PINNACLE WEST CAPITAL CORP

FORM 10-Q
(Quarterly Report)

Filed 08/14/01 for the Period Ending 06/30/01

Address	400 NORTH FIFTH STREET MS8695 PHOENIX, AZ 85004
Telephone	602 250 1000
CIK	0000764622
Symbol	PNW
SIC Code	4911 - Electric Services
Industry	Electric Utilities
Sector	Utilities
Fiscal Year	12/31

PINNACLE WEST CAPITAL CORP

FORM 10-Q
(Quarterly Report)

Filed 8/14/2001 For Period Ending 6/30/2001

Address	400 NORTH FIFTH STREET .
	PHOENIX, Arizona 85004
Telephone	602-379-2500
CIK	0000764622
Industry	Electric Utilities
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Fiscal Year	12/31

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, 2001

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)

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

(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 10, 2001: 84,721,335

Glossary

ACC - Arizona Corporation Commission

ACC Staff - Staff of the Arizona Corporation Commission

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

APS Energy Services - 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

EITF - Emerging Issues Task Force

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

El Paso - El Paso Natural Gas Company

ERMC - Energy Risk Management Committee

FASB - Financial Accounting Standards Board

FERC - United States Federal Energy Regulatory Commission

Four Corners - Four Corners Power Plant

GWh - gigawatt-hour, one billion watts per hour

ISO - California Independent System Operator

ITC -investment tax credit

KW - kilowatt, one thousand watts

KWh - kilowatt-hour, one thousand watts per hour

March 2001 10-Q - Pinnacle West Capital Corporation Quarterly Report on Form 10-Q for the fiscal quarter ended March 31, 2001

MW - megawatt, one million watts

MWh -megawatt-hour, one million watts per hour

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

NPC - Nevada Power Company

Palo Verde - Palo Verde Nuclear Generating Station

PG&E - PG&E Corp.

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

PX - California Power Exchange

Rules - ACC retail electric competition rules

Salt River Project - Salt River Project Agricultural Improvement and Power District

SCE - Southern California Edison

SFAS - Statement of Financial Accounting Standards

SunCor - SunCor Development Company, a subsidiary of the Company

2000 10-K - Pinnacle West Capital Corporation Annual Report on Form 10-K for the fiscal year ended December 31, 2000

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS.

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

(dollars in thousands, except per share amounts)

	Three Months Ended June 30, 2001	Three Months Ended June 30, 2000
Operating Revenues		
Electric	$ 1,261,358	$ 720,174
Real estate	32,454	36,374
Total	1,293,812	756,548
Operating Expenses		
Purchased power and fuel	858,757	289,244
Operations and maintenance	132,139	107,335
Real estate operations	32,437	34,574
Depreciation and amortization	106,129	108,843
Taxes other than income taxes	25,462	25,610
Total	1,154,924	565,606
Operating Income	138,888	190,942
Other Income (Expense)	3,237	(7,034)
Income Before Interest and Income Taxes	142,125	183,908
Interest Expense		
Interest charges	43,823	42,102
Capitalized interest	(12,527)	(4,786)
Total	31,296	37,316
Income Before Income Taxes	110,829	146,592
Income Taxes	43,972	56,691
Net Income	$ 66,857	$ 89,901
Average Common Shares Outstanding - Basic	84,744	84,730
Average Common Shares Outstanding - Diluted	85,042	84,891
Earnings Per Average Common Share Outstanding		
Net Income - Basic	$ 0.79	$ 1.06
Net Income - Diluted	0.79	1.06
Dividends Declared Per Share	$ 0.375	$ 0.35

See Notes to Condensed Consolidated Financial Statements.

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

(dollars in thousands, except per share amounts)

	Six Months Ended June 30, 2001	Six Months Ended June 30, 2000
Operating Revenues		
Electric	$ 2,167,852	$ 1,166,402
Real estate	64,789	78,263
Total	2,232,641	1,244,665
Operating Expenses		
Purchased power and fuel	1,375,181	414,676
Operations and maintenance	257,389	217,784
Real estate operations	63,445	67,394
Depreciation and amortization	210,910	211,300
Taxes other than income taxes	50,765	51,002
Total	1,957,690	962,156
Operating Income	274,951	282,509
Other Income	2,499	28,457
Income From Continuing Operations Before Interest and Income Taxes	277,450	310,966
Interest Expense		
Interest charges	86,572	81,601
Capitalized interest	(22,954)	(8,635)
Total	63,618	72,966
Income From Continuing Operations Before Income Taxes	213,832	238,000
Income Taxes	84,770	94,029
Income From Continuing Operations	129,062	143,971
Cumulative Effect of a Change in Accounting for Derivatives - Net of Income Tax Benefit of $1,793	(2,755)	--
Net Income	$ 126,307	$ 143,971
Average Common Shares Outstanding - Basic	84,736	84,729
Average Common Shares Outstanding - Diluted	85,005	84,859
Earnings Per Average Common Share Outstanding		
Continuing Operations - Basic	$ 1.52	$ 1.70
Net Income - Basic	1.49	1.70
Continuing Operations - Diluted	1.52	1.70
Net Income - Diluted	1.49	1.70
Dividends Declared Per Share	$ 0.75	$ 0.70

See Notes to Condensed Consolidated Financial Statements.

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

(dollars in thousands, except per share amounts)

	Twelve Months Ended June 30, 2001	Twelve Months Ended June 30, 2000
Operating Revenues		
Electric	$ 4,533,260	$ 2,534,169
Real estate	144,891	151,202
Total	4,678,151	2,685,371
Operating Expenses		
Purchased power and fuel	2,893,297	974,583
Operations and maintenance	489,810	454,051
Real estate operations	130,473	135,274
Depreciation and amortization	430,839	423,604
Taxes other than income taxes	99,543	96,764
Total	4,043,962	2,084,276
Operating Income	634,189	601,095
Other Income (Expense)	(26,364)	41,074
Income From Continuing Operations Before Interest and Income Taxes	607,825	642,169
Interest Expense		
Interest charges	171,418	159,520
Capitalized interest	(35,957)	(12,036)
Total	135,461	147,484
Income From Continuing Operations Before Income Taxes	472,364	494,685
Income Taxes	184,941	180,334
Income From Continuing Operations	287,423	314,351
Income Tax Benefit From Discontinued Operations	--	38,000
Extraordinary Charge - Net of Income Taxes of $94,115	--	(139,885)
Cumulative Effect of a Change in Accounting for Derivatives - Net of Income Tax Benefit of $1,793	(2,755)	--
Net Income	$ 284,668	$ 212,466
Average Common Shares Outstanding - Basic	84,736	84,735
Average Common Shares Outstanding - Diluted	85,007	84,902
Earnings Per Average Common Share Outstanding		
Continuing Operations - Basic	$ 3.39	$ 3.71
Net Income - Basic	3.36	2.51
Continuing Operations - Diluted	3.38	3.70
Net Income - Diluted	3.35	2.50
Dividends Declared Per Share	$ 1.475	$ 1.05

See Notes to Condensed Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

ASSETS
(dollars in thousands)

	June 30, 2001 (unaudited)	December 31, 2000
Current Assets		
Cash and cash equivalents	$ 13,090	$ 10,363
Trust fund for bond redemption	72,370	--
Customer and other receivables--net	310,675	513,822
Accrued utility revenues	105,334	74,566
Materials and supplies	80,060	71,966
Fossil fuel	25,401	19,405
Deferred income taxes	5,793	5,793
Assets from risk management and trading activities	137,938	17,506
Other current assets	75,136	80,492
Total current assets	825,797	793,913
Investments and Other Assets		
Real estate investments--net	399,199	371,323
Other assets	397,363	318,249
Total investments and other assets	796,562	689,572
Property, Plant and Equipment		
Plant in service and held for future use	8,045,482	7,809,566
Less accumulated depreciation and amortization	3,277,947	3,188,302
Total	4,767,535	4,621,264
Construction work in progress	626,558	464,540
Nuclear fuel, net of amortization	48,062	47,389
Net property, plant and equipment	5,442,155	5,133,193
Deferred Debits		
Regulatory assets	403,840	469,867
Other deferred debits	79,112	62,606
Total deferred debits	482,952	532,473
Total Assets	$7,547,466	$7,149,151

See Notes to Condensed Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

LIABILITIES AND EQUITY
(dollars in thousands)

	June 30, 2001 (unaudited)	December 31, 2000
Current Liabilities		
Accounts payable	$ 196,191	$ 375,805
Accrued taxes	184,674	89,246
Accrued interest	37,729	42,954
Short-term borrowings	301,949	82,775
Current maturities of long-term debt	400,266	463,469
Customer deposits	28,085	26,189
Liabilities from risk management and trading activities	178,210	37,179
Other current liabilities	8,482	73,681
Total current liabilities	1,335,586	1,191,298
Long-Term Debt Less Current Maturities	2,104,586	1,955,083
Deferred Credits and Other		
Deferred income taxes	1,083,168	1,143,040
Unamortized gain - sale of utility plant	66,348	68,636
Other	568,585	408,380
Total deferred credits and other	1,718,101	1,620,056
Commitments and contingencies (Notes 6, 7, 9 and 12)		
Common Stock Equity		
Common stock, no par value	1,528,490	1,532,831
Accumulated other comprehensive loss	(51,912)	--
Retained earnings	912,615	849,883
Total common stock equity	2,389,193	2,382,714
Total Liabilities and Equity	$ 7,547,466	$ 7,149,151

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, 2001	Six Months Ended June 30, 2000
CASH FLOWS FROM OPERATING ACTIVITIES		
Income from continuting operations	$ 129,062	$ 143,971
Items not requiring cash		
Depreciation and amortization	210,910	211,300
Nuclear fuel amortization	14,178	15,124
Deferred income taxes--net	(24,299)	(31,528)
Other--net	--	(3,623)
Changes in current assets and liabilities		
Customer and other receivables--net	203,147	(107,755)
Accrued utility revenues	(30,768)	(39,342)
Materials, supplies and fossil fuel	(14,090)	81
Other current assets	5,356	(18,079)
Accounts payable	(183,525)	60,918
Accrued taxes	95,428	126,571
Accrued interest	(5,225)	350
Risk management and trading activities - net	(62,418)	--
Other current liabilities	(63,303)	(25,178)
Change in El Dorado partnership investment	766	(26,794)
Decrease/(Increase) in land held for sale	(25,786)	4,314
Other--net	23,970	654
Net Cash Flow Provided By Operating Activities	273,403	310,984
CASH FLOWS FROM INVESTING ACTIVITIES		
Trust fund for bond redemption	(72,370)	--
Capital expenditures	(427,062)	(223,361)
Capitalized interest	(22,954)	(8,635)
Other--net	14,469	(1,541)
Net Cash Flow Used For Investing Activities	(507,917)	(233,537)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	482,500	139,000
Short-term borrowings--net	219,174	162,575
Dividends paid on common stock	(63,573)	(59,307)
Repayment of long-term debt	(396,512)	(270,223)
Other--net	(4,348)	203
Net Cash Flow Provided by /(Used for) Financing Activities	237,241	(27,752)
Net Cash Flow	2,727	49,695
Cash and Cash Equivalents at Beginning of Period	10,363	20,705
Cash and Cash Equivalents at End of Period	$ 13,090	$ 70,400
Supplemental Disclosure of Cash Flow Information:		
Cash paid during the period for:		
Interest, net of amounts capitalized	$ 63,653	$ 72,475
Income taxes	$ 15,954	$ 6,361

See Notes to Condensed Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION

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, APS Energy Services, 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 Notes 9 and 10), the extraordinary charge (see Note 5) and the tax benefit from discontinued operations (see Note 13). 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 2000 10-K.

3. Weather conditions and trading and wholesale power marketing activities can have significant impacts on our results for interim periods. Results for interim periods do not necessarily represent results to be expected for the year.

4. See "Liquidity and Capital Resources" in Part I, Item 2 of this report for changes in capitalization for the six months ended June 30, 2001.

5. Regulatory Accounting

APS is regulated by the ACC and the FERC. The accompanying financial statements reflect the ratemaking policies of these commissions. For regulated operations, we prepare our financial statements in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in its financial statements.

During 1997, the EITF of the FASB issued EITF 97-4. EITF 97-4 requires that SFAS No. 71 be discontinued no later than when legislation is passed or a rate order is issued that contains sufficient detail to determine its effect on the portion of the business being deregulated, which could result in write-downs or write-offs of physical and/or regulatory assets. Additionally, the EITF determined that regulatory assets should not be written off if they are to be recovered from a portion of the entity which continues to apply SFAS No. 71.

The 1999 Settlement Agreement was approved by the ACC in September 1999 (see Note 6 for a discussion of the agreement). Consequently, we have discontinued the application of SFAS No. 71 for our generation operations. As a result, we tested the generation assets for impairment and determined that the generation assets were not impaired. Pursuant to the 1999 Settlement Agreement, a regulatory disallowance removed $234 million pretax ($183 million net present value) from ongoing regulatory cash flows and was recorded as a net reduction of regulatory assets. This reduction ($140 million after income taxes, or $1.65 per basic or diluted share) was reported as an extraordinary charge on the income statement during the third quarter of 1999. Prior to the 1999 Settlement Agreement, under the 1996 regulatory agreement (see Note 6), the ACC accelerated the amortization of substantially all of our regulatory assets to an eight-year period that would have ended June 30, 2004.

The regulatory assets to be recovered under the 1999 Settlement Agreement are now being amortized through June 30, 2004 as follows (dollars in millions):

1999	2000	2001	2002	2003	1/1 - 6/30 2004	Total
$164	$158	$145	$115	$86	$18	$686

The majority of our remaining regulatory assets relate to deferred income taxes and rate synchronization cost deferrals.

The consolidated balance sheets include the amounts listed below for generation assets not subject to SFAS No. 71 (for additional generation information see Note 8):

(dollars in thousands)	June 30, 2001	December 31, 2000
Electric plant in service and held for future use ..	$ 3,943,538	$ 3,856,600
Accumulated depreciation and amortization	(1,745,428)	(1,693,079)
Construction work in progress	460,815	304,992
Nuclear fuel, net of amortization	48,062	47,389

6. Regulatory Matters

ELECTRIC INDUSTRY RESTRUCTURING

STATE

1999 SETTLEMENT AGREEMENT. On May 14, 1999, APS entered into a comprehensive Settlement Agreement with various parties, including representatives of major consumer groups, related to the implementation of retail electric competition. On September 23, 1999, the ACC voted to approve the 1999 Settlement Agreement, with some modifications. On December 13, 1999, two parties filed lawsuits challenging the ACC's approval of the 1999 Settlement Agreement. Each party bringing the lawsuits appealed the ACC's order approving the 1999 Settlement Agreement directly to the Arizona Court of Appeals, as provided by Arizona law. In one of the appeals, on December 26, 2000, the Arizona Court of Appeals affirmed the ACC's approval of the 1999 Settlement Agreement. This decision was not appealed and has become final. In the other appeal, on April 5, 2001, the Arizona Court of Appeals again affirmed the ACC's approval of the 1999 Settlement Agreement. The Arizona Consumers Council, which filed that appeal, has petitioned the Arizona Supreme Court for review of the Court of Appeals' decision.

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 the July 1, 1999 retail price decrease of approximately $11 million ($7 million after income taxes) related to the 1996 regulatory agreement. See "1996 Regulatory Agreement" below. Based on the price reduction authorized in the 1999 Settlement Agreement, there were retail price decreases of approximately $28 million ($17 million after taxes), or 1.5%, effective July 1, 2000, and approximately $27 million ($16 million after taxes), or 1.5%, effective July 1, 2001. For customers having loads three MW or greater, standard offer rates will be 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, or material changes in APS' cost of service for ACC-regulated services resulting from federal, tribal, state or local laws, regulatory requirements, judicial decisions, actions or orders.

* APS will be permitted to defer for later recovery prudent and reasonable costs of complying with the ACC electric competition 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 electric competition 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 the 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 generating assets and competitive services at book value as of the date of transfer, and will complete the transfer no later than December 31, 2002. Accordingly, APS plans to complete the move of such assets and services from APS to the parent company or to Pinnacle West Energy by the end of 2002, as required. 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.

* When the 1999 Settlement Agreement approved by the ACC is no longer subject to judicial review, APS will move to dismiss all of its litigation pending against the ACC as of the date APS entered into the 1999 Settlement Agreement. To protect its rights, APS has several lawsuits pending on ACC orders relating to stranded cost recovery and the adoption and amendment of the ACC's electric competition rules, which would be voluntarily dismissed at the appropriate time under this provision.

As discussed in Note 5 above, we have discontinued the application of SFAS No. 71 for our generation operations.

Although the Rules allow retail customers to have access to competitive providers of energy and energy services (see "Retail Electric Competition Rules" below), APS is the "provider of last resort" for standard offer customers under rates that have been approved by the ACC. Energy prices in the western wholesale market vary and, during the course of the last year, have been volatile. At various times, prices in the spot wholesale market have significantly exceeded the amount included in APS' current retail rates. APS expects similar market conditions to continue through 2001 and 2002. We believe that through a combination of hedging and our current generation portfolio, we will be able to adequately manage our exposure to the volatility of the power market. However, in the event of shortfalls due to unforeseen increases in load demand or generation outages, APS may need to purchase additional supplemental power in the wholesale spot market. Unless APS is able to obtain an adjustment of its rates under the 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.

RETAIL ELECTRIC COMPETITION RULES. On September 21, 1999, the ACC voted to approve rules that provide a framework for the introduction of retail electric competition in Arizona. 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 December 8, 1999, APS filed a lawsuit to protect its legal rights regarding the Rules. This lawsuit is pending, along with several other lawsuits on ACC orders relating to stranded cost recovery (including those described above involving APS), the adoption or amendment of the Rules, and the certification of competitive electric service providers.

On November 27, 2000, a Maricopa County, Arizona, Superior Court judge issued a final judgment holding that the Rules are unconstitutional and unlawful in their entirety due to failure to establish a fair value rate base for competitive electric service providers and because certain of the Rules were not submitted to the Arizona Attorney General for certification. The judgment also invalidates all ACC orders authorizing competitive electric service providers, including APS Energy Services, 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 case has been appealed to the Arizona Supreme Court, where a decision is pending.

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 non-competitive 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 generation assets and services either to an unaffiliated party or to a separate corporate affiliate. Under the 1999 Settlement Agreement, APS received a waiver to allow transfer of its generation and other competitive assets and services to affiliates no later than December 31, 2002. APS plans to complete the move of such assets by the end of 2002, as required.

1996 REGULATORY AGREEMENT. In April 1996, the ACC approved a regulatory agreement between the ACC Staff and APS. Based on the price reduction formula authorized in the agreement, the ACC approved retail price decreases (approximate) as follows (dollars in millions):

Annual Electric Revenue Decrease	Percentage Decrease	Effective Date
$49	3.4%	July 1, 1996
$18	1.2%	July 1, 1997
$17	1.1%	July 1, 1998
$11	0.7%	July 1, 1999 (a)

(a) Included in the first rate reduction under the 1999 Settlement Agreement (see above).

The regulatory agreement also required that we infuse $200 million of common equity into APS in annual payments of $50 million from 1996 through 1999. All of these equity infusions were made by December 31, 1999.

LEGISLATION. In May 1998, a law was enacted to facilitate implementation of retail electric competition in Arizona. The law includes the following major provisions:

* Arizona's largest government-operated electric utility (Salt River Project) and, at their option, smaller municipal electric systems must (i) make at least 20% of their 1995 retail peak demand available to electric service providers by December 31, 1998 and for all retail customers by December 31, 2000; (ii) decrease rates by at least 10% over a ten-year period beginning as early as January 1, 1991; (iii) implement procedures and public processes comparable to those already applicable to public service corporations for establishing the terms, conditions, and pricing of electric services as well as certain other decisions affecting retail electric competition;

* describes the factors which form the basis of consideration by Salt River Project in determining stranded costs; and

* metering and meter reading services must be provided on a competitive basis during the first two years of competition only for customers having demands in excess of one MW (and that are eligible for competitive generation services), and thereafter for all customers receiving competitive electric generation.

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.

FEDERAL

The 1992 Energy Act and recent rulemakings by FERC have promoted increased competition in the wholesale energy markets. We do not expect these rules to have a material impact on our financial statements.

Several electric utility industry restructuring bills will undoubtedly be introduced during the current congressional session. Several bills have been written to allow consumers to choose their electricity suppliers beginning in 2001 and beyond. These bills and other bills that are expected to be introduced, and ongoing discussions at the federal level suggest a wide range of opinion that will need to be narrowed before any comprehensive restructuring of the electric utility industry can occur.

In June 2001 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 remains in effect until September 30, 2002. The Company cannot accurately predict the overall financial impact of the plan on the various aspects of its business, including its wholesale and purchased power activities.

7. Nuclear Insurance

The Palo Verde participants have insurance for public liability payments 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' 29.1% interest in the three Palo Verde units, APS' maximum potential assessment per incident 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 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.

8. Business Segments

We have two principal business segments (determined by products, services and regulatory environment),which consist of the transmission and distribution of electricity activities (delivery business segment) and the generation of electricity and wholesale activities (generation business segment).

These reportable segments reflect a change in the reporting of our functional activities. Before January 1, 2001, our reported segment information combined transmission and distribution of electricity activities with wholesale activities. Our current operational activities are more closely based on the strong integration of our wholesale activities and our generation of electricity activities, and have been combined for segment reporting purposes. The corresponding information for earlier periods has been restated.

The periods ended September 30, 2000 and December 31, 2000 have not yet been reported on a restated basis. When earnings are restated, the following amounts for the periods ended September 30, 2000 will be moved to the generation business segment from the delivery business segment: $29 million for the three months; $53 million for the nine months; and $54 million for the twelve months. The restatement for the twelve month period ended December 31, 2000 will result in $61 million in earnings being moved to the generation business segment from the delivery business segment.

Beginning in 2001, we changed our method of allocating revenues between the delivery business segment and the generation business segment to reflect the seasonal impact of market prices. This change had the impact of increasing delivery segment income and decreasing generation segment income in all the periods presented when compared to the prior comparable periods. The after-tax change is $35 million in the three-month ended period and $43 million in the six and twelve-month ended periods.

The other amounts include activity relating to the parent company and other subsidiaries, including APS Energy Services, SunCor and El Dorado. Eliminations primarily relate to intersegment sales of electricity. Segment information for the three, six and twelve months ended June 30, 2001 and 2000 is as follows (dollars in millions):

	3 Months Ended June 30,		6 Months Ended June 30,		12 Months Ended June 30,	
	2001	2000	2001	2000	2001	2000
Operating Revenues:						
Delivery	$ 557	$ 508	$ 965	$ 880	$ 2,055	$ 1,875
Generation	964	446	1,658	692	3,452	1,510
Other	32	37	70	79	149	152
Eliminations	(259)	(234)	(460)	(406)	(978)	(852)
Total	$ 1,294	$ 757	$ 2,233	$ 1,245	$ 4,678	$ 2,685
Income from Continuing Operations:						
Delivery	$ 65	$ 32	$ 89	$ 56	$ 138	$ 145
Generation	5	64	48	73	173	149
Other	(3)	(6)	(8)	15	(24)	20
Total	$ 67	$ 90	$ 129	$ 144	$ 287	$ 314

	As of June 30, 2001	As of December 31, 2000
Assets:		
Delivery	$3,934	$3,987
Generation	3,110	2,687
Other	503	475
Total	$7,547	$7,149

9. Accounting Matters

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 sheet and measure those instruments at fair value. Changes in the fair value of derivative financial instruments are either recognized periodically in income or shareholder's equity (as a component of other comprehensive income), depending on whether or not the derivative meets specific hedge accounting criteria. Hedge effectiveness is measured based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in the fair value resulting from ineffectiveness is recognized immediately in net income. This new standard may result in additional volatility in our net income and comprehensive income.

In June 2001, the FASB determined that electricity contracts, including those with option characteristics and those subject to "bookout," would qualify for the normal purchases and sales exception if certain criteria were met. Prior to the issuance of the guidance, we accounted for electricity contracts with characteristics of options and those subject to "bookout" as normal purchases and sales. As a result, we did not mark these contracts to their fair market values each reporting period. The effective date of this new guidance is July 1, 2001.

We estimate the impacts of the new guidance are a $12 million after-tax loss in net income and an $8 million after-tax gain in equity (as a component of other comprehensive income). These adjustments resulted from option contracts that did not meet the new criteria for the normal purchases and sales exception. The impact of the new guidance will be reflected as a cumulative effect of a change in accounting principle in the third quarter of 2001. See Note 10 for discussion on the impact of SFAS No. 133.

In July 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets." This Statement addresses financial accounting and reporting for acquired goodwill and other intangible assets and supersedes APB Opinion No. 17, "Intangible Assets." We are currently evaluating the new standard and do not expect it to have a material impact on our financial statements.

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/credits. The changes in market value of such contracts have a high correlation to price changes in the hedged commodity. In addition, subject to specified risk parameters established by the Board of Directors and monitored by the ERMC, we engage in trading activities intended to profit from market price movements.

As a result of adopting SFAS No. 133, we recognized $118 million of derivative assets and $16 million of derivative liabilities in our balance sheet as of January 1, 2001. Also as of January 1, 2001, we recorded a $3 million after-tax loss, or $0.03 per basic or diluted share, in net income as a cumulative effect of a change in accounting principle and a $65 million after-tax gain in equity (as a component of other comprehensive income). The gain resulted from unrealized gains on cash flow hedges. See Note 9 for discussion on SFAS No. 133.

The change in derivative fair value in the consolidated statements of income for the three, six and twelve months ending June 30, 2001 and 2000 is comprised of the following (dollars in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,		Twelve Months Ended June 30,	
	2001	2000	2001	2000	2001	2000
Ineffective portion of derivatives qualifying for hedge accounting (a)	$(1,941)	$ --	$ (312)	$ --	$ (312)	$ --
Discontinuance of cash flow hedges for forecasted transactions that will not occur	(7,718)	--	(7,718)	--	(7,718)	--
TOTAL	$(9,659)	$ --	$(8,030)	$ --	$(8,030)	$ --

(a) Time value component of options excluded from assessment of hedge effectiveness.

As of June 30, 2001, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted transactions is forty-two months. During the twelve months ending June 30, 2002, we estimate that a net loss of $7 million before income taxes will be reclassified from accumulated other comprehensive income as an offset to the effect on earnings of market price changes for the related hedged transaction.

Net gains and losses on derivatives utilized for trading activities are recognized in power marketing revenues on a current basis (the mark to market method). Trading positions are measured at fair value as of the balance sheet date. The net gains recognized in power marketing revenues were the following for the three, six and twelve months ended June 30, 2001 and 2000 (dollars in millions):

	Three Months Ended June 30,		Six Months Ended June 30,		Twelve Months Ended June 30,	
	2001	2000	2001	2000	2001	2000
Mark to market gains	$ 42	$ 22	$ 95	$ 27	$ 76	$ 28
Realized gains	3	14	10	14	45	19
Total trading gains	$ 45	$ 36	$105	$ 41	$121	$ 47

11. Comprehensive Income

Components of comprehensive income for the three-month, six-month and twelve-month periods ended June 30, 2001 and 2000, are as follows (dollars in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,		Twelve Months Ended June 30,	
	2001	2000	2001	2000	2001	2000
Net Income	$ 66,857	$ 89,901	$ 126,307	$ 143,971	$ 284,668	$ 212,466
Other comprehensive income/(loss), net of tax:						
Cumulative effect of change in accounting for derivatives	--	--	64,700	--	64,700	--
Unrealized holding losses arising during period	(87,475)	--	(97,928)	--	(97,928)	--
Reclassification adjustment for derivatives	(1,862)	--	(18,684)	--	(18,684)	--
Total other comprehensive loss	(89,337)	--	(51,912)	--	(51,912)	--
Comprehensive Income/(Loss)	$ (22,480)	$ 89,901	$ 74,395	$ 143,971	$ 232,756	$ 212,466

12. Generation Expansion

PINNACLE WEST ENERGY

Pinnacle West Energy has announced plans to build about 2,840 MW of generating capacity from 2001-2006 at an estimated cost of about $1.6 billion.

Site	MW
West Phoenix 4 - In Service	120
West Phoenix 5	530
Redhawk 1	530
Redhawk 2	530
Redhawk 3	530
Redhawk 4	530
Southern Arizona	70
TOTAL	2,840

Pinnacle West Energy is also considering additional expansion, which may result in additional expenditures. Pinnacle West Energy is currently funding its capital requirements through capital infusions from the parent company, 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.

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

* A 650 MW expansion of the West Phoenix Power Plant. 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 electrical generating station near Palo Verde, called Redhawk. Redhawk Units 1 and 2 will be natural gas fired combined cycle units. Construction began in December 2000, and commercial operation is currently scheduled for the summer of 2002. Pinnacle West Energy is evaluating initially constructing Redhawk Units 3 and 4 as simple cycle units, to be converted to combined cycle units at a later date.

* Pinnacle West Energy is also planning the construction of a 70 MW natural gas fired simple cycle power plant in southern Arizona. Construction is expected to begin in the fall of 2001, with an expected commercial operation date of mid-2002.

Pinnacle West Energy entered into an agreement with NPC to purchase NPC's 72 MW gas-fired Harry Allen Power Station about 30 miles northeast of Las Vegas, Nevada, for a net purchase price, after adjustments for purchased power commitments, of approximately $65.2 million. However, recently-enacted Nevada legislation provides that "[b]efore July 1, 2003, an electric utility shall not dispose of a generation asset." Although the NPC purchase agreement remains in effect, unless this Nevada law is amended, Pinnacle West Energy would not be able to acquire the Harry Allen Power Station under the NPC purchase agreement. Pinnacle West Energy continues to pursue opportunities to construct a 570 MW combined cycle plant in southern Nevada, with a potential commercial operation date in early 2004. The plans and permits for this plant are expected to be finalized by year end 2001.

Pinnacle West Energy 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. Results are expected by late 2001.

13. Income Tax Benefit

In September 1999, we recorded a tax benefit of $38 million, or $0.45 per basic or diluted share, which stemmed from the resolution of income tax matters related to a former subsidiary, MeraBank, A Federal Savings Bank. This amount is reflected as a tax benefit from discontinued operations in the income statement.

14. El Dorado Partnership Investment Income

Net other income consists primarily of El Dorado's share in the earnings of a venture capital partnership. We record our share of the earnings from the partnership as the partnership adjusts the value of its investment. In 2001, El Dorado received a distribution of securities representing substantially all of El Dorado's investment in the partnership. The securities were sold in the first quarter of 2001 and a gain was recognized in other income.

15. California Energy Market Issues and Refunds in the Pacific Northwest

We are closely monitoring developments in the California energy market and the potential impact of these developments on us and our subsidiaries. We have evaluated, among other things, SCE's role as a Palo Verde and Four Corners participant; APS' transactions with the PX and the ISO; contractual relationships with SCE and PG&E; APS Energy Services' retail transactions involving SCE and PG&E; and power marketing exposures. Based on our current evaluations, we have reserved $10 million before income taxes for our credit exposure related to the California energy situation. We cannot predict with certainty, however, the impact that any future resolution, or attempted resolution, of the California energy market situation may have on us or our subsidiaries or the regional energy market in general.

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 FERC after the California ISO provides necessary historical data. FERC also ordered an evidentiary proceeding to discuss and evaluate possible refunds for the Pacific Northwest. Although FERC has not yet calculated the refund amounts, we do not expect that the resolution of this issue will have a material adverse impact on our financial position, results of operations or liquidity.

16. Legal Proceedings

SunCor is a party to a lawsuit pending in Maricopa County Superior Court entitled SUNCOR DEVELOPMENT COMPANY V. BERGSTROM CORPORATION, CV 98-11472. On March 15, 2001, a jury returned a verdict against SunCor in the amount of $28.6 million, $25.7 million of which represents a punitive damage award. The verdict was based on the Bergstrom Corporation's claims that it was defrauded in connection with the acquisition of approximately ten acres of land in a SunCor commercial development and a subsequent settlement agreement relating to those claims. SunCor believes that the verdict is neither supported by the evidence or the law and has filed post-trial motions to that effect and, if necessary, will appeal. We do not expect this litigation to have a material adverse impact on our financial position, results of operations or liquidity.

17. Power Service Agreement

By letter dated March 7, 2001, Citizens Communications Company 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. 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.

18. 2001 Generation Summer Reliability Program

We recently added over 500 MW of generating capability to enhance reliability for the summer of 2001 in light of market conditions in the western United States. The additional capacity included the 120 MW West Phoenix Unit 4 (see Note 12) and approximately 200 MW of gas-fired portable generators leased for the summer of 2001 by Pinnacle West Energy. Additionally, APS restored approximately 100 MW of previously mothballed gas-fired steam units at the West Phoenix Power Plant and refurbished the entire fossil plant fleet during the spring of 2001 (which resulted in additional capability of approximately 110 MW).

SUPPLEMENTAL ITEM. SELECTED CONSOLIDATED DATA

	Three Months Ended June 30, 2001	Three Months Ended June 30, 2000	Six Months Ended June 30, 2001	Six Months Ended June 30, 2000	Twelve Months Ended June 30, 2001	Twelve Months Ended June 30, 2000
ELECTRIC OPERATING REVENUES (dollars in millions)						
Retail						
Residential	$ 234	$ 228	$ 407	$ 385	$ 903	$ 843
Business	258	253	457	449	943	934
Total retail	492	481	864	834	1,846	1,777
Sales for resale	732	178	1,210	252	2,552	639
Transmission for others	5	4	10	7	17	13
Miscellaneous services	32	57	84	73	118	105
Net electric operating revenues	$ 1,261	$ 720	$ 2,168	$ 1,166	$ 4,533	$ 2,534
ELECTRIC SALES (GWh)						
Retail						
Residential	2,467	2,370	4,589	4,247	10,122	9,287
Business	3,446	3,377	6,269	6,114	12,909	12,510
Total retail	5,913	5,747	10,858	10,361	23,031	21,797
Sales for resale	4,979	3,769	9,401	6,702	24,674	16,555
Total sales	10,892	9,516	20,259	17,063	47,705	38,352
ELECTRIC CUSTOMERS (end of period)						
Retail						
Residential	764,741	736,039				
Business	95,998	92,469				
Total retail	860,739	828,508				
Sales for resale	66	67				
Total electric customers	860,805	828,575				
POWER PLANT PERFORMANCE (capacity factors)						
Nuclear	83.6%	88.0%	90.0%	93.0%	91.1%	93.1%
Coal	86.8%	84.6%	82.7%	80.1%	84.5%	82.6%
Total baseload (nuclear and coal)	84.9%	86.6%	86.9%	87.6%	88.3%	88.7%
Gas and Oil	46.1%	20.0%	42.7%	16.1%	39.7%	17.9%
BOOK VALUE PER SHARE (end of period)	$ 28.17	$ 27.00				

PINNACLE WEST CAPITAL CORPORATION

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-month, six-month and twelve-month periods ended June 30, 2001 and 2000;

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

* our capital needs and resources;

* major factors that affect our financial outlook; and

* our management of market risks.

We suggest this section be read along with the 2000 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.

OVERVIEW OF OUR BUSINESS

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

Our other major subsidiaries are wholly-owned and are:

* Pinnacle West Energy, through which we intend to conduct our unregulated generation operations;

* APS Energy Services, which sells energy and energy-related products and services in competitive retail markets in the western United States;

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

* El Dorado, which is an investment firm.

We have two principal business segments, determined by products, services, and regulatory environment:

* The electricity delivery business segment, which consists of the transmission and distribution of electricity activities; and

* The generation business segment, which consists of our generation and wholesale activities.

See "Business Segments" in Note 8 for more information about our business segments.

In general, we have structured our discussion below based on existing legal entities. The "Operating Results," for example, primarily reflect the results of APS' operations because APS currently owns the substantial portion of our assets and produces substantially all of our profits.

Operating Results

The following table summarizes net income for the three, six and twelve months ended June 30, 2001 and the comparable prior year periods for Pinnacle West and each of its subsidiaries (dollars in millions):

	3 Months Ended June 30,		6 Months Ended June 30,		12 Months Ended June 30,	
	2001	2000	2001	2000	2001	2000
APS	$ 70	$ 96	$ 134	$ 129	$ 312	$ 294
Pinnacle West Energy	1	(1)	1	(1)	--	(1)
APS Energy Services	--	(2)	(7)	(4)	(17)	(10)
SunCor	--	1	--	6	6	8
El Dorado	--	(3)	--	16	(14)	27
Parent Company	(4)	(1)	1	(2)	1	(4)
Income from continuing operations	67	90	129	144	288	314
Income tax benefit from discontinued operations	--	--	--	--	--	38
Extraordinary charge - net of income taxes of $94	--	--	--	--	--	(140)
Cumulative effect of a change in accounting - net of income taxes of $2	--	--	(3)	--	(3)	--
Net income	$ 67	$ 90	$ 126	$ 144	$ 285	$ 212

OPERATING RESULTS - THREE-MONTH PERIOD ENDED JUNE 30, 2001 COMPARED WITH THREE-MONTH PERIOD ENDED JUNE 30, 2000

Our consolidated net income for the three months ended June 30, 2001 was $67 million compared with $90 million for the same period in the prior year. The decrease in net income of $23 million, or 26%, is primarily because of increases in purchased power and fuel costs, higher operations and maintenance expenses, reductions in retail electricity prices and miscellaneous factors. The positive factors partially offsetting these decreases were an increase in the contribution of wholesale power marketing activities, increases in other income and decreases in interest expense. See Note 6 for information on the price reductions.

Electric operating revenues increased approximately $541 million primarily because of:

* increased power marketing revenues related to trading and other wholesale activities ($422 million);
* increased wholesale revenues primarily related to higher prices for surplus generation sales ($107 million);
* higher retail sales volumes primarily related to weather impacts and customer growth, partially offset by lower average usage per customer ($13 million); and
* other miscellaneous factors ($6 million).

As mentioned above, these positive factors were partially offset by reductions in retail electricity prices ($7 million).

Purchased power and fuel expenses increased approximately $570 million primarily because of:

* increased power marketing costs related to trading and other wholesale activities ($413 million);
* increased costs related to wholesale sales of surplus generation ($71 million);
* increased costs related to higher retail sales volumes primarily related to higher purchased power and fuel prices and weather impacts ($33 million);
* higher replacement power costs primarily for increased plant outages ($31 million);
* replacement power costs related to the Palo Verde outage extension to replace fuel control element assemblies ($12 million); and
* a SFAS No. 133 adjustment related to changes in natural gas market prices ($10 million).

See Notes 9 and 10 for additional information on SFAS No. 133 and trading activities.

The increase in operations and maintenance expenses primarily related to the generation summer reliability program and increased power plant maintenance ($17 million) and increased pension and other costs ($8 million). See Note 18 for additional information on the generation summer reliability program.

Net other income increased $10 million primarily because of insurance recovery of environmental remediation costs.

Interest expense decreased by $6 million primarily because of increased capitalized interest resulting from our generation expansion plan. See Note 12 for information on the generation expansion plan.

OPERATING RESULTS - SIX-MONTH PERIOD ENDED JUNE 30, 2001 COMPARED WITH SIX-MONTH PERIOD ENDED JUNE 30, 2000

Our consolidated net income for the six months ended June 30, 2001 was $126 million compared with $144 million for the same period in the prior year. In January 2001, we recognized a $3 million after-tax loss in net income as a cumulative effect of a change in accounting for derivatives. See Notes 9 and 10 for further discussion.

Income from continuing operations decreased $15 million, or 10% less than the comparable period in 2000, primarily because of increases in purchased power and fuel costs, higher operations and maintenance expenses, lower earnings from El Dorado, reductions in retail electricity prices and miscellaneous factors. The positive factors partially offsetting these decreases were an increase in the contribution of wholesale power marketing activities and a decrease in interest expense. See Note 6 for information on the price reductions.

Electric operating revenues increased approximately $1.0 billion primarily because of:

* increased power marketing revenues related to trading and other wholesale activities ($744 million);
* increased wholesale revenues primarily related to higher prices for surplus generation sales ($225 million);
* higher retail sales volumes primarily related to weather impacts and customer growth, partially offset by lower average usage per customer ($36 million); and
* other miscellaneous factors ($9 million).

As mentioned above, these positive factors were partially offset by reductions in retail electricity prices ($13 million).

Purchased power and fuel expenses increased approximately $961 million primarily because of:

* increased power marketing costs related to trading and other wholesale activities ($680 million);
* increased costs related to wholesale sales of surplus generation ($145 million);
* higher replacement power costs primarily for increased plant outages ($67 million);
* increased costs related to higher retail sales volumes primarily attributable to higher purchased power and fuel prices and weather impacts ($49 million);
* replacement power costs related to the Palo Verde outage extension to replace fuel control element assemblies ($12 million); and
* SFAS No. 133 adjustments related to changes in natural gas market prices ($8 million).

See Notes 9 and 10 for additional information on SFAS No. 133 and trading activities.

The increase in operations and maintenance expenses primarily related to the generation summer reliability program and increased power plant maintenance ($27 million), increased pension and other costs ($8 million) and a provision for credit exposure related to the California energy situation ($5 million). See Note 18 for additional information on the generation summer reliability program.

Net other income decreased by $26 million primarily because of a change in the market value of El Dorado's investment in a technology-related venture capital partnership (see Note 14) and other non-operating costs, partially offset by an insurance recovery of environmental remediation costs.

Interest expense decreased by $9 million primarily because of increased capitalized interest resulting from our generation expansion plan. See Note 12 for additional information on the generation expansion plan.

OPERATING RESULTS - TWELVE-MONTH PERIOD ENDED JUNE 30, 2001 COMPARED WITH TWELVE-MONTH PERIOD ENDED JUNE 30, 2000

Consolidated net income for the twelve months ended June 30, 2001 was $285 million compared with $212 million for the same period in the prior year. The increase primarily relates to a $140 million after-tax extraordinary charge recorded in the third quarter of 1999, partially offset by a $38 million income tax benefit from discontinued operations (also recorded in the third quarter of 1999) and a $3 million after-tax loss for a cumulative effect of a change in accounting for derivatives recorded in 2001.

The extraordinary charge related to a regulatory disallowance that resulted from APS' 1999 Settlement Agreement that was approved by the ACC. See Notes 5 and 6 for additional information about the regulatory disallowance and the 1999 Settlement Agreement.

The income tax benefit from discontinued operations resulted from the resolution of income tax matters related to a former subsidiary, MeraBank. See Note 13.

The cumulative effect of a change in accounting for derivatives resulted from the implementation of SFAS No. 133. See Notes 9 and 10.

Income from continuing operations for the twelve months ended June 30, 2001 decreased $27 million, or 9% less than the comparable prior-year period, primarily because of higher purchased power and fuel costs, decreased earnings from El Dorado, the completion of the amortization of ITCs in 1999, higher operations and maintenance expenses, reductions in retail electricity prices and miscellaneous factors. The positive factors partially offsetting these decreases were an increase in the contribution of wholesale power marketing activities and weather impacts. See Note 6 for information on the price reductions. See "Income Taxes" below for a discussion of the ITC amortization.

Electric operating revenues increased approximately $2.0 billion because of:

* increased power marketing revenues related to trading and other wholesale activities ($1.69 billion);
* increased wholesale revenues primarily related to higher prices for surplus generation sales ($235 million);
* increases in the number of customers and the average amount of electricity used by customers ($51 million); and
* weather impacts on retail revenues ($48 million).

These positive factors were partially offset by reductions in retail electricity prices ($28 million).

Purchased power and fuel expenses increased approximately $1.92 billion primarily because of:

* increased power marketing costs related to trading and other wholesale activities ($1.63 billion);
* increased costs related to wholesale sales of surplus generation ($102 million);
* higher replacement power costs primarily for increased plant outages ($106 million);
* higher costs related to retail sales volumes and to purchased power and fuel prices ($45 million);
* replacement power costs related to the Palo Verde outage extension to replace fuel control element assemblies ($12 million);
* weather impacts on purchased power and fuel ($12 million); and
* SFAS No. 133 adjustments related to changes in natural gas market prices ($8 million).

See Notes 9 and 10 for additional information on SFAS No. 133 and trading activities.

The increase in operations and maintenance expenses primarily related to generation summer reliability programs and increased power plant maintenance ($35 million), increased pension and other costs ($11 million), and provisions for credit exposure related to the California energy situation ($10 million), partially offset by approximately $15 million of non-recurring items recorded in 1999. See "Business Outlook - California Energy Market Issues and Refunds in the Pacific Northwest" below. See Note 18 for additional information on the generation summer reliability program.

Net other income decreased $67 million primarily because of a change in the market value of El Dorado's investment in a technology-related venture capital partnership (see Note 14) and other non-operating costs offset by an insurance recovery of environmental remediation costs.

Interest expense decreased by $12 million primarily because of increased capitalized interest resulting from our generation expansion plan. See Note 12 for additional information on the generation expansion plan.

INCOME TAXES

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

SFAS NO. 133

The FASB has issued new guidance regarding the accounting treatment of derivatives effective July 1, 2001. We estimate the impacts of the new guidance are a $12 million after-tax loss in net income and an $8 million after-tax gain in equity (as a component of other comprehensive income). These adjustments resulted from option contracts that did not meet the new criteria for the normal purchases and sales exception. The impact of the new guidance will be reflected as a cumulative effect of a change in accounting principle in the third quarter of 2001. See Notes 9 and 10 for additional discussion of SFAS No. 133.

LIQUIDITY AND CAPITAL RESOURCES

CAPITAL EXPENDITURE REQUIREMENTS

The following table summarizes the actual capital expenditures for the six-months ended June 30, 2001 and estimated capital expenditures for the next three years:

CAPITAL EXPENDITURES
(dollars in millions)

	(actual)	(estimated)		
	Six-months ended June 30, 2001	Years ending December 31, 2001	2002	2003
APS				
Delivery	$ 169	$ 340	$ 354	$ 321
Existing generation (a)	62	121	156	--
	231	461	510	321
Pinnacle West Energy (b)				
Generation expansion	199	531	226	168
Existing generation (a)	--	--	--	122
	199	531	226	290
SunCor (c)	61	84	66	27
Other (d)	--	24	16	8
Total	$ 491	$1,100	$ 818	$ 646

(a) Pursuant to the 1999 Settlement Agreement, APS is required to move its generating assets and competitive services no later than December 31, 2002.
(b) See Note 12 and "Capital Resources and Cash Requirements - Pinnacle West Energy" below.
(c) Consists primarily of capital expenditures for land development and retail and office building construction.
(d) Primarily APS Energy Services.

CAPITAL RESOURCES AND DEBT FINANCING

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 2000 10-K.

During the six-months ended June 30, 2001, the parent company increased its outstanding indebtedness by about $265 million. During the six-month period ended June 30, 2001, the parent company issued $300 million in long-term debt and $237 million in short-term borrowings and repaid $272 million of long- and short-term debt. The majority of these borrowings were used to fund Pinnacle West Energy capital expenditures. On August 2, 2001, the parent company issued $250 million of its Floating Rate Notes due August 1, 2003, a substantial portion of the proceeds of which was used to repay short-term debt incurred for capital contributions to Pinnacle West Energy.

APS

APS' long-term debt redemption requirements, including optional repayments on long-term debt are: $383 million in 2001; $125 million in 2002; and zero in 2003. During 2001, APS expects to satisfy its long-term debt redemption requirements with cash from operations and long and short-term borrowings. Through June 2001, APS redeemed $58 million of its long-term debt. 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

See Note 12 of Notes to Condensed Consolidated Financial Statements for a discussion of construction and financing programs relating to Pinnacle West Energy.

OTHER SUBSIDIARIES

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

SunCor's capital needs consist primarily of capital expenditures for land development and retail and office building construction. See the Capital Expenditures table above for actual capital expenditures for the six-months ended June 30, 2001 and projected capital expenditures through 2003. SunCor expects to fund its capital requirements from internally generated cash and its own external financings.

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

BUSINESS OUTLOOK

This section describes several major factors affecting our financial outlook.

COMPETITION AND ELECTRIC INDUSTRY RESTRUCTURING

See "Business Outlook - Competition and Industry Restructuring" in Item 7 of the 2000 10-K and Note 6 above for a discussion of developments affecting retail and wholesale electric competition. See Note 5 for a discussion of regulatory accounting.

GENERATION EXPANSION

See Note 12 for information regarding our generation expansion plans. The planned additional generation is expected to increase revenues, fuel expenses, operating expenses, and financing costs.

CALIFORNIA ENERGY MARKET ISSUES AND REFUNDS IN THE PACIFIC NORTHWEST

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 ISO. In April 2001, PG&E filed for bankruptcy protection. See Note 15 for additional information.

FACTORS AFFECTING OPERATING REVENUES

Electric operating revenues are derived from sales of electricity in regulated retail markets in Arizona and in competitive retail and wholesale bulk power markets in the western United States.

These revenues are expected to be affected by electricity sales volumes related to customer mix, customer growth and average usage per customer, as well as electricity prices and variations in weather from period to period.

In APS' regulated retail market area, APS will provide electricity services to standard-offer, full-service customers and to energy delivery customers who have chosen another provider for their electricity commodity needs (unbundled customers). Customer growth in APS' service territory averaged 3.8% a year for the three years 1998 through 2000; we currently expect customer growth to average 3.5% to 4% a year for 2001 through 2003. We currently estimate that retail electricity sales in kilowatt-hours will grow 3.5% to 4.5% a year in 2001 through 2003, before the retail effects of weather variations. The customer growth and sales growth referred to in this paragraph apply to energy delivery customers. As industry restructuring evolves in the regulated market area, we cannot predict the number of APS' standard offer customers that will switch to unbundled service.

Wholesale activities will be affected by electricity prices and costs of available fuel and purchased power in the western United States, as well as competitive market conditions and regulatory and legislative changes in various state and federal jurisdictions, including the price mitigation plan adopted by FERC in June 2001 (see Note 6). These factors have significantly affected our trading and wholesale power activities and their resultant earnings contributions over the last several years. We cannot predict future contributions from trading and wholesale activities. See Item 3 below for additional information.

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

OTHER FACTORS AFFECTING FUTURE FINANCIAL RESULTS

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, and our hedging program for managing such costs. See "Natural Gas Supply" in Part II for additional information on gas transportation costs.

Operations and maintenance expenses are expected to be affected by sales mix and volumes, power plant operations, inflation, and other factors.

Depreciation and amortization expenses are expected to be affected by net additions to existing utility plant and other property, changes in regulatory asset amortization, and our generation expansion program. See Note 5 for the regulatory asset amortization that is being recorded in 1999 through 2004 pursuant to the 1999 Settlement Agreement.

Taxes other than income taxes consist primarily of property taxes, which are affected by tax rates and the value of property in service and under construction. We expect property taxes to increase primarily due to our generation expansion program and our additions to existing facilities.

Interest expense is affected by the amount of debt outstanding and the interest rates on that debt. The primary factors affecting borrowing levels in the next several years are expected to be our generation expansion program and our internally generated cash flow.

The annual earnings contribution from our real estate subsidiary, SunCor, is expected to remain modest over the next several years.

El Dorado's historical results are not necessarily indicative of future performance for El Dorado. See Note 14 for additional information regarding El Dorado. El Dorado's strategies focus on realization of the value of its existing investments. Any future investments are expected to be related to the energy business.

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 Notes 9 and 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 6 for a discussion of a price reduction effective as of July 1, 2001, 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

This document contains forward-looking statements based on current expectations and we assume no obligation to update these statements. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from results or outcomes currently expected or sought by us. These factors include the ongoing restructuring of the electric industry; the outcome of regulatory and legislative proceedings relating to the restructuring; state and federal regulatory and legislative decisions and actions, including the price mitigation plan adopted by FERC in June 2001; regional economic and market conditions, including the California energy situation, which could affect customer growth and the cost of power supplies; the cost of debt and equity capital; weather variations affecting local and regional customer energy usage; conservation programs; power plant performance; the successful completion of our generation expansion program; regulatory issues associated with generation expansion, such as permitting and licensing; our ability to compete successfully outside traditional regulated markets (including the wholesale market); technological developments in the electric industry; and the 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 commodity prices, interest rates, 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 our 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 these derivative transactions to ensure that we have enough energy for our customers and limit our exposure to volatile wholesale prices for power and fuel. In addition, we engage in trading activities intended to profit from favorable movements of market prices.

As of June 30, 2001, a hypothetical adverse price movement of 10% in the market price of our commodity derivative portfolio would decrease the fair market value of these contracts by approximately $46 million. This analysis does not include the favorable impact this same hypothetical price move would have on the underlying physical exposures being hedged with the commodity derivative portfolio. We plan to complete the move of our wholesale power marketing and trading activities from APS to the parent company by the end of 2002.

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

Changing interest rates will affect interest paid on variable-rate debt and interest earned by our 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 nuclear decommissioning fund also has risks associated with changing market values of equity investments. Nuclear decommissioning costs are recovered in regulated electricity prices.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

As previously reported, in June 1999, the Navajo Nation served Salt River Project with a lawsuit naming Salt River Project, several Peabody Coal Company entities, SCE and other defendants, and citing various claims in connection with the renegotiations of the coal royalty and lease agreements under which Peabody mines coal for Navajo Generating Station and the Mohave Generating Station. THE NAVAJO NATION V. PEABODY HOLDING COMPANY, INC., et al., United States District Court for the District of Columbia, CA-99-0469-EGS. APS is a 14% owner of the Navajo Generating Station, which Salt River Project operates. See "Legal Proceedings" in Item 3 of the 2000 10-K. In July 2001, the court dismissed all claims against Salt River Project.

See Notes 16 and 17 of Notes to Condensed Consolidated Financial Statements for additional matters.

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

At our Annual Meeting of Shareholders held on May 23, 2001, the following persons were elected as directors:

	Votes For	Votes Against	Abstain
CLASS I (TERM TO EXPIRE AT 2004 ANNUAL MEETING)			
Roy A. Herberger, Jr.	76,186,028	886,571	N/A
Humberto S. Lopez	76,133,103	930,477	N/A
Robert G. Matlock	75,851,903	1,217,929	N/A
Kathryn L. Munro	76,165,608	896,016	N/A
CLASS III (TERM TO EXPIRE AT 2003 ANNUAL MEETING)			
Jack E. Davis	76,342,077	735,573	N/A

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 6 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of competition and the rules regarding the introduction of retail electric competition in Arizona and a settlement agreement with the ACC.

WATER SUPPLY

A summons served on APS in early 1986 required all water claimants in the Lower Gila River Watershed in Arizona to assert any claims to water on or before January 20, 1987. See "Water Supply" in Part II, Item 5 of the March 2001 10-Q. APS and other parties petitioned the U.S. Supreme Court for review of the Arizona Supreme Court's decision affirming the lower court's criteria for resolving groundwater claims, and that petition was denied.

TAX WAIVER

The lease for the Four Corners plant site waived, until July 2001, the requirement that the coal supplier and vendors pay certain taxes to the Navajo Nation. The coal supplier currently pays a possessory interest tax (PIT) and business activity tax (BAT) to the Navajo Nation, which is reimbursed by the Four Corners participants, including APS. The PIT is due from the coal supplier, one half on November 1 and one half on May 1 of each year, beginning on November 1, 2001, and the BAT is due from the coal supplier 45 days after the calendar quarter ends, beginning November 15, 2001. APS anticipates that the Navajo Nation will levy additional taxes; however, APS cannot currently predict the outcome of this matter or the amount of any additional taxes. The coal supplier, the Navajo Nation, and the Four Corners participants are continuing to investigate alternative contractual arrangements and business relationships in an effort to permit the electricity generated at Four Corners to be priced competitively.

PURPORTED NAVAJO ENVIRONMENTAL REGULATIONS

As previously reported, on July 12, 2000, the Four Corners participants and the Navajo Generating Station participants each filed a petition with the Navajo Supreme Court for review of the operating permit regulations. See "Purported Navajo Environmental Regulations" in Part I, Item 1 of the 2000 10-K. The Navajo Nation and the Four Corners and Navajo Generating Station participants agreed to indefinitely stay this proceeding so that the parties may attempt to resolve the dispute without litigation. The Court has stayed this proceeding pursuant to a request by the parties. We cannot currently predict the outcome of this matter.

NATURAL GAS SUPPLY

The gas supply for APS and Pinnacle West Energy gas-fired facilities located, and to be located (see Note 12), in Pinal, Maricopa and Yuma Counties in Arizona, is transported pursuant to a firm, Full Requirements Transportation Service Agreement with El Paso Natural Gas Company. The transportation agreement features a 10 year rate moratorium established in a comprehensive rate case settlement entered into in 1996.

In a pending FERC proceeding, El Paso 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. Various parties, including APS and Pinnacle West Energy, have challenged this allocation as being inconsistent with El Paso's existing contractual obligations and the 1996 settlement. At this time, there are ongoing discussions among FERC, El Paso and other affected parties to resolve these issues. We cannot currently predict the outcome of this matter.

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) Exhibits

Exhibit No.	Description
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.1	DATE EFFECTIVE
10.1	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
10.2	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, 2001, and the period from July 1 through August 14, 2001, we filed the following reports on Form 8-K:

Report dated April 5, 2001 regarding the Arizona Court of Appeals affirming the ACC's approval of the 1999 Settlement Agreement and Regulation FD disclosure.

Report dated June 12, 2001 regarding Regulation FD disclosure.

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(1) Reports filed under Files Nos. 1-4473 and 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 14, 2001                  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 12.1

PINNACLE WEST CAPITAL CORPORATION
COMPUTATION OF EARNINGS TO FIXED CHARGES(a)
(THOUSANDS OF DOLLARS)

	Six Months Ended	Twelve Months Ended December 31				
	6/30/01	2000	1999	1998	1997	1996
Earnings:						
Net Income from Continuing Operations	$129,062	$302,332	$269,772	$242,892	$235,856	$211,059
Income Taxes	84,770	194,200	141,592	138,589	126,943	99,224
Fixed Charges	103,834	202,804	194,070	201,184	215,201	230,978
Total	317,666	699,336	605,434	582,665	578,000	541,261
Fixed Charges:						
Interest Expense	86,572	166,447	157,142	163,975	177,383	192,705
Estimated Interest Portion of Annual Rents	17,262	36,357	36,928	37,209	37,818	38,273
Total Fixed Charges	103,834	202,804	194,070	201,184	215,201	230,978
Ratio of Earnings to Fixed Charges (rounded down)	3.05	3.44	3.11	2.89	2.68	2.34
Estimated interest portion of Unit 2 lease payments included in estimated interest portion of annual rentals	$ 16,186	$ 33,411	$ 33,878	$ 34,315	$ 34,720	$ 35,083

(a) We have reclassified certain prior year amounts to conform to the current year presentation.