demand contracts by November 1, 2002. In addition, the FERC order set forth procedures to encourage parties to resolve the details of such conversions through the settlement process. APS and other Full Requirement contract holders have sought rehearing of the FERC order and have requested a stay of the November 1, 2002 implementation date. We cannot currently predict the outcome of this matter.

COAL SUPPLY

Because covenants under the Four Corners lease and related federal rights-of-way and grants expired in July 2001, the Navajo Nation assessed taxes on the coal supplier and the plant. See "Generating Fuel and Purchased Power - Coal Supply - Four Corners" in Part I, Item 1 of the 2001 10-K. In July 2002, APS and the Navajo Nation negotiated a settlement agreement relating to the plant pursuant to which APS will make settlement payments to the Navajo Nation. That settlement agreement is expected to be executed in August 2002. Pursuant to the terms of the settlement agreement, APS does not expect the payments to have a material adverse impact on its financial position, results of operations or liquidity.

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) Exhibits

Exhibit No.	Description
10.1	Amendment to Letter Agreement effective as of January 1, 2002 between APS and William L. Stewart
10.2	Summary of James M. Levine Retirement Benefits
12.1	Ratio of Earnings to Fixed Charges

In addition, the Company hereby incorporates the following Exhibits pursuant to Exchange Act Rule 12b-32 and Regulation ss.229.10(d) by reference to the filings set forth below:

Exhibit No.	Description	Originally Filed as Exhibit:	File No.(a)	Date Effective
3.1	Articles of Incorporation restated as of July 29, 1988	19.1 to the Company's September 30, 1988 Form 10-Q Report	1-8962	11-14-88
3.2	Bylaws, amended as of December 15, 1999	4.1 to the Company's Registration Statement on Form S-8 No. 333-95035	1-8962	1-20-00

(b) Reports on Form 8-K

During the quarter ended June 30, 2002, and the period from July 1 through August 13, 2002, we filed the following reports on Form 8-K:

Report dated March 31, 2002 regarding a motion filed by APS in a consolidated ACC docket.

Report dated April 26, 2002 regarding procedural orders issued by the ACC in a consolidated ACC docket.

Report dated May 22, 2002 regarding responses to FERC data requests that were filed with the FERC on May 22, 2002.

Report dated June 5, 2002 regarding responses to FERC data requests that were filed with the FERC on June 5, 2002.

Report dated June 11, 2002 comprised of a slide presentation for use at an analyst conference.

Report dated July 11, 2002 regarding a letter filed by APS with the ACC discussing the circumstances under which APS would support a temporary suspension or stay of certain Arizona electric competition rules.

Report dated June 30, 2002 comprised of exhibits relating to financial information and earnings variance explanations.

Report dated July 23, 2002 regarding ALJ recommendations in a consolidated ACC docket.

(a) Reports filed under File No. 1-8962 were filed in the office of the Securities and Exchange Commission located in Washington, D.C.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Company has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PINNACLE WEST CAPITAL CORPORATION
(Registrant)

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Dated: August 13, 2002                  By: Chris N. Froggatt
                                            ------------------------------------
                                            Chris N. Froggatt
                                            Vice President and Controller
                                            (Principal Accounting Officer
                                            and Officer Duly Authorized
                                            to sign this Report)
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Exhibit 10.1

AMENDMENT TO AGREEMENT

THIS AMENDMENT is made and entered into by and between Arizona Public Service Company and its Affiliates ("APS") and William L. Stewart ("Employee").

WITNESSETH:

WHEREAS, APS and Employee entered into an Agreement on December 13, 1999 ("Agreement"); pursuant to which Employee would remain employed by APS as President, Generation, through December 31, 2002; and

WHEREAS, the parties desire to amend the Agreement to extend Employee's employment beyond December 31, 2002, and to extend deferred payments and repayment of lines of credit, and to make certain other changes:

NOW, THEREFORE, effective as of January 1, 2002, the Agreement is amended as follows:

1. The third sentence of Section II, paragraph B is revised to read as follows:

All outstanding amounts will be due in full on or before March 31, 2005, except as provided in Section II, paragraph G, below.

2. The last sentence of Section II, paragraph C is revised to read as follows:

Payment of the deferred amount, plus interest, will be made on January 3, 2005, in a lump sum, except as provided in Section II, paragraph G, below.

3. Section II, paragraph D is revised to read as follows:

D. ADDITIONAL PAYMENTS. In addition, if Employee continues full-time employment through December 31, 2002, Employee will receive an additional $800,000 on January 3, 2005.

4. The second sentence of Section II, paragraph G is revised to read as follows:

If Employee separates from employment prior to December 31, 2002, for any reason, other than death or disability:

5. Section II, paragraph G, subparagraph 4 is revised to read as follows:

If Employee separates from employment prior to December 31, 2002, for any reason, other than death or disability, Employee will not receive the additional payment of $800,000 due on January 3, 2005.

6. Section II, paragraphs J and K are deleted.

ARIZONA PUBLIC SERVICE COMPANY

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By: William J. Post                        Date:      8-7-02
    -------------------------------             --------------------
    William J. Post
    Chief Executive Officer


    William L. Stewart                     Date:     7-30-02
    --------------------------------             -------------------
    William L. Stewart
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Exhibit 10.2

James M. Levine Retirement Benefits

Effective January 1, 2002, James M. Levine received an additional five years of service for purposes of calculating the annual benefits that would be provided to Mr. Levine under the Pinnacle West Capital Corporation Employees' Retirement Plan and the Pinnacle West Capital Corporation Supplemental Excess Benefit Retirement Plan. Accordingly, Mr. Levine's credited years of service increased from thirteen to eighteen. In addition, also beginning in 2002, the percentage of Mr. Levine's annual compensation payable to him at age 65 following his retirement will increase by three percent (3%) per year, up to a maximum of 70%, rather than the current two percent (2%) per year, from its present level of forty-six percent (46%). The Board of Directors of Pinnacle West Capital Corporation approved the foregoing changes to Mr. Levine's retirement benefits on June 19, 2002.

Exhibit 12.1

PINNACLE WEST CAPITAL CORPORATION
Computation of Earnings to Fixed Charges
($000's)

	Six Months Ended 6/30/02	2001	2000	1999	1998	1997
Income From Continuing Operations	$129,122	$327,367	$302,332	$269,772	$242,892	$235,856
Income Taxes	84,672	213,535	194,200	141,592	138,589	126,943
Fixed Charges	108,027	211,958	202,804	194,070	201,184	215,201
Total	321,821	752,860	699,336	605,434	582,665	578,000
Fixed Charges:						
Interest Expense	91,684	175,822	166,447	157,142	163,975	177,383
Estimated Interest Portion of Annual Rents	16,343	36,136	36,357	36,928	37,209	37,818
Total Fixed Charges	108,027	211,958	202,804	194,070	201,184	215,201
Ratio of Earnings to Fixed Charges (rounded down)	2.97	3.55	3.44	3.11	2.89	2.68