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FORM 10-Q
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

(Mark One)

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2005

OR

o **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	Exact Name of Each Registrant as specified in its charter; State of Incorporation; Address; and Telephone Number	IRS Employer Identification No.
1-8962	**PINNACLE WEST CAPITAL CORPORATION** (an Arizona corporation) 400 North Fifth Street, P.O. Box 53999 Phoenix, Arizona 85072-3999 (602) 250-1000	86-0512431
1-4473	**ARIZONA PUBLIC SERVICE COMPANY** (an Arizona corporation) 400 North Fifth Street, P.O. Box 53999 Phoenix, Arizona 85072-3999 (602) 250-1000	86-0011170

Indicate by check mark whether each 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 ☑ No o

Indicate by check mark whether each registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2).

PINNACLE WEST CAPITAL CORPORATION	Yes ☑ No o
ARIZONA PUBLIC SERVICE COMPANY	Yes o No ☑

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

PINNACLE WEST CAPITAL CORPORATION	Number of shares of common stock, no par value, outstanding as of May 5, 2005: 98,350,044
ARIZONA PUBLIC SERVICE COMPANY	Number of shares of common stock, $2.50 par value, outstanding as of May 5, 2005: 71,264,947

Arizona Public Service Company meets the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and is therefore filing this form with the reduced disclosure format allowed under that General Instruction.

This combined Form 10-Q is separately filed by Pinnacle West Capital Corporation and Arizona Public Service Company. Each registrant is filing on its own behalf all of the information contained in this Form 10-Q that relates to such registrant. Neither registrant is filing any information that does not relate to such registrant, and therefore makes no representation as to any such information.

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GLOSSARY

ACC — Arizona Corporation Commission

ADEQ — Arizona Department of Environmental Quality

AFUDC — allowance for funds used during construction

ALJ — Administrative Law Judge

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

Clean Air Act — Clean Air Act, as amended

Company — Pinnacle West Capital Corporation

DOE — United States Department of Energy

EITF — FASB's Emerging Issues Task Force

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

EPA — United States Environmental Protection Agency

ERMC — Energy Risk Management Committee

FASB — Financial Accounting Standards Board

FERC — United States Federal Energy Regulatory Commission

FIN — FASB Interpretation

Financing Order — ACC Order that authorized APS' $500 million loan to Pinnacle West Energy in May 2003

FSP — FASB Staff Position

GAAP — accounting principles generally accepted in the United States of America

IRS — United States Internal Revenue Service

Moody's — Moody's Investors Service

MW — megawatt, one million watts

MWh — megawatt-hours, one million watts per hour

NAC — collectively, NAC Holding Inc. and NAC International Inc., subsidiaries of El Dorado that were sold in November 2004

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

NRC — United States Nuclear Regulatory Commission

Nuclear Waste Act — Nuclear Waste Policy Act of 1982, as amended

OCI — other comprehensive income

Palo Verde — Palo Verde Nuclear Generating Station, also known as ANPP

Pinnacle West — Pinnacle West Capital Corporation, the Company

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

PPL Sundance — PPL Sundance Energy, LLC

PRP — potentially responsible party

PSA — power supply adjuster

PWEC Dedicated Assets — the following Pinnacle West Energy power plants, each of which is dedicated to serving APS' customers: Redhawk Units 1 and 2, West Phoenix Units 4 and 5 and Saguaro Unit 3

PX — California Power Exchange

RFP — request for proposals

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

SEC — United States Securities and Exchange Commission

SFAS — Statement of Financial Accounting Standards

SNWA — Southern Nevada Water Authority

Standard & Poor's — Standard & Poor's Corporation

SunCor — SunCor Development Company, a subsidiary of the Company

Sundance Plant — PPL Sundance's 450-megawatt generating facility located approximately 55 miles southeast of Phoenix, Arizona

Superfund — Comprehensive Environmental Response, Compensation and Liability Act

T&D — transmission and distribution

Track A Order — ACC order dated September 10, 2002 regarding generation asset transfers and related issues

Track B Order — ACC order dated March 14, 2003 regarding competitive solicitation requirements for power purchases by Arizona's investor-owned electric utilities

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

2004 Settlement Agreement — an agreement proposing terms under which APS' general rate case would be settled

2004 Form 10-K — Pinnacle West/APS Annual Report on Form 10-K for the fiscal year ended December 31, 2004

VIE — variable interest entity

INTRODUCTION

Filing Format

This Quarterly Report on Form 10-Q is a combined report being filed by two separate registrants: Pinnacle West and APS. The information required with respect to each company is set forth within the applicable items.

The Management's Discussion and Analysis of Financial Condition and Results of Operations included under Item 2 of this report is divided into the following two sections:

- **Pinnacle West Consolidated**—This section describes the financial condition and results of operations of Pinnacle West and its subsidiaries on a consolidated basis. It includes discussions of Pinnacle West's regulated utility and non-utility operations. A substantial part of Pinnacle West's revenues and earnings is derived from its regulated utility, APS.

- **APS**—This section includes a detailed description of the results of operations and contractual obligations of APS.

Item 1 of this report includes Condensed Consolidated Financial Statements of Pinnacle West and Condensed Financial Statements of APS. Item 1 also includes Notes to Pinnacle West's Condensed Consolidated Financial Statements, the majority of which also relate to APS, and Supplemental Notes to APS' Condensed Financial Statements.

Certain Notes to APS' Condensed Financial Statements are combined with the Notes to Pinnacle West's Condensed Consolidated Financial Statements. See page 34 of this Report for a list of the Notes to Pinnacle West's Condensed Consolidated Financial Statements, the majority of which also relate to APS' Condensed Financial Statements, as well as the Supplemental Notes, which are required disclosures for APS and should be read in conjunction with Pinnacle West's Condensed Consolidated Notes.

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

PINNACLE WEST CAPITAL CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(unaudited)

(dollars and shares in thousands, except per share amounts)

	Three Months Ended March 31,	
	2005	2004
OPERATING REVENUES		
Regulated electricity segment	$ 416,030	$ 415,464
Marketing and trading segment	116,866	88,383
Real estate segment	72,056	51,593
Other revenues	10,135	10,905
Total	615,087	566,345
OPERATING EXPENSES		
Regulated electricity segment purchased power and fuel	78,423	88,611
Marketing and trading segment purchased power and fuel	100,641	67,764
Operations and maintenance	156,496	137,386
Real estate operations segment	56,476	47,690
Depreciation and amortization	94,231	101,616
Taxes other than income taxes	35,190	30,330
Other expenses	8,374	8,750
Total	529,831	482,147
OPERATING INCOME	85,256	84,198
OTHER		
Allowance for equity funds used during construction	2,603	2,002
Other income (Note 15)	1,744	11,412
Other expense (Note 15)	(5,309)	(5,945)
Total	(962)	7,469
INTEREST EXPENSE		
Interest charges	49,195	50,319
Capitalized interest	(3,289)	(4,911)
Total	45,906	45,408
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	38,388	46,259
INCOME TAXES	14,732	15,468
INCOME FROM CONTINUING OPERATIONS	23,656	30,791
Income from discontinued operations — net of income tax expense of $518 and $411	792	635
NET INCOME	$ 24,448	$ 31,426
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — BASIC	91,962	91,294
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — DILUTED	92,045	91,376
EARNINGS PER WEIGHTED — AVERAGE COMMON SHARES OUTSTANDING		
Income from continuing operations — basic	$ 0.26	$ 0.34
Net income — basic	0.27	0.34
Income from continuing operations — diluted	0.26	0.34
Net income — diluted	0.27	0.34
DIVIDENDS DECLARED PER SHARE	$ 0.95	$ 0.90

See Notes to Pinnacle West's Condensed Consolidated Financial Statements.

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

	March 31, 2005	December 31, 2004
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 172,116	$ 163,366
Investment in debt securities	100,000	181,175
Customer and other receivables	265,538	367,863
Allowance for doubtful accounts	(4,632)	(4,896)
Accrued utility revenues	78,156	93,227
Materials and supplies (at average cost)	109,568	101,333
Fossil fuel (at average cost)	22,244	20,512
Assets from risk management and trading activities (Note 10)	300,440	166,896
Assets held for sale (Note 18)	34,393	—
Other current assets	57,919	47,654
Total current assets	1,135,742	1,137,130
INVESTMENTS AND OTHER ASSETS		
Real estate investments — net	345,809	382,398
Assets from risk management and trading activities-long term (Note 10)	358,024	224,341
Decommissioning trust accounts	266,497	267,700
Other assets	101,857	107,212
Total investments and other assets	1,072,187	981,651
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	10,544,621	10,486,648
Less accumulated depreciation and amortization	3,437,733	3,365,954
Total	7,106,888	7,120,694
Construction work in progress	269,010	258,119
Intangible assets, net of accumulated amortization	127,537	105,486
Nuclear fuel, net of accumulated amortization	58,092	51,188
Net property, plant and equipment	7,561,527	7,535,487
DEFERRED DEBITS		
Regulatory assets	138,374	135,051
Other deferred debits	109,384	107,428
Total deferred debits	247,758	242,479
TOTAL ASSETS	$10,017,214	$ 9,896,747

See Notes to Pinnacle West's Condensed Consolidated Financial Statements.

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

	March 31, 2005	December 31, 2004
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 194,540	$ 373,526
Accrued taxes	277,379	245,611
Accrued interest	48,683	38,795
Dividends payable	43,751	—
Short-term borrowings	63,252	71,030
Current maturities of long-term debt	517,805	617,165
Customer deposits	56,693	55,558
Deferred income taxes	9,057	9,057
Liabilities from risk management and trading activities (Note 10)	201,476	113,406
Liabilities held for sale (Note 18)	28,947	—
Other current liabilities	145,784	101,748
Total current liabilities	1,587,367	1,625,896
LONG-TERM DEBT LESS CURRENT MATURITIES	2,576,360	2,584,985
DEFERRED CREDITS AND OTHER		
Deferred income taxes	1,283,476	1,227,553
Regulatory liabilities	513,798	506,646
Liability for asset retirements	252,926	251,612
Pension liability	250,328	234,445
Liabilities from risk management and trading activities-long term (Note 10)	199,648	156,262
Unamortized gain — sale of utility plant	49,189	50,333
Other	311,080	308,819
Total deferred credits and other	2,860,445	2,735,670
COMMITMENTS AND CONTINGENCIES (Notes 5, 12 and 13)		
COMMON STOCK EQUITY		
Common stock, no par value	1,781,050	1,769,047
Treasury stock	(35)	(428)
Total common stock	1,781,015	1,768,619
Accumulated other comprehensive income (loss):		
Minimum pension liability adjustment	(81,788)	(81,788)
Derivative instruments	152,662	59,243
Total accumulated other comprehensive income (loss)	70,874	(22,545)
Retained earnings	1,141,153	1,204,122
Total common stock equity	2,993,042	2,950,196
TOTAL LIABILITIES AND EQUITY	$10,017,214	$9,896,747

See Notes to Pinnacle West's Condensed Consolidated Financial Statements.

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

	Three Months Ended March 31,	
	2005	2004
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 24,448	$ 31,426
Adjustment to reconcile net income to net cash provided by operating activities:		
Income from discontinued operations, net of tax	(792)	(635)
Depreciation and amortization	94,231	101,616
Nuclear fuel amortization	2,101	7,599
Allowance for equity funds used during construction	(2,603)	(2,002)
Deferred income taxes	(4,281)	9,060
Change in mark-to-market valuations	(18,557)	(22,920)
Changes in current assets and liabilities:		
Customer and other receivables	102,061	70,857
Accrued utility revenues	15,071	(718)
Materials, supplies and fossil fuel	(9,967)	3,668
Other current assets	(10,265)	(505)
Accounts payable	(179,467)	(52,208)
Accrued taxes	31,768	33,891
Accrued interest	9,888	(4,748)
Other current liabilities	42,982	21,552
Proceeds from the sale of real estate assets	53,820	9,800
Real estate investments	(13,797)	(10,634)
Increase in regulatory assets	(3,323)	(847)
Change in risk management and trading activities — assets	(1,198)	5,875
Change in risk management and trading activities — liabilities	37,707	19,427
Change in customer advances	2,189	3,070
Change in pension liability	15,883	14,704
Change in other long-term assets	4,871	(11,106)
Change in other long-term liabilities	3,181	(994)
Net cash flow provided by operating activities	195,951	225,228
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(121,120)	(116,122)
Capitalized interest	(3,289)	(4,911)
Discontinued operations — Real Estate	(2,785)	133
Discontinued operations — NAC	—	3,555
Purchases of investment securities	(343,525)	(193,345)
Proceeds from sale of investment securities	424,700	285,195
Other	6,138	(4,194)
Net cash flow used for investing activities	(39,881)	(29,689)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	163,999	179,000
Short-term borrowings and payments — net	(7,778)	149,005
Dividends paid on common stock	(43,666)	(41,080)
Repayment of long-term debt	(264,805)	(601,427)
Common stock equity issuance	12,649	—
Other	(7,719)	2,752
Net cash flow used for financing activities	(147,320)	(311,750)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	8,750	(116,211)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	163,366	131,062
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 172,116	$ 14,851
Supplemental disclosure of cash flow information		
Cash paid during the period for:		
Income taxes paid	$ 15,230	$ 6,767
Interest paid, net of amounts capitalized	$ 71,327	$ 72,367

See Notes to Pinnacle West's Condensed Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. Consolidation and Nature of Operations

The condensed consolidated financial statements include the accounts of Pinnacle West and our wholly-owned subsidiaries: APS, Pinnacle West Energy, APS Energy Services, SunCor and El Dorado. All significant intercompany accounts and transactions between the consolidated companies have been eliminated. Our accounting records are maintained in accordance with GAAP. The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. We have reclassified certain prior year amounts to conform to the current year presentation.

2. Condensed Consolidated Financial Statements

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. 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 2004 Form 10-K.

3. Quarterly Fluctuations

Weather conditions cause significant seasonal fluctuations in our revenues. In addition, real estate, trading and wholesale marketing activities can have significant impacts on our results for interim periods. For these reasons as well as others, results for interim periods do not necessarily represent results to be expected for the year.

4. Changes in Liquidity

On January 15, 2005, APS repaid its $100 million 6.25% Notes due 2005. APS used cash on hand to redeem these notes.

On March 1, 2005, Maricopa County, Arizona Pollution Control Corporation issued $164 million of variable interest rate pollution control bonds, 2005 Series A-E, due 2029. The bonds were issued to refinance $164 million of outstanding pollution control bonds. The Series A-E bonds are payable solely from revenues obtained from APS pursuant to a loan agreement between APS and Maricopa County, Arizona Pollution Control Corporation. These bonds are classified as long-term debt on our Condensed Consolidated Balance Sheets.

On April 11, 2005 Pinnacle West Energy issued $500 million of Floating Rate Senior Notes due April 1, 2007. Pinnacle West has unconditionally guaranteed these notes. Pinnacle West Energy used the proceeds of this issuance to repay a $500 million loan from APS. See “ACC Financing Order” in Note 5. APS intends to use the proceeds to pay a portion of the purchase price of the PWEC Dedicated Assets. In the interim, APS intends to invest the proceeds or use them for general corporate purposes. In the event that the FERC does not approve the transfer of the PWEC Dedicated Assets, APS will use the proceeds for general corporate purposes.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

On May 2, 2005, Pinnacle West redeemed at par all of its $165 million Floating Rate Senior Notes due November 1, 2005. We used cash on hand to redeem the notes.

On May 2, 2005, Pinnacle West issued 6,095,000 shares of its common stock at an offering price of $42 per share, resulting in net proceeds of approximately $248 million. Pinnacle West anticipates using the net proceeds of the offering for general corporate purposes, including making capital contributions to APS, which will, in turn, use such funds to pay a portion of the approximately $190 million purchase price of its pending acquisition of the Sundance Plant and other capital expenditures expected to be incurred to meet the growing needs of APS' service territory. See "Request for Proposals and Asset Purchase Agreement" in Note 5 for information regarding APS' pending acquisition of the Sundance Plant.

APS had $566 million of pollution control bonds outstanding under which interest rates are reset on a daily, weekly or annual basis as of March 31, 2005. The holders of $223 million of these bonds have the right to cause APS to purchase their bonds on the applicable reset date if the bonds are not remarketed. Of these bonds, $50 million of such bonds are classified as current maturities of long-term debt. The remaining $173 million of bonds are classified as long-term debt because APS has the intent and ability, as demonstrated by credit agreements in place that extend for more than one year, to refinance any bonds that APS is required to purchase.

The following is a list of principal payments due on Pinnacle West's consolidated long-term debt and capitalized lease requirements as of March 31, 2005:

- $517 million in 2005;
- $395 million in 2006;
- $174 million in 2007;
- $7 million in 2008;
- $1 million in 2009; and
- $2.013 billion thereafter.

We have investments in auction rate securities in which interest rates are reset on a short-term basis; however, the underlying contract maturity dates extend beyond three months. We classify the investments in auction rate securities as investments in debt securities on our Condensed Consolidated Balance Sheets. The purchase and sale activities related to these investments have been reclassified on the Consolidated Statement of Cash Flows for the prior-year period.

5. Regulatory Matters

Electric Industry Restructuring

State

APS General Rate Case

On April 7, 2005, the ACC issued an order in the general rate case that APS filed on June 27, 2003. The order became final and non-appealable on April 28, 2005. In its order, the ACC approved the 2004 Settlement Agreement, with certain revisions. Certain key financial components of the order include:

- APS received an annual retail rate increase of approximately $75.5 million, or 4.21%, which was effective as of April 1, 2005. This increase does not include the impact of

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

the PSA (discussed below), which is estimated to be 5% in 2006. These increases could be further impacted if the ACC approves additional surcharges.

- The PSA provides for the annual adjustment of rates to reflect variations in fuel and purchased power costs, subject to specified parameters and procedures, including the following:
  - APS will record deferrals for recovery or refund to the extent actual fuel and purchased power costs vary from $0.020743 per kWh;
  - amounts to be recovered or refunded through the PSA are limited to plus or minus $0.004 per kWh over the life of the PSA;
  - in addition, the ACC order provides for a surcharge mechanism as follows:
    - each time the accumulated pretax net deferrals reach $50 million, APS must notify the ACC, but prior to the deferral balance exceeding $100 million, APS must file with the ACC to recover or refund such deferral balance through a surcharge;
    - amounts recovered or refunded through any surcharge are not included in the $0.004 per kWh PSA limit;
  - the recoverable amount of net fuel and purchased power costs is capped at $776.2 million per year (APS does not expect such costs to exceed $776.2 million in 2005 or 2006);
  - the PSA will remain in effect for a minimum five-year period, but the ACC may eliminate the PSA at any time, if appropriate, in the event APS files a rate case before the expiration of the five-year period or if APS does not comply with the terms of the PSA; and
  - the first adjustment of rates under the PSA would occur on April 1, 2006, unless the ACC approves a special surcharge prior to that date.
- The 2004 Settlement Agreement included a self-build moratorium for generating plants to be in service prior to January 1, 2015. The ACC order modified that moratorium to include the acquisition of a generating unit, or an interest in a generating unit, from any utility or merchant generator without prior ACC approval.
- APS was authorized to acquire Redhawk Units 1 and 2, West Phoenix Units 4 and 5, and Saguaro Unit 3, which are dedicated to serving APS' customers (the "PWEC Dedicated Assets") from PWEC, with a net carrying value of approximately $850 million, and to rate base the PWEC Dedicated Assets at a rate base value of $700 million, which will result in a mandatory rate base disallowance of approximately $150 million. As a result, for financial reporting purposes, APS will recognize a one-time, after-tax net plant write-off of approximately $90 million in the period when the assets are recorded on APS' books. This transfer remains subject to approval of the FERC.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

- To bridge the time between the effective date of the rate increase and the actual date the PWEC Dedicated Assets transfer, effective April 1, 2005, APS and PWEC entered into a cost-based purchase power agreement (the "Bridge PPA"), which is based on the value of the PWEC Dedicated Assets. When the Bridge PPA became effective, prior power purchase agreements entered into between APS and PWEC were terminated. The Bridge PPA will remain in effect until the FERC approves the transfer of the PWEC Dedicated Assets to APS and the transfer is completed.

  - If the FERC were to issue an order denying APS' request to acquire the PWEC Dedicated Assets, the Bridge PPA would become a 30-year purchase power agreement, with prices reflecting cost-of-service as if APS had acquired and rate-based the PWEC Dedicated Assets at the value described above.

  - If the FERC were to issue an order (a) approving APS' request to transfer the PWEC Dedicated Assets at a value materially less than $700 million, (b) approving the transfer of fewer than all of the PWEC Dedicated Assets, or (c) that was materially inconsistent with the ACC order, APS would file an appropriate application with the ACC so that rates could be adjusted. In these circumstances, the Bridge PPA would continue at least until the conclusion of the subsequent proceeding to consider any appropriate adjustment to APS' rates.

ACC Financing Order

On May 12, 2003, APS issued $500 million of debt pursuant to the Financing Order and made a $500 million loan to Pinnacle West Energy. Pinnacle West Energy distributed the net proceeds of that loan to us to fund the repayment of a portion of the debt we incurred to finance the construction of the PWEC Dedicated Assets. On April 11, 2005, this loan was repaid with the proceeds of a new debt issuance. See "Capital Needs and Resources — By Company — Pinnacle West Energy" in Part I, Item 2 below.

The ACC granted the Financing Order subject to various conditions. One of these conditions is that APS must maintain a common equity ratio of at least 40% and may not pay common dividends if such payment would reduce its common equity ratio below that threshold, unless otherwise waived by the ACC. This condition is an ongoing requirement and was not affected by Pinnacle West Energy's repayment of APS' $500 million loan.

In addition, the Financing Order required the ACC staff to conduct an inquiry into our and our affiliates' compliance with the retail electric competition and related rules and decisions. On June 13, 2003, APS submitted its report on these matters to the ACC staff. As part of the ACC order in APS' general rate case discussed above, this inquiry was concluded with no further action by the ACC.

Retail Electric Competition Rules

In 1999, the ACC approved rules for the introduction of retail electric competition in Arizona. The rules include the following major provisions:

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

- 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.

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. The ACC and other parties aligned with the ACC appealed the ruling to the Arizona Court of Appeals, and in January 2004, the Court invalidated some, but not all, of the rules as either violative of Arizona's constitutional requirement that the ACC consider the "fair value" of a utility's property in setting rates or as being beyond the ACC's constitutional and statutory powers. Other rules were set aside for failure to submit such regulations to the Arizona Attorney General for certification as required by statute. A request for the Arizona Supreme Court to review the Court of Appeals decision was denied on January 4, 2005. To date, the ACC has taken no action on either the rules or the orders authorizing competitive electric service providers in response to the now final Court of Appeals decision. As a result, at present only limited electric retail competition exists in Arizona and only with certain entities not regulated by the ACC.

Track A Order

On September 10, 2002, the ACC issued the Track A Order, in which the ACC, among other things:

- reversed its decision, as reflected in the rules, to require APS to transfer its generation assets either to an unrelated third party or to a separate corporate affiliate; and
- unilaterally modified the 1999 Settlement Agreement, which authorized APS' transfer of its generating assets, and directed APS to cancel its activities to transfer its generation assets to Pinnacle West Energy.

On November 15, 2002, APS filed appeals of the Track A Order in the Maricopa County, Arizona Superior Court and in the Arizona Court of Appeals. Arizona Public Service Company vs. Arizona Corporation Commission, CV 2002-0222 32; Arizona Public Service Company vs. Arizona

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Corporation Commission, 1CA CC 02-0002. On December 13, 2002, APS and the ACC staff agreed to principles for resolving certain issues raised by APS in its appeals of the Track A Order. The major provisions of the principles include, among other things, the following:

- APS and the ACC staff agreed that it would be appropriate for the ACC to consider the following matters in APS' general rate case:
  - the generating assets to be included in APS' rate base, including the question of whether the PWEC Dedicated Assets should be included in APS' rate base;
  - the appropriate treatment of the $234 million pretax asset write-off agreed to by APS as part of the 1999 Settlement Agreement; and
  - the appropriate treatment of costs incurred by APS in preparation for the previously anticipated transfer of generation assets to Pinnacle West Energy.
- As a result of the ACC's issuance of the Financing Order, APS' appeals of the Track A Order are limited to the issues described in the preceding bullet points.

On August 27, 2003, APS, Pinnacle West and Pinnacle West Energy filed a lawsuit asserting damage claims relating to the Track A Order. Arizona Public Service Company et al. v. The State of Arizona ex rel., Superior Court of the State of Arizona, County of Maricopa, No. CV2003-016372.

As a result of the ACC's order in APS' general rate case discussed above, APS, Pinnacle West, and Pinnacle West Energy are presently in the process of seeking dismissal of the above litigation.

Track B Order

On March 14, 2003, the ACC issued the Track B Order, which required APS to solicit bids for certain estimated amounts of capacity and energy for periods beginning July 1, 2003. For 2003, APS was required to solicit competitive bids for about 2,500 MW of capacity and about 4,600 gigawatt-hours of energy, or approximately 20% of APS' total retail energy requirements.

APS issued requests for proposals in March 2003 and, by May 6, 2003, APS entered into contracts to meet all or a portion of its requirements for the years 2003 through 2006 as follows:

(1) Pinnacle West Energy agreed to provide 1,700 MW in July through September of 2003 and in June through September of 2004, 2005 and 2006, by means of a unit contingent contract.

(2) PPL EnergyPlus, LLC agreed to provide 112 MW in July through September of 2003 and 150 MW in June through September of 2004 and 2005, by means of a unit contingent contract.

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(3) Panda Gila River LP agreed to provide 450 MW in October of 2003 and 2004 and May of 2004 and 2005, and 225 MW from November 2003 through April 2004 and from November 2004 through April 2005, by means of firm call options.

With final ACC approval of the 2004 Settlement Agreement, the Track B contract with Pinnacle West Energy was cancelled, effective April 1, 2005 and replaced by the Bridge PPA. The Track B contract with PPL will be cancelled upon closing of the purchase of the Sundance Plant (see below).

Request for Proposals and Asset Purchase Agreement

In early December 2003, APS issued a request for proposals for long-term power supply resources. On June 1, 2004, APS and PPL Sundance, a wholly-owned subsidiary of PPL Corporation, entered into an asset purchase agreement by which APS agreed to purchase the Sundance Plant. The Sundance Plant, which began commercial operation in July 2002, would provide peaking generation support for APS' system and reduce APS' growing needs for new generation resources. The purchase price for the Sundance Plant is approximately $190 million.

On June 1, 2004, APS and PPL Sundance filed a joint application with the ACC with respect to APS' proposed acquisition of the Sundance Plant. On January 20, 2005, the ACC issued an order confirming APS' authority to "self-build or buy new generation assets for native load" and stated that APS' acquisition of the Sundance Plant would be a proper purpose under APS' existing ACC financing authorizations. APS' filings with the ACC also requested that the ACC allow APS to defer for future recovery certain capital and operating costs (net of fuel and purchased power savings) associated with the Sundance Plant acquisition until rate treatment for the Sundance Plant could be considered in APS' next general rate case. APS' filings estimated that the deferrals would be approximately $10 million to $15 million before income taxes on an annualized basis. The order issued by the ACC allows APS to record the deferrals for up to 36 months, subject to a number of conditions. However, if APS has a general rate case pending at the end of the 36-month period, the deferral period could extend until the rate case had been decided. The conditions imposed by the order are expected to substantially limit the amount of deferrals that APS will be able to record.

APS' acquisition of the Sundance Plant, which was approved by the FERC on May 6, 2005, is subject to customary closing conditions. The transaction is targeted to close in the spring of 2005. Pursuant to the asset purchase agreement, as amended, either party may terminate the agreement if the transaction does not close by May 27, 2005, subject to PPL Sundance's right to extend the closing date by 60 days. In connection with the FERC proceeding, APS committed to an independent market monitoring plan that provides for an independent expert to monitor APS' generation dispatch and operation of its transmission system and report to the FERC any potentially anti-competitive conduct. The plan will be effective upon closing of the transaction and will continue in effect until the FERC approves a regional market monitoring plan or five years, whichever is earlier.

General

The regulatory developments and legal challenges to the ACC's retail electric competition rules discussed in this Note have raised considerable uncertainty about the status and pace of retail electric competition and of electric restructuring in Arizona. Although some very limited retail competition existed in APS' service area in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to APS' customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter APS' service territory. 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.

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Federal

In July 2002, 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 FERC adopted a price cap of $250 per MWh for the period subsequent to October 31, 2002. Sales at prices above the cap must be justified and are subject to potential refund.

On July 31, 2002, the FERC issued a Notice of Proposed Rulemaking for Standard Market Design for wholesale electric markets. Voluminous comments and reply comments were filed on virtually every aspect of the proposed rule. On April 28, 2003, the FERC Staff issued an additional white paper on the proposed Standard Market Design. The white paper discusses several policy changes to the proposed Standard Market Design, including a greater emphasis on flexibility for regional needs. We cannot currently predict what, if any, impact there may be to the Company if the FERC adopts the proposed rule or any modifications proposed in the comments.

On August 11, 2004, Pinnacle West, APS, Pinnacle West Energy, and APS Energy Services (collectively, the “Pinnacle West Companies”) submitted to the FERC an update to its three-year market-based rate review, pursuant to the FERC’s order implementing a new generation market power analysis. On December 20, 2004, the FERC issued an order approving market-based rates for control areas other than those of APS, Public Service Company of New Mexico and Tucson Electric Company. The order required the Pinnacle West Companies to submit additional data with respect to these control areas, and on February 18, 2005, the Pinnacle West Companies submitted such data. On April 11, 2005, APS and a group of APS wholesale electric customers, the Arizona Districts, submitted a settlement that resolved concerns raised by the Arizona Districts in the proceeding. On May 2, 2005, a protest and a motion to intervene were filed by the Yavapai-Apache Energy Office with respect to the settlement between APS and the Arizona Districts. On April 5, 2005, the FERC issued a deficiency letter seeking further information from the Pinnacle West Companies relating to the APS control area and the Pinnacle West Companies filed a response on April 22, 2005. The notice period for filing comments on that filing expired on May 5, 2005, and no additional comments were filed. We cannot currently predict the outcome of this proceeding, but we do not believe that the outcome will have a material adverse effect on our financial position, results of operations or liquidity.

6. Retirement Plans and Other Benefits

Pinnacle West sponsors a qualified defined benefit and account balance pension plan, a nonqualified supplemental excess benefit retirement plan, and other postretirement benefit plans for the employees of Pinnacle West and our subsidiaries.

The following table provides details of the plans’ benefit costs for the three months ended March 31, 2005 and 2004. Also included is the portion of these costs charged to expense, including administrative costs and excluding amounts billed to electric plant participants or amounts capitalized as overhead construction (dollars in millions):

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	Pension Benefits Three Months Ended March 31,		Other Benefits Three Months Ended March 31,	
	2005	2004	2005	2004
Service cost-benefits earned during the period	$ 12	$ 10	$ 6	$ 3
Interest cost on benefit obligation	23	21	9	6
Expected return on plan assets	(24)	(20)	(8)	(4)
Amortization of:				
Transition (asset) obligation	(1)	(1)	1	1
Prior service cost	1	1	—	—
Net actuarial loss	5	4	2	2
Net periodic benefit cost	$ 16	$ 15	$ 10	$ 8
Portion of cost charged to expense	$ 7	$ 7	$ 4	$ 3
APS share of costs charged to expense	$ 6	$ 6	$ 4	$ 3

Contributions

The minimum required contribution to be made to our pension plan in 2005 is estimated to be approximately $50 million, $13 million of which was contributed on April 15, 2005. The contribution to be made to other postretirement benefit plans in 2005 is estimated to be approximately $40 million. APS' share is approximately 92% of both plans.

7. Business Segments

We have three principal business segments (determined by products, services and the regulatory environment):

- our regulated electricity segment, which consists of traditional regulated retail and wholesale electricity businesses (primarily electricity service to Native Load customers) and related activities and includes electricity generation, transmission and distribution;
- our marketing and trading segment, which consists of our competitive energy business activities, including wholesale marketing and trading and APS Energy Services' commodity-related energy services; and
- our real estate segment, which consists of SunCor's real estate development and investment activities.

Financial data for the three months ended March 31, 2005 and 2004 and at March 31, 2005 and December 31, 2004 by business segment is provided as follows (dollars in millions):

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	Three Months Ended March 31,	
	2005	2004
Operating Revenues:		
Regulated electricity	$ 416	$ 415
Marketing and trading	117	88
Real estate	72	52
Other	10	11
Total	$ 615	$ 566
Net Income:		
Regulated electricity	$ 13	$ 18
Marketing and trading	1	10
Real estate	9	2
Other	1	1
Total	$ 24	$ 31

	As of March 31, 2005	As of December 31, 2004
Assets:		
Regulated electricity	$ 8,670	$ 8,674
Marketing and trading	871	746
Real estate	452	454
Other	24	23
Total	$ 10,017	$ 9,897

8. New Accounting Standards

In December 2004, the FASB issued SFAS No. 123(R), “Share-Based Payment.” The standard establishes accounting for transactions in which an entity exchanges its equity instruments for goods or services. It also addresses transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity’s equity instruments or that may be settled by the issuance of those equity instruments. SFAS No. 123(R) is effective for us as of January 1, 2006. We are currently evaluating the impacts of this new guidance, but we do not believe it will have a material impact on our financial statements.

In March 2005, the FASB issued FIN No. 47, “Accounting for Conditional Asset Retirement Obligations.” FIN No. 47 clarifies that an entity must record a liability for the fair value of an asset retirement obligation for which the timing and (or) method of settlement are conditional on a future event if the liability’s fair value can be reasonably estimated. FIN No. 47 is effective no later than the end of fiscal years ending after December 15, 2005. We are currently evaluating the new guidance, but do not expect the adoption of this interpretation to have a material impact on our financial statements.

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9. Variable Interest Entities

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

APS is exposed to losses under the Palo Verde sale leaseback agreements upon the occurrence of certain events that APS does not consider to be reasonably likely to occur. Under certain circumstances (for example, the NRC issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), APS would be required to assume the debt associated with the transactions, make specified payments to the equity participants, and take title to the leased Unit 2 interests, which, if appropriate, may be required to be written down in value. If such an event had occurred as of March 31, 2005, APS would have been required to assume approximately $250 million of debt and pay the equity participants approximately $192 million.

10. Derivative and Energy Trading Accounting

We are exposed to the impact of market fluctuations in the commodity price of electricity, natural gas, coal and emissions allowances and in interest rates. We manage risks associated with these market fluctuations by utilizing various instruments that qualify as derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. As part of our overall risk management program, we use such instruments to hedge our exposure to changes in interest rates and to hedge purchases and sales of electricity, fuels, and emissions allowances and credits. As of March 31, 2005, we hedged exposures to the price variability of the commodities for a maximum of eight years. The changes in market value of such contracts have a high correlation to price changes in the hedged transactions. In addition, subject to specified risk parameters monitored by the ERMC, we engage in marketing and trading activities intended to profit from market price movements.

Cash Flow Hedges

The changes in the fair value of our hedged positions included in the Condensed Consolidated Statements of Income for the three months ended March 31, 2005 and 2004 were comprised of the following (dollars in thousands):

	Three Months Ended March 31,	
	2005	2004
Gains on the ineffective portion of derivatives qualifying for hedge accounting	$ 7,324	$ 1,384
Gains from the change in options' time value excluded from measurement of effectiveness	858	80
Gains from the discontinuance of cash flow hedges	385	1,137

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During the twelve months ending March 31, 2006, we estimate that a net gain of $136 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 transactions.

Our assets and liabilities from risk management and trading activities are presented in two categories, consistent with our business segments:

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

- Marketing and Trading – both non-trading and trading derivative instruments of our competitive business segment.

The following table summarizes our assets and liabilities from risk management and trading activities at March 31, 2005 and December 31, 2004 (dollars in thousands):

March 31, 2005

	Current Assets	Investments	Current Liabilities	Other Liabilities	Net Asset (Liability)
Regulated electricity:					
Mark-to-market	$ 132,810	$ 49,156	$ (24,974)	$ (4,179)	$ 152,813
Options and futures – at cost	19,334	—	(44,903)	—	(25,569)
Marketing and trading:					
Mark-to-market	148,296	307,773	(101,010)	(195,469)	159,590
Options and futures and emission allowances – at cost	—	1,095	(30,589)	—	(29,494)
Total	$ 300,440	$ 358,024	$ (201,476)	$ (199,648)	$ 257,340

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December 31, 2004

	Current Assets	Investments	Current Liabilities	Other Liabilities	Net Asset (Liability)
Regulated electricity:					
Mark-to-market	$ 45,220	$ 19,417	$ (19,191)	$ (12,000)	$ 33,446
Options and margin account	18,821	118	(8,879)	—	10,060
Marketing and trading:					
Mark-to-market	102,855	204,512	(68,008)	(132,683)	106,676
Emission allowances – at cost and margin account	—	294	(17,328)	(11,579)	(28,613)
Total	$ 166,896	$ 224,341	$ (113,406)	$ (156,262)	$ 121,569

Cash or other assets may be required to serve as collateral against our open positions on certain energy-related contracts. Collateral provided to counterparties was $3 million at March 31, 2005 and $1 million at December 31, 2004, and is included in other current assets on the Condensed Consolidated Balance Sheets. Collateral provided to us by counterparties was $57 million at March 31, 2005 and $24 million at December 31, 2004, and is included in other current liabilities on the Condensed Consolidated Balance Sheets.

Fair Value Hedges

On January 29, 2004, we entered into two fixed-for-floating interest rate swap transactions on our $300 million 6.4% Senior Notes. The purpose of these hedges is to protect against significant fluctuations in the fair value of our debt. Our interest rate swaps are considered to be fully effective with any resulting gains or losses on the derivative offset by a similar loss or gain amount on the underlying fair value of debt. The fair value of the interest rate swaps was a loss of approximately $5 million at March 31, 2005 and is included in deferred credits and other with the corresponding offset in long-term debt less current maturities on the Condensed Consolidated Balance Sheets.

Credit Risk

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 two counterparties for which a worst case exposure represents approximately 30% of Pinnacle West's $658 million of risk management and trading assets as of March 31, 2005. Our risk management process assesses and monitors the financial exposure of these 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 counterparties 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, local distribution companies and financial institutions. 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.

11. Comprehensive Income

Components of comprehensive income for the three months ended March 31, 2005 and 2004, are as follows (dollars in thousands):

	Three Months Ended March 31,	
	2005	2004
Net income	$ 24,448	$ 31,426
Other comprehensive income:		
Unrealized gain on derivative instruments, net of tax (a)	97,016	28,886
Reclassification of realized gain to income, net of tax (b)	(3,597)	(98)
Total other comprehensive income	93,419	28,788
Comprehensive income	$ 117,867	$ 60,214

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

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

12. Commitments and Contingencies

Palo Verde Nuclear Generating Station

Spent Nuclear Fuel and Waste Disposal

Nuclear power plant operators are required to enter into spent fuel disposal contracts with the DOE, and the DOE is required to accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by domestic power reactors. Although the Nuclear Waste Act required the DOE to develop a permanent repository for the storage and disposal of spent nuclear fuel by 1998, the DOE has announced that the repository cannot be completed before 2010 and it does not intend to begin accepting spent nuclear fuel prior to that date. In November 1997, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued a decision preventing the DOE from excusing its own delay, but refused to order the DOE to begin accepting spent nuclear fuel. Based on this decision and the DOE's delay, a number of utilities, including APS (on behalf of itself and the other Palo Verde owners), filed damages actions against the DOE in the Court of Federal Claims. Arizona Public Service Company v. United States of America, United States Court of Federal Claims, 03-2832C.

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APS currently estimates it will incur $115 million (in 2004 dollars) over the life of Palo Verde for its share of the costs related to the on-site interim storage of spent nuclear fuel. As of March 31, 2005, APS had spent $12 million for on-site interim spent nuclear fuel storage. APS has recorded a regulatory asset of $12 million for the costs.

California Energy Market Issues and Refunds in the Pacific Northwest

FERC

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. APS was a seller and a purchaser in the California markets at issue, and to the extent that refunds are ordered, APS should be a recipient as well as a payor of such amounts. The FERC is still considering the evidence and refund amounts have not yet been finalized. APS does not anticipate material changes in its exposure and still believes, subject to the finalization of the revised proxy prices, that it will be entitled to a net refund.

On March 19, 2002, the State of California filed a complaint with the FERC alleging that wholesale sellers of power and energy, including the Company, failed to properly file rate information at the FERC in connection with sales to California from 2000 to the present under market-based rates. 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 was dismissed by the FERC and the State of California appealed the matter to the Ninth Circuit Court of Appeals. In an order issued September 9, 2004, the Ninth Circuit upheld the FERC’s authority to permit market-based rates, but rejected the FERC’s claim that it was without authority to consider retroactive refunds when a utility has not strictly adhered to the quarterly reporting requirements of the market-based rate system. On September 9, 2004, the Ninth Circuit remanded the case to the FERC for further proceedings. State of California ex rel. Bill Lockyer, Attorney General v. FERC, No. 02-73093. Several of the intervenors in this appeal filed a petition for rehearing of this decision on October 25, 2004. The petition for rehearing has not been acted upon, and the outcome of the further proceedings cannot be predicted at this time.

The FERC also ordered an evidentiary proceeding to discuss and evaluate possible refunds for the Pacific Northwest. The FERC affirmed the ALJ’s conclusion that the prices in the Pacific Northwest were not unreasonable or unjust and refunds should not be ordered in this proceeding. This decision has now been appealed to the Ninth Circuit Court of Appeals. Although the FERC ruling in the Pacific Northwest matter is being appealed and the FERC has not yet 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.

On March 26, 2003, FERC made public a Final Report on Price Manipulation in Western Markets, prepared by its staff and covering spot markets in the West in 2000 and 2001. The report stated that a significant number of entities who participated in the California markets during the 2000-2001 time period, including APS, may potentially have been involved in arbitrage transactions that allegedly violated certain provisions of the ISO tariff. After reviewing the matter, along with the data supplied by APS, the FERC staff moved to dismiss the claims against APS and to dismiss the

proceeding. The motion to dismiss was granted by the FERC on January 22, 2004. Certain parties have sought rehearing of this order, and that request is pending.

California Civil Energy Market Litigation

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 PX and California independent system operator 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, which, after moving to state court, has been removed to the federal court for a second time. James Millar, et al. v. Allegheny Energy Supply, et al., San Francisco Superior Court, Case No. 407867, U.S. District Court (Northern District) C-04-0519 SBA. The First Amended Complaint alleges basically that the contracts entered into were the result of an unfair and unreasonable market, in violation of California unfair competition laws. The 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 and numerous other PX participants. Cal PX v. The State of California, Superior Court in and for the County of Sacramento, JCCP No. 4203. Various motions continue to be filed, and we currently believe these claims will have no material adverse impact on our financial position, results of operations or liquidity.

Natural Gas Supply

Pursuant to the terms of a comprehensive settlement entered into in 1996 with El Paso Natural Gas Company, the rates charged for natural gas transportation are subject to a rate moratorium through December 31, 2005.

On July 9, 2003 the FERC issued an order that altered the capacity rights of parties to the 1996 settlement but maintained the cost responsibility provisions agreed to by parties to that settlement. On December 28, 2004, the D.C. Court of Appeals upheld the FERC's authority to alter the capacity rights of parties to the settlement. With respect to the FERC's authority to maintain the cost responsibility provisions of the settlement, a party has sought appellate review and is seeking to reallocate the costs responsibility associated with the changed contractual obligations in a way that would be less favorable to APS and Pinnacle West Energy than under the FERC's July 9, 2003 order. Should this party prevail on this point, APS and Pinnacle West Energy's annual capacity cost could be increased by approximately $3 million per year, from September 2003 through December 2005.

El Paso is required under the terms of the 1996 settlement to file a new rate case by July 1, 2005, with new rates to become effective on January 1, 2006. APS cannot currently assess the financial impact that El Paso's filing could have on rates.

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Navajo Nation Litigation

In June 1999, the Navajo Nation served Salt River Project with a lawsuit naming Salt River Project, several Peabody Coal Company entities (collectively, "Peabody"), Southern California Edison Company 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 the 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 (the "D.C. Lawsuit"). APS is a 14% owner of the Navajo Generating Station, which Salt River Project operates. The D.C. Lawsuit alleges, among other things, that the defendants obtained a favorable coal royalty rate by improperly influencing the outcome of a federal administrative process under which the royalty rate was to be adjusted. The suit seeks $600 million in damages, treble damages, punitive damages of not less than $1 billion, and the ejection of defendants "from all possessory interests and Navajo Tribal lands arising out of the [primary coal lease]". In July 2001, the court dismissed all claims against Salt River Project.

In January, 2005, Peabody served APS with a lawsuit naming APS and the other Navajo Generating Station participants and seeking, among other things, a declaration that the participants "are obligated to reimburse Peabody for any royalty, tax, or other obligation arising out of the D.C. Lawsuit". Peabody Western Coal Company v. Salt River Project Agricultural Improvement and Power District, et al., Circuit Court for the City of St. Louis, Division No. 1, Cause No. 042-08561. Based on APS' ownership interest in the Navajo Generating Station, APS could be liable for up to 14% of any such obligation. Because the litigation is in preliminary stages, APS cannot currently predict the outcome of this matter.

Environmental Matters

Superfund Superfund establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who generated, transported or disposed of hazardous substances at a contaminated site are among those who are PRPs. PRPs may be strictly, and often jointly and severally, liable for clean-up. On September 3, 2003, the EPA advised APS that the EPA considers APS to be a PRP in the Motorola 52nd Street Superfund Site, Operable Unit 3 (OU3) in Phoenix, Arizona. APS has facilities that are within this Superfund site. APS and Pinnacle West have agreed with the EPA to perform certain investigative activities of the APS facilities within OU3. Because the investigation has not yet been completed and ultimate remediation requirements are not yet finalized, neither APS nor Pinnacle West can currently estimate the expenditures which may be required.

Litigation

We are party to various other claims, legal actions and complaints arising in the ordinary course of business, including but not limited to environmental matters related to the Clean Air Act, Navajo Nation issues and EPA and ADEQ issues. In our opinion, the ultimate resolution of these matters will not have a material adverse effect on our financial position, results of operations or liquidity.

13. 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 $300 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 $101 million, subject to an annual limit of $10 million per incident. Based on APS' interest in the three Palo Verde units, APS' maximum potential assessment per incident for all three units is approximately $88 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.

14. Stock-Based Compensation

Pinnacle West offers stock-based compensation plans for officers and key employees of the Company and our subsidiaries. Beginning with our 2002 stock option grants we began applying the fair value method of accounting for stock-based compensation as provided for in SFAS No. 123, "Accounting for Stock-Based Compensation." In prior years, we recognized stock compensation expense based on the intrinsic value method allowed in Accounting Principles Board Opinion (APB) No. 25, "Accounting for Stock Issued to Employees." For the three months ended March 31, 2005 and 2004, the reported compensation expense, net income and earnings per share were not materially different from pro forma amounts for both Pinnacle West and APS.

15. Other Income and Other Expense

The following table provides detail of other income and other expense for the three months ended March 31, 2005 and 2004 (dollars in thousands):

	Three Months Ended March 31,	
	2005	2004
Other income:		
Investment gains – net	$ —	$ 2,218
Interest income	1,338	3,802
SunCor joint venture earnings (loss)	(28)	1,185
Asset sales	241	3,651
Miscellaneous	193	556
Total other income	$ 1,744	$ 11,412
Other expense:		
Non-operating costs (a)	$ (3,098)	$ (2,802)
Asset sales	(64)	(2,139)
Investment losses – net	(1,249)	—
Miscellaneous	(898)	(1,004)
Total other expense	$ (5,309)	$ (5,945)

(a) As defined by the FERC, includes below-the-line non-operating utility costs (primarily community relations and other costs excluded from utility rate recovery).

16. Guarantees

We have issued parental guarantees and letters of credit and obtained surety bonds on behalf of our unregulated subsidiaries. Our parental guarantees related to Pinnacle West Energy consist of equipment and performance guarantees related to our generation construction program, and long-

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

term service agreement guarantees for new power plants. Our credit support instruments enable APS Energy Services to offer commodity energy and energy-related products. Non-performance or payment under the original contract by our unregulated subsidiaries would require us to perform under the guarantee or surety bond. No liability is currently recorded on the Condensed Consolidated Balance Sheets related to Pinnacle West's guarantees on behalf of its subsidiaries. Our guarantees have no recourse or collateral provisions to allow us to recover amounts paid under the guarantee. The amounts and approximate terms of our guarantees and surety bonds for each subsidiary at March 31, 2005 are as follows (dollars in millions):

	Guarantees		Surety Bonds	
	Amount	Term (in years)	Amount	Term (in years)
Parental:				
Pinnacle West Energy	$ 17	1	$ —	—
APS Energy Services	26	1	61	1
Total	$ 43		$ 61	

At March 31, 2005, we had entered into approximately $41 million of letters of credit which support various transmission and construction agreements. These letters of credit expire in 2005 and 2006. We intend to provide from either existing or new facilities for the extension, renewal or substitution of the letters of credit to the extent required. At March 31, 2005, Pinnacle West had approximately $4 million of letters of credit related to workers' compensation expiring in 2006.

APS has entered into various agreements that require letters of credit for financial assurance purposes. At March 31, 2005, approximately $200 million of letters of credit were outstanding to support existing pollution control bonds of approximately $200 million. The letters of credit are available to fund the payment of principal and interest of such debt obligations. In July 2004, $150 million of these letters of credit were renewed for a three-year term and expire in 2007. The remainder expire in 2005. APS has also entered into approximately $100 million of letters of credit to support certain equity lessors in the Palo Verde sale leaseback transactions (see Note 9 for further details on the Palo Verde sale leaseback transactions). These letters of credit expire in 2005. Additionally, APS has approximately $5 million of letters of credit related to counterparty collateral requirements expiring in 2006. APS intends to provide from either existing or new facilities for the extension, renewal or substitution of the letters of credit to the extent required.

We enter into agreements that include indemnification provisions relating to liabilities arising from or related to certain of our agreements. APS has agreed to indemnify the equity participants and other parties in the Palo Verde sale leaseback transactions with respect to certain tax matters. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. Based on historical experience and evaluation of the specific indemnities, we do not believe that any material loss related to such indemnification provisions is likely.

See Note 4 for information regarding Pinnacle West's guarantee of $500 million of Pinnacle West Energy's debt obligations.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

17. Earnings Per Share

The following table presents earnings per weighted average common share outstanding for the three months ended March 31, 2005 and 2004:

	Three Months Ended March 31,	
	2005	2004
Basic earnings per share:		
Income from continuing operations	$ 0.26	$ 0.34
Income from discontinued operations	0.01	—
Earnings per share – basic	$ 0.27	$ 0.34
Diluted earnings per share:		
Income from continuing operations	$ 0.26	$ 0.34
Income from discontinued operations	0.01	—
Earnings per share – diluted	$ 0.27	$ 0.34

Dilutive stock options increased average common shares outstanding by approximately 83,000 shares for the three months ended March 31, 2005 and 82,000 shares for the three months ended March 31, 2004.

Options to purchase 868,934 shares for the three-month period ended March 31, 2005 were outstanding but were not included in the computation of earnings per share because the options' exercise prices were greater than the average market price of the common shares. Options to purchase shares of common stock that were not included in the computation of diluted earnings per share for that same reason were 2,381,699 shares for the three-month period ended March 31, 2004.

18. Discontinued Operations

Due to pending sales of certain SunCor commercial properties in 2005, the related assets and liabilities have been reclassified to assets and liabilities held for sale on the Condensed Consolidated Balance Sheets at March 31, 2005. The assets held for sale at March 31, 2005 relate to property in the amount of $34 million, and the liabilities held for sale relate to current maturities of long-term debt in the amount of $29 million. Operating revenues and expenses related to these commercial properties for the prior-year periods are immaterial and therefore have not been reclassified on the Condensed Consolidated Statements of Income.

19. Silverhawk Power Station

Pinnacle West Energy has a 75% ownership in the Silverhawk Power Station. As of March 31, 2005 we concluded that there was no impairment of this asset under SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," ("SFAS 144").

Recently, we have received proposals from several parties that have expressed interest in purchasing this ownership interest. If an agreement is reached with a party and approved by the Board of Directors, we anticipate that the asset at that point would be classified as held for sale and, accordingly, an impairment loss would be recognized using the fair value method required by SFAS 144. Management's best estimate of this impairment would result in a loss in the range of $50 million to $60 million after income taxes. If such a transaction were to occur, we would plan to invest the net sale proceeds, estimated to be in the range of $200 million to $215 million, into APS. No assurance can be given that a transaction will occur.

ARIZONA PUBLIC SERVICE COMPANY

CONDENSED STATEMENTS OF INCOME
(unaudited)
(dollars in thousands)

	Three Months Ended March 31,	
	2005	2004
ELECTRIC OPERATING REVENUES		
Regulated electricity	$ 418,434	$ 420,299
Marketing and trading	22,858	20,803
Total	441,292	441,102
OPERATING EXPENSES		
Regulated electricity purchased power and fuel	81,914	88,592
Marketing and trading purchased power and fuel	28,302	25,758
Operations and maintenance	142,294	125,912
Depreciation and amortization	82,214	88,848
Income taxes	16,380	17,362
Other taxes	31,445	27,580
Total	382,549	374,052
OPERATING INCOME	58,743	67,050
OTHER INCOME (DEDUCTIONS)		
Income taxes	(837)	(2,469)
Allowance for equity funds used during construction	2,603	2,002
Other income (Note S-4)	6,161	11,235
Other expense (Note S-4)	(3,860)	(4,904)
Total	4,067	5,864
INTEREST DEDUCTIONS		
Interest on long-term debt	35,517	35,646
Interest on short-term borrowings	1,191	2,501
Debt discount, premium and expense	1,004	1,195
Capitalized interest	(1,947)	(857)
Total	35,765	38,485
NET INCOME	$ 27,045	$ 34,429

See Notes to Pinnacle West's Condensed Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Condensed Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
CONDENSED BALANCE SHEETS
(unaudited)
(dollars in thousands)

	March 31, 2005	December 31, 2004
ASSETS		
UTILITY PLANT		
Electric plant in service and held for future use	$ 9,203,579	$ 9,120,407
Less accumulated depreciation and amortization	3,328,892	3,266,181
Total	5,874,687	5,854,226
Construction work in progress	262,097	249,243
Intangible assets, net of accumulated amortization	102,218	103,701
Nuclear fuel, net of accumulated amortization	58,092	51,188
Utility plant-net	6,297,094	6,258,358
INVESTMENTS AND OTHER ASSETS		
Note receivable from Pinnacle West Energy (Notes 5 and S-5)	498,646	498,489
Decommissioning trust accounts	266,497	267,700
Assets from risk management and trading activities long term (Note S-2)	57,990	20,123
Other assets	60,302	61,364
Total investments and other assets	883,435	847,676
CURRENT ASSETS		
Cash and cash equivalents	101,816	49,575
Investment in debt securities	—	181,175
Accounts receivable:		
Service customers	124,521	214,487
Other	89,391	63,131
Allowance for doubtful accounts	(3,107)	(3,444)
Accrued utility revenues	69,030	76,154
Materials and supplies (at average cost)	87,470	83,893
Fossil fuel (at average cost)	22,238	20,506
Assets from risk management and trading activities (Note S-2)	173,787	70,430
Other current assets	8,068	10,187
Total current assets	673,214	766,094
DEFERRED DEBITS		
Regulatory assets	138,374	135,051
Unamortized debt issue costs	24,401	21,832
Other deferred debits	72,884	69,541
Total deferred debits	235,659	226,424
TOTAL ASSETS	$ 8,089,402	$ 8,098,552

See Notes to Pinnacle West's Condensed Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Condensed Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
CONDENSED BALANCE SHEETS
(unaudited)
(dollars in thousands)

	March 31, 2005	December 31, 2004
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION		
Common stock	$ 178,162	$ 178,162
Additional paid-in capital	1,246,804	1,246,804
Retained earnings	844,740	860,196
Accumulated other comprehensive income (loss):		
Minimum pension liability adjustment	(71,087)	(71,087)
Derivative instruments	83,102	18,327
Common stock equity	2,281,721	2,232,402
Long-term debt less current maturities	2,266,700	2,267,094
Total capitalization	4,548,421	4,499,496
CURRENT LIABILITIES		
Current maturities of long-term debt	351,393	451,247
Accounts payable	92,097	215,076
Accrued taxes	340,360	292,521
Accrued interest	37,944	33,332
Customer deposits	52,825	51,804
Deferred income taxes	9,057	9,057
Liabilities from risk management and trading activities (Note S-2)	90,890	34,292
Other current liabilities	87,315	91,441
Total current liabilities	1,061,881	1,178,770
DEFERRED CREDITS AND OTHER		
Deferred income taxes	1,149,522	1,108,571
Regulatory liabilities	513,798	506,646
Liability for asset retirements	252,926	251,612
Pension liability	217,961	203,668
Customer advances for construction	61,374	59,185
Unamortized gain — sale of utility plant	49,189	50,333
Liabilities from risk management and trading activities - long term (Note S-2)	18,490	13,124
Other	215,840	227,147
Total deferred credits and other	2,479,100	2,420,286
COMMITMENTS AND CONTINGENCIES (Notes 5, 12, 13 and S-5)		
TOTAL LIABILITIES AND EQUITY	$ 8,089,402	$ 8,098,552

See Notes to Pinnacle West's Condensed Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Condensed Financial Statements.

ARIZONA PUBLIC SERVICE COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
(unaudited)
(dollars in thousands)

	Three Months Ended March 31,	
	2005	2004
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 27,045	$ 34,429
Items not requiring cash:		
Depreciation and amortization	82,214	88,848
Nuclear fuel amortization	2,101	7,599
Allowance for equity funds used during construction	(2,603)	(2,002)
Deferred income taxes	(1,009)	2,714
Change in mark-to-market valuations	(8,234)	(19,582)
Changes in current assets and liabilities:		
Accounts receivable	63,369	34,880
Accrued utility revenues	7,124	(2,111)
Materials, supplies and fossil fuel	(5,309)	3,757
Other current assets	3,089	1,557
Accounts payable	(123,460)	(6,333)
Accrued taxes	47,839	49,109
Accrued interest	4,612	(5,950)
Other current liabilities	(3,105)	11,203
Increase in regulatory assets	(3,323)	(1,248)
Change in risk management and trading activities — assets	(395)	2,562
Change in risk management and trading activities - liabilities	36,204	18,856
Change in customer advances	2,189	3,070
Change in pension liability	14,293	13,074
Change in other long-term assets	(4,879)	(5,383)
Change in other long-term liabilities	(10,314)	(12,237)
Net cash flow provided by operating activities	127,448	216,812
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(117,501)	(99,684)
Capitalized interest	(1,947)	(857)
Purchases of investment securities	(67,450)	(24,200)
Proceeds from sale of investment securities	248,625	94,050
Other	6,073	(5,412)
Net cash flow provided by (used for) investing activities	67,800	(36,103)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	163,975	179,000
Short-term borrowings	—	25,200
Dividends paid on common stock	(42,500)	(42,500)
Repayment and reacquisition of long-term debt	(264,482)	(384,561)
Net cash flow used for financing activities	(143,007)	(222,861)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	52,241	(42,152)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	49,575	42,152
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 101,816	$ —
Supplemental disclosure of cash flow information:		
Cash paid during the year for:		
Income taxes paid	$ 9	$ —
Interest, net of amounts capitalized	$ 30,149	$ 42,228

See Notes to Pinnacle West's Condensed Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Condensed Financial Statements.

Certain notes to APS' Condensed Financial Statements are combined with the Notes to Pinnacle West's Condensed Consolidated Financial Statements. Listed below are the Condensed Consolidated Notes to Pinnacle West's Condensed Consolidated Financial Statements, the majority of which also relate to APS' Condensed Financial Statements. In addition, listed below are the Supplemental Notes which are required disclosures for APS and should be read in conjunction with Pinnacle West's Condensed Consolidated Notes.

	Condensed Consolidated Footnote Reference	APS' Supplemental Footnote Reference
Consolidation and Nature of Operations	Note 1	—
Condensed Consolidated Financial Statements	Note 2	—
Quarterly Fluctuations	Note 3	—
Changes in Liquidity	Note 4	Note S-1
Regulatory Matters	Note 5	—
Retirement Plans and Other Benefits	Note 6	—
Business Segments	Note 7	—
New Accounting Standards	Note 8	—
Variable Interest Entities	Note 9	—
Derivative and Energy Trading Accounting	Note 10	Note S-2
Comprehensive Income	Note 11	Note S-3
Commitments and Contingencies	Note 12	—
Nuclear Insurance	Note 13	—
Stock-Based Compensation	Note 14	—
Other Income and Other Expense	Note 15	Note S-4
Guarantees	Note 16	—
Earnings Per Share	Note 17	—
Discontinued Operations	Note 18	—
Silverhawk Power Station	Note 19	—
Related Party Transactions	—	Note S-5

S-1. Changes in Liquidity

The following is a list of principal payments due on APS' total long-term debt and capitalized lease requirements:

- $351 million in 2005;
- $86 million in 2006;
- $174 million in 2007;
- $1 million in 2008;
- $1 million in 2009; and
- $2.013 billion, thereafter.

ARIZONA PUBLIC SERVICE COMPANY
SUPPLEMENTAL NOTES TO THE CONDENSED FINANCIAL STATEMENTS

S-2. Derivative and Energy Trading Accounting

APS is exposed to the impact of market fluctuations in the commodity price of electricity, natural gas and coal. As part of its overall risk management program, APS uses various commodity instruments that qualify as derivatives to hedge purchases and sales of electricity and fuels. As of March 31, 2005, APS hedged exposures to these risks for a maximum of three years.

Cash Flow Hedges

The changes in the fair value of APS' hedged positions included in the APS Condensed Statements of Income for the three months ended March 31, 2005 and 2004 were comprised of the following (dollars in thousands):

	Three Months Ended March 31,	
	2005	2004
Gains on the ineffective portion of derivatives qualifying for hedge accounting	$ 7,417	$ 1,411
Gains from the change in options' time value excluded from measurement of effectiveness	858	80
Gains from the discontinuance of cash flow hedges	302	575

During the twelve months ending March 31, 2006, we estimate that a net gain of $95 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 transactions.

APS' assets and liabilities from risk management and trading activities are presented in two categories, consistent with our business segments:

- Regulated Electricity — non-trading derivative instruments that hedge APS' purchases and sales of electricity and fuel for its Native Load requirements; and

- Marketing and Trading — both non-trading and trading derivative instruments.

The following table summarizes APS' assets and liabilities from risk management and trading activities at March 31, 2005 and December 31, 2004 (dollars in thousands):

ARIZONA PUBLIC SERVICE COMPANY
SUPPLEMENTAL NOTES TO THE CONDENSED FINANCIAL STATEMENTS

March 31, 2005

	Current Assets	Investments	Current Liabilities	Other Liabilities	Net Asset (Liability)
Regulated Electricity:					
Mark-to-market	$ 132,809	$ 49,157	$ (24,974)	$ (4,179)	$ 152,813
Options and futures-at cost	19,334	—	(44,903)	—	(25,569)
Marketing and Trading:					
Mark-to-market	21,644	8,828	(20,834)	(14,311)	(4,673)
Options and futures and other-at cost	—	5	(179)	—	(174)
Total	$ 173,787	$ 57,990	$ (90,890)	$ (18,490)	$ 122,397

December 31, 2004

	Current Assets	Investments	Current Liabilities	Other Liabilities	Net Asset (Liability)
Regulated Electricity:					
Mark-to-market	$ 45,220	$ 19,417	$ (19,191)	$ (12,000)	$ 33,446
Options and futures-at cost	18,821	118	(8,879)	—	10,060
Marketing and Trading:					
Mark-to-market	6,389	581	(6,222)	(1,124)	(376)
Other-at cost	—	7	—	—	7
Total	$ 70,430	$ 20,123	$ (34,292)	$ (13,124)	$ 43,137

Cash or other assets may be required to serve as collateral against APS' open positions on certain energy-related contracts. No collateral was provided to counterparties at March 31, 2005 or December 31, 2004. Collateral provided to us by counterparties was $37 million at March 31, 2005 and $6 million at December 31, 2004, and is included in other current liabilities on the Condensed Balance Sheets.

S-3. Comprehensive Income

Components of APS' comprehensive income for the three months ended March 31, 2005 and 2004, are as follows (dollars in thousands):

ARIZONA PUBLIC SERVICE COMPANY
SUPPLEMENTAL NOTES TO THE CONDENSED FINANCIAL STATEMENTS

	Three Months Ended March 31,	
	2005	2004
Net income	$ 27,045	$ 34,429
Other comprehensive income:		
Unrealized gains on derivative instruments, net of tax (a)	65,612	18,315
Reclassification of realized gain to income, net of tax (b)	(837)	(1,130)
Total other comprehensive income	64,775	17,185
Comprehensive income	$ 91,820	$ 51,614

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

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

S-4. Other Income and Other Expense

The following table provides detail of APS' other income and other expense for the three months ended March 31, 2005 and 2004 (dollars in thousands):

	Three Months Ended March 31,	
	2005	2004
Other income:		
Interest income	$ 5,423	$ 5,038
Asset sales	241	3,651
Investment gains-net	—	2,047
Miscellaneous	497	499
Total other income	$ 6,161	$ 11,235
Other expense:		
Non-operating costs(a)	$ (2,628)	$ (2,232)
Asset sales	(64)	(2,139)
Investment losses-net	(502)	—
Miscellaneous	(666)	(533)
Total other expense	$ (3,860)	$ (4,904)

(a) As defined by the FERC, includes below-the-line non-operating utility costs (primarily community relations and other).

ARIZONA PUBLIC SERVICE COMPANY
SUPPLEMENTAL NOTES TO THE CONDENSED FINANCIAL STATEMENTS

S-5. Related Party Transactions

From time to time, APS enters into transactions with Pinnacle West or Pinnacle West's subsidiaries. The following table summarizes the amounts included in the APS Condensed Statements of Income and Condensed Balance Sheets related to transactions with affiliated companies (dollars in millions):

	Three Months Ended March 31,	
	2005	2004
Electric operating revenues:		
Pinnacle West — marketing and trading	$ 1	$ 4
Pinnacle West Energy	1	1
Total	$ 2	$ 5
Purchased power and fuel costs:		
Pinnacle West Energy	$ 8	$ 10
Total	$ 8	$ 10
Other:		
Pinnacle West Energy interest income	$ 5	$ 5
Total	$ 5	$ 5

	As of March 31, 2005	As of December 31, 2004
Net intercompany receivables (payables):		
Pinnacle West Energy	$ 484	$ 467
Pinnacle West — marketing and trading	17	19
APS Energy Services	7	9
Pinnacle West	23	(5)
Total	$ 531	$ 490

Electric revenues include sales of electricity to affiliated companies at contract prices. Purchased power includes purchases of electricity from affiliated companies at contract prices. The Company purchases electricity from and sells electricity to APS Energy Services; however, these transactions are settled net and reported net in accordance with EITF 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not 'Held for Trading Purposes' As Defined in Issue No. 2-3." Intercompany receivables primarily include the amounts related to the loan APS made to Pinnacle West Energy and intercompany sales of electricity. Intercompany payables primarily include amounts related to the intercompany purchases of electricity. Intercompany receivables and payables are generally settled on a current basis in cash.

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

INTRODUCTION

The following discussion should be read in conjunction with Pinnacle West's Condensed Consolidated Financial Statements and Arizona Public Service Company's Condensed Financial Statements and the related Notes that appear in Item 1 of this report.

OVERVIEW

Pinnacle West owns all of the outstanding common stock of APS. APS is a vertically-integrated electric utility that provides retail and wholesale electric service to most of the state of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona. Through its marketing and trading division, APS also generates, sells and delivers electricity to wholesale customers in the western United States. APS has historically accounted for a substantial part of our revenues and earnings. Customer growth in APS' service territory is about three times the national average and remains a fundamental driver of our revenues and earnings.

Pinnacle West Energy is our unregulated generation subsidiary. The ACC's order in APS' general rate case authorized Pinnacle West Energy to transfer the PWEC Dedicated Assets to APS. This transfer remains subject to FERC approval. See "APS General Rate Case" in Note 5. Following the transfer, Pinnacle West Energy's remaining generating plant will be the Silverhawk Power Station, a 570 MW combined cycle plant located north of Las Vegas, Nevada. See Note 19 of Notes to Condensed Consolidated Financial Statements for a discussion of proposals to purchase our 75% ownership interest in the Silverhawk Power Station.

SunCor, our real estate development subsidiary, has been and is expected to be an important source of earnings and cash flow, particularly during the years 2003 through 2005 due to accelerated asset sales activity.

Our subsidiary, APS Energy Services, provides competitive commodity-related energy services and energy-related products and services to commercial and industrial retail customers in the western United States.

El Dorado, our investment subsidiary, owns minority interests in several energy-related investments and Arizona community-based ventures.

We continue to focus on solid operational performance in our electricity generation and delivery activities. In the generation area, 2004 represented the thirteenth consecutive year Palo Verde was the largest power producer in the United States. In the delivery area, we focus on superior reliability and customer satisfaction while expanding our transmission and distribution system to

meet growth and sustain reliability. We plan to expand long-term resources to meet our retail customers' growing electricity needs.

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

EARNINGS CONTRIBUTION BY BUSINESS SEGMENT

We have three principal business segments (determined by products, services and the regulatory environment):

- our regulated electricity segment, which consists of traditional regulated retail and wholesale electricity businesses (primarily electric service to "Native Load" customers) and related activities and includes electricity generation, transmission and distribution;
- our marketing and trading segment, which consists of our competitive energy business activities, including wholesale marketing and trading and APS Energy Services' commodity-related energy services; and
- our real estate segment, which consists of SunCor's real estate development and investment activities.

The following table summarizes net income for the three months ended March 31, 2005 and 2004 (dollars in millions):

	Three Months Ended March 31	
	2005	2004
Regulated electricity	$ 13	$ 18
Marketing and trading	1	10
Real estate	9	2
Other	1	1
Net income	$ 24	$ 31

General

Throughout the following explanations of our results of operations, we refer to "gross margin." With respect to our regulated electricity segment and our marketing and trading segment, gross margin refers to electric operating revenues less purchased power and fuel costs. "Gross margin" is a "non-GAAP financial measure," as defined in accordance with SEC rules. Exhibit 99.3 reconciles this non-GAAP financial measure to operating income, which is the most directly comparable financial measure calculated and presented in accordance with GAAP. We view gross margin as an important performance measure of the core profitability of our operations. This measure is a key component of our internal financial reporting and is used by our management in analyzing our business segments. We believe that investors benefit from having access to the same financial measures that our management uses. In addition, we have reclassified certain prior period amounts to conform to our current period presentation.

Operating Results — Three-month period ended March 31, 2005 compared with the three-month period ended March 31, 2004

Our consolidated net income for the three months ended March 31, 2005 was $24 million compared with $31 million for the prior-year period. The $7 million decrease in the period-to-period comparison reflected the following changes in earnings by segment:

- Regulated Electricity Segment — Net income decreased approximately $5 million primarily due to higher operations and maintenance costs primarily related to customer service, generation and benefit costs; lower other income, net of other expense, primarily due to gains on asset sales in the prior year period; increased property taxes due to increased plant in service; and the effects of milder weather on retail sales. These negative factors were partially offset by the absence of regulatory asset amortization; higher retail sales volumes due to customer growth and usage; decreased purchased power and fuel costs due to lower hedged gas and power prices; and lower replacement power costs due to fewer unplanned outages.

- Marketing and Trading Segment — Net income decreased approximately $9 million primarily due to increased costs related to the Silverhawk Power Station, which was placed in service in mid-2004 and lower margins on competitive retail sales in California by APS Energy Services.

- Real Estate Segment — Net income increased approximately $7 million primarily due to increased land sales.

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

	Increase (Decrease)	
	Pretax	After Tax
Regulated electricity segment gross margin:		
Higher retail sales volumes due to customer growth, excluding weather effects	$ 7	$ 4
Decreased purchased power and fuel costs due to lower hedged gas and power prices	5	3
Lower replacement power costs due to fewer unplanned outages	4	3
Effects of weather on retail sales	(5)	(3)
Net increase in regulated electricity segment gross margin	11	7
Marketing and trading segment gross margin:		
Lower competitive retail unit margins in California by APS Energy Services	(6)	(4)
Lower realized margins on wholesale sales primarily due to lower unit margins	(1)	(1)
Increase in generation sales other than Native Load due to higher sales volumes	3	2
Net decrease in marketing and trading segment gross margin	(4)	(3)
Net increase in gross margin for regulated electricity and marketing and trading segments	7	4
Higher real estate segment contribution primarily related to increased land sales	12	7
Higher operations and maintenance expense primarily related to customer service, generation and benefit costs	(19)	(11)
Depreciation and amortization decreases (increases):		
Absence of regulatory asset amortization	9	5
Increased delivery and other assets	(2)	(1)
Higher property taxes due to increased plant in service	(5)	(3)
Lower other income net of other expense primarily due to gain on asset sales and higher interest income in prior-year period	(9)	(5)
Miscellaneous items, net	(1)	(3)
Net decrease in net income	$ (8)	$ (7)

The increase in net costs (primarily depreciation, interest expense, property taxes and operations and maintenance expense, net of gross margin contributions) related to the Silverhawk Power Station, which was placed in service in mid-2004 by Pinnacle West Energy totaled approximately $4 million after income taxes in the three months ended March 31, 2005 compared with the prior-year period.

Regulated Electricity Segment Revenues

Regulated electricity segment revenues were $1 million higher for the three months ended March 31, 2005 compared with the prior-year period primarily as a result of:

- a $13 million increase in retail revenues related to customer growth, excluding weather effects;
- a $13 million decrease in retail revenues related to milder weather; and
- a $1 million increase due to miscellaneous factors.

Marketing and Trading Segment Revenues

Marketing and trading segment revenues were $29 million higher for the three months ended March 31, 2005 compared with the prior-year period primarily as a result of:

- a $36 million increase from generation sales other than Native Load primarily due to higher sales volumes, including sales from the Silverhawk Power Station, and higher wholesale market prices;
- $1 million of higher energy trading revenues on realized sales of electricity primarily due to higher electricity prices; and
- an $8 million decrease from lower competitive retail sales and prices in California by APS Energy Services.

Real Estate Revenues

Real estate revenues were $20 million higher for the three months ended March 31, 2005 compared with the prior-year period primarily due to higher land and home sales.

LIQUIDITY AND CAPITAL RESOURCES

Capital Needs and Resources — Pinnacle West Consolidated

Capital Expenditure Requirements

The following table summarizes the actual capital expenditures for the three months ended March 31, 2005 and estimated capital expenditures for the next three years.

CAPITAL EXPENDITURES
(dollars in millions)

	Three Months Ended March 31,	Estimated for the Year Ended December 31,		
	2005	2005	2006	2007
APS				
Delivery	$ 84	$ 390	$ 395	$ 440
Generation (a) (b)	26	352	158	195
Other (c)	9	30	7	6
Subtotal	119	772	560	641
Pinnacle West Energy (a)	—	7	5	2
SunCor (d)	19	114	61	63
Other	1	8	7	4
Total	$ 139	$ 901	$ 633	$ 710

(a) As discussed in Note 5 under “APS General Rate Case,” as part of the ACC’s order in APS’ general rate case, APS received rate base treatment of the PWEC Dedicated Assets. The estimated capital expenditures related to the PWEC Dedicated Assets are reflected in APS for the years 2005, 2006 and 2007.

(b) The estimate for 2005 includes about $190 million for acquisition of the Sundance Plant. See “Request for Proposals and Asset Purchase Agreement” in Note 5 for a discussion of the asset purchase agreement between APS and PPL Sundance.

(c) Primarily information systems and facilities projects.

(d) Consists primarily of capital expenditures for land development and retail and office building construction reflected in “Real estate investments” on the Condensed Consolidated Statements of Cash Flows.

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. Major transmission projects are driven by strong regional customer growth. APS will begin major projects each year for the next several years, and expects to spend about $200 million on major transmission projects during the 2005 to 2007 time frame. These amounts are included in “APS-Delivery” in the table above. Completion of these projects is expected by at least 2008.

Generation capital expenditures are comprised of various improvements to APS’ existing fossil and nuclear plants, the acquisition of the Sundance Plant and the replacement of Palo Verde steam generators (see below). Examples of the types of projects included in this category are additions, upgrades and capital replacements of various power plant equipment such as turbines, boilers and environmental equipment. Generation also includes nuclear fuel expenditures of approximately $30 million annually for 2005 through 2007.

Replacement of the steam generators in Palo Verde Unit 2 was completed during the fall outage of 2003 at a cost to APS of approximately $70 million. The Palo Verde owners have approved the manufacture of two additional sets of steam generators. These generators will be

installed in Unit 1 (scheduled completion in the fall of 2005) and Unit 3 (scheduled completion in the fall of 2007). Our portion of steam generator expenditures for Units 1 and 3 is approximately $140 million, which will be spent through 2008. In 2005 through 2007, approximately $95 million of the costs for steam generator replacements at Units 1 and 3 are included in the generation capital expenditures table above and will be funded with internally-generated cash or external financings.

Contractual Obligations

Our future contractual obligations have not changed materially from the amounts disclosed in Part II, Item 7 of the 2004 Form 10-K, with the exception of our aggregate purchased power and fuel commitments, which increased approximately $46 million for the years 2005 through 2007 to $901 million.

See Note 4 for a list of payments due on total long-term debt and capitalized lease requirements.

Off-Balance Sheet Arrangements

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

APS is exposed to losses under the Palo Verde sale leaseback agreements upon the occurrence of certain events that APS does not consider to be reasonably likely to occur. Under certain circumstances (for example, the NRC issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), APS would be required to assume the debt associated with the transactions, make specified payments to the equity participants, and take title to the leased Unit 2 interests, which, if appropriate, may be required to be written down in value. If such an event had occurred as of March 31, 2005, APS would have been required to assume approximately $250 million of debt and pay the equity participants approximately $192 million.

Guarantees and Letters of Credit

We and certain of our subsidiaries have issued guarantees and letters of credit in support of our unregulated businesses. We have also obtained surety bonds on behalf of APS Energy Services. We have not recorded any liability on our Condensed Consolidated Balance Sheets with respect to these obligations. We generally agree to indemnification provisions related to liabilities arising from or related to certain of our agreements, with limited exceptions depending on the particular agreement. See Note 16 for additional information regarding guarantees and letters of credit.

See “Pinnacle West Energy” below for information regarding Pinnacle West’s guarantee of $500 million of Pinnacle West Energy’s debt obligations.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of May 9, 2005 are shown below and are considered to be “investment-grade” ratings. The ratings reflect the respective views of the rating

agencies, from which an explanation of the significance of their ratings may be obtained. There is no assurance that these ratings will continue for any given period of time. The ratings may be revised or withdrawn entirely by the rating agencies, if, in their respective judgments, circumstances so warrant. Any downward revision or withdrawal may adversely affect the market price of Pinnacle West's or APS' securities and serve to increase those companies' cost of and access to capital. It may also require additional collateral related to certain derivative instruments (see Note 10).

	Moody's	Standard & Poor's
Pinnacle West		
Senior unsecured	Baa2	BBB-
Commercial paper	P-2	A-2
Outlook	Stable	Stable
APS		
Senior unsecured	Baa1	BBB
Secured lease obligation bonds	Baa1	BBB
Commercial paper	P-2	A-2
Outlook	Stable	Stable

Debt Provisions

Pinnacle West's and APS' debt covenants related to their respective bank financing arrangements include a debt-to-total-capitalization ratio and an interest coverage test. Pinnacle West and APS comply with these covenants and each anticipates it will continue to meet these and other significant covenant requirements. These covenants require that the ratio of debt to total capitalization cannot exceed 65% for the Company and for APS. At March 31, 2005, the ratio was approximately 52% for Pinnacle West and 53% for APS. The provisions regarding interest coverage require a minimum cash coverage of two times the interest requirements for each of the Company and APS. The interest coverage is approximately 4 times under the Company's and APS' bank financing agreements. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants.

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

All of Pinnacle West's bank agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under these loan agreements if Pinnacle West or APS were to default under other agreements. All of APS' bank agreements contain cross-default provisions that would result in defaults and the potential acceleration of payment under these bank agreements if APS were to default under other agreements. Pinnacle West's and APS' credit agreements generally contain provisions under which the lenders could refuse to advance loans in the event of a material adverse change in financial condition or financial prospects, except that Pinnacle

West and APS do not have a material adverse change restriction for revolver borrowings equal to outstanding commercial paper amounts.

See Note 4 for further discussions.

Capital Needs and Resources — By Company

Pinnacle West (Parent Company)

Our primary cash needs are for dividends to our shareholders; interest payments and optional and mandatory repayments of principal on our long-term debt. The level of our common dividends and future dividend growth will be dependent on a number of factors including, but not limited to, payout ratio trends, free cash flow and financial market conditions.

Our primary sources of cash are dividends from APS, external financings and cash distributions from our other subsidiaries, primarily SunCor. We expect SunCor to make cash distributions to the parent company of approximately $80 to $100 million in 2005 based on anticipated asset sales activities. As discussed in Note 5 under “ACC Financing Order,” APS must maintain a common equity ratio of at least 40% and may not pay common dividends if the payment would reduce its common equity below that threshold. As defined in the Financing Order, common equity ratio is common equity divided by common equity plus long-term debt, including current maturities of long-term debt. At March 31, 2005, APS’ common equity ratio as defined was approximately 47%.

Pinnacle West sponsors a qualified pension plan for the employees of Pinnacle West and our subsidiaries. We contribute at least the minimum amount required under IRS regulations, but no more than the maximum tax-deductible amount. The minimum required funding takes into consideration the value of the fund assets and our pension obligation. We contributed $35 million in 2004. APS and other subsidiaries fund their share of the pension contribution, of which APS represents approximately 92% of the total funding amounts described above. The assets in the plan are comprised of common stocks, bonds and real estate. Future year contribution amounts are dependent on fund performance and fund valuation assumptions. The minimum required contribution to be made to our pension plan in 2005 is estimated to be approximately $50 million, $13 million of which was contributed on April 15, 2005. The expected contribution to our other postretirement benefit plans in 2005 is estimated to be approximately $40 million. We have not yet made any 2005 contributions to our other postretirement benefit plans.

On May 2, 2005, Pinnacle West redeemed at par all of its $165 million Floating Rate Senior Notes due November 1, 2005. The Company used cash on hand to redeem the notes.

On May 2, 2005, Pinnacle West issued 6,095,000 shares of its common stock at an offering price of $42 per share, resulting in net proceeds of approximately $248 million. Pinnacle West anticipates using the net proceeds of the offering for general corporate purposes, including making capital contributions to APS, which will, in turn, use such funds to pay a portion of the approximately $190 million purchase price of its pending acquisition of the Sundance Plant and other capital expenditures expected to be incurred to meet the growing needs of APS’ service territory. See “Request for Proposals and Asset Purchase Agreement” in Note 5 for information regarding APS’ pending acquisition of the Sundance Plant.

APS

APS' capital requirements consist primarily of capital expenditures and optional and mandatory redemptions of long-term debt. See "ACC Financing Order" in Note 5 for a discussion of the $500 million loan from APS to Pinnacle West Energy authorized by the ACC pursuant to the Financing Order. This loan was repaid on April 11, 2005.

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

On January 15, 2005, APS repaid its $100 million 6.25% Notes due 2005. APS used cash on hand to redeem these notes.

On March 1, 2005, Maricopa County, Arizona Pollution Control Corporation issued $164 million of variable interest rate pollution control bonds, 2005 Series A-E, due 2029. The bonds were issued to refinance $164 million of outstanding pollution control bonds. The Series A-E bonds are payable solely from revenues obtained from APS pursuant to a loan agreement between APS and Maricopa County, Arizona Pollution Control Corporation. These bonds are classified as long-term debt on our Condensed Consolidated Balance Sheets.

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

Pinnacle West Energy

Pinnacle West Energy's capital requirements consist primarily of capital expenditures. See the capital expenditures table above for actual capital expenditures during the three months ended March 31, 2005 and projected capital expenditures for the next three years (the estimated capital expenditures related to the PWEC Dedicated Assets are reflected in APS). Pinnacle West Energy's sources of cash will be cash infusions from the parent and cash from operations.

See "ACC Financing Order" in Note 5 for a discussion of the $500 million loan from APS to Pinnacle West Energy authorized by the ACC pursuant to the Financing Order. On April 11, 2005 Pinnacle West Energy issued $500 million Floating Rate Senior Notes due April 1, 2007. Pinnacle West has unconditionally guaranteed these notes. Pinnacle West Energy used the proceeds of this issuance to repay the APS loan.

See Note 19 of Notes to Condensed Consolidated Financial Statements above for a discussion of proposals to purchase our 75% ownership interest in the Silverhawk Power Station.

Other Subsidiaries

During the past three years, SunCor funded its cash requirements with cash from operations and its own external financings. SunCor's capital needs consist primarily of capital expenditures for land development and retail and office building construction. See the capital expenditures table above for actual capital expenditures during the three months ended March 31, 2005 and projected

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

We expect SunCor to make cash distributions to the parent company of approximately $80 to $100 million in 2005 based on anticipated asset sales activities.

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

APS Energy Services expects minimal capital expenditures over the next three years.

CRITICAL ACCOUNTING POLICIES

In preparing the financial statements in accordance with GAAP, management must often make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures at the date of the financial statements and during the reporting period. Some of those judgments can be subjective and complex, and actual results could differ from those estimates. Our most critical accounting policies include the impacts of regulatory accounting and the determination of the appropriate accounting for our pension and other postretirement benefits and derivatives accounting. There have been no changes to our critical accounting policies since our 2004 Form 10-K except for the impact of recent accounting pronouncements as discussed in Note 8. See “Critical Accounting Policies” in Item 7 of the 2004 Form 10-K for further details about our critical accounting policies.

PINNACLE WEST CONSOLIDATED – FACTORS AFFECTING OUR FINANCIAL OUTLOOK

Factors Affecting Operating Revenues, Purchased Power and Fuel Costs

General Electric operating revenues are derived from sales of electricity in regulated retail markets in Arizona and from competitive retail and wholesale power markets in the western United States. These revenues are 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. Competitive sales of energy and energy-related products and services are made by APS Energy Services in western states that have opened to competition.

Customer and Sales Growth The customer and sales growth referred to in this paragraph applies to Native Load customers and sales to them. Customer growth in APS’ service territory averaged about 3.4% a year for the three years 2002 through 2004; we currently expect customer growth to average about 3.8% per year from 2005 to 2007. We currently estimate that total retail electricity sales in kilowatt-hours will grow 5.0% on average, from 2005 through 2007, before the effects of weather variations. Customer growth for the three-month period ended March 31, 2005 compared with the prior year period was 4.0%.

Actual sales growth, excluding weather-related variations, may differ from our projections as a result of numerous factors, such as economic conditions, customer growth and usage patterns. Our experience indicates that a reasonable range of variation in our kilowatt-hour sales projection

attributable to such economic factors can result in increases or decreases in annual net income of up to $10 million.

Retail Rate Changes See “APS General Rate Case” in Note 5 for a discussion of the ACC’s order in APS’ general rate case. APS expects to file another general rate case in late 2005.

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

Purchased Power and Fuel Costs Purchased power and fuel costs are impacted by our electricity sales volumes, existing contracts for purchased power and generation fuel, our power plant performance, transmission availability or constraints, prevailing market prices, new generating plants being placed in service and our hedging program for managing such costs. See “Natural Gas Supply” in Note 12 for more information on fuel costs. See “APS General Rate Case” in Note 5 for information regarding the PSA approved by the ACC in APS’ general rate case.

Wholesale Power Market Conditions The marketing and trading division focuses primarily on managing APS’ purchased power and fuel risks in connection with its costs of serving retail customer demand. The marketing and trading division, subject to specified parameters, markets, hedges and trades in electricity, fuels and emission allowances and credits. Our future earnings will be affected by the strength or weakness of the wholesale power market.

Other Factors Affecting Financial Results

Operations and Maintenance Expenses Operations and maintenance expenses are impacted by growth, power plant additions and operations, inflation, outages, higher trending pension and other postretirement benefit costs and other factors.

Depreciation and Amortization Expenses Depreciation and amortization expenses are impacted by net additions to utility plant and other property, which includes generation construction or acquisition, and changes in regulatory asset amortization. See Note 19 for information on the potential sale of the Silverhawk Power Station. APS plans to acquire the Sundance Plant in 2005 and to issue requests for proposals to acquire additional long-term resources in 2006 and 2007.

Property Taxes 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 9.2% of assessed value for 2004 and 9.3% for 2003. We expect property taxes to increase as new power plants, the planned acquisition of the Sundance Plant and our additions to transmission and distribution facilities phase-in to the property tax base.

Interest Expense Interest expense is affected by the amount of debt outstanding and the interest rates on that debt. The primary factors affecting borrowing levels in the next several years are expected to be our capital requirements and our internally generated cash flow. Capitalized interest offsets a portion of interest expense while capital projects are under construction. We stop accruing capitalized interest on a project when it is placed in commercial operation. We placed new power plants in commercial operation in 2001, 2002, 2003 and 2004. Interest expense is also

affected by interest rates on variable-rate debt and interest rates on the refinancing of the Company's future liquidity needs.

Retail Competition The regulatory developments and legal challenges to the ACC's retail electric competition rules discussed in Note 5 have raised considerable uncertainty about the status and pace of retail electric competition and of electric restructuring in Arizona. Although some very limited retail competition existed in APS' service area in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to APS' customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter APS' service territory.

Subsidiaries In the case of SunCor, efforts to accelerate asset sales activities in 2004 were successful. A portion of these sales have been, and additional amounts may be required to be, reported as discontinued operations on our Condensed Consolidated Statements of Income. SunCor's net income was $45 million in 2004. See Note 18 for further discussion. We anticipate SunCor's earnings contributions in 2005 to be approximately $50 million after income taxes.

El Dorado's historical results are not indicative of future performance.

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

Market Risks

Our operations include managing market risks related to changes in interest rates, commodity prices and investments held by our nuclear decommissioning trust fund.

Interest Rate and Equity Risk

Our major financial market risk exposure is to changing interest rates. 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.

Commodity Price Risk

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

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

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

- Marketing and Trading – non-trading and trading derivative instruments of our competitive business segment.

The following tables show the pretax changes in mark-to-market of our non-trading and trading derivative positions for the three months ended March 31, 2005 and 2004 (dollars in millions):

	Three Months Ended March 31, 2005		Three Months Ended March 31, 2004	
	Regulated Electricity	Marketing and Trading	Regulated Electricity	Marketing and Trading
Mark-to-market of net positions at beginning of period	$ 34	$ 107	$ —	$ 69
Change in mark-to-market gains (losses) for future period deliveries	4	8	10	8
Changes in cash flow hedges recorded in OCI	108	(4)	30	17
Ineffective portion of changes in fair value recorded in earnings	8	—	1	1
Mark-to-market losses (gains) realized during the period	(1)	49	6	(2)
Mark-to-market of net positions at end of period	$ 153	$ 160	$ 47	$ 93

The tables below show the fair value of maturities of our non-trading and trading derivative contracts (dollars in millions) at March 31, 2005 by maturities and by the type of valuation that is performed to calculate the fair values. See Note 1, "Derivative Accounting," in Item 8 of our 2004 Form 10-K for more discussion of our valuation methods.

Regulated Electricity

Source of Fair Value	2005	2006	2007	Total fair value
Prices actively quoted	$ 93	$ 42	$ 13	$ 148
Prices provided by other external sources	—	5	1	6
Prices based on models and other valuation methods	(1)	—	—	(1)
Total by maturity	$ 92	$ 47	$ 14	$ 153

Marketing and Trading

Source of Fair Value	2005	2006	2007	2008	2009	Years thereafter	Total fair value
Prices actively quoted	$ 55	$ —	$ —	$ —	$ —	$ —	$ 55
Prices provided by other external sources	—	64	74	33	(1)	(1)	169
Prices based on models and other valuation methods	(8)	(21)	(27)	(8)	—	—	(64)
Total by maturity	$ 47	$ 43	$ 47	$ 25	$ (1)	$ (1)	$ 160

The table below shows the impact that hypothetical price movements of 10% would have on the market value of our risk management and trading assets and liabilities included on Pinnacle West's Condensed Consolidated Balance Sheets at March 31, 2005 and December 31, 2004 (dollars in millions).

	March 31, 2005 Gain (Loss)		December 31, 2004 Gain (Loss)	
Commodity	Price Up 10%	Price Down 10%	Price Up 10%	Price Down 10%
Mark-to-market changes reported in earnings (a):				
Electricity	$ (4)	$ 4	$ (4)	$ 4
Natural gas	2	(2)	2	(2)
Other	1	(1)	1	(1)
Mark-to-market changes reported in OCI (b):				
Electricity	47	(45)	35	(35)
Natural gas	62	(62)	43	(43)
Total	$ 108	$ (106)	$ 77	$ (77)

(a) These contracts are primarily structured sales activities 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 and electricity. The impact of these hypothetical price movements would substantially offset the

impact that these same price movements would have on the physical exposures being hedged.

Credit Risk

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We have risk management and trading contracts with many counterparties, including two counterparties for which a worst case exposure represents approximately 30% of Pinnacle West's $658 million of risk management and trading assets as of March 31, 2005. See Note 1, "Derivative Accounting" in Item 8 of our 2004 Form 10-K for a discussion of our credit valuation adjustment policy. See Note 10 for further discussion of credit risk.

ARIZONA PUBLIC SERVICE COMPANY – RESULTS OF OPERATIONS

General

Throughout the following explanations of APS' results of operations, we refer to "gross margin." Gross margin refers to electric operating revenues less purchased power and fuel costs. "Gross margin" is a "non-GAAP financial measure," as defined in accordance with SEC rules. Exhibit 99.4 reconciles this non-GAAP financial measure to operating income, which is the most directly comparable financial measure calculated and presented in accordance with GAAP. We view gross margin as an important performance measure of the core profitability of our operations. This measure is a key component of our internal financial reporting and is used by our management in analyzing our business segments. We believe that investors benefit from having access to the same financial measures that our management uses. In addition, we have reclassified certain prior period amounts to conform to our current period presentation.

Operating Results – Three-month period ended March 31, 2005 compared with the three-month period ended March 31, 2004

APS' net income for the three months ended March 31, 2005 was $27 million compared with $34 million for the prior-year period. The $7 million decrease in the period-to-period comparison reflects higher operations and maintenance costs primarily related to customer service, generation and benefit costs; the effects of milder weather on retail sales; lower other income, net of other expense, primarily due to gains on asset sales in the prior year period; and increased purchased power and fuel costs due to higher fuel and power prices. These negative factors were partially offset by the absence of regulatory asset amortization; higher retail sales volumes due to customer growth and usage; and lower replacement power costs due to fewer unplanned outages.

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

	Increase (Decrease)	
	Pretax	After Tax
Gross margin:		
Higher retail sales volumes due to customer growth, excluding weather effects	$ 7	$ 4
Lower replacement power costs due to fewer unplanned outages	4	2
Effects of weather on retail sales	(5)	(3)
Increased purchased power and fuel costs due to higher fuel and power prices	(2)	(1)
Net increase in gross margin	4	2
Higher operations and maintenance expense primarily related to customer service, generation and benefit costs	(16)	(10)
Depreciation and amortization decreases (increases):		
Absence of regulatory asset amortization	9	5
Increased delivery and other assets	(2)	(1)
Lower other income net of other expense primarily due to gain on asset sales in the prior-year period	(4)	(2)
Miscellaneous items, net	(1)	(1)
Net decrease in net income	$ (10)	$ (7)

Regulated Electricity Revenues

Regulated electricity revenues were $2 million lower for the three months ended March 31, 2005 compared with the prior-year period primarily as a result of:

- a $13 million increase in retail revenues related to customer growth, excluding weather effects;
- a $13 million decrease in retail revenues related to milder weather; and
- a $2 million decrease due to miscellaneous factors.

Marketing and Trading Revenues

Marketing and trading revenues were $2 million higher for the three months ended March 31, 2005 compared with the prior-year period primarily as a result of:

- a $7 million increase from generation sales other than Native Load primarily due to higher wholesale market prices and higher sales volumes; and
- $5 million of lower mark-to-market gains for future delivery due to higher prices.

LIQUIDITY AND CAPITAL RESOURCES – ARIZONA PUBLIC SERVICE COMPANY

Contractual Obligations

APS' future contractual obligations have not changed materially from the amounts disclosed in Part II, Item 7 of the 2004 Form 10-K. See Note S-1 for a list of APS' payments due on total long-term debt and capitalized lease requirements.

RISK FACTORS

Exhibit 99.1 and Exhibit 99.2, which are hereby incorporated by reference, contain a discussion of risk factors affecting Pinnacle West and APS, respectively.

FORWARD-LOOKING STATEMENTS

This document contains forward-looking statements based on current expectations, and neither Pinnacle West nor APS assumes any obligation to update these statements or make any further statements on any of these issues, except as required by applicable law. These forward-looking statements are often identified by words such as “estimate,” “predict,” “hope,” “may,” “believe,” “anticipate,” “plan,” “expect,” “require,” “intend,” “assume” and similar words. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from results or outcomes currently expected or sought by Pinnacle West or APS. In addition to the “Risk Factors” described in Exhibits 99.1 and 99.2 to this report, these factors include, but are not limited to:

- state and federal regulatory and legislative decisions and actions, including by the FERC;
- the ongoing restructuring of the electric industry, including the introduction of retail electric competition in Arizona and decisions impacting wholesale competition;
- the outcome of regulatory, legislative and judicial proceedings relating to the restructuring;
- market prices for electricity and natural gas;
- power plant performance and outages;
- transmission outages and constraints;
- weather variations affecting local and regional customer energy usage;
- customer growth and energy usage;
- regional economic and market conditions, including the results of litigation and other proceedings resulting from the California energy situation, volatile purchased power and fuel costs and the completion of generation and transmission construction in the region, which could affect customer growth and the cost of power supplies;
- the cost of debt and equity capital and access to capital markets;
- the uncertainty that current credit ratings will remain in effect for any given period of time;
- our ability to compete successfully outside traditional regulated markets (including the wholesale market);
- the performance of our marketing and trading activities due to volatile market liquidity and any deteriorating counterparty credit and the use of derivative contracts in our business (including the interpretation of the subjective and complex accounting rules related to these contracts);
- changes in accounting principles generally accepted in the United States of America and the interpretation of those principles;
- the performance of the stock market and the changing interest rate environment, which affect the amount of required contributions to Pinnacle West’s pension plan and APS’ nuclear decommissioning trust funds, as well as the reported costs of providing pension and other postretirement benefits;

- technological developments in the electric industry;
- the strength of the real estate market in SunCor's market areas, which include Arizona, Idaho, New Mexico and Utah; and
- other uncertainties, all of which are difficult to predict and many of which are beyond the control of Pinnacle West and APS.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See “Pinnacle West Consolidated – Factors Affecting Our Financial Outlook” in Item 2 above for a discussion of quantitative and qualitative disclosures about market risks.

ITEM 4. CONTROLS AND PROCEDURES

(a) Disclosure Controls and Procedures

The term “disclosure controls and procedures” means controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Securities Exchange Act of 1934 (the “Exchange Act”) (15 U.S.C. 78a *et seq*.) is recorded, processed, summarized and reported, within the time periods specified in the SEC’s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is accumulated and communicated to a company’s management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

Pinnacle West’s management, with the participation of Pinnacle West’s Chief Executive Officer and Chief Financial Officer, have evaluated the effectiveness of Pinnacle West’s disclosure controls and procedures as of March 31, 2005. Based on that evaluation, Pinnacle West’s Chief Executive Officer and Chief Financial Officer have concluded that, as of that date, Pinnacle West’s disclosure controls and procedures were effective.

APS’ management, with the participation of APS’ Chief Executive Officer and Chief Financial Officer, have evaluated the effectiveness of APS’ disclosure controls and procedures as of March 31, 2005. Based on that evaluation, APS’ Chief Executive Officer and Chief Financial Officer have concluded that, as of that date, APS’ disclosure controls and procedures were effective.

(b) Changes In Internal Control Over Financial Reporting

The term “internal control over financial reporting” (defined in SEC Rule 13a-15(f)) refers to the process of a company that is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

No change in Pinnacle West’s or APS’ internal control over financial reporting occurred during the fiscal quarter ended March 31, 2005 that materially affected, or is reasonably likely to materially affect, Pinnacle West’s or APS’ internal control over financial reporting.

Part II — OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

See Note 12 of Notes to Condensed Consolidated Financial Statements in regard to pending or threatened litigation or other disputes.

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.

Regulatory Matters

See Note 5 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of regulatory developments.

Environmental Matters

See “Environmental Matters — Superfund” in Note 12 of Notes to Condensed Consolidated Financial Statements for a discussion of a Superfund site.

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Item 6. EXHIBITS

(a) Exhibits

Exhibit No.	*Registrant(s)*	*Description*
12.1	Pinnacle West	Ratio of Earnings to Fixed Charges
12.2	APS	Ratio of Earnings to Fixed Charges
31.1	Pinnacle West	Certificate of William J. Post, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended
31.2	Pinnacle West	Certificate of Donald E. Brandt, Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended
31.3	APS	Certificate of Jack E. Davis, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended
31.4	APS	Certificate of Donald E. Brandt, Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended
32.1	Pinnacle West	Certification of Chief Executive Officer and Chief Financial Officer, pursuant to 18 U.S.C. Section 1850, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	APS	Certification of Chief Executive Officer and Chief Financial Officer, pursuant to 18 U.S.C. Section 1850, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1	Pinnacle West	Pinnacle West Risk Factors
99.2	APS	APS Risk Factors
99.3	Pinnacle West	Reconciliation of Operating Income to Gross Margin

Exhibit No.	Registrant(s)	Description
99.4	APS	Reconciliation of Operating Income to Gross Margin
99.5	Pinnacle West/APS	Opinion and Order, ACC Decision No. 67744 dated April 7, 2005 (see Exhibit No. 99.6 below for Attachment A to the Opinion and Order, the 2004 Settlement Agreement)

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

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit [1]	Date Effective
3.1	Pinnacle West	Articles of Incorporation, restated as of July 29, 1988	19.1 to Pinnacle West's September 1988 Form 10-Q Report, File No. 1-8962	11-14-88
3.2	Pinnacle West	Pinnacle West Capital Corporation Bylaws, amended as of June 23, 2004	3.1 to Pinnacle West's June 30, 2004 Form 10-Q Report, File No. 1-8962	8-9-04
3.3	APS	Articles of Incorporation, restated as of May 25, 1988	4.2 to APS' Form S-3 Registration Nos. 33-33910 and 33-55248 by means of September 24, 1993 Form 8-K Report, File No. 1-4473	9-29-93
3.4	APS	Arizona Public Service Company Bylaws, amended as of June 23, 2004	3.1 to APS' June 30, 2004 Form 10-Q Report, File No. 1-4473	8-9-04
99.6	Pinnacle West APS	2004 Settlement Agreement dated August 18, 2004	99.1 to Pinnacle West's August 18, 2004 Form 8-K Report, File No. 1-8962	8-18-04

1 Reports filed under File 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, each registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PINNACLE WEST CAPITAL CORPORATION
(Registrant)

Dated: May 9, 2004 By: /s/ Donald E. Brandt
Donald E. Brandt
Executive Vice President and Chief
Financial Officer
(Principal Financial Officer
and Officer Duly Authorized to sign this Report)

ARIZONA PUBLIC SERVICE COMPANY
(Registrant)

Dated: May 9, 2004 By: /s/ Donald E. Brandt
Donald E. Brandt
Executive Vice President and Chief
Financial Officer
(Principal Financial Officer
and Officer Duly Authorized to sign this Report)

Exhibit Index

Exhibit No.	*Registrant(s)*	*Description*
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99.1	Pinnacle West	Pinnacle West Risk Factors
99.2	APS	APS Risk Factors
99.3	Pinnacle West	Reconciliation of Operating Income to Gross Margin
99.4	APS	Reconciliation of Operating Income to Gross Margin
99.5	Pinnacle West/APS	Opinion and Order, ACC Decision No. 67744 dated April 7, 2005

Exhibit 12.1

PINNACLE WEST CAPITAL CORPORATION
COMPUTATION OF EARNINGS TO FIXED CHARGES
(Thousands of Dollars)

	Three Months Ended March 31,	Twelve Months Ended December 31,				
	2005	2004	2003	2002	2001	2000
Earnings:						
Income from continuing Operations	$ 23,656	$ 235,218	$ 225,803	$ 241,998	$ 327,367	$ 302,332
Income Taxes	14,732	128,857	102,473	155,710	213,535	194,200
Fixed Charges	56,747	227,135	235,407	219,178	211,958	202,804
Total Earnings	$ 95,135	$ 591,210	$ 563,683	$ 616,886	$ 752,860	$ 699,336
Fixed Charges:						
Interest Expense	$ 49,195	$ 195,859	$ 204,339	$ 187,039	$ 175,822	$ 166,447
Estimated Interest Portion of Annual Rents	7,552	31,276	31,068	32,139	36,136	36,357
Total Fixed Charges	$ 56,747	$ 227,135	$ 235,407	$ 219,178	$ 211,958	$ 202,804
Ratio of Earnings to Fixed Charges (rounded down)	1.67	2.60	2.39	2.81	3.55	3.44

Exhibit 12.2

ARIZONA PUBLIC SERVICE COMPANY
COMPUTATION OF EARNINGS TO FIXED CHARGES
($000's)

	Three Months Ended March 31,	Twelve Months Ended December 31,				
	2005	2004	2003	2002	2001	2000
Earnings:						
Income from continuing operations	$ 27,045	$ 199,627	$ 180,937	$ 199,343	$ 280,688	$ 306,594
Income taxes	17,217	120,030	86,854	126,805	183,136	195,665
Fixed charges	45,044	181,372	181,793	168,985	166,939	179,381
Total earnings	$ 89,306	$ 501,029	$ 449,584	$ 495,133	$ 630,763	$ 681,640
Fixed Charges:						
Interest charges	$ 36,708	$ 146,983	$ 147,610	$ 133,878	$ 130,525	$ 141,886
Amortization of debt discount	1,004	4,854	3,337	2,888	2,650	2,105
Estimated interest portion of annual rents	7,332	29,535	30,846	32,219	33,764	35,390
Total fixed charges.	$ 45,044	$ 181,372	$ 181,793	$ 168,985	$ 166,939	$ 179,381
Ratio of Earnings to Fixed Charges (rounded down)	1.98	2.76	2.47	2.93	3.77	3.79

EXHIBIT 31.1

CERTIFICATION

I, William J. Post, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Pinnacle West Capital Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 9, 2005.

/s/ William J. Post

William J. Post
Chairman and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Donald E. Brandt, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Pinnacle West Capital Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 9, 2005.

/s/ Donald E. Brandt

Donald E. Brandt
Executive Vice President &
Chief Financial Officer

EXHIBIT 31.3

CERTIFICATION

I, Jack E. Davis, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Arizona Public Service Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 9, 2005.

/s/ Jack E. Davis

Jack E. Davis
President and Chief Executive Officer

EXHIBIT 31.4

CERTIFICATION

I, Donald E. Brandt, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Arizona Public Service Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 9, 2005.

/s/ Donald E. Brandt

Donald E. Brandt
Executive Vice President &
Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION
OF
CHIEF EXECUTIVE OFFICER
AND
CHIEF FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, William J. Post, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Quarterly Report on Form 10-Q of Pinnacle West Capital Corporation for the fiscal quarter ended March 31, 2005, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that the information contained in such Quarterly Report on Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Pinnacle West Capital Corporation.

Date: May 9, 2005.

/s/ William J. Post
William J. Post
Chairman and Chief Executive Officer

I, Donald E. Brandt, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Quarterly Report on Form 10-Q of Pinnacle West Capital Corporation for the fiscal quarter ended March 31, 2005 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that the information contained in such Quarterly Report on Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Pinnacle West Capital Corporation.

Date: May 9, 2005.

/s/ Donald E. Brandt
Donald E. Brandt
Executive Vice President and
Chief Financial Officer

EXHIBIT 32.2

CERTIFICATION
OF
CHIEF EXECUTIVE OFFICER
AND
CHIEF FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Jack E. Davis, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Quarterly Report on Form 10-Q of Arizona Public Service Company for the fiscal quarter ended March 31, 2005 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that the information contained in such Quarterly Report on Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Arizona Public Service Company.

Date: May 9, 2005.

/s/ Jack E. Davis
Jack E. Davis
President and Chief Executive Officer

I, Donald E. Brandt, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Quarterly Report on Form 10-Q of Arizona Public Service Company for the fiscal quarter ended March 31, 2005 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that the information contained in such Quarterly Report on Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Arizona Public Service Company.

Date: May 9, 2005.

/s/ Donald E. Brandt
Donald E. Brandt
Executive Vice President and
Chief Financial Officer

Exhibit 99.1

PINNACLE WEST RISK FACTORS

(Report on Form 10-Q for the fiscal quarter ended March 31, 2005)

Set forth below and in other documents we file with the Securities and Exchange Commission are risks and uncertainties that could affect our financial results.

Deregulation or restructuring of the electric industry may result in increased competition, which could have a significant adverse impact on our business and our financial results.

In 1999, the Arizona Corporation Commission (the "ACC") approved rules for the introduction of retail electric competition in Arizona. Retail competition could have a significant adverse financial impact on us due to an impairment of assets, a loss of retail customers, lower profit margins or increased costs of capital. Legal challenges to the rules have raised considerable uncertainty about the status and pace of retail electric competition and of electric restructuring in Arizona. Although some very limited retail competition existed in the service area of Arizona Public Service Company ("APS") in 1999 and 2000, there are currently no active retail competitors offering unbundled energy or other utility services to APS' customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter APS' service territory.

As a result of changes in federal law and regulatory policy, competition in the wholesale electricity market has greatly increased due to a greater participation by traditional electricity suppliers, non-utility generators, independent power producers, and wholesale power marketers and brokers. This increased competition could affect our load forecasts, plans for power supply and wholesale energy sales and related revenues. As a result of the changing regulatory environment and the relatively low barriers to entry, we expect wholesale competition to increase. As competition continues to increase, our financial position and results of operations could be adversely affected.

We are subject to complex government regulation that may have a negative impact on our business and our results of operations.

We are, directly and through our subsidiaries, subject to governmental regulation that may have a negative impact on our business and results of operations. We are a "holding company" within the meaning of the Public Utility Holding Company Act of 1935 ("PUHCA"); however, we are exempt from the provisions of PUHCA (except Section 9(a)(2) thereof) by virtue of our filing of an annual exemption statement with the Securities and Exchange Commission (the "SEC").

APS is subject to comprehensive regulation by several federal, state and local regulatory agencies, which significantly influence its operating environment and may affect its ability to recover costs from utility customers. APS is required to have numerous permits, approvals and certificates from the agencies that regulate APS' business. The FERC, the Nuclear Regulatory Commission ("NRC"), the Environmental Protection Agency ("EPA"), and the ACC regulate many aspects of our utility operations, including siting and construction of facilities, customer service and the rates that APS can charge customers. We believe the necessary permits, approvals and certificates have been obtained for APS' existing operations. However, changes in regulations or the imposition of additional regulations could have an adverse impact on our results of operations. We are also unable to predict the impact on our business and operating results from pending or future regulatory activities of any of these agencies.

We are subject to numerous environmental laws and regulations that may increase our cost of operations, impact our business plans, or expose us to environmental liabilities.

We are subject to numerous environmental laws and regulations affecting many aspects of our present and future operations, including air emissions, water quality, wastewater discharges, solid waste, and hazardous waste. These laws and regulations can result in increased capital, operating, and other costs, particularly with regard to enforcement efforts focused on power plant emissions obligations. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations. We cannot predict the outcome (financial or operational) of any related litigation that may arise.

In addition, we may be a responsible party for environmental clean up at sites identified by a regulatory body. We cannot predict with certainty the amount and timing of all future expenditures related to environmental matters

because of the difficulty of estimating clean-up costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties.

We cannot be sure that existing environmental regulations will not be revised or that new regulations seeking to protect the environment will not be adopted or become applicable to us. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from APS' customers, could have a material adverse effect on our results of operations.

There are inherent risks in the operation of nuclear facilities, such as environmental, health and financial risks and the risk of terrorist attack.

Through APS, we have an ownership interest in and operate, on behalf of a group of owners, the Palo Verde Nuclear Generating Station ("Palo Verde"), which is the largest nuclear electric generating facility in the United States. Palo Verde is subject to environmental, health and financial risks such as the ability to dispose of spent nuclear fuel, the ability to maintain adequate reserves for decommissioning, potential liabilities arising out of the operation of these facilities, and the costs of securing the facilities against possible terrorist attacks and unscheduled outages due to equipment and other problems. We maintain nuclear decommissioning trust funds and external insurance coverage to minimize our financial exposure to some of these risks; however, it is possible that damages could exceed the amount of insurance coverage.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of noncompliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. In addition, although we have no reason to anticipate a serious nuclear incident at Palo Verde, if an incident did occur, it could materially and adversely affect our results of operations or financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit.

The uncertain outcome regarding the creation of regional transmission organizations, or RTOs, and implementation of the FERC's standard market design may materially impact our operations, cash flows or financial position.

In a December 1999 order, the FERC established characteristics and functions that must be met by utilities in forming and operating RTOs. The characteristics for an acceptable RTO include independence from market participants, operational control over a region large enough to support efficient and nondiscriminatory markets and exclusive authority to maintain short-term reliability. Additionally, in a pending notice of proposed rulemaking, the FERC is considering implementing a standard market design for wholesale markets. On October 16, 2001, APS and other owners of electric transmission lines in the southwestern U.S. filed with the FERC a request for a declaratory order confirming that their proposal to form WestConnect RTO, LLC would satisfy the FERC's requirements for the formation of an RTO. On October 10, 2002, the FERC issued an order finding that the WestConnect proposal, if modified to address specified issues, could meet the FERC's RTO requirements and provide the basic framework for a standard market design for the southwestern U.S. Since that time, APS has been evaluating a phased approach to RTO implementation in the desert Southwest. APS is currently participating with other entities in the southwestern U.S. in a cost/benefit analysis of implementing the WestConnect RTO, the results of which are expected to be completed in 2005.

If APS ultimately joins an RTO, APS could incur increased transmission-related costs and receive reduced transmission service revenues; APS may be required to expand its transmission system according to decisions made by the RTO rather than its internal planning process; and APS may experience other impacts on its operations, cash flows or financial position that will not be quantifiable until the final tariffs and other material terms of the RTO are known.

Recent events in the energy markets that are beyond our control may have negative impacts on our business.

As a result of the energy crisis in California during the summer of 2001, the recent volatility of natural gas prices in North America, the filing of bankruptcy by the Enron Corporation, and investigations by governmental

authorities into energy trading activities, companies generally in the regulated and unregulated utility businesses have been under an increased amount of public and regulatory scrutiny. The capital markets and rating agencies also have increased their level of scrutiny. We believe that we are in material compliance with all applicable laws, but it is difficult or impossible to predict or control what effect these or related issues may have on our business or our access to the capital markets.

Our results of operations can be adversely affected by milder weather.

Weather conditions directly influence the demand for electricity and affect the price of energy commodities. Electric power demand is generally a seasonal business. In Arizona, demand for power peaks during the hot summer months, with market prices also peaking at that time. As a result, our overall operating results fluctuate substantially on a seasonal basis. In addition, we have historically sold less power, and consequently earned less income, when weather conditions are milder. As a result, unusually mild weather could diminish our results of operations and harm our financial condition.

Our cash flow largely depends on the performance of our subsidiaries.

We conduct our operations primarily through subsidiaries. Substantially all of our consolidated assets are held by such subsidiaries. Accordingly, our cash flow is dependent upon the earnings and cash flows of these subsidiaries and their distributions to us. The subsidiaries are separate and distinct legal entities and have no obligation to make distributions to us.

The debt agreements of some of our subsidiaries may restrict their ability to pay dividends, make distributions or otherwise transfer funds to us. As part of the ACC's approval of a $500 million financing arrangement between APS and Pinnacle West Energy, an ACC order requires APS to indefinitely maintain a common equity ratio of at least 40% and does not allow APS to pay common dividends if the payment would reduce its common equity below that threshold. As defined in the ACC financing order approving the arrangement, common equity ratio is common equity divided by common equity plus long-term debt, including current maturities of long-term debt. At March 31, 2005, APS' common equity ratio, as defined, was approximately 47%.

Our debt securities will be structurally subordinated to the debt securities and other obligations of our subsidiaries.

Because we are structured as a holding company, all existing and future debt and other liabilities of our subsidiaries will be effectively senior in right of payment to our debt securities. None of the indentures under which we or our subsidiaries may issue debt securities limits our ability or the ability of our subsidiaries to incur additional debt in the future. The assets and cash flows of our subsidiaries will be available, in the first instance, to service their own debt and other obligations. Our ability to have the benefit of their assets and cash flows, particularly in the case of any insolvency or financial distress affecting our subsidiaries, would arise only through our equity ownership interests in our subsidiaries and only after their creditors have been satisfied.

If we are not able to access capital at competitive rates, our ability to implement our financial strategy will be adversely affected.

We rely on access to short-term money markets, longer-term capital markets and the bank markets as a significant source of liquidity and for capital requirements not satisfied by the cash flow from our operations. We believe that we will maintain sufficient access to these financial markets based upon current credit ratings. However, certain market disruptions or a downgrade of our credit ratings may increase our cost of borrowing or adversely affect our ability to access one or more financial markets. Such disruptions could include:

- an economic downturn;
- capital market conditions generally;
- the bankruptcy of an unrelated energy company;
- increased market prices for electricity and gas;
- terrorist attacks or threatened attacks on our facilities or those of unrelated energy companies; or

- the overall health of the utility industry.

Changes in economic conditions could result in higher interest rates, which would increase our interest expense on our debt and reduce funds available to us for our current plans. Additionally, an increase in our leverage could adversely affect us by:

- increasing the cost of future debt financing;
- increasing our vulnerability to adverse economic and industry conditions;
- requiring us to dedicate a substantial portion of our cash flow from operations to payments on our debt, which would reduce funds available to us for operations, future business opportunities or other purposes; and
- placing us at a competitive disadvantage compared to our competitors that have less debt.

A significant reduction in our credit ratings could materially and adversely affect our business, financial condition and results of operations.

We cannot be sure that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Any downgrade could increase our borrowing costs, which would diminish our financial results. We would likely be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources could decrease. In addition, borrowing costs under certain of our existing credit facilities depend on our credit ratings. A downgrade could also require us to provide additional support in the form of letters of credit or cash or other collateral to various counterparties. If our short-term ratings were to be lowered, it could limit our access to the commercial paper market. We note that the ratings from rating agencies are not recommendations to buy, sell or hold our securities and that each rating should be evaluated independently of any other rating.

The use of derivative contracts in the normal course of our business and changing interest rates and market conditions could result in financial losses that negatively impact our results of operations.

Our operations include managing market risks related to commodity prices and, subject to specified risk parameters, engaging in marketing and trading activities intended to profit from market price movements. We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal, and emissions allowances and credits. We have 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.

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

Changing interest rates will affect interest paid on variable-rate debt and interest earned by our pension plan and nuclear decommissioning trust funds. Our policy is to manage interest rates through the use of a combination of fixed-rate and floating-rate debt. The pension plan is also impacted by the discount rate, which is the interest rate used to discount future pension obligations. Continuation of recent decreases in the discount rate would result in increases in pension costs, cash contributions, and charges to other comprehensive income. The pension plan and nuclear decommissioning trust funds also have risks associated with changing market values of equity investments. A significant portion of the pension costs and all of the nuclear decommissioning costs are recovered in regulated electricity prices.

Actual results could differ from estimates used to prepare our financial statements.

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

- Regulatory Accounting — Regulatory accounting allows for the actions of regulators, such as the ACC and the FERC, to be reflected in our financial statements. Their actions may cause us to capitalize costs that would otherwise be included as an expense in the current period by unregulated companies. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings. We had $138 million of regulatory assets on the Consolidated Balance Sheets at March 31, 2005.

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

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

The market price of our common stock may be volatile.

The market price of our common stock could be subject to significant fluctuations in response to factors such as the following, some of which are beyond our control:

- variations in our quarterly operating results;

- operating results that vary from the expectations of management, securities analysts and investors;

- changes in expectations as to our future financial performance, including financial estimates by securities analysts and investors;

- developments generally affecting industries in which we operate, particularly the energy distribution and energy generation industries;

- announcements by us or our competitors of significant contracts, acquisitions, joint marketing relationships, joint ventures or capital commitments;

- announcements by third parties of significant claims or proceedings against us;

- favorable or adverse regulatory developments;

- our dividend policy;

- future sales of our equity or equity-linked securities; and

- general domestic and international economic conditions.

In addition, the stock market in general has experienced volatility that has often been unrelated to the operating performance of a particular company. These broad market fluctuations may adversely affect the market price of our common stock.

Our common stock price could be affected because a substantial number of our shares could be available for sale in the future.

Sales in the public market of a substantial number of shares of common stock could depress the market price of the common stock and could impair our ability to raise capital through the sale of additional equity securities. Because of the number of shares of our common stock that we are authorized to issue under our articles of incorporation, a substantial number of shares of our common stock could be available for future sale.

We may enter into credit and other agreements from time to time that restrict our ability to pay dividends.

Payment of dividends on our common stock may be restricted by credit and other agreements entered into by us from time to time. At March 31, 2005, there were no material restrictions on our ability to pay dividends under any such agreement.

Certain provisions of our articles of incorporation and bylaws and of Arizona law make it more difficult for shareholders to change the composition of our board and may discourage takeover attempts that could be beneficial to us and our shareholders.

Certain provisions of our articles of incorporation and bylaws and of Arizona law make it more difficult for shareholders to change the composition of our board and may discourage unsolicited attempts to acquire us, which could preclude our shareholders from receiving a change of control premium. These provisions include the following:

- provisions of our bylaws and Arizona law that restrict our ability to engage in a wide range of “business combination” transactions with an “interested shareholder” (generally, any person who owns 10% or more of our outstanding voting power or any of our affiliates or associates) or any affiliate or associate of an interested shareholder, unless specific conditions are met;

- anti-greenmail provisions of Arizona law and our bylaws that prohibit us from purchasing shares of our voting stock from beneficial owners of more than 5% of our outstanding shares unless specified conditions are satisfied;

- provisions of our bylaws and Arizona law that provide that shareholder action may be taken only at an annual or special meeting or by unanimous written consent, and provisions of our bylaws that provide that a special meeting of shareholders may only be called by a majority of our Board of Directors, the Chairman of our Board of Directors, or our President;

- advance notice procedures for nominating candidates to our Board of Directors or presenting matters at shareholder meetings;

- provisions of our articles and bylaws that provide for a staggered Board of Directors;

- provisions of our bylaws that provide that shareholders may only remove a director with or without cause if the votes cast in favor of such removal exceed the votes cast against such removal (with special requirements, based on cumulative voting rights, if less than the entire board is to be removed); and

- the ability of our Board of Directors to issue additional shares of common stock and shares of preferred stock and to determine the price and, with respect to preferred stock, the other terms, including preferences and voting rights, of those shares without shareholder approval.

In addition, we have adopted a shareholder rights plan that may have the effect of discouraging unsolicited takeover proposals, including takeover proposals that could result in a premium over the market price of our common stock.

While these provisions have the effect of encouraging persons seeking to acquire control of us to negotiate with our Board of Directors, they could enable the board to hinder or frustrate a transaction that some, or a majority, of our shareholders might believe to be in their best interests and, in that case, may prevent or discourage attempts to remove and replace incumbent directors.

Exhibit 99.2

APS RISK FACTORS

(Report on Form 10-Q for the fiscal quarter ended March 31, 2005)

Set forth below and in other documents we file with the Securities and Exchange Commission are risks and uncertainties that could affect our financial results.

Deregulation or restructuring of the electric industry may result in increased competition, which could have a significant adverse impact on our business and our financial results.

In 1999, the Arizona Corporation Commission (the "ACC") approved rules for the introduction of retail electric competition in Arizona. Retail competition could have a significant adverse financial impact on us due to an impairment of assets, a loss of retail customers, lower profit margins or increased costs of capital. Legal challenges to the rules have raised considerable uncertainty about the status and pace of retail electric competition and of electric restructuring in Arizona. Although some very limited retail competition existed in our service area in 1999 and 2000, there are currently no active retail competitors offering unbundled energy or other utility services to our customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter our service territory.

As a result of changes in federal law and regulatory policy, competition in the wholesale electricity market has greatly increased due to a greater participation by traditional electricity suppliers, non-utility generators, independent power producers, and wholesale power marketers and brokers. This increased competition could affect our load forecasts, plans for power supply and wholesale energy sales and related revenues. As a result of the changing regulatory environment and the relatively low barriers to entry, we expect wholesale competition to increase. As competition continues to increase, our financial position and results of operations could be adversely affected.

We are subject to complex government regulation that may have a negative impact on our business and our results of operations.

We are subject to governmental regulation that may have a negative impact on our business and results of operations. We are a "subsidiary company" of a "holding company" within the meaning of the Public Utility Holding Company Act of 1935 ("PUHCA"); however, we are exempt from the provisions of PUHCA (except Section 9(a)(2) thereof) by virtue of the filing of an annual exemption statement with the Securities and Exchange Commission (the "SEC") by our parent company, Pinnacle West Capital Corporation ("Pinnacle West").

We are subject to comprehensive regulation by several federal, state and local regulatory agencies, which significantly influence our operating environment and may affect our ability to recover costs from utility customers. We are required to have numerous permits, approvals and certificates from the agencies that regulate our business. The FERC, the Nuclear Regulatory Commission ("NRC"), the Environmental Protection Agency ("EPA"), and the ACC regulate many aspects of our utility operations, including siting and construction of facilities, customer service and the rates that we can charge customers. We believe the necessary permits, approvals and certificates have been obtained for our existing operations. However, changes in regulations or the imposition of additional regulations could have an adverse impact on our results of operations. We are also unable to predict the impact on our business and operating results from pending or future regulatory activities of any of these agencies.

We are subject to numerous environmental laws and regulations that may increase our cost of operations, impact our business plans, or expose us to environmental liabilities.

We are subject to numerous environmental laws and regulations affecting many aspects of our present and future operations, including air emissions, water quality, wastewater discharges, solid waste, and hazardous waste. These laws and regulations can result in increased capital, operating, and other costs, particularly with regard to enforcement efforts focused on power plant emissions obligations. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations. We cannot predict the outcome (financial or operational) of any related litigation that may arise.

In addition, we may be a responsible party for environmental clean up at sites identified by a regulatory body. We cannot predict with certainty the amount and timing of all future expenditures related to environmental matters because of the difficulty of estimating clean-up costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties.

We cannot be sure that existing environmental regulations will not be revised or that new regulations seeking to protect the environment will not be adopted or become applicable to us. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our results of operations.

There are inherent risks in the operation of nuclear facilities, such as environmental, health and financial risks and the risk of terrorist attack.

We have an ownership interest in and operate, on behalf of a group of owners, the Palo Verde Nuclear Generating Station ("Palo Verde"), which is the largest nuclear electric generating facility in the United States. Palo Verde is subject to environmental, health and financial risks such as the ability to dispose of spent nuclear fuel, the ability to maintain adequate reserves for decommissioning, potential liabilities arising out of the operation of these facilities, and the costs of securing the facilities against possible terrorist attacks and unscheduled outages due to equipment and other problems. We maintain nuclear decommissioning trust funds and external insurance coverage to minimize our financial exposure to some of these risks; however, it is possible that damages could exceed the amount of insurance coverage.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of noncompliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. In addition, although we have no reason to anticipate a serious nuclear incident at Palo Verde, if an incident did occur, it could materially and adversely affect our results of operations or financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit.

The uncertain outcome regarding the creation of regional transmission organizations, or RTOs, and implementation of the FERC's standard market design may materially impact our operations, cash flows or financial position.

In a December 1999 order, the FERC established characteristics and functions that must be met by utilities in forming and operating RTOs. The characteristics for an acceptable RTO include independence from market participants, operational control over a region large enough to support efficient and nondiscriminatory markets and exclusive authority to maintain short-term reliability. Additionally, in a pending notice of proposed rulemaking, the FERC is considering implementing a standard market design for wholesale markets. On October 16, 2001, we and other owners of electric transmission lines in the southwestern U.S. filed with the FERC a request for a declaratory order confirming that our proposal to form WestConnect RTO, LLC would satisfy the FERC's requirements for the formation of an RTO. On October 10, 2002, the FERC issued an order finding that the WestConnect proposal, if modified to address specified issues, could meet the FERC's RTO requirements and provide the basic framework for a standard market design for the southwestern U.S. Since that time, we have been evaluating a phased approach to RTO implementation in the desert Southwest. We are currently participating with other entities in the southwestern U.S. in a cost/benefit analysis of implementing the WestConnect RTO, the results of which are expected to be completed in 2005.

If we ultimately join an RTO, we could incur increased transmission-related costs and receive reduced transmission service revenues; we may be required to expand our transmission system according to decisions made by the RTO rather than our internal planning process; and we may experience other impacts on our operations, cash flows or financial position that will not be quantifiable until the final tariffs and other material terms of the RTO are known.

Recent events in the energy markets that are beyond our control may have negative impacts on our business.

As a result of the energy crisis in California during the summer of 2001, the recent volatility of natural gas prices in North America, the filing of bankruptcy by the Enron Corporation, and investigations by governmental authorities into energy trading activities, companies generally in the regulated and unregulated utility businesses have been under an increased amount of public and regulatory scrutiny. The capital markets and rating agencies also have increased their level of scrutiny. We believe that we are in material compliance with all applicable laws, but it is difficult or impossible to predict or control what effect these or related issues may have on our business or our access to the capital markets.

Our results of operations can be adversely affected by milder weather.

Weather conditions directly influence the demand for electricity and affect the price of energy commodities. Electric power demand is generally a seasonal business. In Arizona, demand for power peaks during the hot summer months, with market prices also peaking at that time. As a result, our overall operating results fluctuate substantially on a seasonal basis. In addition, we have historically sold less power, and consequently earned less income, when weather conditions are milder. As a result, unusually mild weather could diminish our results of operations and harm our financial condition.

If we are not able to access capital at competitive rates, our ability to implement our financial strategy will be adversely affected.

We rely on access to short-term money markets, longer-term capital markets and the bank markets as a significant source of liquidity and for capital requirements not satisfied by the cash flow from our operations. We believe that we will maintain sufficient access to these financial markets based upon current credit ratings. However, certain market disruptions or a downgrade of our credit ratings may increase our cost of borrowing or adversely affect our ability to access one or more financial markets. Such disruptions could include:

- an economic downturn;
- capital market conditions generally;
- the bankruptcy of an unrelated energy company;
- increased market prices for electricity and gas;
- terrorist attacks or threatened attacks on our facilities or those of unrelated energy companies; or
- the overall health of the utility industry.

Changes in economic conditions could result in higher interest rates, which would increase our interest expense on our debt and reduce funds available to us for our current plans. Additionally, an increase in our leverage could adversely affect us by:

- increasing the cost of future debt financing;
- increasing our vulnerability to adverse economic and industry conditions;
- requiring us to dedicate a substantial portion of our cash flow from operations to payments on our debt, which would reduce funds available to us for operations, future business opportunities or other purposes; and
- placing us at a competitive disadvantage compared to our competitors that have less debt.

A significant reduction in our credit ratings could materially and adversely affect our business, financial condition and results of operations.

We cannot be sure that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Any downgrade could increase our borrowing costs, which would diminish our financial results. We would likely be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources could decrease. In addition, borrowing costs under certain of our existing credit facilities depend on our credit ratings. A downgrade could also require us to provide additional support in the form of letters of credit or cash or other collateral to various counterparties. If our short-term ratings were to be lowered, it could limit our access to the commercial paper market. We note that the ratings from rating agencies are not recommendations to buy, sell or hold our securities and that each rating should be evaluated independently of any other rating.

The use of derivative contracts in the normal course of our business and changing interest rates and market conditions could result in financial losses that negatively impact our results of operations.

Our operations include managing market risks related to commodity prices and, subject to specified risk parameters, engaging in marketing and trading activities intended to profit from market price movements. We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal, and emissions allowances and credits. We have 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.

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

Changing interest rates will affect interest paid on variable-rate debt and interest earned by our pension plan and nuclear decommissioning trust funds. Our policy is to manage interest rates through the use of a combination of fixed-rate and floating-rate debt. The pension plan is also impacted by the discount rate, which is the interest rate used to discount future pension obligations. Continuation of recent decreases in the discount rate would result in increases in pension costs, cash contributions, and charges to other comprehensive income. The pension plan and nuclear decommissioning trust funds also have risks associated with changing market values of equity investments. A significant portion of the pension costs and all of the nuclear decommissioning costs are recovered in regulated electricity prices.

Actual results could differ from estimates used to prepare our financial statements.

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

- Regulatory Accounting — Regulatory accounting allows for the actions of regulators, such as the ACC and the FERC, to be reflected in our financial statements. Their actions may cause us to capitalize costs that would otherwise be included as an expense in the current period by unregulated companies. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings. We had $138 million of regulatory assets on our balance sheet at March 31, 2005.

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

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

EXHIBIT 99.3

PINNACLE WEST CAPITAL CORPORATION
NON-GAAP MEASURE RECONCILIATION — OPERATING INCOME (GAAP MEASURE) TO GROSS MARGIN (NON-GAAP MEASURE)
(in thousands)

	THREE MONTHS ENDED MARCH 31,		Pretax Increase (Decrease)	After Tax Increase (Decrease)
	2005	2004		
RECONCILIATION OF REGULATED ELECTRICITY SEGMENT GROSS MARGIN				
Operating Income (closest GAAP measure)	$ 85,256	$ 84,198	$ 1,058	$ 643
Plus:				
Operations and maintenance	156,496	137,386	19,110	11,613
Real estate segment operations	56,476	47,690	8,786	5,339
Depreciation and amortization	94,231	101,616	(7,385)	(4,488)
Taxes other than income taxes	35,190	30,330	4,860	2,953
Other expenses	8,374	8,750	(376)	(228)
Marketing and trading segment purchased power and fuel	100,641	67,764	32,877	19,979
Less:				
Real estate segment revenues	72,056	51,593	20,463	12,435
Other revenues	10,135	10,905	(770)	(468)
Marketing and trading segment revenues	116,866	88,383	28,483	17,309
Regulated electricity segment gross margin	$ 337,607	$ 326,853	$ 10,754	$ 6,535
RECONCILIATION OF MARKETING AND TRADING SEGMENT GROSS MARGIN				
Operating Income (closest GAAP measure)	$ 85,256	$ 84,198	$ 1,058	$ 643
Plus:				
Operations and maintenance	156,496	137,386	19,110	11,613
Real estate segment operations	56,476	47,690	8,786	5,339
Depreciation and amortization	94,231	101,616	(7,385)	(4,488)
Taxes other than income taxes	35,190	30,330	4,860	2,953
Other expenses	8,374	8,750	(376)	(228)
Regulated electricity segment purchased power and fuel	78,423	88,611	(10,188)	(6,191)
Less:				
Real estate segment revenues	72,056	51,593	20,463	12,435
Other revenues	10,135	10,905	(770)	(468)
Regulated electricity segment revenues	416,030	415,464	566	344
Marketing and trading segment gross margin	$ 16,225	$ 20,619	$ (4,394)	$ (2,670)

EXHIBIT 99.4

ARIZONA PUBLIC SERVICE COMPANY
NON-GAAP MEASURE RECONCILIATION — OPERATING INCOME (GAAP MEASURE) TO GROSS MARGIN (NON-GAAP MEASURE)
(in thousands)

	THREE MONTHS ENDED MARCH 31,		Pretax Increase (Decrease)	After Tax Increase (Decrease)
	2005	2004		
RECONCILIATION OF GROSS MARGIN				
Operating Income (closest GAAP measure)	$ 58,743	$ 67,050	$ (8,307)	$ (5,037)
Plus:				
Operations and maintenance	142,294	125,912	16,382	9,932
Depreciation and amortization	82,214	88,848	(6,634)	(4,022)
Income taxes	16,380	17,362	(982)	(595)
Other taxes	31,445	27,580	3,865	2,343
Gross margin	$ 331,076	$ 326,752	$ 4,324	$ 2,621

EXHIBIT 99.5

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

Arizona Corporation Commission
DOCKETED

APR - 7 2005
DOCKETED BY NR

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT.

DOCKET NO. E-01345A-03-0437

DECISION NO. 67744

OPINION AND ORDER

DATES OF PROCEDURAL CONFERENCES:	August 13, 2003, January 6, February 18, April 7, 15, 28 May 26, June 14, August 18, and October 27, 2004
DATES OF HEARING:	November 8, 9, 10, 29, 30, December 1, 2, and 3, 2004
PLACE OF HEARING:	Phoenix, Arizona
ADMINISTRATIVE LAW JUDGE:	Lyn Farmer
IN ATTENDANCE:	Marc Spitzer, Chairman William A. Mundell, Commissioner Jeff Hatch-Miller, Commissioner Mike Gleason, Commissioner Kristin K. Mayes, Commissioner
APPEARANCES:	Mr. Thomas L. Mumaw and Ms. Karilee S. Ramaley, PINNACLE WEST CAPITAL CORPORATION; Mr. Jeffrey B. Guldner and Ms. Kimberly Grouse, SNELL & WILMER, L.L.P., on behalf of Arizona Public Service Company; Mr. C. Webb Crockett, FENNEMORE CRAIG, P.C., on behalf of AECC and Phelps Dodge; Mr. Patrick J. Black, FENNEMORE CRAIG, P.C., on behalf of Panda Gila River; Mr. S. David Childers, LOW & CHILDERS, P.C., Mr. James M. Van Nostrand, and Ms. Katherine McDowell STOEL RIVES, L.L.P., on behalf of Arizona Competitive Power Alliance; Mr. Lawrence V. Robertson, Jr., MUNGER

CHADWICK, on behalf of Southwestern Power Group II, Mesquite Power, and Bowie Power Station, LLC, and Mr. Theodore Roberts, SEMPRA ENERGY RESOURCES, on behalf of Mesquite Power;

Mr. Scott S. Wakefield, Chief Counsel, and Mr. Daniel Pozefsky, on behalf of the Residential Utility Consumer Office;

Mr. Walter W. Meek, President, on behalf of the Arizona Utility Investors Association;

Mr. Raymond S. Heyman, Ms. Laura E. Schoeler, and Ms. Laura Sixkiller, ROSHKA, HEYMAN & DeWULF, on behalf of UniSource Energy Services;

Major Allen G. Erickson on behalf of the Federal Executive Agencies;

Mr. Jay I. Moyes, MOYES STOREY, on behalf of PPL Sundance and PPL Southwest Generation Holdings;

Mr. Nicolas J. Enoch, LUBIN & ENOCH, on behalf of the International Brotherhood of Electrical Workers;

Mr. William P. Sullivan and Mr. Michael A. Curtis, MARTINEZ & CURTIS, P.C., on behalf of the Town of Wickenburg, Arizona;

Mr. Bill Murphy, MURPHY CONSULTING and Mr. Douglas V. Fant, LAW OFFICES OF DOUGLAS V. FANT, on behalf of the Arizona Cogeneration Association;

Mr. Marvin S. Cohen, SACKS TIERNEY, P.A., on behalf of Constellation NewEnergy and Strategic Energy;

Mr. Andrew W. Bettwy and Ms. Karen S. Haller, on behalf of Southwest Gas Corporation;

Mr. Timothy M. Hogan, ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST, and Ms. Anne C. Ronan, on behalf of Western Resources Advocates and Southwest Energy Efficiency Project;

Mr. Jesse A. Dillon, on behalf of PPL Services Corporation;

Mr. Brian Babiars and Ms. Cynthia Zwick, WESTERN ARIZONA COUNCIL OF GOVERNMENTS, on behalf of Arizona Community Action Association;

Mr. Paul R. Michaud, MICHAUD LAW FIRM, on behalf of Dome Valley Energy Partners, LLC;

Mr. Michael L. Kurtz, BOEHM, KURTZ & LOWRY, on behalf of Kroger Company;

Mr. Christopher Kempley, Chief Counsel, Mr. Jason D. Gellman and Ms. Janet F. Wagner, Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

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BY THE COMMISSION:

I. DISCUSSION

On June 27, 2003, Arizona Public Service Company ("APS" or "Company") filed with the Arizona Corporation Commission ("Commission") an application for a rate increase and for approval of a purchased power contract. The application states that the $175.1 million rate increase is needed to maintain the Company's credit ratings and attract new capital on reasonable terms, recover its cost of service, and permit APS to earn a fair rate of return on the fair value of its assets devoted to public service. The application requested that the Commission recognize the higher fuel and purchased power expenses being incurred by the Company; allow APS to include in rates at cost of service certain generation assets of Pinnacle West Energy Corporation ("PWEC"); permit APS to recover the $234 million write-off taken under the 1999 Settlement Agreement; and provide for the recovery of all prudently incurred costs to comply with the Commission's Retail Electric Competition Rules, A.A.C. R14-2-1601, et seq. ("Electric Competition Rules"), including the one-third of costs associated with the planned divestiture of generation from APS to PWEC that was not previously deferred. APS also requested approval of depreciation and amortization rates and a review of its long-term purchased power contract with PWEC if the assets are not rate based.

On July 25, 2003, the Utilities Division Staff ("Staff") of the Commission filed a letter stating that the application was found sufficient and classified the applicant as a Class A utility.

By Procedural Order issued August 6, 2003, a Procedural Conference was scheduled for August 13, 2003, and intervention was granted to the Arizonans for Electric Choice and Competition ("AECC"), the Federal Executive Agencies ("FEA"), the Kroger Company ("Kroger"), the Residential Utility Consumer Office ("RUCO"), the Arizona Utility Investors Association, Inc., ("AUIA") and Phelps Dodge Corporation and Phelps Dodge Mining Company ("Phelps Dodge").

By various Procedural Orders, intervention was granted to: the International Brotherhood of Electrical Workers, AFL-CIO, CLC, Local Unions 387, 640 and 769 (collectively, "IBEW"), the Arizona Cogeneration Association/Distributed Generation Association of Arizona ("ACA" or "DEAA"), Panda Gila River, L.P. ("Panda"), Arizona Water Company ("AWC"), Southwest Gas Corporation ("SWG"), Western Resource Advocates ("WRA"), Constellation NewEnergy, Inc.

("CNE"), Strategic Energy, L.L.C. ("SEL"), Dome Valley Energy Partners, LLC ("DVEP"), UniSource Energy Services ("UES"), Arizona Community Action Association ("ACAA"), Arizona Competitive Power Alliance ("Alliance"), the Town of Wickenburg ("Wickenburg")(1), the Arizona Solar Energy Industries Association ("AriSEIA"), the Arizona Association of Retired Persons ("AARP"), Southwest Energy Efficiency Project ("SWEEP"), PPL Sundance, LLC ("PPL Sundance"), PPL Southwest Generation Holdings, LLC ("PPL Southwest"), Southwestern Power Group II, LLC ("SWPG"), Mesquite Power, LLC ("Mesquite") and Bowie Power Station, LLC ("Bowie").

On November 5, 2003, Staff filed a Motion to Consolidate ("Motion") the preliminary inquiry created by Decision No. 65796 and by Procedural Order the Motion was granted, authorizing Staff to include its report in this docket.

II. PRE-SETTLEMENT POSITIONS OF PARTIES

	APS	Staff	RUCO	Settlement Agreement
Revenue requirement	+$175.1 M	-$142.7 M	-$53.6 M	+$ 75.5 M
Return on Equity	11.5 %	9.0%	9.5%	10.25%
Debt cost	5.8 %	5.8%	5.8%	5.8%
Capital Structure	50/50	55/45	55/45	55/45
Cost of Capital	8.67 %	7.3%	7.43%	7.8%
PWEC assets	$ 848 M	-	(2)	$ 700 M

III. SETTLEMENT AGREEMENT

a. INTRODUCTION

On August 18, 2004, a Settlement Agreement signed by 22 parties(3) was docketed with the Commission. AWC, SWG, and UES do not oppose the Settlement Agreement, and the AARP made public comment supporting it. The only party opposed to the Commission's adoption of the Settlement Agreement that presented testimony and evidence is the Arizona Cogeneration

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(1) On August 18, 2004, Wickenburg moved to withdraw its intervention.

(2) Phase 1.

(3) APS, ACAA, Alliance, AECC, AriSEIA, AUIA, Bowie, CNE, DVEP, FEA, IBEW, Kroger, Mesquite, Phelps Dodge, PPL Southwest, PPL Sundance, RUCO, SWEEP, SWPG, Staff, SEL, and WRA.

Association/Distributed Generation Association of Arizona.(4)

APS' central objectives in settling were to preserve the company's financial integrity;(5) resolve the issue of asset "bifurcation"; and to determine the company's future public service obligations.

Staff believes that the Settlement Agreement is in the public interest because: it is fair to ratepayers because it precludes inappropriate utility profits and results in just and reasonable rates; it is fair to the utility because it provides revenues necessary to provide reliable electric service along with an opportunity for a reasonable profit; the proposal balances many diverse interests including those of low-income customers, the renewable energy sector, Demand Side Management ("DSM") advocates, merchant generators, and retail energy marketers; it allows APS to rate base the PWEC assets, which are the generating plants originally built by APS' affiliate, PWEC, at a value that is significantly below their book value; potentially anti-competitive effects that may be associated with rate basing the PWEC assets are addressed through a self-build moratorium, a competitive solicitation in 2005, through workshops to address future resource planning and acquisition issues, and by adopting cost-based unbundling for generation and revenue cycle services in the rate design for general service customers, encouraging those customers to shop for competitive services; the Settlement Agreement resolves long, complex litigation by resolving issues associated with prior Commission decisions that are on appeal; the Settlement Agreement facilitates the provision of electric service at the lowest reasonable rates; it provides additional discounts to low-income APS customers, increases funding for advertising these discounts, and increases funding for APS' low-income weatherization program; and because it includes a comprehensive DSM proposal intended to foster the development of new DSM programs while ensuring that the expenditures will be reasonable and subject to appropriate Commission oversight.(6)

RUCO noted that this rate case allowed sufficient opportunity for it to fully audit the Company's cost-of-service study and allowed all parties to be included in the negotiations. RUCO points to the very substantial, nearly universal consensus reached in the Settlement Agreement as

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(4) New Harquahala Generating Company, LLC and Panda made statements objecting to the rate basing of the PWEC assets.

(5) Defined as the ability to attract capital on reasonable terms and earn a reasonable return. Tr. p. 420.

(6) Summary of settlement testimony of Ernest Johnson.

indicating that the public interest has been served. According to RUCO, the "ultimate expression of the agreement having met the Public Interest is the degree to which rate increases have been minimized without jeopardizing the financial integrity of the applicant."(7)

The Alliance's central objective is to continue towards a viable and effective wholesale market into which Alliance members can sell their power. According to the Alliance, there are several key provisions in the Settlement Agreement that accomplish that goal: the restrictions on self-build coupled with the high growth rate in APS' service territory; and the 1,000 megawatt Request for Proposal ("RFP") in 2005. The Settlement Agreement also preserves the financial stability and creditworthiness of the Alliance's target customer - APS.(8)

b. REVENUE REQUIREMENTS

For ratemaking purposes and for purposes of the Settlement Agreement, the parties agree that APS will receive a total increase of $75.5 million over its adjusted 2002 test year ("TY") revenue of $1,791,584,000. This represents an increase in base rates of $67.6 million and a Competition Rules Compliance Charge ("CRCC") surcharge collecting $7.9 million. Pursuant to the Settlement Agreement filed on August 18, 2004, as corrected in the hearing, the Company's fair value rate base ("FVRB") is $5,054,426,000.(9) According to the Settlement Agreement, this revenue increase will allow the Company the opportunity to earn a fair value rate of return of 5.92 percent. According to the Company and Staff, the revenue requirement contained in the Settlement Agreement provides sufficient revenues for APS to provide adequate and reliable service.(10)

c. PWEC ASSET TREATMENT

The Settlement Agreement provides that APS will acquire and rate base generation units owned by PWEC.(11) Those units include: West Phoenix CC-4; West Phoenix CC-5; Saguaro CT-3; Redhawk CC-1; and Redhawk CC-2 ("PWEC assets"). Pursuant to the Settlement Agreement, the

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(7) Summary of settlement testimony of Stephen Ahearn.

(8) Tr. p. 458.

(9) Paragraph 4 to the Settlement Agreement states the FVRB is $6,281,885,000, however, during the hearing, that amount was corrected to $5,054,426,000. Tr. p. 692.

(10) Tr. p. 810.

(11) On November 10, 2004, PWEC filed a letter with the Commission indicating that it would abide by the provisions of the Settlement Agreement that require PWEC to take or refrain from taking any action in order to carry out the intent of the Settlement Agreement.

original cost rate base ("OCRB") of the PWEC assets will be $700 million which is $148 million less than the original cost of the assets as of December 31, 2004. According to the Settlement Agreement, this represents a reasonable estimate of the value of the remaining term of the Track B contract between APS and PWEC.(12) APS agrees to forgo any present or future claims of stranded costs associated with these PWEC assets. According to the Settlement Agreement, APS is required to seek approval of certain aspects of the asset transfer from the Federal Energy Regulatory Commission ("FERC"). APS agreed to file a request for FERC approval within 30 days of the Commission's approval of the Settlement Agreement, and the parties have agreed not to oppose the FERC application. The Settlement Agreement provides for a bridge purchased power agreement ("Bridge PPA") to be implemented once new rates are put in place, until the actual date of the transfer of assets. APS and PWEC will execute a cost-based PPA which will be based on the value of the PWEC assets, and fuel costs and off-system sales revenue will flow into the power supply adjustor ("PSA"). If FERC denies the asset transfer, then the Bridge PPA will become a 30 year PPA, with prices reflecting cost-of-service as if the PWEC assets were rate-based at the $700 million amount in the Settlement Agreement, and with the associated fuel costs and off-system sales revenue flowing through the PSA. The basis point credit established in Decision No. 65796 will continue as long as the debt between APS and PWEC associated with the PWEC assets is outstanding. Credit for amounts deferred after December 31, 2004 will be accounted for in APS' next rate case. The Settlement Agreement also provides that West Phoenix CC-4 and West Phoenix CC-5 will be deemed "local generation" and during must-run conditions, generation from the West Phoenix facilities will be available at FERC-approved cost-of-service prices to electric service providers ("ESPs") serving direct access loads in the Phoenix load pocket.

Treatment of the PWEC assets requires not only a regulatory ratemaking type analysis, but also an analysis of how rate basing these assets fits with the Commission's overall plan for wholesale and retail electric competition in Arizona.

For the last ten years, the Commission has studied, discussed, and deliberated about electric

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(12) Docket Nos. E-00000A-02-0051 et al.

competition through workshops, rulemakings, hearings, and open meetings. Several versions of electric competition rules have been adopted, and litigation concerning Commission decisions has been conducted. Throughout this time, the Commission has always maintained its intent to encourage competition in the electric industry. In the wake of the California energy crisis the Commission opened dockets to examine changing industry and market conditions and introspectively analyzed their impact on Arizona's existing rules. The Commission reacted in a measured manner to flawed rules in other jurisdictions and corrected, but did not change, its course.

The Commission continues to support competition as yielding economic and environmental benefits to Arizona consumers. The $148,000,000 discount from book for the rate-based PWEC assets is indicative of these benefits. Recent transactions reflected in the record, including below-cost sales, foreclosures and bankruptcies, establish that the shareholders of the power plants' builders absorbed the costs and bore the brunt of a declining market, rather than Arizona ratepayers. The discounted conveyance of the PWEC assets to APS is further support for this proposition. APS' request and the Settlement Agreement's provision allowing APS to acquire the PWEC assets and put them in rate base raises the issue of whether such action would undermine the Commission's stated intent to encourage retail and wholesale competition. The terms of the Settlement Agreement taken as a whole indicate to us that the answer to that question is "no".

During the hearing on the Settlement Agreement, the parties presented evidence demonstrating that the PWEC acquisition was the most beneficial option for ratepayers. Staff testified that the responses to APS' last formal RFP did not indicate to Staff that the market would provide a superior alternative to the rate basing of the PWEC assets. The testimony indicates that growth in APS' service territory is a minimum of 3 percent per year. APS argued that even with rate basing the PWEC assets, APS' needs would not be met, and it would have to procure additional power to meet the needs of its customers. The Settlement Agreement provides that APS will issue an RFP for an additional 1000 megawatts, thereby giving other market participants an opportunity to compete. The organization created to represent the interests of the merchant community, the Alliance, supports the transfer of assets, because it believes that resolving the broader issues of overall market structure, the self-build guidelines and future RFPs, together with the reduction in

litigation risk will further its overall goal of promoting a viable and effective wholesale market. The key provision that the Alliance relies on is the 1,000 megawatt RFP in 2005 that provides a degree of certainty regarding the timing of an initial increment of APS' future needs to be met from the wholesale market. Also, the Alliance believes that opportunities will exist for its members because of the self-build limitation and the high growth rate in Arizona. The proponents of retail competition also support the asset transfer; in large part because APS agrees to forgo any present or future claims of stranded costs associated with the PWEC assets, because rates are unbundled, and because of the treatment of the West Phoenix facilities.

We believe that nothing in the Settlement Agreement prevents the continued development of electric competition. Any potential anti-competitive effects of the asset transfer will be addressed through the competitive solicitations, the self-build moratorium,(13) and Staff's workshops to address future resource planning and acquisition issues. As discussed below, the evidence indicates that the asset transfer captures the benefit of the competitive procurement that took place as a result of the Track B proceeding.

The original cost of the PWEC assets at December 31, 2004 was $848 million. Traditionally, when a utility builds plant, unless there is a finding of imprudency, that portion of the plant that is used and useful is put into rate base and the utility is allowed an opportunity to earn a reasonable rate of return on that investment. This situation is different from the traditional rate case. APS did not build the PWEC assets; they were built by APS' affiliate during a time when the Commission intended APS to divest itself of generation. During the proceeding on APS' financing application, concern was raised that APS and its affiliates took actions that gave it an unfair advantage as compared to its potential competitors. In Decision No. 65796, which granted APS' financing request, we directed Staff to conduct a preliminary inquiry into the issue of APS and its affiliate's compliance with our electric competition rules, Decision No. 61973, and applicable law. The Settlement Agreement provides that the preliminary inquiry will be concluded with no further action by the

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(13) Neither APS nor PWEC will build the Redhawk Units 3 & 4. PWEC's February 2003 self-certification filing with the Commission stated that the two remaining units pursuant to its Certificate of Environmental Compatibility ("CEC") would not be built. Tr. pp. 594-5.

Commission. Accordingly, we make no finding as to why or for whom the PWEC assets were built, and base our resolution of the rate basing issue solely on the merits of the terms of acquisition. We believe that if there were a serious threat to competition, we would hear from those affected, loudly and strongly. Therefore, we were keenly interested in the position of the members of the Alliance, as they are one type of entity that could be harmed. The Alliance supports the acquisition of the PWEC assets by APS. Every person or entity that will be affected by the rate basing of the PWEC assets had the opportunity to participate and present evidence and testimony on this issue. Although two independent power producers made comments objecting to the acquisition without an RFP, neither presented any evidence that demonstrated that competition would be harmed, nor rebutted the testimony and evidence concerning APS' recent RFP.

Initially Staff recommended that the PWEC assets not be rate based, but after analyzing the Company's rebuttal testimony and evidence, agreed that a reduction of $148 million in original cost rate base made the acquisition beneficial to ratepayers. The evidence in the record is substantial that APS' analysis of other options versus rate basing PWEC assets showed that: using an "other build" analysis, rate basing the PWEC assets would cost $300-600 million less than cost to build other plants such as Combustion Turbines ("CT"); using a comparable sales analysis showed that other recent sales had a per kW cost in excess of $527 and the PWEC assets are at $417; when compared to the offers resulting from the recent RFP conducted by APS, the PWEC assets (when valued at the before discount $848 million level) showed benefits of $600-900 million; and using a discounted cash flow analysis the PWEC assets had a savings of $250 million to $1 billion.

As part of the settlement, APS agreed to reflect an original cost rate base value of $700 million, representing a $148 million disallowance. The effect of a reduction in rate base is to immediately reduce the revenue requirement, and to preserve that diminished revenue requirement for the life of the plant.

The analyses showing that the rate basing of the PWEC assets will result in lower rates than other options, together with no showing that such an acquisition would harm the development of a competitive wholesale or retail market indicate that it is reasonable and in the public interest for APS to acquire and rate base the PWEC assets as set forth in the Settlement Agreement.

d. COST OF CAPITAL

The Settlement Agreement adopts a capital structure of 55 percent long-term debt and 45 percent equity for ratemaking purposes. The parties agree that a 10.25 percent return on common equity and a 5.8 percent embedded cost of long-term debt is appropriate.

e. POWER SUPPLY ADJUSTOR (PSA)

The Settlement Agreement provides that a PSA be implemented and remain in effect for a minimum of five years, with reviews available during APS' next rate case, or upon APS' filing its report on the PSA four years after rates are implemented in this rate case. Regardless of the review/report, the PSA cannot be abolished until five years have expired. The Settlement Agreement provides that APS will file a plan of administration as part of its tariff filing that describes how the PSA will operate. According to the Settlement Agreement, the PSA will have the following characteristics:

- Includes both fuel and purchased power;

- The adjustor rate will initially be set at zero and will thereafter be reset on April 1 of each year, beginning with April 1, 2006. APS will submit a publicly available report on March 1 showing the calculation of the new rate, which will become effective unless suspended by the Commission;

- Incentive mechanism where APS and its customers share 10 percent and 90 percent, respectively, the costs and savings;

- Bandwidth that limits annual change in adjustor of plus or minus $0.004 per kilowatt hour, with additional recoverable or refundable amounts recorded in balancing account;

- Surcharge possible if balancing account reaches plus or minus $50 million and Commission approves;

- Off-system sales margins credited to PSA balance;

- Recovery of prudent, direct costs of contracts for hedging fuel and purchased power costs;

- Interest on balancing account will accrue based on the one-year nominal Treasury constant maturities rate;

- The Commission or its Staff may review the prudence of fuel and power purchases at any

time;

- The Commission or its Staff may review any calculations associated with the PSA at any time; and

- Any costs flowed through the adjustor are subject to refund if the Commission later determines that the costs were not prudently incurred.

The Settlement Agreement provides that APS shall provide monthly reports to Staff's Compliance Section and to RUCO detailing all calculations related to the PSA, and shall also provide monthly reports to Staff about APS' generating units, power purchases, and fuel purchases. An APS officer must certify under oath that all the information provided in the reports is true and accurate to the best of his or her information and belief. The Settlement Agreement also provides that direct access customers and customers served under rates E-36, SP-1, Solar-1, and Solar-2 are excluded from paying PSA charges. Under the Settlement Agreement, the PSA remains in effect for 5 years, and if after that, the Commission abolishes the PSA, it must provide for any under- or over-recovery and can adjust base rates to reflect costs for fuel and purchased power. The parties agree that a base cost of fuel and purchased power of $.020743 per kWh should be reflected in APS' base rates.

Decision No. 61973 (October 6, 1999) adopting the previous APS settlement, required APS to request, and the Commission to approve, a "power supply adjuster" mechanism to recover the cost of providing power for standard offer and/or provider of last resort customers.

In Decision No. 66567 (November 18, 2003), the Commission approved the concept of a Purchased Power Adjustor ("PPA") which included purchased power costs and did not include the cost of fuel. The Decision noted that the adjustor mechanism approved therein may be modified or eliminated in this rate case. As noted in that Decision, there are advantages and disadvantages to adjustor mechanisms:

Advantages: 1) the reporting requirements and forecasts facilitate utility planning and Staff overview of costs; 2) an adjustor that works correctly, over time, reduces the volatility of a utility's earnings and the risk reduction can be reflected in the cost of equity capital in a rate case and result in lower rates; 3) adjustors can create price signals to consumers, but the effectiveness is reduced considerably when a band is included; 4) adjustors can help reduce the frequency of rate cases; 5)

regulatory lag between the incurrence of an expense and its recovery is reduced and generational inequities are also reduced.

Disadvantages: 1) adjustors can reduce incentives to minimize costs; 2) an adjustor that includes fuel or purchased power costs potentially biases capital investment decisions towards those with lower capital costs and higher fuel costs; 3) adjustors create another layer of regulation to rate cases, increasing the cost of regulation to the utility, its customers, and to the Commission; 4) an adjustor can shift a disproportionate proportion of the risk of forced outages and systems operations from shareholders to ratepayers; 5) adjustors result in piecemeal regulation - an adjustor reflects an increase in one expense but ignores offsetting savings in other costs; 6) adjustors are complex and often difficult for analysts to read and interpret, and are difficult to explain to customers; 7) proper monitoring of adjustor filings and audits require the devotion of significant Staff resources; and 8) rates are less stable, resulting in rates changing frequently, making it difficult for customers to plan energy consumption and the purchase of energy consuming appliances.

Although we recently approved the concept of a PSA, we are concerned about the PSA as proposed in the Settlement Agreement. The benefits of this PSA are that over time, the utility's earnings will be stabilized, thereby preserving its financial integrity and in the longer term, improve the likelihood that the company will attract capital on reasonable terms, to the benefit of ratepayers. Further, as part of the negotiations, the parties were able to agree on a lower overall revenue increase because a PSA was to be implemented. AECC pointed out that if an adjustor remains in effect for long enough, it becomes a credit, and therefore, the PSA should remain in effect for five years.(14)

The disadvantages are real and significant - from a customer standpoint, adjustors are difficult to understand and they can cause annual price increases. From a regulatory standpoint, they require significant Commission staff resources to properly monitor filings, costs, and compliance and to respond to consumer inquiries and complaints. The most significant change that will occur with a PSA is the shifting of the risk that fuel costs will increase above the base rates established in the Settlement Agreement. Currently, if fuel costs or any other costs rise above the level embedded in

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(14) Tr. p. 1249.

the existing rate structure, the company's shareholders feel the impact. Likewise, if the costs decrease, the shareholders benefit. Under a PSA, the shareholders are insulated from the change in costs, because now the ratepayers are obligated to pay the additional costs. Further, the testimony was clear that costs are going to be increasing, not only because natural gas prices will increase, but also because APS' "mix" of fuel will change as growth occurs.(15) That mix will include an increasing amount of natural gas to supply the new generation. When compared to APS' other fuel sources such as nuclear or coal, natural gas is a substantially higher cost fuel. So here, the PSA will not only be collecting additional revenues due to fuel price increases, but also increases due to growth that is met with generation from a high cost fuel.(16)

Although the Settlement Agreement provides that APS will increase its demand side management and renewables, and we agree that those resources are increasingly important, they will not likely have a significant ameliorating cost impact in the near future. We disagree with the parties that a 90/10 sharing is sufficient incentive for APS to continue to effectively hedge its natural gas costs. Going from a 100 percent at-risk position to 10 percent at-risk almost seems like a "free pass," especially when a revenue increase is added. Although the Settlement Agreement provides that all costs will be subject to review for prudency before they can be recovered, prudency reviews, especially transactions in the wholesale market, can be difficult to conduct after the fact. Although we have confidence in our Staff's ability to conduct prudency reviews, we do not believe they provide as much incentive to APS on the front end to hedge costs as exists today without a PSA. The band-width limit will help limit drastic increases, but ultimately, APS will be able to recover all the costs from ratepayers.(17)

Accordingly, for these reasons, we believe that provisions of the PSA need to be modified to protect the ratepayers. We agree that the use of an adjustor when fuel costs are volatile prevents a

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(15) As growth occurs, the per unit cost of fuel will increase. Tr. p. 1238. Currently, nuclear is 32 percent of sales and represents 7.4 percent of the costs of generation; coal is 45 percent of sales and 29.7 percent of generation costs; natural gas is 18 percent of sales and 47.4 percent of generation costs; and purchased power is 5 percent of sales and 15.5 percent of generation costs. Tr. p. 1257. In five years, natural gas is expected to be 29-30 percent of sales. TR. p. 1258.

(16) See discussion Tr. p. 1259, PSA will always be increasing.

(17) Staff's late-filed exhibit S-35 filed December 14, 2004 in response to a request from Commissioner Mundell to extrapolate the effects of the PSA over several years, contained an error and on March 9, 2005, Staff filed a corrected exhibit.

utility's financial condition from deteriorating. We are less inclined, however, to adopt an adjustor as a way to keep pace with load growth. Although APS' rebuttal testimony indicated that its fixed costs would increase in relation to its load growth, we are concerned about the potential for single-issue ratemaking and whether APS' fixed costs will increase in the same proportion as its fuel costs. According to the late-filed exhibits, the majority of the increased fuel costs are caused by increased load growth, rather than price volatility in fuel. In effect, the adjustor as designed provides annual step increases in rates. We believe APS must have an incentive to file a rate case so that we can determine the accuracy of its assertion about expenses. Therefore, we will adopt an adjustor that collects or refunds the annual fuel costs that differ from the base year level. However, we will limit the adjustor to 4 mil from the base level over the entire term of the PSA and will cap the balancing account to an aggregate amount of $100 million. Should the Company seek to recover or refund a bank balance pursuant to Paragraph 19E of the Settlement Agreement, the timing and manner of recovery or refund of that existing bank balance will be addressed at such time. In no event shall the Company allow the bank balance to reach $100 million prior to seeking recovery or refund. Following a proceeding to recover or refund a bank balance between $50 million and $100 million, the bank balance shall be reset to zero unless otherwise ordered by the Commission.

Further, we will limit the amount of "annual net fuel and purchased power costs" (as shown in Staff Exhibit 23)(18) that can be used to calculate the annual PSA to no more than $776,200,000. Any fuel or purchased power costs above that level will not be recovered from ratepayers. We believe that this "cap" on fuel and purchased power costs will further encourage APS to manage its costs, and will help to prevent large account balances from occurring in one year. Because the PSA actually adjusts for growth, putting a "cap" on recovery of these costs will help insure that APS will file a rate application when necessary.(19) Since there is no moratorium on filing a rate case, APS can file a rate case to reset base rates if it deems it necessary because that cap is reached. Further, although the Settlement Agreement provides that the PSA will be in effect for 5 years, if APS files a rate case

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(18) For example, under "Average Usage Scenario One", the line reads "Annual Net Fuel and Purchased Power Costs: $524,600,000."

(19) See S-35 filed March 9, 2005, Scenario 11A - even when the price of gas remains constant, the PSA adjustor increases, because the adjustor uses total costs (not price) which reflects the growth which is being met by the higher priced fuel, natural gas.

prior to the expiration of that 5 year term or if we find that APS has not complied with the terms of the PSA, we believe that the Commission should be able to eliminate the PSA if appropriate. Finally, we will not allow any fuel costs from 2005 that were incurred prior to the effective date of this Decision to be included in the calculation of the PSA implemented in 2006. We believe that these additional provisions to the PSA will help to lessen the detrimental impact to ratepayers of this change to an adjustor mechanism.

Implementing an adjustor mechanism will have a significant impact upon both APS and its customers. For many years now, in their monthly bills, APS customers have paid rates that reflect the costs that APS is allowed to recover for providing that service. With the implementation of an adjustor, those ratepayers will be obligated to pay additional amounts for service they received in the previous year. This represents a major shift in responsibility for increased costs, from APS and its shareholders to ratepayers. According to APS, such a shift is necessary for the company to preserve its financial integrity.

Although the parties submitted a written statement describing the calculation of off-system sales in response to a question from Commissioner Mundell, we are concerned that the method may not capture the full margin on each sale.(20) Additionally, we want to make sure that off-system sales are not being made below costs - Staff needs to study ways to insure that these off-system sales margins are being determined accurately and that ratepayers are receiving the full 90 percent of the benefits. Accordingly, we will direct Staff to establish a method that accurately reflects the appropriate fuel costs and revenue for off-system sales, so that the full margin is known and properly accounted for. Within three years of the effective date of this Decision, Staff shall commence a procurement review of APS' fuel, purchased power, generating practices and off-system sales practices.

In response to Commissioner Gleason's suggestion to set up a webpage explaining its bill, APS indicated that it was planning to have a new bill format, and agreed to also set up a website to

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(20) For example, a wholesale contract may have an embedded cost of fuel built into the price of the energy that is different from the cost of fuel use to generate the energy - if the "sales margin" is defined as the difference between the actual cost of fuel and the revenue from the sale, the true sales margin will not be captured. We also take administrative notice of FERC Docket No. PA04-11-000 and the FERC's December 16, 2004 Order Approving Audit Reports and Directing Compliance Actions, specifically relating to treatment of off-system sales.

explain the bills. Because the implementation of an adjustor will be a major change in the way that customers are billed, we believe that APS should also implement a customer education program explaining how its PSA will work and we will order APS to maintain on its website information explaining the billing format, rates, and charges, including up-to-date information about the PSA and current gas costs. It is important that the customer education program be implemented in a timely fashion, before this summer. APS needs to make its customers aware that with the implementation of an adjustor, ratepayers will be obligated to pay additional amounts for service they received in the previous year. It is essential, and only fair, that customers understand that their usage this summer can have an effect on their electric bills the following year.

Because we are concerned about the impact of the PSA on low-income customers, the PSA shall not apply to the bills of individuals who are enrolled in the Company's Energy Support program. Finally, given our concerns and the modifications we require to the PSA, we will require the parties to the Settlement Agreement to submit a PSA Plan of Administration that reflects the determinations in this Decision, for our approval.

f. DEPRECIATION

The Settlement Agreement adopts Staff's recommended service lives, and Appendix A to the Settlement Agreement sets forth the remaining service lives, net salvage allowance, annual depreciation rates, and reserve allocation for each category of APS depreciable property as agreed to by the parties. The parties agree that the Statement of Financial Accounting Standards ("SFAS") 143 will not be adopted for ratemaking purposes.

g. $234 MILLION WRITE-OFF

The Settlement Agreement provides that APS will not recover the $234 million write-off attributable to Decision No. 61973 in this case, nor shall APS seek to recover the write-off in any subsequent proceeding. The ESP and large consumer witnesses testified that this provision was critical to the development of flourishing retail markets and will help direct access service from being undercut by future stranded costs claims.

h. DEMAND SIDE MANAGEMENT ("DSM")

Demand-side management ("DSM") is "the planning, implementation, and evaluation of

programs to shift peak load to off-peak hours, to reduce peak demand (kW), and to reduce energy consumption (kWh) in a cost-effective manner."(21)

DSM is addressed in three areas of the Settlement Agreement: in the funding, programs, plans and reporting provisions; in the study of rate design modifications; and in the competitive procurement process.

Funding for DSM comes in both base rates ($10 million per year) and through implementation of an adjustor (average of $6 million per year).(22) DSM funding will be used for "approved eligible DSM-related items," including "energy-efficiency DSM programs,"(23) a performance incentive,(24) and low income bill assistance.(25) APS is obligated to spend $13 million in 2005 on DSM projects.(26)

Appendix B to the Settlement Agreement is a preliminary plan ("Preliminary Plan") for eligible DSM-related items for 2005. The Preliminary Plan includes $6.9 million for commercial, industrial, and small business customer programs, including new construction, retrofitting existing facilities, training and education, design assistance, and financial incentives; it includes $6.2 million for residential customers, including new construction and existing homes and HVAC, education, training, expanded low income weatherization, and bill assistance; $1.3 million for measurement, evaluation, and research; and $1.6 million for performance incentive.(27) Within 120 days of the Commission's approval of the Preliminary Plan, APS will, with input and assistance from the collaborative working group, submit a Final Plan for Commission approval.

In order to help the state's public and charter schools mitigate the effects of the rate increase, the DSM Working Group should make every effort to target DSM programs to schools and to make the implementation of DSM in schools a top priority.

The adjustor will collect DSM costs that are above the $10 million annual level included in

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(21) Direct testimony of Barbara Keene, February 3, 2004.

(22) APS will spend at least $48 million during calendar years 2005-2007.

(23) "Energy-efficient DSM" is defined as "the planning, implementation and evaluation of programs that reduce the use of electricity by means of energy-efficiency products, services, or practices." Settlement Agreement par. 40.

(24) Id. par. 45.

(25) Id. par. 42.

(26) Tr. p. 969.

(27) APS' share of DSM net economic benefits, capped at 10 percent of total DSM expenditures.

base rates. The adjustor rate will initially be set at zero, and will be adjusted yearly on March 1, based upon the account balance and the appropriate kWh or kW charge. The DSM adjustor will apply to both standard offer and direct access customers.

The Settlement Agreement does not provide for the recovery of net lost revenues. The Settlement Agreement provides that if during 2005 through 2007, APS does not spend at least $30 million of the base rate allowance for approved and eligible DSM-related items; the unspent amount will be credited to the account balance for the DSM adjustor.

On residential customers' bills, the DSM adjustor will be combined with the EPS adjustor and be called an "Environmental Benefits Surcharge."(28) As part of its tariff compliance filing, within 60 days of this Decision, APS must file a Plan of Administration for Staff review and approval.

Pursuant to the Settlement Agreement, APS is required to "implement and maintain a collaborative DSM working group to solicit and facilitate stakeholder input, advise APS on program implementation, develop future DSM programs, and review DSM program performance."(29) The working group will review the plans, but APS is responsible for demonstrating appropriateness of its programs to the Commission. APS is required to conduct a study to review and evaluate whether large customers should be allowed to self-direct DSM investments and file the study within one year. APS is also required to study rate designs that encourage energy efficiency, discourage wasteful and uneconomic use of energy, and reduce peak demand. The plan for the study and analysis of rate design modifications must be presented to the collaborative DSM working group within 90 days, and APS must submit to the Commission the final results as part of its next rate case, or within 15 months of this Decision, whichever is first. APS is required to develop and propose appropriate rate design modifications. Additionally, APS is required to file mid-year and end-year reports on each DSM program. All DSM year-end reports filed at the Commission by APS must be certified by an Officer of the Company.

Pursuant to the Settlement Agreement, APS is to invite DSM resources to participate in its RFP and other competitive solicitations, and must evaluate them in a consistent and comparable

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(28) Settlement Agreement par. 50.

(29) Id. par. 54.

manner.

SWEEP supports the DSM provisions in the Settlement Agreement. Although it originally recommended that the Commission should substantially increase energy efficiency by setting target goals of 7 percent of total energy resources needed to meet retail load in 2010 from energy efficiency and 17 percent in 2020, it agreed that the Settlement Agreement's requirement of DSM funding is reasonable and justified given the cost-effective benefits that will be achieved. SWEEP believes that the level of funding in the Settlement Agreement is a valuable and meaningful step towards encouraging and supporting energy efficiency for APS customers, especially since the Commission can approve additional DSM program funding through the adjustment mechanism.

In response to questioning from Commissioner Spitzer, the witness for SWEEP testified that DSM is the most efficient way to mitigate market and fuel price increases and it reduces customer vulnerability to price volatility, by reducing the need for new power plant construction and new transmission lines.(30) Even customers who do not participate in the DSM programs will benefit, both from an economic perspective as well as from the environmental and health standpoint.(31) The Preliminary DSM Plan attached as Exhibit B to the Settlement Agreement is a good start towards developing cost-effective DSM programs. However, we are concerned that our approval of the Settlement Agreement and Exhibit B may result in stakeholders focusing too narrowly when attempting to comply with the DSM goals of this Order. Particularly, we note that there are no demand response programs included in Exhibit B. Given the response by APS' customers to last summer's outage as discussed by Commissioner Hatch-Miller,(32) it is clear that when proper signals are given, customers will respond by reducing their demand.

We also think it is clear that the traditional demand response programs that define "off-peak" hours as between 9:00 p.m. to 9:00 a.m. are ineffective in creating an incentive to residential ratepayers to shift their electricity consumption to "off peak" hours. Common sense indicates that a substantial number of ratepayers cannot or are not able to take advantage of such programs as 9:00 p.m. is an unrealistic time to commence the "off peak" period because most ratepayers are either

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(30) Tr. p. 877.

(31) Tr. p. 930.

(32) See discussion Tr. pp. 1384-1394.

asleep or preparing to sleep at that time.(33) Further, the start time begins many hours after the actual peak has subsided. Finally, the inconvenience of a 9:00 p.m. start time assures that the demand response to "off peak" hours and programs is miscalculated. Therefore, in an effort to expedite APS' addressing demand response programs, we will order APS to file additional time-of-use programs that are similar to the Time Advantage and Combined Advantage Plans with different peak schedule(s) and tariff(s) options, within six months of the effective date of this Decision.

We believe that it would be beneficial, perhaps in conjunction with the rate design time-of-use study and the use of "advanced" or "smart" meters, to evaluate and implement programs designed to reduce APS' summer peak demand. Accordingly, we will encourage submission of such DSM programs.

i. ENVIRONMENTAL PORTFOLIO STANDARD AND OTHER RENEWABLES PROGRAMS

The Settlement Agreement addresses renewable energy in three areas: a special renewable energy solicitation; the environmental portfolio standard ("EPS") and in the competitive procurement of power.

The Settlement Agreement requires APS to issue a special RFP in 2005 seeking at least 100 MW and at least 250,000 MWh per year of renewable energy resources including solar, biomass/biogas, wind, small hydro (under 10 MW), hydrogen (other than from natural gas) or geothermal for delivery beginning in 2006. In order to take advantage of any available federal tax credits for renewable energy production, APS should issue the 100 MW RFP no later than May 15, 2005. APS also will seek to acquire at least ten percent of its annual incremental peak capacity needs from renewable resources. Among other requirements, the renewable resources must be no more costly than 125 percent of the reasonably estimated market price of conventional resource alternatives and APS can acquire out-of-state resources to meet the goal if sufficient in-state qualified bids are not received. However, if APS determines that it cannot meet this requirement through in-state resources, it must bring its proposal to purchase out-of-state resources to Staff and obtain Commission approval before making the out-of-state purchase.

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(33) We do not need a study, workshop or to evaluate the proposed test demand programs to convince us regarding residential demand programs in this matter.

The Settlement Agreement also provides that renewable resources acquired through the special RFP or future solicitations shall be subject to the Commission's customary prudence review. And while the Settlement Agreement further stipulates that a renewable resource purchase shall not be found imprudent solely because the cost of the renewable resource exceeds market price, we stipulate conversely that a renewable resource purchase shall not be rendered prudent solely by virtue of the resource's cost being below 125 percent of market price.

The special RFP does not displace APS' requirements under the EPS. APS will continue to collect $6 million annually in base rates and the existing EPS surcharge, which provided $6.5 million during the test year, will be converted to an adjustment mechanism, which will allow for Commission-approved changes to APS' EPS funding.

The Settlement Agreement does not alter the existing EPS or the current level of funding, but it changes the EPS surcharge into an adjustor so that the Commission has the flexibility to change funding levels and rates in the future. APS' current rates and surcharge total $12.5 million and pursuant to the Settlement Agreement, $6 million of this amount will be recovered in base rates and $6.5 million in the EPS adjustor.

Under the Settlement Agreement, APS will allow and encourage all renewable resources to participate in its competitive power procurement.

In response to a request from Commissioner Spitzer, several parties filed late-filed exhibits concerning the recently enacted American Jobs Creation Act of 2004. According to APS, the Act provides for a domestic production deduction for its generation activities, and also extends renewable electricity production credits through 2005 and expands the types of renewable resources eligible for the credits.(34) In its December 10, 2004 response, WRA stated that "renewable energy appears to be at a disadvantage relative to gas-fired generation because the tax burden tends to fall more heavily on capital intensive projects such as renewable energy generation. Therefore, such tax burden differentials may add further support for the preference for renewable energy in the settlement agreement and for production tax credits as means to `level the playing field' between gas-fired

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(34) Previously, only wind, closed-loop biomass and poultry waste were included, and now open-loop biomass, geothermal energy, solar energy, small irrigation power, and municipal solid waste are included as qualified energy resources.

resources and renewable energy."

j. COMPETITIVE PROCUREMENT OF POWER

The Settlement Agreement provides that APS will issue an RFP or other competitive solicitation(s) in 2005 seeking long-term resources of not less than 1000 MW for 2007 and beyond. "Long-term" resource is defined as acquisition of a generating facility or an interest in one, or any PPA of 5 years or longer. No APS affiliate will participate in this RFP/solicitation, and in the future will not participate unless an independent monitor is appointed. Further, APS will not self-build any facility with an in-service date prior to January 1, 2015, unless expressly authorized by the Commission. As defined in the Settlement Agreement, "self-build" does not include the acquisition of a generating unit or interest in one from a non-affiliated merchant or utility generator, the acquisition of temporary generation needed for system reliability, distributed generation of less than 50 MW per location, renewable resources, or the up-rating of APS generation.

We generally agree that the self-build moratorium proposed in the Agreement is useful for addressing the potentially anti-competitive effects that may be associated with rate-basing the PWEC assets. However, to fully realize the benefits of the moratorium for that purpose, the moratorium should apply to the acquisition of a generating unit or interest in one from any merchant or utility generator, as well as to building new units. Accordingly, we will modify the definition of "self-build" to include the acquisition of a generating unit or interest in a generating unit from any merchant or utility generator. Consistent with the definition in the Settlement Agreement, "self-build" will not include the acquisition of temporary generation needed for system reliability, distributed generation of less than fifty MW per location, renewable resources, or up-rating of APS generation, which up-rating shall not include the installation of new units.

Similarly, we will require APS to obtain the Commission's expressed approval for APS' acquisition of any generating facility or interest in a generating facility pursuant to a RFP or other competitive solicitation(35) issued before January 1, 2015. Our determination herein should not be construed as signaling in any manner the ultimate regulatory treatment that can or will be accorded to

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(35) Competitive solicitation includes a RFP issued pursuant to Paragraph 78 of the Settlement Agreement or any solicitation issued by APS in using its Secondary Procurement Protocol pursuant to Paragraph 80 of the Settlement Agreement.

any generating facility or interest in any generating facility ultimately acquired by APS. APS will continue to use its Secondary Procurement Protocol except as modified by the Settlement Agreement or by Commission decision. The Commission's Staff will schedule workshops on resource planning, focusing on developing needed infrastructure and a flexible, timely, and fair competitive procurement process. As discussed above, the rate basing of PWEC assets, at a discount, should not be construed as an abandonment of competition by this Commission. The industry-wide question, "how will new generation be built and by whom?", is particularly trenchant in Arizona due to high forecast growth in customer load. The self-build moratorium agreed to by APS is consistent with the Commission's support for competitive wholesale electricity markets.

The workshops conducted by Staff on the development of needed infrastructure shall include consideration of the feasibility and implementation of an expanded use of utility-scale solar electric generation integrated with existing coal fired operations. APS' aging coal fired plants face an increasingly emissions regulated future which may require sizeable investments to improve emissions control performance.

By integrating solar generation with the existing generation and transmission infrastructure at coal fired facilities, it may be possible to create synergies that take advantage of existing site infrastructure to lower the cost of building and operating solar electric generation, while reducing the environmental impact of coal fired generation. Generation from a solar electric project will add fuel-free, net-plant energy output resulting in environmental benefits and lower energy specific water usage. A long-term benefit of such a strategy would be that after all life extension measures are exhausted for the fueled power complexes, there will be many decades of useful life remaining in the transmission assets serving these sites. These valuable assets could be utilized by emission and water free solar generation built incrementally over the next decades in the expansive buffer zone property around many of the existing coal plants.

k. REGULATORY ISSUES

In the Settlement Agreement, the parties acknowledge that APS has the obligation to plan for and serve all customers in its certificated service area and to recognize through its planning, the existence of any Commission direct access program and the potential for future direct access

customers. Any change in retail access as well as the resale by APS and other Affected Utilities of Revenue Cycle Services to ESPs will be addressed through the Electric Competition Advisory Group ("ECAG") or similar process. The parties acknowledge that APS may join a FERC-approved Regional Transmission Organization ("RTO") or entity and may participate in those activities without further order or authorization from the Commission.

l. COMPETITION RULES COMPLIANCE CHARGE ("CRCC")

Included in the total test year revenue requirement is approximately $8 million for the Competition Rules Compliance Charge. APS will recover $47.7 million plus interest through a CRCC of $0.000338/kWh over a collection period of 5 years. When that amount is collected, the CRCC will immediately terminate, and if the amount is under or over recovered, then APS must file an application for the appropriate remedy.

m. LOW INCOME PROGRAMS

APS will increase funding for marketing its E-3 and E-4 tariffs to a total of $150,000 as set forth in the Settlement Agreement. The parties' intent is to insulate eligible low income customers from the effects of the rate increase resulting from the Settlement Agreement. On December 17, 2004, the ACAA filed a response to Commissioner Mayes' question about automatic enrollment in utility discount programs, indicating that they have initiated a discussion with the Arizona Department of Economic Security ("DES") to facilitate the automatic enrollment in utility discount programs, as well as other agency managed programs. ACAA is in the process of adding the utility discount application forms to its website, which will allow the form to be sent electronically to the appropriate entity for processing. Concerning marketing efforts, ACAA stated that it engages in various outreach efforts throughout the state, providing information about the E-3 discount program available through APS. ACAA indicated that DES is currently charged with the official marketing of the program, but there is currently no affirmative marketing of the program "as their resources are severely limited." Also in response to Commissioner Mayes' request, APS filed information concerning its low income programs. APS stated that it has renewed its conversations with DES and ACAA, requesting feedback on increasing participation through automated signup for the E-3 and E-4 programs. Both agencies expressed interest and APS states that it will continue to work with both

agencies to determine the efficiency and practicality of such a streamlined approach.

The Commission believes that APS should work to make its low-income assistance programs widely available, including to Native Americans living inside the Company's service territory. Within six months of the effective date of this Order, APS shall develop an outreach plan that will enable it to better inform the state's Tribes about the Company's low-income assistance programs. The plan should be filed with the Commission and made available to Tribal authorities within APS' service territory.

n. RETURNING CUSTOMER DIRECT ACCESS CHARGE ("RCDAC")

The Settlement Agreement provides that APS can recover from Direct Access customers the additional cost that would otherwise be imposed on other Standard Offer customers if and when the former return to Standard Offer from their competitive suppliers. The RCDAC shall not last longer than 12 months for any individual customer. The charge will apply only to individual customers or aggregated groups of 3 MW or greater who do not provide APS with one year's advance notice of intent to return to Standard Offer service. APS will file a Plan of Administration as part of its tariff compliance filing.

o. SERVICE SCHEDULE CHANGES

The Settlement Agreement adopts several of APS' proposed changes to service schedules, including Schedule 3, but with the retention of the 1,000 foot construction allowance for individual residential customers and also with any individual residential advances of costs being refundable. Several APS customers made public comment about the line extension policy and how it has not been modified in a long time. We will direct Staff to work with APS to review its line extension policy and determine whether the construction allowance should be modified.

p. NUCLEAR DECOMMISSIONING

The decommissioning costs as recommended by APS are adopted as set forth in Appendix I to the Settlement Agreement.

q. TRANSMISSION COST ADJUSTOR ("TCA")

The Settlement Agreement establishes a transmission cost adjustor ("TCA") to ensure that any potential direct access customers pay the same for transmission as Standard Offer customers.

The TCA is limited to recovery of costs associated with changes in APS' open access transmission tariff ("OATT") or equivalent tariff. The TCA goes into effect when the transmission component of retail rates exceeds the test year base amount of $0.00476(36) per kWh by 5 percent and APS obtains Commission approval of a TCA rate.

r. DISTRIBUTED GENERATION

Generally, distributed generation is small-scale power generation units strategically located near customers and load centers. According to the ACA/DEAA, the benefits of distributed energy systems include: greater grid reliability; increased grid stability (voltage support along transmission lines); increased system efficiency (reduction in transmission line losses); increased efficiency; flexibility; decreased pressure on natural gas (demand and cost); leverage of resources; and sustainable installations.

The Settlement Agreement provides that Staff shall schedule workshops to consider outstanding issues affecting distributed generation and shall refer to the results of the prior distributed generation workshops for issues to study.

ACA/DEAA presented its objectives at hearing as follows: a DG workshop with strong Staff leadership; clear goals, ground rules, milestones, and deadlines; participants with authority; continuing reports to ACC and management; and a process to bring contested issues to the Commission for resolution. None of the proponents of the Settlement Agreement oppose Commission adoption of these objectives.

In its post-hearing brief, ACA/DEAA listed the following guidelines as "overriding criteria": 1) rates must be fair; 2) rates should be designed to send as efficient as possible pricing signals to consumers; 3) impediments to customer choices, such as unnecessarily difficult and expensive interconnection to the grid, should be eliminated to the maximum extent possible; 4) all generators should be treated fairly - large and small; and 5) proposals, if implemented, should not interfere with the Commission's public policy goals. ACA/DEAA made 3 recommendations: 1) Rate Design - the Commission should adopt an experimental rate for partial requirement customers. The proposal

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(36) Paragraph 106 of the Settlement Agreement contains a typo; the amount "$0.000476" should actually be "$0.00476," Tr. p. 1168.

would mimic SRP's E-32 rate, which includes time of day rates and summer/winter rates. ACA/DEAA proposed to limit participation to 50 MWs of new customer load each year for 5 years - both generation and supplemental load. It appears that this is the first alternative rate schedule that ACA/DEAA has proposed, and no party has had an opportunity to evaluate and comment on the proposal. Accordingly, we decline to adopt the proposal in this docket, but we believe that this proposal may be a good starting point for discussion in the DG workshop.

ACA/DEAA further recommended that the Texas standard is best suited for application to the APS system and that the provisions of California rule 21 would serve as a second choice for DG standards in Arizona. ACA/DEAA also recommended that the Commission consider a program to install self generation to reduce the electricity on the power grid. We believe that both of these recommendations should also be discussed and developed during the course of the workshop.

The proponents of the Settlement Agreement recommend that specific issues concerning DG should be addressed in workshops devoted to distributed generation. Paragraphs 108 and 109 direct Staff to schedule workshops to address outstanding DG issues. They believe that such a process would use the work done in previous workshops and would also address the technical aspects of connecting distributed generation in a way that would apply to all regulated utilities in Arizona. To be successful, the process would require a strict timetable for producing recommendations for the Commission's consideration. The proponents argue that Schedule E-32 should not be redesigned to meet the specialized needs of partial requirements service, but that the rate design for partial requirements service should be addressed in the workshop. Approximately 95,000 full requirement customers receive service under Schedule E-32, and according to the proponents, it is an integral part of the Settlement Agreement. The proponents believe that ACA/DEAA's proposal to put the rate increase in the energy portion would create a massive subsidy from higher load factor customers to lower load factor customers. The demand related charges are necessary for pricing the capacity related costs of the APS system for the full requirement customers. The proponents argue that DG requires partial requirement service - which is a very specialized product that includes maintenance power, standby power, and supplemental power - and it should have its own rate, which can be addressed in the proposed DG workshop.

We agree with ACA/DEAA that DG can have significant benefits to APS and to its ratepayers and we want to encourage the growth of DG that can provide those benefits. Additionally, we find some of the suggestions made in ACA/DEAA's post hearing brief persuasive. However, our decision is rooted in the record made in this case, and those suggestions were not fully delineated, nor subjected to cross examination at the Hearing. At this point, we agree with the participants that the E-32 schedule should not be modified to accommodate the particular needs associated with DG. Therefore, we believe that the parties should address the issue of an appropriate rate schedule for DG during the workshop process, and direct the parties to develop a schedule that is designed particularly for DG customers. Further, we direct the parties to begin the process by evaluating the three recommendations made by ACA/DEAA in its post hearing brief.

s. BARK BEETLE REMEDIATION

APS is authorized to defer for later recovery the reasonable and prudent direct costs of bark beetle remediation that exceed the test year levels of tree and brush control. In the next rate case, the Commission will determine the reasonableness, prudence, and allocation of the costs, and will determine the appropriate amortization period.

t. RATE DESIGN

Attached to the Settlement Agreement is Appendix J, which sets forth the rates adopted in the Settlement Agreement. The rates are designed to permit APS to recover an additional $67.5 million in base revenues, including an additional 3.94 percent for the residential rate class and a 3.57 percent increase for the general service rate class. The rates were designed to move toward costs and remove subsidizations, thereby promoting equity among customers. The base rates will also permit cost-based unbundling of distribution and revenue cycle services, including metering, and meter reading and billing. The parties believe that this will give appropriate price signals necessary for shopping. APS will continue on-peak and off-peak rates for winter billing for all residential time-of-use customers under Schedules ET-1 and ECT-1R. Within 180 days APS will submit a study to Staff that examines other ways APS can implement more flexibility in changing APS' on- and off-peak time periods and other time-of-use characteristics, making those periods more reflective of actual system peak time periods. APS shall also include in the aforementioned study a cost-benefit analysis

of Surepay, APS' automatic payment program. The Company is to examine the cost effectiveness of the program and to explore the possibility of offering a discount to those customer who participate in Surepay. The Settlement Agreement adopts APS' proposed experimental time-of-use periods for ET-1 and ECT-1R. For general service customers, the existing on-peak time periods will remain the same and the summer rate period will begin in May and conclude in October. The general service rate schedules will also permit cost-based unbundling of generation and revenue cycle services and will be differentiated by voltage levels. An additional primary service discount of $2.74/kW for military base customers served directly from APS substations will be adopted. The Settlement Agreement modifies Schedule E-32 in order to simplify the design, make it more cost-based, and to smooth out the rate impact across customers of varying sizes within the rate schedule. Changes include the addition of an energy block for customers with loads under 20 kW and an additional demand billing block for customers with loads greater than 100 kW. A time-of-use option will also be available to E-32 customers. Testimony was offered at the hearing that there was an inadvertent omission in Appendix J to the Settlement Agreement for Rate E-32-TOU in that the delivery-related demand charge for Rate E-32-TOU should have been reduced after the first 100 kW of demand for residual off-peak demand(37) and that the initial rate block for residual off-peak delivery should be applied only to the first 100kW of combined on-peak and residual off-peak demand. We will, therefore, direct APS to modify Rate E-32-TOU in accordance with these changes in its compliance filings. As discussed above, ACA/DEAA objected to the company's E-32 schedule. One of ACA/DEAA's concern was the almost doubling of the demand charge. The Commission has open dockets involving APS' metering and bill estimation procedures, including the estimation of demand. Although we are not resolving those issues in this rate case, we are concerned that APS properly meter, read meters and bill its customers timely and accurately. (38) It is imperative, especially given

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(37) Instead of remaining at the initial level of $7.722 per kW-month, after the first 100 kW of demand, the unbundled residual off-peak demand charge for delivery at Secondary voltage will be reduced to $3.497; after the first 100kW of demand, the unbundled residual off-peak demand charge for delivery at Primary voltage will be reduced to $2.877, with both of these changes incorporated into the bundled rate as well.

(38) Also, we note that apparently APS is deleting a bill estimation procedure for EC-1 and ECT-1R. It is not clear whether these are the tariffs that Staff has alleged APS has not been following, but nothing in this Decision will affect our ability to make findings in Docket Nos. E-01345A-04-0657, et al. or impose any appropriate fines, sanctions, or remedies in those dockets.

the increase in the demand charge, that APS reduce the instances where it estimates demand.

In a response (dated August 18, 2004) to a question from Commissioner Mundell regarding the break-over points for tiered rates, the parties to the Settlement Agreement indicated that rate E-12 has the most customers. The response also stated that the average use by a customer on rate E-12 is 770 kWh per month. Rate E-12 has three tiers with break-over points at 400 kWh per month and 800 kWh per month. Paragraph 57 of the Settlement Agreement requires APS to conduct a rate design study analyzing rate design modifications to promote energy efficiency, conservation, and reduce peak demand. As part of the study, we will require that one of the rate design modifications that APS shall investigate is to lower the first break-over point in rate E-12 to 350 kWh per month and lower the second break-over point to 750 kWh per month. In addition, the charge (rate) per kWh in the first tier (less than 350 kWh per month) should be lowered, while the rate for the third tier (over 750 kWh per month) should be raised. We will require that APS propose this type of rate design, or something very similar, for rate E-12 in its next rate case. We believe this type rate design, coupled with the DSM measures outlined in this Order, will encourage customers, especially high-use customers, to conserve energy (thereby lowering overall demand) and/or move to time-of-use rates (thereby lowering peak demand). If APS or any party to the next APS rate case believes this type rate design would be detrimental to APS and/or its customers, that party shall provide a detailed explanation and examples as to how and why this type rate design would be detrimental.

Several schedules are "frozen" and APS will provide notice approved by Staff to those customers that those rates will be eliminated in APS' next rate case. Such notice will be provided at the conclusion of this docket and at the time that APS files its next rate case.

u. LITIGATION AND OTHER ISSUES

The Settlement Agreement provides that APS will dismiss with prejudice all appeals of Decision No. 65154, the Track A Order, and APS and its affiliates will dismiss litigation related to Decision Nos. 65154 and 61973 and/or any alleged breach of contract, and APS and its affiliates shall forgo any claim that APS, PWEC, Pinnacle West Capital Corporation or any of APS' affiliates were harmed by Decision No. 65154, and the Preliminary Inquiry ordered in Decision No. 65796 shall be concluded with no further action by the Commission, once the Settlement Agreement is approved in

accordance with Section XXI of the Settlement Agreement by a Commission Decision that is final and no longer subject to judicial review.

The Commission is also concerned that service reliability on rural Tribal lands has become degraded. Therefore, within six months of the effective date of this Order, APS should compile its SAIFI, CAIDI and SAIDI numbers for all Tribal territories it serves and provide to the Commission a report on proposed options for improving reliability in these areas. Moreover, APS shall participate in any future dockets related to enhancing reliability statewide.

v. SUMMARY

This Settlement Agreement resolves numerous significant, complex, and conflicting issues affecting many parties with very different perspectives and interests. As with every settlement, the give and take nature of negotiations ends up with a product that no one party initially proposed. The key question when deciding whether to approve such a settlement is whether the end result resolves the important issues fairly and reasonably when taken together as a whole, and in such a way that will promote the public interest. We believe that the Settlement Agreement reached by these 22 parties, with the modifications that we make herein, reaches such a result. Our agreement to rate base the PWEC assets does not mean that we are retreating from our commitment to encourage the development of competition, and we expect APS and its affiliates to fully comply with all the pro-competition requirements in the Settlement Agreement and other Commission decisions and rules. Additionally, our adoption of a PSA will be a significant change for APS customers, and we expect APS to educate and inform its customers about all aspects of that adjustor charge in a way that will minimize confusion and misunderstandings. We also expect APS to have the required information posted to its website and its customer education program up and running before June 1, 2005, in order to allow customers the opportunity to implement their own conservation measures. Finally, we want to make it clear to APS that our adoption of a PSA does not relieve it of its obligation to effectively and efficiently manage its fuel costs, and that we will closely monitor APS' performance.

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

IV. FINDINGS OF FACT

1. APS is a public service corporation principally engaged in furnishing electricity in the State of Arizona. APS provides either retail or wholesale electric service to substantially all of Arizona, with the major exceptions of the Tucson metropolitan area and about one-half of the Phoenix metropolitan area. APS also generates, sells and delivers electricity to wholesale customers in the western United States.

2. On June 27, 2003, APS filed with the Commission an application for a $175.1 million rate increase and for approval of a purchased power contract.

3. Notice of the application was provided in accordance with the law.

4. Intervention was granted to AECC, FEA, Kroger, RUCO, AUIA, Phelps Dodge, IBEW, ACA/DEAA, Panda, AWC, SWG, WRA, CNE, SEL, DVEP, UES, ACAA, Alliance, Wickenburg, AriSEIA, AARP, SWEEP, PPL Sundance, PPL Southwest, SWPG, Mesquite, and Bowie.

5. By Procedural Order issued August 15, 2003, the hearing was set to commence on April 7, 2004, and procedural dates were established for the filing of testimony and evidence.

6. On February 6, 2004, APS filed a Motion to Amend the Rate Case Procedural Schedule, and a procedural conference was held on February 18, 2004 to discuss the Motion.

7. By Amended Rate Case Procedural Order issued on February 20, 2004, the hearing date was rescheduled for May 25, 2004 and other procedural dates were modified.

8. On April 6, 2004, Staff filed a Motion to Amend the Procedural Schedule and on April 8, 2004, Staff filed a Memorandum indicating that representatives of APS had contacted Staff about the possibility of conducting settlement negotiations.

9. A public comment hearing was held on April 7, 2004.

10. On April 13, 2004, APS filed its Response to Staff's Motion and Staff Notice of Settlement Negotiations and requested a temporary suspension of the procedural schedule in order for settlement discussions to take place.

11. Pursuant to Procedural Orders issued April 7 and 12, 2004, a procedural conference to discuss Staff's Motion was held on April 15, 2004. By Procedural Order issued April 16, 2004, new

procedural dates were established and another procedural conference was scheduled for April 28, 2004.

12. The April 28, 2004 procedural conference was held as scheduled and by Procedural Order issued April 29, 2004, the procedural schedule was stayed and another procedural conference was scheduled for May 26, 2004.

13. Pursuant to procedural conferences held on May 26 and June 14, 2004, and Procedural Orders issued on May 26, June 18, and July 20, 2004, the stay was extended in order to allow the parties to discuss settlement.

14. At the August 18, 2004 Procedural Conference, the parties announced that they had reached a settlement, and the Settlement Agreement was docketed on that date.

15. On August 20, 2004, an Amended Rate Case Procedural Order was issued setting the hearing on the Settlement Agreement to commence on November 8, 2004.

16. The hearing was held as scheduled on November 8, 9, 10, 29, 30 and December 1, 2, and 3, 2004. Public comment was taken and testimony from the proponents of the Settlement Agreement was presented in panel format, and testimony from the ACA/DEAA was also presented in a panel format.

17. The Test Year ending 2002 Plant in Service was $4,876,901,000, excluding transmission plant, and including the PWEC assets as of December 31, 2004.

18. APS' FVRB is $5,054,426,000 and a 5.92 fair value rate of return is appropriate.

19. It is just and reasonable to authorize a total annual revenue increase in the amount of $75,500,000, consisting of an increase in base rates of approximately 3.77 percent or $67.6 million, and an increase in the CRCC surcharge of approximately .44 percent, which will collect $7.9 million.

20. A Power Supply Adjustor as set forth in the Settlement Agreement and as modified herein, is in the public interest.

21. APS is authorized to acquire the PWEC generation assets and rate base those assets at a value of $700 million as of December 31, 2004, under the terms and conditions as set forth in the Settlement Agreement and herein.

22. The Settlement Agreement will allow APS the opportunity to earn a reasonable rate of

return on its investment, will provide revenues sufficient for the Company to provide efficient and reliable service, and will allow for continued development of electric competition in Arizona.

23. APS shall implement a customer education program explaining how its PSA will work and shall maintain on its website information explaining the billing format, rates, and charges, including up-to-date information about the PSA and current gas costs. APS shall submit its plan to implement its customer education program within 30 days of the effective date of this Decision to the Director of the Utilities Division for review and Staff shall keep the Commission apprised of the consumer education program. Furthermore, APS shall post the required information on its website within 30 days of the effective date of this Decision.

24. The parties to the Settlement Agreement shall submit a PSA Plan of Administration that reflects the determinations in this Decision for Commission approval within 60 days of the effective date of this Decision.

25. The depreciation rates and the costs for nuclear decommissioning as set forth in the Settlement Agreement are reasonable and appropriate.

26. Testimony was offered at the hearing that there was an inadvertent omission in Appendix J to the Settlement Agreement for Rate E-32-TOU in that the delivery-related demand charge for Rate E-032-TOU should have been reduced after the first 100 kW of demand for residual off-peak demand and that the initial rate block for residual off-peak delivery should be applied only to the first 100 kW of combined on-peak and residual off-peak demand. We will, therefore, direct APS to modify Rate E-32-TOU in accordance with these changes in its compliance filings.

27. We direct the parties to begin the DG workshop process by evaluating the three recommendations made by ACA/DEAA in its post hearing brief.

28. In its study to be filed within 180 days of the effective date of this Decision concerning flexibility of on- and off-peak time periods and other time-of-use characteristics, APS shall also include a cost-benefit analysis of Surepay, APS' automatic payment program. The Company shall examine the cost effectiveness of the program and explore the possibility of offering a discount to those customers who participate in Surepay.

29. APS shall file additional time-of-use programs that are similar to the Time Advantage

and Combined Advantage Plans with different peak schedule(s) and tariff(s) options, within six months of the effective date of this Decision.

30. In a response (dated August 18, 2004) to a question from Commissioner Mundell regarding the break-over points for tiered rates, the parties to the Settlement Agreement indicated that rate E-12 has the most customers. The response also stated that the average use by a customer on rate E-12 is 770 kWh per month. Rate E-12 has three tiers with break-over points at 400 kWh per month and 800 kWh per month. Paragraph 57 of the Settlement Agreement requires APS to conduct a rate design study analyzing rate design modifications to promote energy efficiency, conservation, and reduce peak demand. As part of the study, we will require that one of the rate design modifications that APS shall investigate is to lower the first break-over point in rate E-12 to 350 kWh per month and lower the second break-over point to 750 kWh per month. In addition, the charge (rate) per kWh in the first tier (less than 350 kWh per month) should be lowered, while the rate for the third tier (over 750 kWh per month) should be raised. We will require that APS propose this type of rate design, or something very similar, for rate E-12 in its next rate case. We believe this type rate design, coupled with the DSM measures outlined in this Order, will encourage customers, especially high-use customers, to conserve energy (thereby lowering overall demand) and/or move to time-of-use rates (thereby lowering peak demand). If APS or any party to the next APS rate case believes this type rate design would be detrimental to APS and/or its customers, that party shall provide a detailed explanation and examples as to how and why this type rate design would be detrimental.

31. In order to help the state's public and charter schools mitigate the effects of the rate increase, the DSM Working Group should make every effort to target DSM programs to schools and to make the implementation of DSM in schools a top priority.

32. All DSM year-end reports filed at the Commission by APS must be certified by an Officer of the Company.

33. We are modifying the definition of "self-build" to include the acquisition of a generating unit or interest in a generating unit from any merchant or utility generator, and we will require APS to obtain the Commission's expressed approval for APS' acquisition of any generating facility or interest in a generating facility pursuant to a RFP or other competitive solicitation issued

before January 1, 2015. Our determination herein should not be construed as signaling in any manner the ultimate regulatory treatment that can or will be accorded to any generating facility or interest in a generating facility ultimately acquired by APS.

34. The workshops conducted by Staff on the development of needed infrastructure shall include consideration of the feasibility and implementation of an expanded use of utility-scale solar electric generation integrated with existing coal fired operations. APS' aging coal fired plants face an increasingly emissions regulated future which may require sizeable investments to improve emissions control performance.

35. The Settlement Agreement also provides that renewable resources acquired through the special RFP or future solicitations shall be subject to the Commission's customary prudence review. And while the Settlement Agreement further stipulates that a renewable resource purchase shall not be found imprudent solely because the cost of the renewable resource exceeds market price, we stipulate conversely that a renewable resource purchase shall not be rendered prudent solely by virtue of the resource's cost being below 125 percent of market price.

36. In order to take advantage of any available federal tax credits for renewable energy production, APS should issue the 100 MW RFP no later than May 15, 2005.

37. If Arizona Public Service Company determines that it cannot meet the goal for renewable energy resources as set forth in Paragraph 69 of the Settlement Agreement, through in-state resources, it shall bring its proposal to purchase out-of-state resources to Staff and obtain Commission approval before making the out-of-state purchase.

38. We agree that the use of an adjustor when fuel costs are volatile prevents a utility's financial condition from deteriorating. We are less inclined, however, to adopt an adjustor as a way to keep pace with load growth. Although APS' rebuttal testimony indicated that its fixed costs would increase in relation to its load growth, we are concerned about the potential for single-issue ratemaking and whether APS' fixed costs will increase in the same proportion as its fuel costs. According to the late-filed exhibits, the majority of the increased fuel costs are caused by increased load growth, rather than price volatility in fuel. In effect, the adjustor as designed provides annual step increases in rates. We believe APS must have an incentive to file a rate case so that we can

determine the accuracy of its assertion about expenses. Therefore, we will adopt an adjustor that collects or refunds the annual fuel costs that differ from the base year level. However, we will limit the adjustor to 4 mil from the base level over the entire term of the PSA and will cap the balancing account to an aggregate amount of $100 million. Should the Company seek to recover or refund a bank balance pursuant to Paragraph 19E of the Settlement Agreement, the timing and manner of recovery or refund of that existing bank balance will be addressed at such time. In no event shall the Company allow the bank balance to reach $100 million prior to seeking recovery or refund. Following a proceeding to recover or refund a bank balance between $50 million and $100 million, the bank balance shall be reset to zero unless otherwise ordered by the Commission.

39. Within three years of the effective date of this Decision, Staff shall commence a procurement review of APS' fuel, purchased power, generating practices and off-system sales practices.

40. Because we are concerned about the impact of the PSA on low-income customers, the PSA shall not apply to the bills of individuals who are enrolled in the Company's Energy Support program.

41. APS should work to make its low-income assistance programs widely available, including to Native Americans living inside the Company's service territory. Within six months of the effective date of this Order, APS shall develop an outreach plan that will enable it to better inform the state's Tribes about the Company's low-income assistance program. The plan should be filed with the Commission and made available to Tribal authorities within APS' service territory.

42. The Commission is also concerned that service reliability on rural Tribal lands has become degraded. Therefore, within six months of the effective date of this Order, APS should compile its SAIFI, CAIDI and SAIDI numbers for all Tribal territories it serves and provide to the Commission a report on proposed options for improving reliability in these areas. Moreover, APS shall participate in any future dockets related to enhancing reliability statewide.

V. CONCLUSIONS OF LAW

1. Arizona Public Service Company is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. Sections 40-222, 250, 251, and 376.

2. The Commission has jurisdiction over Arizona Public Service Company and the subject matter of the application.

3. Notice of the application was provided in accordance with the law.

4. The Settlement Agreement, with the modifications and additional provisions contained herein, resolves all matters raised by APS' rate application in a manner that is just and reasonable, and promotes the public interest.

5. The fair value of APS' rate base is $5,054,426,000, and 5.92 percent is a reasonable rate of return on APS' rate base.

6. The rates, charges, and conditions of service established herein are just and reasonable.

7. APS should be directed to file revised tariffs consistent with the Settlement Agreement and the findings contained in this Order.

VI. ORDER

IT IS THEREFORE ORDERED that the Settlement Agreement attached hereto as Attachment A as modified herein is approved.

IT IS FURTHER ORDERED that Arizona Public Service Company is hereby directed to file with the Commission on or before March 31, 2005, revised schedules of rates and charges consistent with Exhibit A and the findings herein.

IT IS FURTHER ORDERED that the revised schedules of rates and charges shall be effective for all service rendered on and after April 1, 2005.

IT IS FURTHER ORDERED that Arizona Public Service Company shall notify its affected customers of the revised schedules of rates and charges authorized herein by means of an insert in its next regularly scheduled billing and by posting on its website, in a form approved by the Commission's Utilities Division Staff.

IT IS FURTHER ORDERED that Arizona Public Service Company shall implement a customer education program explaining how its PSA will work and shall maintain on its website information explaining the billing format, rates, and charges, including up-to-date information about the PSA and current gas costs.

IT IS FURTHER ORDERED that within 30 days of the effective date of this Decision, Arizona Public Service Company shall submit its plan to implement its customer education program to the Director of the Utilities Division for review and Staff shall keep the Commission apprised of the consumer education program.

IT IS FURTHER ORDERED that within 30 days of the effective date of this Decision, Arizona Public Service Company shall post on its website, information explaining the billing format, rates, and charges, including up-to-date information about the PSA and current gas costs.

IT IS FURTHER ORDERED that Arizona Public Service Company shall implement and comply with the terms of the Settlement Agreement including filing all reports, studies, and plans as set forth in the Settlement Agreement and as modified herein.

IT IS FURTHER ORDERED that the parties to the Settlement Agreement shall submit a PSA Plan of Administration that reflects the determinations in this Decision for Commission approval within 60 days of the effective date of this Decision.

IT IS FURTHER ORDERED that Arizona Public Service Company shall forgo any present or future claims of stranded costs associated with any of the PWEC assets.

IT IS FURTHER ORDERED that the Commission's Utilities Division Staff shall schedule workshops on resource planning issues and distributed generation issues within 90 days of the effective date of this Decision.

IT IS FURTHER ORDERED that Arizona Public Service Company shall modify Rate E-32-TOU in accordance with the discussion and findings herein.

IT IS FURTHER ORDERED that the parties shall begin the DG workshop process by evaluating the three recommendations made by ACA/DEAA in its post hearing brief.

IT IS FURTHER ORDERED that in its study to be filed within 180 days of the effective date of this Decision concerning flexibility of on- and off-peak time periods and other time-of-use characteristics, Arizona Public Service Company shall also include a cost-benefit analysis of Surepay, Arizona Public Service Company's automatic payment program. The Company shall examine the cost effectiveness of the program and explore the possibility of offering a discount to those customers who participate in Surepay.

IT IS FURTHER ORDERED that Arizona Public Service Company shall file additional time-of-use programs that are similar to the Time Advantage and Combined Advantage Plans with different peak schedule(s) and tariff(s) options, within six months of the effective date of this Decision.

IT IS FURTHER ORDERED that Arizona Public Service Company's rate design study shall include the issues addressed in Findings of Fact No. 30, and Arizona Public Service Company shall propose a rate design addressing these issues in its next rate case.

IT IS FURTHER ORDERED that in order to help the state's public and charter schools mitigate the effects of the rate increase, the DSM Working Group should make every effort to target DSM programs to schools and to make the implementation of DSM in schools a top priority.

IT IS FURTHER ORDERED that all DSM year-end reports filed at the Commission by Arizona Public Service Company must be certified by an Officer of the Company.

IT IS FURTHER ORDERED that Arizona Public Service Company shall comply with Findings of Facts No. 33 when acquiring a generating unit or an interest in one.

IT IS FURTHER ORDERED that the resource planning workshops shall include consideration of the feasibility and implementation of an expanded use of utility-scale solar electric generation integrated with existing coal fired operations.

IT IS FURTHER ORDERED that in order to take advantage of any available federal tax credits for renewable energy production, Arizona Public Service Company shall issue the 100 MW RFP no later than May 15, 2005.

IT IS FURTHER ORDERED that if Arizona Public Service Company determines that it cannot meet the goal for renewable energy resources as set forth in Paragraph 69 of the Settlement Agreement, through in-state resources, it shall bring its proposal to purchase out-of-state resources to Staff and obtain Commission approval before making the out-of-state purchase.

IT IS FURTHER ORDERED that within three years of the effective date of this Decision, Staff shall commence a procurement review of Arizona Public Service Company's fuel, purchased power, generating practices and off-system sales practices.

IT IS FURTHER ORDERED that the PSA shall not apply to the bills of individuals who are

enrolled in the Company's Energy Support program.

IT IS FURTHER ORDERED that within six months of the effective date of this Decision, Arizona Public Service Company shall develop an outreach plan that will enable it to better inform the state's Tribes about the Company's low-income assistance programs. The plan shall be filed with the Commission and made available to Tribal authorities within Arizona Public Service Company's service territory.

IT IS FURTHER ORDERED that within six months of the effective date of this Decision, Arizona Public Service Company shall compile its SAIFI, CAIDI and SAIDI numbers for all Tribal territories it serves and provide to the Commission a report on proposed options for improving reliability in these areas, and Arizona Public Service Company shall participate in any future dockets related to enhancing reliability statewide.

IT IS FURTHER ORDERED that the Commission's Utilities Division Staff shall initiate a rulemaking proceeding to modify A.A.C. R14-2-1618 within 120 days of the effective date of this Decision.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

/s/ Jeff Hatch-Miller
CHAIRMAN

/s/ William A. Mundell
COMMISSIONER

/s/ Marc Spitzer
COMMISSIONER

/s/ Kristin K. Mayes
COMMISSIONER

COMMISSIONER

IN WITNESS WHEREOF, I, BRIAN C. McNEIL, Executive Secretary of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 7th day of April, 2005.

/s/ Brian C. McNEIL
BRIAN C. McNEIL
EXECUTIVE SECRETARY

DISSENT /s/ Mike Gleason

DISSENT _____

SERVICE LIST FOR: ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO.: E-01345A-03-0437

THOMAS L. MUMAW
KARILEE S. RAMALEY
PINNACLE WEST
CAPITAL CORPORATION
P.O. BOX 53999, MS 8695
PHOENIX, ARIZONA 85072-3999

KIMBERLY GROUSE
SNELL & WILMER
ONE ARIZONA CENTER
400 E. VAN BUREN STREET
PHOENIX, ARIZONA 85004-2202
ATTORNEYS FOR ARIZONA PUBLIC SERVICE COMPANY

C. WEBB CROCKETT
FENNEMORE CRAIG
3003 N. CENTRAL AVENUE, SUITE 2600
PHOENIX, ARIZONA 85012
ATTORNEYS FOR AECC AND PHELPS DODGE

MAJOR ALLEN G. ERICKSON
AFCES A/ULT
139 BARNES DRIVE, SUITE 1
TYNDALL AFB, FLORIDA 32403-5319
ATTORNEY FOR FEA

MICHAEL L. KURTZ
BOEHM, KURTZ & LOWRY
36 E. SEVENTH STREET, SUITE 2110
CINCINNATI, OHIO 45202
ATTORNEYS FOR KROGER COMPANY

SCOTT WAKEFIELD
RUCO
1110 W. WASHINGTON ST., SUITE 220
PHOENIX, ARIZONA 85007

WALTER W. MEEK
AUIA
2100 N. CENTRAL AVE., SUITE 210
PHOENIX, ARIZONA 85067

NICHOLAS J. ENOCH
LUBIN & ENOCH
349 N. FOURTH AVENUE
PHOENIX, ARIZONA 85003
ATTORNEYS FOR IBEW

BILL MURPHY
MURPHY CONSULTING
2422 E. PALO VERDE DRIVE
PHOENIX, ARIZONA 85016
CONSULTANT FOR ARIZONA COGENERATION ASSN.

JAY L. SHAPIRO
PATRICK J. BLACK
FENNEMORE CRAIG
3003 N. CENTRAL AVENUE, SUITE 2600
PHOENIX, ARIZONA 85012
ATTORNEYS FOR PANDA GILA RIVER, L.P.

ROBERT W. GEAKE
ARIZONA WATER COMPANY
P.O. BOX 29006
PHOENIX, ARIZONA 85038-9006

ANDREW W. BETTWY
BRIDGET A. BRANIGAN
SOUTHWEST GAS CORPORATION
5241 SPRING MOUNTAIN ROAD
LAS VEGAS, NEVADA 89150

TIMOTHY M. HOGAN
ARIZONA CENTER FOR LAW
IN THE PUBLIC INTEREST
202 E. MCDOWELL RD., SUITE 153
PHOENIX, ARIZONA 85004
ATTORNEYS FOR WESTERN RESOURCE ADVOCATES AND
SOUTHWEST ENERGY EFFICIENCY PROJECT

PAUL R. MICHAUD
MICHAUD LAW FIRM
23 CRIMSON HEIGHTS ROAD,
PORTLAND, CT 06480
ATTORNEYS FOR DOME VALLEY ENERGY PARTNERS, LLC

MARVIN S. COHEN
SACKS TIERNEY, P.A.
4250 NORTH DRINKWATER BLVD.,
4TH FLOOR
SCOTTSDALE, AZ 85251-3693
ATTORNEYS FOR CONSTELLATION NEWENERGY, INC., STRATEGIC ENERGY, L.L.C.

JEFF SCHLEGEL
SWEEP ARIZONA REPRESENTATIVE
1167 W. SAMALAYUCA DRIVE
TUCSON, AZ 85704

RAYMOND S. HEYMAN
LAURA SCHOELER
ROSHKA, HEYMAN & DEWULF
400 E. VAN BUREN, SUITE 800
PHOENIX, ARIZONA 85004
ATTORNEYS FOR UNISOURCE ENERGY SERVICES

DEBORAH R. SCOTT
UNISOURCE ENERGY SERVICES
ONE SOUTH CHURCH STREET, SUITE 200
TUCSON, ARIZONA 85702

J. WILLIAM MOORE
1144 E. JEFFERSON
PHOENIX, ARIZONA 85034
ATTORNEY FOR KROGER CO.

CYNTHIA ZWICK
ARIZONA COMMUNITY ACTION ASSOCIATION
2627 N. 3RD STREET, STE. TWO
PHOENIX, AZ 85004

S. DAVID CHILDERS LOW & CHILDERS
2999 NORTH 44TH STREET, STE. 250
PHOENIX, AZ 85018
ATTORNEY FOR ARIZONA COMPETITIVE POWER ALLIANCE

JAMES M. VAN NOSTRAND
KATHERINE MCDOWELL
GEORGE M. GALLOWAY
STOEL RIVES
900 SW FIFTH AVENUE, STE. 2600
PORTLAND, OR 97204
ATTORNEYS FOR ARIZONA COMPETITIVE POWER ALLIANCE

GREG PATTERSON, EXECUTIVE DIRECTOR
ARIZONA COMPETITIVE POWER ALLIANCE
916 WEST ADAMS, STE. 3
PHOENIX, AZ 85007

MICHAEL A. CURTIS
MARTINEZ & CURTIS, P.C.
2712 N. SEVENTH STREET
PHOENIX, AZ 85006-1090
ATTORNEYS FOR TOWN OF WICKENBURG

REBECCA C. SALISBURY
56TH FIGHTER WING JA
7383 N. LITCHFIELD ROAD
LUKE AFB, AZ 85309-1540
ATTORNEY FOR FEDERAL EXECUTIVE AGENCIES

JON POSTON
AARP ELECTRIC RATE PROJECT
6733 EAST DALE LANE
CAVE CREEK, AZ 85331

CORALETTE HANNON
AARP DEPARTMENT OF STATE AFFIARS
6705 REEDY CREEK ROAD
CHARLOTTE, NC 28215

LAWRENCE V. ROBERTSON
MUNGER CHADWICK
333 N. WILMOT, STE. 300
TUCSON, AZ 85711
ATTORNEYS FOR SOUTHWESTERN POWER GROUP II, LLC,
MESQUITE POWER AND BOWIE POWER STATION

JAY I. MOYES
MOYES STOREY
1850 N. CENTRAL AVE, #1100
PHOENIX, AZ 85004
ATTORNEYS FOR PPL SUNDANCE, LLC AND PPL SOUTHWEST GENERATION HOLDINGS, LLC

JESSE A. DILLON
PPL SERVICES CORPORATION
TWO N. NINTH STREET
ALLENTOWN, PA 18101

SEAN SEITZ
ARISEIA
5056 S. 40TH STREET, SUITE C
PHOENIX, ARIZONA 85040

ROBERT ANNAN
ANNAN GROUP
6605 E. EVENING GLOW DRIVE
PHOENIX, AZ 85262

DOUGLAS V. FANT
AZCOGEN ASSOCIATION
80 E. COLUMBUS
PHOENIX, AZ 85012

CYNTHIA ZWICK
ARIZONA COMMUNITY ACTION ASSOCIATION
224 SOUTH THIRD AVE
YUMA, AZ 85364

CHRISTOPHER KEMPLEY, CHIEF COUNSEL
LEGAL DIVISION
ARIZONA CORPORATION COMMISSION
1200 WEST WASHINGTON STREET
PHOENIX, AZ 85007

ERNEST G. JOHNSON, DIRECTOR
UTILITIES DIVISION
ARIZONA CORPORATION COMMISSION
1200 WEST WASHINGTON STREET
PHOENIX, AZ 85007

ATTACHMENT A

PROPOSED SETTLEMENT

OF

DOCKET NO. E-01345A-03-0437

ARIZONA PUBLIC SERVICE
COMPANY

REQUEST FOR RATE
ADJUSTMENT