PINNACLE WEST CAPITAL CORP

FORM 10-Q
(Quarterly Report)

Filed 11/14/00 for the Period Ending 09/30/00

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

PINNACLE WEST CAPITAL CORP

FORM 10-Q
(Quarterly Report)

Filed 11/14/2000 For Period Ending 9/30/2000

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

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

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

For the quarterly period ended September 30, 2000

OR

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

For the transition period from ________________ to ________________

Commission file number 1-8962

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

Arizona	86-0512431
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
400 E. Van Buren St., P.O. Box 52132, Phoenix, Arizona	85072-2132
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (602) 379-2500

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [ ]

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

Number of shares of common stock, no par value, outstanding as of November 10, 2000: 84,710,644

Glossary

ACC - Arizona Corporation Commission

ACC Staff - Staff of the Arizona Corporation Commission

APS - Arizona Public Service Company, a Pinnacle West subsidiary

APS Energy Services - APS Energy Services Company, Inc., a Pinnacle West subsidiary

Company - Pinnacle West Capital Corporation

CPUC - California Public Utilities Commission

EITF 97-4 - Emerging Issues Task Force Issue No. 97-4, "Deregulation of the Pricing of Electricity -- Issues Related to the Application of FASB Statements No. 71, Accounting for the Effects of Certain Types of Regulation, and No. 101, Regulated Enterprises -- Accounting for the Discontinuation of Application of FASB Statement No. 71"

El Dorado - El Dorado Investment Company, a Pinnacle West subsidiary

EPA - United States Environmental Protection Agency

FASB - Financial Accounting Standards Board

FERC - United States Federal Energy Regulatory Commission

Four Corners - Four Corners Power Plant

ITC - Investment tax credit

June 10-Q - Pinnacle West Capital Corporation Quarterly Report on Form 10-Q for the fiscal quarter ended June 30, 2000

MW - Megawatts

NGS - Navajo Generating Station

1999 10-K - Pinnacle West Capital Corporation Annual Report on Form 10-K for the fiscal year ended December 31, 1999

Palo Verde - Palo Verde Nuclear Generating Station

Pinnacle West - Pinnacle West Capital Corporation

Pinnacle West Energy - Pinnacle West Energy Corporation, a Pinnacle West subsidiary

SCE - Southern California Edison Company, a subsidiary of Edison International

SFAS No. 71 - Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation"

SFAS No. 133 - Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities"

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

Settlement Agreement - APS' Settlement Agreement approved by the ACC in 1999

SunCor - SunCor Development Company, a Pinnacle West subsidiary

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS.

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

(In thousands, except per share amounts)

	Three Months Ended September 30,	
	2000	1999
Operating Revenues		
Electric	$ 1,567,960	$ 867,630
Real estate	39,396	26,640
Total	1,607,356	894,270
Operating Expenses		
Fuel and purchased power	1,079,436	400,961
Operations and maintenance	113,670	109,006
Real estate operations	33,980	26,757
Depreciation and amortization	98,628	95,068
Taxes other than income taxes	25,641	22,184
Total	1,351,355	653,976
Operating Income	256,001	240,294
Other Income (Expense)	(14,778)	1,040
Income From Continuing Operations Before Interest and Income Taxes	241,223	241,334
Interest Expense		
Interest charges	42,773	39,614
Capitalized interest	(5,240)	(1,990)
Total	37,533	37,624
Income From Continuing Operations Before Income Taxes	203,690	203,710
Income Taxes	87,641	78,131
Income From Continuing Operations	116,049	125,579
Income Tax Benefit From Discontinued Operations	--	38,000
Extraordinary Charge - Net of Income Taxes of $94,115	--	(139,885)
Net Income	$ 116,049	$ 23,694
Average Common Shares Outstanding - Basic	84,745	84,759
Average Common Shares Outstanding - Diluted	85,012	84,989
Earnings Per Average Common Share Outstanding		
Continuing Operations - Basic	$ 1.37	$ 1.48
Net Income - Basic	$ 1.37	$ 0.28
Continuing Operations - Diluted	$ 1.37	$ 1.48
Net Income - Diluted	$ 1.37	$ 0.28
Dividends Declared Per Share	$ 0.35	$ --

See Notes to Condensed Consolidated Financial Statements.

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

(In thousands, except per share amounts)

	Nine Months Ended September 30, 2000	1999
Operating Revenues		
Electric	$ 2,734,362	$ 1,793,047
Real estate	117,659	83,870
Total	2,852,021	1,876,917
Operating Expenses		
Fuel and purchased power	1,495,218	636,062
Operations and maintenance	331,754	319,212
Real estate operations	101,374	78,393
Depreciation and amortization	293,607	289,361
Taxes other than income taxes	76,643	73,028
Total	2,298,596	1,396,056
Operating Income	553,425	480,861
Other Income (Expense)		
Preferred stock dividend requirements of APS	--	(1,016)
Net other income and expense	13,785	(898)
Total	13,785	(1,914)
Income From Continuing Operations Before Interest and Income Taxes	567,210	478,947
Interest Expense		
Interest charges	126,996	121,488
Capitalized interest	(13,875)	(10,253)
Total	113,121	111,235
Income From Continuing Operations Before Income Taxes	454,089	367,712
Income Taxes	194,069	142,741
Income From Continuing Operations	260,020	224,971
Income Tax Benefit From Discontinued Operations	--	38,000
Extraordinary Charge - Net of Income Taxes of $94,115	--	(139,885)
Net Income	$ 260,020	$ 123,086
Average Common Shares Outstanding - Basic	84,735	84,715
Average Common Shares Outstanding - Diluted	84,901	85,087
Earnings Per Average Common Share Outstanding		
Continuing Operations - Basic	$ 3.07	$ 2.66
Net Income - Basic	$ 3.07	$ 1.45
Continuing Operations - Diluted	$ 3.06	$ 2.64
Net Income - Diluted	$ 3.06	$ 1.45
Dividends Declared Per Share	$ 1.05	$ 0.975

See Notes to Condensed Consolidated Financial Statements.

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

(In thousands, except per share amounts)

	Twelve Months Ended September 30, 2000	Twelve Months Ended September 30, 1999
Operating Revenues		
Electric	$ 3,234,499	$ 2,236,573
Real estate	163,958	126,705
Total	3,398,457	2,363,278
Operating Expenses		
Fuel and purchased power	1,655,265	752,832
Operations and maintenance	459,319	425,239
Real estate operations	142,497	118,454
Depreciation and amortization	389,814	387,644
Taxes other than income taxes	100,221	96,400
Total	2,747,116	1,780,569
Operating Income	651,341	582,709
Other Income (Expense)		
Preferred stock dividend requirements of APS	--	(3,059)
Net other income and expense	25,476	(3,329)
Total	25,476	(6,388)
Income From Continuing Operations Before Interest and Income Taxes	676,817	576,321
Interest Expense		
Interest charges	167,889	163,224
Capitalized interest	(15,286)	(14,588)
Total	152,603	148,636
Income From Continuing Operations Before Income Taxes	524,214	427,685
Income Taxes	219,393	167,186
Income From Continuing Operations	304,821	260,499
Income Tax Benefit From Discontinued Operations	--	38,000
Extraordinary Charge - Net of Income Taxes of $94,115	--	(139,885)
Net Income	$ 304,821	$ 158,614
Average Common Shares Outstanding - Basic	84,732	84,719
Average Common Shares Outstanding - Diluted	84,898	85,140
Earnings Per Average Common Share Outstanding		
Continuing Operations - Basic	$ 3.60	$ 3.07
Net Income - Basic	$ 3.60	$ 1.87
Continuing Operations - Diluted	$ 3.59	$ 3.06
Net Income - Diluted	$ 3.59	$ 1.86
Dividends Declared Per Share	$ 1.40	$ 1.30

See Notes to Condensed Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

ASSETS
(Thousands of Dollars)

	September 30, 2000 (Unaudited)	December 31, 1999
Current Assets		
Cash and cash equivalents	$ 87,682	$ 20,705
Customer and other receivables--net	669,858	244,599
Accrued utility revenues	111,315	72,919
Materials and supplies	73,506	69,977
Fossil fuel	14,553	21,869
Deferred income taxes	10,081	8,163
Other current assets	71,531	60,562
Total current assets	1,038,526	498,794
Investments and Other Assets		
Real estate investments--net	366,386	344,293
Other assets	249,157	267,458
Total investments and other assets	615,543	611,751
Property, Plant and Equipment		
Plant in service and held for future use	7,727,739	7,546,314
Less accumulated depreciation and amortization	3,194,323	3,026,194
Total	4,533,416	4,520,120
Construction work in progress	362,472	209,281
Nuclear fuel, net of amortization	51,274	49,114
Net property, plant and equipment	4,947,162	4,778,515
Deferred Debits		
Regulatory assets	502,595	613,729
Other deferred debits	70,954	105,717
Total deferred debits	573,549	719,446
Total Assets	$7,174,780	$6,608,506

See Notes to Condensed Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

LIABILITIES AND EQUITY
(Thousands of Dollars)

	September 30, 2000 (Unaudited)	December 31, 1999
Current Liabilities		
Accounts payable	$ 498,161	$ 186,524
Accrued taxes	231,738	70,510
Accrued interest	26,410	33,253
Short-term borrowings	1,984	38,300
Current maturities of long-term debt	4,887	114,798
Customer deposits	25,603	26,098
Other current liabilities	45,820	26,007
Total current liabilities	834,603	495,490
Long-Term Debt Less Current Maturities	2,354,911	2,206,052
Deferred Credits and Other		
Deferred income taxes	1,108,274	1,183,855
Unamortized gain - sale of utility plant	69,780	73,212
Other	431,380	444,164
Total deferred credits and other	1,609,434	1,701,231
Commitments and Contingencies (Notes 6, 7, 9 and 10)		
Common Stock Equity		
Common stock, no par value	1,536,493	1,537,449
Retained earnings	839,339	668,284
Total common stock equity	2,375,832	2,205,733
Total Liabilities and Equity	$7,174,780	$6,608,506

See Notes to Condensed Consolidated Financial Statements.

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

(thousands of dollars)

	Nine Months Ended September 30, 2000	1999
CASH FLOWS FROM OPERATING ACTIVITIES		
Income From Continuing Operations	$ 260,020	$ 224,971
Items not requiring cash		
Depreciation and amortization	293,607	289,361
Nuclear fuel amortization	23,139	24,306
Deferred income taxes--net	(42,984)	(74,670)
Other--net	(3,350)	(18,908)
Changes in current assets and liabilities		
Customer and other receivables--net	(425,259)	(106,815)
Accrued utility revenues	(38,396)	(33,543)
Materials, supplies and fossil fuel	3,787	(4,758)
Other current assets	(10,969)	(12,055)
Accounts payable	308,407	81,805
Accrued taxes	161,228	130,371
Accrued interest	(6,843)	(7,871)
Other current liabilities	24,845	13,964
Change in El Dorado partnership investment	(11,897)	--
Increase in land held	(21,073)	(4,237)
Other--net	38,717	28,431
Net Cash Flow Provided By Operating Activities	552,979	530,352
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(398,994)	(235,568)
Capitalized interest	(13,875)	(10,253)
Other--net	20,259	(5,567)
Net Cash Flow Used For Investing Activities	(392,610)	(251,388)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	494,000	249,191
Short-term borrowings--net	(36,316)	44,670
Dividends paid on common stock	(88,963)	(82,652)
Repayment of long-term debt	(461,157)	(379,936)
Redemption of preferred stock	--	(96,499)
Other--net	(956)	(10,250)
Net Cash Flow Used For Financing Activities	(93,392)	(275,476)
Net Cash Flow	66,977	3,488
Cash and Cash Equivalents at Beginning of Period	20,705	20,538
Cash and Cash Equivalents at End of Period	$ 87,682	$ 24,026
Supplemental Disclosure of Cash Flow Information:		
Cash paid during the period for:		
Interest, net of amounts capitalized	$ 109,778	$ 109,702
Income taxes	$ 127,013	$ 95,590

See Notes to Condensed Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

2. Our unaudited condensed consolidated financial statements reflect all adjustments which we believe are necessary for the fair presentation of our financial position and results of operations for the periods presented. These adjustments are of a normal recurring nature with the exception of the extraordinary charge and the tax benefit from discontinued operations. 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 1999 10-K.

3. Weather conditions and wholesale power marketing and trading activities can have significant impacts on our results for interim periods. El Dorado's earnings are subject to stock market volatility (see Note 12). For these and other reasons, results for interim periods do not necessarily represent results to be expected for the year.

4. See "Liquidity and Capital Resources" in Part I, Item 2 of this report for changes in capitalization for the nine months ended September 30, 2000.

5. Regulatory Accounting

For regulated operations, APS prepares its financial statements in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in its financial statements.

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

The Settlement Agreement was approved by the ACC in September 1999 (see Note 6 for a discussion of the agreement). Consequently, APS has discontinued the application of SFAS No. 71 for its generation operations. This application means that the generation assets were tested for impairment and the portion of regulatory assets deemed to be unrecoverable through ongoing regulated cash flows was eliminated. APS determined that the generation assets were not impaired. A regulatory disallowance removed $234 million pretax ($183 million net present value) from ongoing regulatory cash flows and was recorded as a net reduction of regulatory assets. This reduction ($140 million after income taxes) was reported as an extraordinary charge on the consolidated income statement during the third quarter of 1999. Prior to the Settlement Agreement, under the 1996 regulatory agreement (see Note 6), the ACC accelerated the amortization of substantially all of APS' regulatory assets to an eight-year period ending June 30, 2004.

The regulatory assets to be recovered under the 1999 Settlement Agreement are now being amortized as follows (millions of dollars):

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

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

The condensed consolidated balance sheets include the amounts listed below for generation assets not subject to SFAS No. 71 (thousands of dollars):

	September 30, 2000	December 31, 1999
Electric plant in service & held for future use	$ 3,819,709	$ 3,770,234
Accumulated depreciation and amortization	(1,725,706)	(1,641,855)
Construction work in progress	224,760	87,819
Nuclear fuel, net of amortization	51,274	49,114

6. Regulatory Matters -- Electric Industry Restructuring

STATE

SETTLEMENT AGREEMENT. On May 14, 1999, APS entered into a comprehensive Settlement Agreement with various parties, including representatives of major consumer groups, related to the implementation of retail electric competition. On September 23, 1999, the ACC voted to approve the Settlement Agreement, with some modifications. On December 13, 1999, two parties filed lawsuits challenging the ACC's approval of the Settlement Agreement. One of the parties questioned the authority of the ACC to approve the Settlement Agreement and both parties challenged several specific provisions of the Settlement Agreement. A decision on the appeals to the Settlement Agreement is not expected until later this year or next year.

The following are the major provisions of the Settlement Agreement, as approved:

* APS has reduced, and will reduce, rates for standard offer service for customers with loads less than three MW in a series of annual retail electric price reductions of 1.5% beginning July 1, 1999 through July 1, 2003, for a total of 7.5%. The first reduction of approximately $24 million ($14 million after income taxes) included the July 1, 1999 retail price decrease of approximately $11 million ($7 million after income taxes) related to the 1996 regulatory agreement. See "1996 Regulatory Agreement" below. Based on the price reduction authorized in the Settlement Agreement, there

was a retail price decrease of approximately $28 million ($17 million after taxes), or 1.5%, effective July 1, 2000. For customers having loads three MW or greater, standard offer rates will be reduced in varying annual increments that total 5% through 2002.

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

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

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

* APS' distribution system opened for retail access effective September 24, 1999. Customers will be eligible for retail access in accordance with the phase-in adopted by the ACC under the electric competition rules (see "Retail Electric Competition Rules" below), with an additional 140 MW being made available to eligible non-residential customers. Unless subject to judicial or regulatory restraint, APS will open its distribution system to retail access for all customers on January 1, 2001.

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

* APS will form a separate corporate affiliate or affiliates and transfer to such affiliate(s) its generating assets and competitive services at book value as of the date of transfer, which transfer shall take place no later than December 31, 2002.

See Management's Discussion and Analysis of Financial Condition and Results of Operations below for a discussion of the planned timing of the transfer. APS will be allowed to defer and later collect, beginning July 1, 2004, sixty-seven percent of its costs to accomplish the required transfer of generation assets to an affiliate.

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

As discussed in Note 5 above, APS has discontinued the application of SFAS No. 71 for its generation operations.

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

On July 12, 2000, a Maricopa County Superior Court judge issued a preliminary ruling and denied most of the substantive challenges to the Rules that had been made by certain electric cooperatives. However, he concluded that some of the Rules were invalid because of procedural deficiencies or were invalid in their application. Specifically, the judge concluded that several non-ratemaking Rules were required to be presented to the Arizona Attorney General for certification prior to becoming effective. Additionally, the judge determined that the Arizona Constitution requires the ACC to make findings regarding the fair value of property in Arizona in establishing rates for competitive electric service providers (ESPs), which rendered the rate setting provisions of the Rules invalid in the application.

On November 2, 2000, the same Superior Court judge amended his July 12 preliminary ruling. This amended ruling indicated the Court's intent to accept the substantive provisions of a form of final judgment submitted by the electric cooperatives that finds the Rules in their entirety to be unconstitutional and unlawful due to failure to establish fair value rate base and because certain of the Rules were not submitted to the Arizona Attorney General for certification. The cooperatives' proposed form of final judgment also invalidates all the ACC orders authorizing competitive electric service providers in Arizona. We do not believe either of the rulings affects the Settlement Agreement with the ACC. The Settlement Agreement was not at issue in the consolidated cases before the judge. Further, the ACC made findings related to the fair value of APS' property in the order approving the APS Settlement Agreement.

Although the ACC has not yet indicated what steps it intends to take after a final judgment is issued, the ACC could appeal the ruling to the Court of Appeals or could elect to take action to correct the deficiencies identified in the judge's ruling. The cooperatives or the ESPs may also appeal the ruling. If the order is appealed by the ACC or any of the ESPs, including APS Energy Services, we believe that it will be automatically stayed pending further judicial review.

The Rules approved by the ACC include the following major provisions:

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

* The Rules require each affected utility, including APS, to make available at least 20% of its 1995 system retail peak demand for competitive generation supply beginning when the ACC makes a final decision on each utility's stranded costs and unbundled rates (Final Decision Date) or January 1, 2001, whichever is earlier, and 100% beginning January 1, 2001. Under the Settlement Agreement, APS will provide retail access to customers representing the minimum 20% required by the ACC and an additional 140 MW of non-residential load in 1999, and to all customers as of January 1, 2001, or such other dates as approved by the ACC.

* Subject to the 20% requirement, all utility customers with single premise loads of one MW or greater will be eligible for competitive electric services on the Final Decision Date, which for APS' customers was the approval of the Settlement Agreement. Customers may also aggregate smaller loads to meet this one MW requirement.

* Residential customers were phased in at 1.25% per quarter calculated beginning on January 1, 1999, subject to the 20% requirement above.

* Electric service providers that get Certificates of Convenience and Necessity (CC&Ns) from the ACC can supply only competitive services, including electric generation, but not electric transmission and distribution.

* Affected utilities must file ACC tariffs that unbundle rates for non-competitive services.

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

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

See Management's Discussion and Analysis of Financial Condition and Results of Operations below for a discussion of the planned timing of the transfer.

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

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

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

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

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

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

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

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

GENERAL

We cannot accurately predict the impact of full retail competition on our financial position, cash flows, or results of operations. As competition in the electric industry continues to evolve, we will continue to evaluate strategies and alternatives that will position the Company and our subsidiaries to compete in the new regulatory environment.

FEDERAL

The Energy Policy Act of 1992 and recent rulemakings by FERC have promoted increased competition in the wholesale electric power markets. APS does not expect these rules to have a material impact on its financial statements.

Several electric utility industry restructuring bills have been introduced during the current congressional session. Several of these bills are written to allow consumers to choose their electricity suppliers beginning in 2000 and beyond. These bills, other bills that are expected to be introduced, and ongoing discussions at the federal level suggest a wide range of opinion that will need to be narrowed before any comprehensive restructuring of the electric utility industry can occur.

7. Nuclear Insurance

The Palo Verde participants have insurance for public liability payments resulting from nuclear energy hazards to the full limit of liability under federal law. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $200 million and the balance by an industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the programs exceed the accumulated funds, APS could be assessed retrospective premium adjustments. The maximum assessment per reactor under the program for each nuclear incident is approximately $88 million, subject to an annual limit of $10 million per incident. Based upon APS' 29.1% interest in the three Palo Verde units, APS' maximum potential assessment per incident is approximately $77 million, with an annual payment limitation of approximately $9 million.

The Palo Verde participants maintain "all risk" (including nuclear hazards) insurance for 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.

8. Business Segments

We have two principal business segments (determined by products, services and regulatory environment) which consist of the transmission and distribution of electricity and wholesale power marketing and trading activities (delivery business segment) and the generation of electricity (generation business segment). The other amounts include activity relating to the parent company and other subsidiaries including APS Energy Services, SunCor and El Dorado. Eliminations primarily relate to intersegment sales of electricity. Segment information for the three, nine and twelve months ended September 30, 2000 and 1999 is as follows (millions of dollars):

	3 Months Ended September 30,		9 Months Ended September 30,		12 Months Ended September 30,	
	2000	1999	2000	1999	2000	1999
Operating Revenues:						
Delivery	$ 1,566	$ 867	$ 2,731	$ 1,793	$ 3,231	$ 2,236
Generation	322	266	750	662	942	852
Other	41	27	121	84	167	127
Eliminations	(322)	(266)	(750)	(662)	(942)	(852)
Total	$ 1,607	$ 894	$ 2,852	$ 1,877	$ 3,398	$ 2,363
Income from Continuing Operations:						
Delivery	$ 57	$ 61	$ 137	$ 115	$ 169	$ 142
Generation	66	69	114	117	117	126
Other	(7)	(4)	9	(7)	19	(8)
Total	$ 116	$ 126	$ 260	$ 225	$ 305	$ 260

	As of September 30, 2000	As of December 31, 1999
Assets:		
Delivery	$4,238	$3,796
Generation	2,452	2,342
Other	485	471
Total	$7,175	$6,609

9. Accounting Matters

In June 1998, the FASB issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities". In June 2000, the FASB issued SFAS No. 138, which amends certain provisions of SFAS133 to clarify certain areas causing difficulties in implementation. The amendment includes expanding the normal purchase and sale exemption for supply contracts. We will adopt SFAS133 and the corresponding amendments under SFAS138 on

January 1, 2001. We are currently determining the impact of SFAS133 on our consolidated results of operations and financial position; however, certain implementation issues are currently being resolved by the FASB's Derivatives Implementation Group that will significantly affect its impact. This statement should have no impact on consolidated cash flows.

10. Generation Expansion

Pinnacle West Energy has announced plans to build and acquire up to 4,000 MW of generating capacity from 2001-2006 at an estimated cost of about $2 billion, assuming all of the announced plants are built or acquired.

Pinnacle West Energy is also considering additional expansion over the next several years, which may result in additional expenditures. Pinnacle West Energy's expenditures are expected to be funded through internally generated cash and debt issued directly by Pinnacle West Energy, as well as capital infusions from Pinnacle West's internally generated cash and debt proceeds.

Pinnacle West Energy is currently planning a 650-megawatt expansion of the West Phoenix Power Plant and the construction of a natural gas-fired electric generating station of up to 2,120 megawatts near Palo Verde, called Redhawk . Construction on West Phoenix Unit 4 began in June 2000, with commercial operation of the unit expected in the summer of 2001. Pinnacle West Energy expects construction to begin on Unit 5 in mid-2001, with commercial operation in mid- 2003, and expects to partner with Calpine on West Phoenix Unit 5. Pinnacle West Energy expects that construction will begin on the first two units of Redhawk near the end of 2000, with commercial operation scheduled for the summer of 2002.

See "Liquidity and Capital Resources -- Capital Expenditure Requirements" in Management's Discussion and Analysis of Financial Condition and Results of Operations below for projected capital expenditures for the above expansion plans.

On April 27, 2000, Pinnacle West Energy entered into two separate agreements with SCE to purchase SCE's 15.8% ownership interest in Palo Verde and its 48% ownership interest in Units 4 and 5 of the Four Corners Power Plant. The purchase price is $550 million in cash to be paid at closing, subject to certain adjustments. The interests to be acquired represent 1,310 MW of generating capacity (600 MW associated with SCE's Palo Verde interest, and 710 MW associated with SCE's Four Corners interest). The transactions are expected to close in 2001, subject to the approval of various governmental authorities, including the CPUC, the FERC, the U.S. Nuclear Regulatory Commission, the Internal Revenue Service, and the Navajo Nation.

The agreements between Pinnacle West Energy and SCE include the following additional terms:

* Prior to and up to 90 days following SCE's filing with the CPUC seeking approval of the transactions, which was made on May 15, 2000, SCE was allowed to solicit offers for, or indications of interest in, (a) its Four Corners interest or (b) its Four Corners interest and its Palo Verde interest. SCE's sale of its interest in Four Corners is also subject to a right of first refusal on the part of the other Four Corners participants, including APS. Pinnacle West Energy had the right to match any offer or indication of interest that SCE

received during this period. This period expired without Pinnacle West Energy matching an indication of interest.

* The Agreements permit SCE, for a period of up to 120 days (until late November), to engage in further negotiations and discussions with any party who submitted an indication of interest. Subject to CPUC approval, Pinnacle West Energy retains the right under the Agreements to match the terms of any binding agreement that SCE elects to enter into.

* Pinnacle West Energy is not obligated to purchase SCE's Four Corners interest unless SCE also sells its Palo Verde interest to Pinnacle West Energy. SCE is not obligated to sell its Palo Verde interest to Pinnacle West Energy unless Pinnacle West Energy (or some other third party) purchases SCE's Four Corners interest.

* SCE will transfer the assets of its Palo Verde decommissioning fund to Pinnacle West Energy, and Pinnacle West Energy will assume SCE's Palo Verde decommissioning obligations.

* Pinnacle West Energy will assume SCE's obligations and liabilities associated with ownership of its interests in Palo Verde and Four Corners, subject to specified exceptions.

* We guaranteed Pinnacle West Energy's obligations under each of the agreements, including Pinnacle West Energy's purchase price obligations.

The CPUC hearing on approval of the sale has been scheduled for February 2001. The Utility Reform Network and the Utility Workers Union of America have jointly filed a motion to dismiss, recommending that the CPUC reject the sale. The California Office of Ratepayer Advocates has also joined in the motion to dismiss.

11. Income Tax Benefit

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

12. El Dorado Partnership Investment Income

Net other income consists primarily of El Dorado's share in the earnings of a venture capital partnership. The partnership adjusts the value of its investments at the end of each fiscal quarter. The value of El Dorado's investment in the partnership is determined by various factors beyond our control, including equity market conditions. Most of the partnership's investments are in technology-related companies whose share prices are highly volatile.

Prior to June 2000, we recorded our share of the earnings from the partnership, as the partnership adjusted the value of its investment, on a one-quarter lag. This procedure was followed due to time constraints in obtaining and analyzing such results for inclusion in our consolidated financial statements on a current basis. Beginning in the second quarter of 2000, we requested a distribution of our share of the investments held by the partnership, and we adjusted our investment to reflect the current market value.

In the third quarter of 2000, we recognized a loss of $9 million after income taxes, which was our share of the partnership's loss for the quarter. This loss was the result of a reduction in the market value of the investments held by the partnership. The book value of El Dorado's investment in the partnership at September 30, 2000 was approximately $18 million.

El Dorado is currently seeking an amendment to the partnership agreement that would result in El Dorado receiving a distribution of securities representing substantially all of El Dorado's investment in the partnership. Upon El Dorado's receipt of these securities, we will account for the securities as available for sale with changes in value recorded in other comprehensive income. Gains and losses from the ultimate sale of such securities will be reflected in our net earnings.

PINNACLE WEST CAPITAL CORPORATION

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

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

* the changes in our earnings for the periods presented
* the factors impacting our business, including competition
* the effects of regulatory decisions on our results and outlook
* our capital needs and resources and
* our management of market risks.

APS, our major subsidiary and Arizona's largest electric utility, provides retail and wholesale electric service to the entire state with the exception of Tucson and about one-half of the Phoenix area. APS also generates, sells, and delivers electricity to wholesale customers in the western United States. SunCor is a developer of residential, commercial, and industrial real estate projects in Arizona, New Mexico, and Utah. El Dorado is primarily a venture capital firm. APS Energy Services was formed in 1998 and sells energy and energy-related products and services in competitive retail markets in the western United States. Pinnacle West Energy, which was formed in 1999, is the subsidiary through which we intend to conduct our unregulated generation operations.

As discussed in Note 6, the Settlement Agreement and the Rules require APS to transfer its generating assets and competitive services to one or more corporate affiliates. We plan to complete the move of our wholesale power marketing and trading activities from APS to the parent company by the end of 2000. APS plans to move certain of its non-nuclear generating facilities and related assets, as well as certain employees of APS' generation business unit, to Pinnacle West Energy on January 1, 2001, or as soon thereafter as requisite approvals are obtained. See Note 6 for information regarding lawsuits challenging the Settlement Agreement and the Rules.

We suggest this section be read along with the 1999 10-K. Throughout this Management's Discussion and Analysis of Financial Condition and Results of Operations, we refer to specific "Notes" in the Notes to Condensed Consolidated Financial Statements in this report. These Notes add further details to the discussion.

OPERATING RESULTS

The following table summarizes net income for the three-month, nine-month and twelve-month periods ended September 30, 2000 and the comparable prior year periods for Pinnacle West and each of its subsidiaries:

(Millions of Dollars)	3 Months Ended September 30, 2000	3 Months Ended September 30, 1999	9 Months Ended September 30, 2000	9 Months Ended September 30, 1999	12 Months Ended September 30, 2000	12 Months Ended September 30, 1999(a)
APS	$ 124	$ 130	$ 253	$ 232	$ 288	$ 268
Pinnacle West Energy	(1)	--	(2)	--	(2)	--
APS Energy Services	--	(2)	(4)	(5)	(8)	(5)
SunCor	2	--	8	4	11	7
El Dorado	(9)	--	7	--	18	--
Parent Company	--	(2)	(2)	(6)	(2)	(9)
Income From Continuing Operations	116	126	260	225	305	261
Income Tax Benefit From Discontinued Operations	--	38	--	38	--	38
Extraordinary Charge - Net of Income Taxes of $94	--	(140)	--	(140)	--	(140)
Net Income	$ 116	$ 24	$ 260	$ 123	$ 305	$ 159

(a) SunCor's 1999 earnings have been restated here to exclude a $37 million deferred tax benefit. In accordance with our intercompany tax sharing agreement, the offset resides with the parent company. There is no consolidated earnings effect as these tax benefits had already been reflected on a consolidated basis.

OPERATING RESULTS - THREE-MONTH PERIOD ENDED SEPTEMBER 30, 2000 COMPARED WITH THREE-MONTH PERIOD ENDED SEPTEMBER 30, 1999

Consolidated net income for the three months ended September 30, 2000 was $116 million compared with $24 million for the same period in the prior year. The increase primarily relates to an extraordinary charge recorded in the third quarter of 1999, partially offset by lower income from continuing operations in the third quarter of 2000, as well as an income tax benefit from discontinued operations also recorded in the third quarter of 1999.

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

The income tax benefit from discontinued operations resulted from the resolution of income tax matters related to a former subsidiary, MeraBank. See Note 11.

Income from continuing operations decreased $10 million over the comparable prior year period primarily because of a loss at El Dorado, the completion of the amortization of ITCs in 1999, an electricity price reduction, and miscellaneous factors. Partially offsetting these factors was an increase in the contribution of wholesale power marketing and trading activities. See Note 6 for information on the price reduction. See "Income Taxes" below for a discussion of the ITC amortization.

Electric operating revenues increased $ 700 million because of:

* increased power marketing, trading, and wholesale revenues ($664 million)

* increases in the number of customers and the average amount of electricity used by customers ($33 million)
* warmer weather impacts ($9 million) and
* miscellaneous factors ($2 million).

As mentioned above, these positive factors were partially offset by the effect of a reduction in retail electricity prices ($8 million).

The increase in power marketing, trading, and wholesale revenues resulted from higher prices and increased activity in the western U.S. wholesale power markets. The revenues were accompanied by an increase in purchased power and fuel expenses of $602 million.

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

Operations and maintenance expenses increased primarily because of higher costs related to customer growth.

Property tax expense increased because of higher tax rates.

Depreciation and amortization expense increased primarily because of higher plant balances.

Net other income and expense decreased $16 million primarily because of a decrease in the market value of El Dorado's investment in a technology-related venture capital partnership. See Note 12.

OPERATING RESULTS - NINE-MONTH PERIOD ENDED SEPTEMBER 30, 2000 COMPARED WITH NINE-MONTH PERIOD ENDED SEPTEMBER 30, 1999

Consolidated net income for the nine months ended September 30, 2000 was $260 million compared with $123 million for the same period in the prior year. The increase primarily relates to an extraordinary charge recorded in the third quarter of 1999, higher income from continuing operations for the nine months ended September 30, 2000, partially offset by an income tax benefit from discontinued operations also recorded in the third quarter of 1999.

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

The income tax benefit from discontinued operations resulted from the resolution of income tax matters related to a former subsidiary, MeraBank. See Note 11.

Income from continuing operations increased $35 million over the comparable prior year period primarily because of an increase in the contribution of wholesale power marketing and trading activities and an increase in El Dorado's earnings. These positive factors more than offset decreases due to the completion of the amortization of ITCs in 1999, electricity price reductions, higher operations and maintenance expense, and miscellaneous factors. See Note 6 for information on the price reductions. See "Income Taxes" below for a discussion of the ITC amortization.

Electric operating revenues increased $941 million because of:

* increased power marketing, trading, and wholesale revenues ($840 million)
* increases in the number of customers and the average amount of electricity used by customers ($87 million)
* warmer weather impacts ($28 million) and
* miscellaneous factors ($4 million).

These positive factors were partially offset by the effect of a reduction in retail electricity prices ($18 million).

The increase in power marketing, trading, and wholesale revenues resulted from higher prices and increased activity in the western U.S. wholesale power markets. The revenues were accompanied by an increase in purchased power and fuel expenses of $734 million.

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

Operations and maintenance expenses increased primarily because of higher costs primarily related to customer growth.

Net other income and expense increased $15 million primarily because of an increase in the market value of El Dorado's investment in a technology-related venture capital partnership. See Note 12.

OPERATING RESULTS - TWELVE-MONTH PERIOD ENDED SEPTEMBER 30, 2000 COMPARED WITH TWELVE-MONTH PERIOD ENDED SEPTEMBER 30, 1999

Consolidated net income for the twelve months ended September 30, 2000 was $305 million compared with $159 million for the same period in the prior year. The increase primarily relates to an extraordinary charge recorded in the third quarter of 1999, higher income from continuing operations in the twelve-month period ended September 30, 2000, partially offset by an income tax benefit from discontinued operations also recorded in the third quarter of 1999.

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

The income tax benefit from discontinued operations resulted from the resolution of income tax matters related to a former subsidiary, MeraBank. See Note 11.

Income from continuing operations increased $44 million over the comparable prior year period primarily because of an increase in the contribution of wholesale power marketing and trading activities, an increase in the number of customers and in the average amount of electricity used by customers, and an increase in El Dorado's earnings. These positive factors more than offset decreases due to the completion of the amortization of ITCs in 1999, reductions in retail electricity prices, higher operations and maintenance expenses and miscellaneous factors. See Note 6 for information on the price reduction. See "Income Taxes" below for a discussion of the ITC amortization.

Electric operating revenues increased $998 million because of:

* increased power marketing, trading, and wholesale revenues ($880 million)
* increases in the number of customers and the average amount of electricity used by customers ($107 million)
* warmer weather impacts ($35 million) and
* miscellaneous factors ($4 million).

These positive factors were partially offset by the effect of a reduction in retail prices ($28 million).

The increase in power marketing, trading, and wholesale revenues resulted primarily from increased activity in western U.S. wholesale power markets and higher prices. The revenues were accompanied by increases in purchased power and fuel expenses of $769 million.

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

Operations and maintenance expenses increased primarily because of customer growth, power marketing costs, and technology related costs.

Net other income and expense increased $29 million primarily because of an increase in the market value of El Dorado's investment in a technology-related venture capital partnership. See Note 12.

INCOME TAXES

As part of a 1994 rate settlement with the ACC, APS accelerated amortization of substantially all deferred ITCs over a five-year period that ended on December 31, 1999. The ITC amortization decreased annual income tax expense by approximately $24 million. Beginning in 2000, no further benefits from these deferred ITCs will be reflected in income tax expense.

Liquidity and Capital Resources

CAPITAL EXPENDITURE REQUIREMENTS

The following table summarizes the actual capital expenditures for the nine-month period ended September 30, 2000 and estimated capital expenditures for the next three years:

CAPITAL EXPENDITURES
(millions of dollars)

	Nine months ended September 30, 2000 (actual)	Twelve months ended December 31, (estimated)(a)		
		2000	2001	2002
APS (b)	$275	$464	$356	$364
Pinnacle West Energy (c)	118	195	544	122
SunCor	42	53	43	51
Total	$435	$712	$943	$537

(a) Includes approximately $40 - $50 million for capital improvements to existing fossil generating facilities in APS for 2000 and approximately $40
- $50 million in capital improvements to existing fossil generating facilities in Pinnacle West Energy for each year thereafter.
(b) Includes about $30 - $35 million each year for nuclear fuel expenditures and approximately $55 - $60 million each year for capital improvements to existing nuclear generating facilities.
(c) Excludes the SCE purchase agreements of approximately $550 million in 2001.
See Note 10 and "Capital Resources and Debt Financing - Pinnacle West Energy" below.

CAPITAL RESOURCES AND DEBT FINANCING

PINNACLE WEST

The parent company's cash requirements and its ability to fund those requirements are discussed under "Capital Needs and Resources" in Management's Discussion and Analysis of Financial Condition and Results of Operation in Part II, Item 7 of the 1999 10-K.

During the nine-months ended September 30, 2000, the parent company increased long-term borrowings by about $65 million.

APS

APS' long-term debt redemption requirements, optional repayments on long-term debt, and payment obligations on a capitalized lease are: $354 million in 2000; $252 million in 2001; and $125 million in 2002. During the nine months ended September 30, 2000, APS redeemed all of its long-term debt requirements for 2000 with cash from operations and short-term borrowings. On August 7, 2000, APS issued $300 million of its 7 5/8% Notes Due 2005.

APS expects to purchase Units 1, 2 and 3 of the West Phoenix Power Plant in December 2000. These units are currently reflected as a capitalized lease.

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

PINNACLE WEST ENERGY

Pinnacle West Energy has announced plans to build and acquire up to 4,000 MW of generating capacity from 2001-2006 at an estimated cost of about $2 billion, assuming all announced plants are built or acquired.

Pinnacle West Energy is also considering additional expansion over the next several years, which may result in additional expenditures. Pinnacle West Energy's expenditures are expected to be funded through internally generated cash and debt issued directly by Pinnacle West Energy, as well as capital infusions from Pinnacle West's internally generated cash and debt proceeds.

Pinnacle West Energy is currently planning a 650-megawatt expansion of the West Phoenix Power Plant and the construction of a natural gas-fired electric generating station of up to 2,120 megawatts near Palo Verde, called Redhawk. Construction on West Phoenix Unit 4 began in June 2000, with commercial operation of the unit expected in the summer of 2001. Pinnacle West Energy expects construction to begin on Unit 5 in mid-2001, with commercial operation in mid-2003, and expects to partner with Calpine on West Phoenix Unit 5. Pinnacle West Energy also expects that construction will begin on the first two units of Redhawk near the end of 2000, with commercial operation scheduled for the summer of 2002.

See the above table for expected capital expenditures for Pinnacle West Energy's share of these expansions on the current schedule.

Pinnacle West Energy has signed two separate agreements with SCE to acquire SCE's interest in the Palo Verde Nuclear Generating Station west of Phoenix and the Four Corners Power Plant near Farmington, New Mexico. Pursuant to the agreements, Pinnacle West Energy will acquire SCE's 15.8% interest in the three unit Palo Verde plant and SCE's 48% interest in Four Corners Units 4 and 5, for a total of approximately 1,300 MW at both plants. The total purchase price is $550 million, subject to certain adjustments. The transactions are expected to close in 2001 following the approval of various governmental authorities, including the CPUC, the FERC, the U.S. Nuclear Regulatory Commission, the Internal Revenue Service, and the Navajo Nation.

Prior to and up to 90 days following SCE's filing with the CPUC seeking approval of the transactions, which was made on May 15, 2000, SCE was allowed to solicit offers for, or indications of interest in, (a) its Four Corners interest or (b) its Four Corners interest and its Palo Verde interest. SCE's sale of its interest in Four Corners is also subject to a right of first refusal on the part of the other Four Corners participants, including APS. Pinnacle West Energy had the right to match any offer or indication of interest that SCE received during this period. This period expired without Pinnacle West Energy matching an indication of interest. The Agreements permit SCE, for a period of up to 120 days (until late November), to engage in further negotiations and discussions with any party who submitted an indication of interest. Subject to CPUC approval, Pinnacle West Energy retains the right under the Agreements to match the terms of any binding agreement that SCE elects to enter into. For additional information about the transactions, see Note 10.

SUNCOR

SunCor's capital needs consist primarily of capital expenditures for land development, retail and office building construction, and home construction. Capital resources to meet these requirements include funds from operations and SunCor's own external financings.

FINANCIAL OUTLOOK

This section describes the major factors affecting our financial outlook. See "Liquidity and Capital Resources" for expected capital expenditures and financing requirements. See "Operating Results" for a summary of each subsidiary's earnings for the three-month, nine-month, and twelve-month periods ended September 30, 2000 and 1999.

The electric industry is restructuring to a competitive, customer-driven environment from a regulated monopoly structure. See Note 6 for a discussion of industry restructuring developments and their potential impacts on our financial outlook. In addition to other issues, APS' Settlement Agreement sets forth electricity prices for its regulated electricity services and the timing for customer eligibility to select competitive energy providers.

We have announced plans to expand our electricity generation capacity. See Note 10 and "Liquidity and Capital Resources - Pinnacle West Energy" for details of the generation expansion program. The planned additional generation is expected to increase revenues, fuel expenses, operating expenses, and financing costs. We have not announced the estimated effects of the generation expansion activities on our financial outlook.

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

In APS' regulated retail market area, APS will provide electricity services to standard-offer, full-service customers and to energy delivery customers who have chosen another provider for their electricity commodity needs (unbundled customers). Customer growth in APS' service territory averaged 3.9% a year for the three years 1997 through 1999; we currently expect customer growth to average 3.5% to 4% a year for 2000 through 2002. We currently estimate that electricity sales in kilowatt-hours will grow 4% to 5% a year in 2000 through 2002, before the effects of weather variations. The customer growth and sales growth referred to in this paragraph apply to energy delivery customers. As industry restructuring continues in the regulated market area, we cannot predict the number of APS' standard offer customers that will switch to unbundled service.

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

Competitive sales of energy and energy-related products and services are made by APS Energy Services in western states that have opened to competitive supply. Such activities are currently not material to our consolidated financial results; however, we currently expect their contribution to grow modestly over the next several years.

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

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

Depreciation and amortization expenses are expected to be affected by net additions to existing utility plant and other property, changes in regulatory asset amortization, and our generation expansion program. See Note 5 for the regulatory asset amortization that is being recorded in 1999 through 2004 pursuant to the Settlement Agreement. See Note 1 of Notes to Consolidated Financial Statements in the 1999 10-K regarding current depreciation rates.

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

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

The annual earnings contribution from our real estate subsidiary, SunCor, is expected to increase modestly over the next several years. SunCor's earnings for 1997, 1998 and 1999 were $5.3 million, $7.5 million (excluding the effects of a deferred tax asset transfer), and $6.1 million, respectively.

El Dorado, our investment subsidiary, is affected by market conditions related to its investments. See Note 12 for a discussion of recent events affecting El Dorado's financial results and its outlook. Historical results are not necessarily indicative of future performance for El Dorado.

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.

COMPETITION AND ELECTRIC INDUSTRY RESTRUCTURING

See Note 5 for a discussion of regulatory accounting. See Note 6 for a discussion of a Settlement Agreement related to the implementation of retail electric competition and to Arizona and federal legal and regulatory developments.

RATE MATTERS

See Note 6 for a discussion of a price reduction effective as of July 1, 2000, and for a discussion of a Settlement Agreement that will, among other things, result in five annual price reductions over a four-year period ending July 1, 2003.

FORWARD-LOOKING STATEMENTS

The above discussion contains forward-looking statements that involve risks and uncertainties. Words such as "estimates," "expects," "anticipates," "plans," "believes," "projects," and similar expressions identify forward-looking statements. These risks and uncertainties include, but are not limited to, the ongoing restructuring of the electric industry; the outcome of the regulatory proceedings relating to the restructuring; regulatory, tax, and environmental legislation; our ability to successfully compete outside traditional regulated markets; regional economic conditions, which could affect customer growth; the cost of debt and equity capital; weather variations affecting customer usage; technological developments in the electric industry; the successful completion of large-scale construction projects; the value of El Dorado's investment in a technology-related venture capital partnership; successfully managing market risks; and the strength of the real estate market.

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

ITEM 3. MARKET RISKS

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

We are exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, coal, and emissions allowances. We employ established procedures to manage our risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange-traded futures and options and over-the-counter forwards, options, and swaps. As part of our overall risk management program, we enter into these derivative transactions to hedge purchases and sales of electricity, fuels and emissions allowances/credits. In addition, we engage in trading activities intended to profit from favorable movements of market prices.

As of September 30, 2000, a hypothetical adverse price movement of 10% in the market price of our commodity derivative portfolio would decrease the fair market value of these contracts by approximately $37 million. This analysis does not include the favorable impact this same hypothetical price move would have on the underlying physical exposures being hedged with the commodity derivative portfolio. We plan to move our wholesale power marketing and trading activities from APS to the parent company by the end of 2000.

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

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

PART II - OTHER INFORMATION

ITEM 5. OTHER INFORMATION

CONSTRUCTION AND FINANCING PROGRAMS

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

COMPETITION AND ELECTRIC INDUSTRY RESTRUCTURING

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

ENVIRONMENTAL MATTERS

Purported Navajo Environmental Regulation

As previously reported, on June 29, 2000, at the request of the Court, APS filed a motion to dismiss Four Corners from a Petition for Review of EPA's regulations on the grounds that the impact of the regulations on pre-existing binding agreements was not "ripe" for judicial resolution based on EPA's issuance of an official notice indicating that it had not yet determined whether the pre-existing binding agreements with Four Corners and NGS were abrogated by the Clean Air Act. See "Environmental Matters--Purported Navajo Environmental Regulation" in Part II, Item 5 of the June 10-Q. The Court recently dismissed Four Corners on the above-mentioned grounds.

WATER SUPPLY

As previously reported, APS and other parties petitioned the U.S. Supreme Court for review of an Arizona Supreme Court decision regarding groundwater rights, and an issue important to the claims to water in the Lower Gila River Watershed in Arizona was pending on appeal before the Arizona Supreme Court. See "Environmental Matters - Water Supply" in Part I - Item 1 of the 1999 10-K. The U.S. Supreme Court denied the petition. In addition, the Arizona Supreme Court issued a decision affirming the lower court's definition of groundwater. APS and other parties have filed a motion for reconsideration on one aspect of that decision.

PURCHASED POWER AGREEMENTS

As previously reported, in July 2000 APS and PacifiCorp became involved in a dispute relating to certain provisions of the Long-Term Power Transaction Agreement dated September 1990. See "Purchased Power Agreements" in Part II, Item 5 of the June 10-Q. APS and PacifiCorp have settled the issues related to the dispute. The resolution of this matter will not have a material adverse impact on our financial position or results of operations.

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) Exhibits

Exhibit No.	Description
10.1	Addendum to Settlement Agreement
27.1	Financial Data Schedule

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

EXHIBIT NO.	DESCRIPTION	ORIGINALLY FILED AS EXHIBIT:	FILE NO(a)	DATE EFFECTIVE
10.1	Articles of Incorporation restated as of July 29, 1988	19.1 to the Company's September 30, 1988 Form 10-Q Report	1-8962	11-14-88
10.2	Bylaws, amended as of December 15, 1999	4.1 to the Company's Registration Statement on Form S-8 No. 333-95035	1-8962	1-20-00

(b) Reports on Form 8-K

During the quarter ended September 30, 2000, and the period from October 1 through November 14, 2000, we filed the following reports on Form 8-K:

Report dated July 12, 2000, relating to a preliminary ruling issued by a Maricopa County Superior Court judge on cross-motions for summary judgment in connection with lawsuits filed relating to the adoption or amendment of the retail electric competition rules.

Report dated October 26, 2000, regarding the written materials presented at an analyst conference in Phoenix, Arizona.

(a) 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, the Company has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PINNACLE WEST CAPITAL CORPORATION
(Registrant)

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Dated: November 14, 2000              By: Chris N. Froggatt
                                          ------------------------------------
                                          Chris N. Froggatt
                                          Vice President and Controller
                                          (Principal Accounting Officer
                                          and Officer Duly Authorized


                                          to sign this Report)
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Exhibit 10.1

[LETTERHEAD OF ARIZONA PUBLIC SERVICE]

December 1, 1999

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Re: APS Settlement Proceeding
ACC Docket Nos. E-01345A-98-0473, E-01345A-97-0773, RE-00000C-94-0165

Dear Sir or Madam:

Pursuant to the Opinion and Order, Decision No. 61973 in the above referenced Dockets, Arizona Public Service is filing an Addendum to the Settlement Agreement incorporating the modifications required by that Decision. This Addendum has been reviewed and executed by all signatories to the original APS Settlement Agreement.

If you have any questions regarding this filing, please contact me at (602)250-2310.

Sincerely,

Jana Van Ness

Jana Van Ness
Manager
State Regulations

Attachment

Cc: Docket Control (18 copies plus original) Parties of Record

ADDENDUM TO SETTLEMENT AGREEMENT

This Addendum is to the Settlement Agreement dated May 14, 1999 (hereafter "Agreement") between Arizona Public Service Company ("APS" or "Company") and the various signatories to the Agreement (collectively with APS, the "Parties"). By signing this Addendum to Settlement Agreement ("Addendum"), the Parties intend to revise certain provisions of the Agreement as directed by the Arizona Corporation Commission ("Commission") in Decision No. 61973 (October 6, 1999) ("Decision"). The Decision adopted and approved the Agreement subject to certain modifications.

I.

INTRODUCTION AND RECITALS

1. On May 14, 1999, the Parties entered into the Agreement;

2. On May 17, 1999, APS filed with the Commission a Notice of Filing Application for Approval of Settlement Agreement and Request for Procedural Order.

3. Commencing on July 14, 1999, and pursuant to a Procedural Order issued by the Hearing Division of the Commission, a full public evidentiary hearing on the Agreement was conducted.

4. On October 6, 1999, the Commission issued its Decision No. 61973 adopting and approving the Agreement as modified in the Decision.

5. The Parties now wish to enter into this Addendum to revise the Agreement as directed in the Decision.

II.

ADDENDUM AGREEMENT

1. METERING, METER READING, AND BILLING CREDITS

A. The Company's revised unbundled rates and charges reflecting the metering, meter reading, and billing credits required by the Decision are attached hereto as Revised Exhibit A.

B. The revised unbundled rates and charges in Revised Exhibit A to this Addendum are substituted for the corresponding tariffs in Exhibit A to the Agreement.

C. Schedules A through C of Exhibit A to the Agreement are not affected by this Addendum and were adopted and approved by the Commission in the Decision as originally proposed in the Agreement.

2. ADVANCED NOTICE FOR LARGE CUSTOMERS. Section 2.3 of the Agreement is replaced with and superceded by the following provision:

2.3. Customers greater than 3 MW who choose a direct access supplier must either (a) give APS one year's advance notice before being eligible to return to Standard Offer service, or (b) pay APS for all additional costs incurred as a result of the customer returning to Standard Offer service without providing APS at least one year's advance notice.

3. DEFERRAL OF TRANSFER COSTS. Section 2.6(3) of the Agreement is replaced with and superceded by the following provision:

(3) compliance with the Electric Competition Rules or Commission-ordered programs or directives related to the implementation of the Electric Competition Rules, as they may be amended from time to time, which costs shall be recovered from all customers receiving services from APS, provided however, that no more than sixty-seven percent (67%) of the costs to transfer generation assets to an affiliate or affiliates shall be allowed to be deferred for future collection under this provision; and

4. RATE MATTERS. Section 2.8 of the Agreement is replaced with and superceded by the following provision:

2.8. Neither the Commission nor APS shall be prevented from seeking or authorizing a change in unbundled or Standard Offer rates prior to July 1, 2004, in the event of (a) conditions or circumstances which constitute an emergency, such as an inability to finance on reasonable terms, or (b) material changes in APS' cost of service for Commission-regulated services resulting from federal, tribal, state or local laws, regulatory requirements, judicial decisions, actions or orders. Except for the changes otherwise specifically contemplated by this Agreement, unbundled and Standard Offer rates shall remain unchanged until at least July 1, 2004.

5. GENERATION AFFILIATE. Section 4.1 of the Agreement is replaced with and superceded by the following provisions:

4.1. Affiliates.

(1) The Commission will approve the formation of an affiliate or affiliates of APS to acquire at book value the competitive services and assets as currently required by the Electric Competition Rules. In order to facilitate the separation of such assets efficiently and at the lowest possible cost, the Commission shall grant APS a two-year extension of time until December 31, 2002, to accomplish such separation. A similar two-year extension shall be authorized for compliance with A.A.C. R14-2-1606(B).

(2) The affiliate or affiliates formed under this Section 4.1 shall be direct subsidiaries of Pinnacle West Capital Corporation, and not APS.

(3) After the extensions granted in this Section 4.1 have expired, APS shall procure generation for Standard Offer customers from the competitive market as provided for in the Electric Competition Rules. An affiliated generation company formed pursuant to this Section 4.1 may competitively bid for APS' Standard Offer load, but enjoys no automatic privilege outside of the market bid on account of its affiliation with APS.

6. STATUTORY WAIVERS. Section 4.3 of the Agreement is deleted in its entirety.

7. WAIVERS OF AFFILIATE INTEREST RULES. The Revised Exhibit D to this Addendum setting forth the Affiliate Rules Waivers is substituted for the corresponding Exhibit D to the Agreement so that the proposed waiver of R14-2-804(A) in the Agreement is deleted.

8. CONFLICTS WITH ELECTRIC COMPETITION RULES. In reliance upon the Commission's directive in Decision No. 61973 (page 9) that "We want to make it clear that the Commission does not intend to revisit the stranded cost portion of the Agreement. It is also not the Commission's intent to undermine the benefits that parties have bargained for," Section 7.1 is replaced with and superseded by the following provision:

7.1. Approval of this Agreement by the Commission shall constitute a waiver of any existing Commission order, rule or regulation to the extent necessary to permit performance of the Agreement, as approved by the Commission. Any future Commission order, rule or regulation shall be construed and administered, insofar as possible, in a manner so as not to conflict with the specific provisions of this Agreement, as approved by the Commission. In the event any of the Parties deems a future Commission order, rule or regulation to be inconsistent with the specific provisions of this Agreement, a waiver of the new Commission order, rule or regulation shall be sought.

Nothing in this Agreement is intended to otherwise interfere with the Commission's ability to exercise its regulatory authority by the issuance of orders, rules or regulations. The requirements of this Agreement shall be performed in accordance with the Commission's Electric Competition Rules including any specific waivers granted by the Commission's order approving this Agreement, except where a specific provision of this Agreement would excuse compliance.

9. INTERIM CODE OF CONDUCT. Section 7.7 of the Agreement is replaced with and superceded by the following provision:

7.7. Within thirty (30) days of the date of the Commission decision approving this Agreement pursuant to Section 6.1, APS shall file an initial proposed Code of Conduct to address inter-affiliate relationships involving APS as a utility distribution company as required by the Electric Competition Rules and which includes provisions to govern the supply of generation during the two-year extension provided for by Section 4.1 of this Agreement. Interested parties may provide APS with comments on the initial proposed Code of Conduct within sixty (60) days of the date of the Commission decision approving this Agreement. APS will file a final proposed Code of Conduct for Commission approval within ninety (90) days of the date of the Commission decision approving this Agreement. Until the Commission approves a Code of Conduct for APS, APS will voluntarily comply with the initial proposed Code of Conduct or, once filed, the final proposed Code of Conduct.

10. Effect of Addendum. Other than as specifically modified by this Addendum, all provisions of the Agreement remain in full force and effect.

AGREED TO AS OF NOVEMBER 24, 1999:

RESIDENTIAL UTILITY CONSUMER OFFICE	ARIZONA PUBLIC SERVICE COMPANY
By Barbara Wytaske	By Jack Davis
Title Acting Director	Title President Delivery & Sales
ARIZONA COMMUNITY ACTION ASSOCIATION	(Party)
By Betty Pruitt	By
Title Acting Executive Director	Title
ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION, a coalition of companies and associations in support of competition that includes Cable Systems International, BHP Copper, Motorola, Chemical Lime, Intel, Hughes, Honeywell, Allied Signal, Cyprus Climax Metals, Asarco, Phelps Dodge, Homebuilders of Central Arizona, Arizona Mining Industry Gets Our Support, Arizona Food Marketing Alliance, Arizona Association of Industries, Arizona Multi-housing Association, Arizona Rock Products Association, Arizona Restaurant Association, Arizona Retailers Association, Boeing, Arizona School Board Association, National Federation of Independent Business, Arizona Hospital Association, Lockheed Martin, Abbot Labs and Raytheon.	(Party) By Title (Party) By Title
By Stan Barnes	
Title President	

Revised
EXHIBIT D
Affiliate Rules Waivers

R14-2-801(5) and R14-2-803, such that the term "reorganization" does not include, and no Commission approval is required for, corporate restructuring that does not directly involve the utility distribution company ("UDC") in the holding company. For example, the holding company may reorganize, form, buy or sell non-UDC affiliates, acquire or divest interests in non-UDC affiliates, etc., without Commission approval.

R14-2-805(A) shall apply only to the UDC

R14-2-805(A)(2)

R14-2-805(A)(6)

R14-2-805(A)(9), (10), and (11)

RECISION OF PRIOR COMMISSION ORDERS

Section X.C of the "Cogeneration and Small Power Production Policy" attached to Decision No. 52345 (July 27, 1981) regarding reporting requirements for cogeneration information.

Decision No. 55118 (July 24, 1986) - Page 15, Lines 5-1/2 through 13-1/2; Finding of Fact No. 24 relating to reporting requirements under the abolished PPFAC.

Decision No. 55818 (December 14, 1987) in its entirety. This decision related to APS Schedule 9 (Industrial Development Rate) which was terminated by the Commission in Decision No. 59329 (October 11, 1995).

9th and 10th Ordering Paragraphs of Decision No. 56450 (April 13, 1989) regarding reporting requirements under the abolished PPFAC.

DA-GS1

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY	A.C.C. No. 5351
Phoenix, Arizona	Tariff or Schedule No. DA-GS1
Filed by: Alan Propper	Original Tariff
Title: Director, Pricing and Regulation	Effective: October 1, 1999

DIRECT ACCESS
GENERAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable to all electric service required when such service is supplied at one point of delivery and measured through one meter. For those customers whose electricity is delivered through more than one meter, service for each meter shall be computed separately under this rate unless conditions in accordance with the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service) are met. For those service locations where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

This rate schedule is not applicable to residential service, resale service or direct access service which qualifies for Rate Schedule DA-GS10.

TYPE OF SERVICE

Service shall be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's premise. Three phase service is furnished under the Company's Conditions Governing Extensions of Electric Distribution Lines and Services (Schedule #3). Transformation equipment is included in cost of extension. Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceed 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for load profiling or hourly metering specified in the Company's Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

June - October Billing Cycles (Summer):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$12.50			
Per kW over 5		$0.721		
Per kWh for the first 2,500 kWh		$0.04255		
Per kWh for the next 100 kWh per kW over 5		$0.04255		

Per kWh for the next 42,000 kWh	$0.02901		
Per kWh for all additional kWh	$0.01811		
Per all kWh		$0.00115	
Per all kW			$2.43

(CONTINUED ON REVERSE SIDE)

A. RATE (continued)

November - May Billing Cycles (Winter):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$12.50			
Per kW over 5		$0.652		
Per kWh for the first 2,500 kWh		$0.03827		
Per kWh for the next 100 kWh per kW over 5		$0.03827		
Per kWh for the next 42,000 kWh		$0.02600		
Per kWh for all additional kWh		$0.01614		
Per all kWh			$0.00115	
Per all kW				$2.43

PRIMARY AND TRANSMISSION LEVEL SERVICE:

1. For customers served at primary voltage (12.5kV to below 69kV), the Distribution charge will be discounted by 11.6%.

2. For customers served at transmission voltage (69kV or higher), the Distribution charge will be discounted 52.6%.

3. Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the average kW supplied during the 15-minute period of maximum use during the month, as determined from readings of the delivery meter.

B. MINIMUM

$12.50 plus $1.74 for each kW in excess of five of either the highest kW established during the 12 months ending with the current month or the minimum kW specified in the agreement for service, whichever is the greater.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$7.62 per month
Meter Reading	$1.69 per month
Billing	$1.33 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customers served under this rate schedule are responsible for acquiring their own generation and any other required competitively supplied services from an ESP or under the Company's Open Access Transmission Tariff. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

(CONTINUED ON PAGE 3)

ON-SITE GENERATION TERMS AND CONDITIONS

Customers served under this rate schedule who have on-site generation connected to the Company's electrical delivery grid shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

CONTRACT PERIOD

0 - 1,999 kW:	As provided in Company's standard agreement for service.
2,000 kW and above:	Three (3) years, or longer, at Company's option for initial period when construction is required. One (1) year, or longer, at Company's option when construction is not required.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These Schedules have provisions that may affect customer's monthly bill.

Exhibit A
DA-R1

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY	A.C.C. No. 5350
Phoenix, Arizona	Tariff or Schedule No. DA-R1
Filed by: Alan Propper	Original Tariff
Title: Director, Pricing and Regulation	Effective: October 1, 1999

DIRECT ACCESS
RESIDENTIAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company and where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable only to electric delivery required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one point of delivery and measured through one meter. For those dwellings and apartments where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating or space heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10.)

TYPE OF SERVICE

Service shall be single phase, 60 Hertz, at one standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's premise). Three phase service is furnished under the Company's Conditions Governing Extensions of Electric Distribution Lines and Services (Schedule #3). Transformation equipment is included in cost of extension. Three phase service is required for motors of an individual rated capacity of 7-1/2 HP or more.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for load profiling or hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

May - October Billing Cycles (Summer):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$10.00			
All kWh		$0.04158	$0.00115	$0.00930

November - April Billing Cycles (Winter):

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$10.00			
All kWh		$0.03518	$0.00115	$0.00930

B. MINIMUM $ 10.00 per month

(CONTINUED ON REVERSE SIDE)

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$4.00 per month
Meter Reading	$1.69 per month
Billing	$1.33 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customers served under this rate schedule are responsible for acquiring their own generation and any other required competitively supplied services from an ESP. The Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

Customers served under this rate schedule who have on-site generation connected to the Company's electrical delivery grid shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to the Company's Terms and Conditions for Standard Offer and Direct Access Services (Schedule #1) and Schedule #10. These schedules have provisions that may affect customer's monthly bill.

Exhibit A
DA-GS10

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY	A.C.C. No. 5352
Phoenix, Arizona	Tariff or Schedule No. DA-GS10
Filed by: Alan Propper	Original Tariff
Title: Director, Pricing and Regulation	Effective: October 1, 1999

DIRECT ACCESS
EXTRA LARGE GENERAL SERVICE

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to customers receiving electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. This rate schedule is applicable only to customers whose monthly maximum demand is 3,000 kW or more for three (3) consecutive months in any continuous twelve (12) month period ending with the current month. Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by individual customer contract. For those customers whose electricity is delivered through more than one meter, service for each meter shall be computed separately under this rate unless conditions in accordance with the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service) are met.

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at Company's standard voltages that are available within the vicinity of customer's premise.

METERING REQUIREMENTS

All customers shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$2,430.00			
per kW		$3.53		$2.82
per kWh		$0.00999	$0.00115	

PRIMARY AND TRANSMISSION LEVEL SERVICE:

1. For customers served at primary voltage (12.5kV to below 69kV), the Distribution charge will be discounted by 4.8%.

2. For customers served at transmission voltage (69kV or higher), the Distribution charge will be discounted 36.7%.

3. Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's)

for those customers taking service at voltage levels of more than 25 kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 15-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

(CONTINUED ON REVERSE SIDE)

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$154.15 per month
Meter Reading	$ 1.69 per month
Billing	$ 1.33 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customers served under this rate schedule are responsible for acquiring their own generation and any other required competitively supplied services from an ESP. T he Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

Customers served under this rate schedule who have on-site generation connected to the Company's electrical delivery grid shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

CONTRACT PERIOD

For service locations in:

a) Isolated Areas: Ten (10) years, or longer, at Company's option, with standard seven (7) year termination period.

b) Other Areas: Three (3) years, or longer, at Company's option.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

Exhibit A
DA-GS11
ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY	A.C.C. No. 5395
Phoenix, Arizona	Tariff or Schedule No. DA-GS11
Filed by: Alan Propper	Original Tariff
Title: Director, Pricing and Regulation	Effective: October 1, 1999

DIRECT ACCESS
RALSTON PURINA

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable only to Ralston Purina (Site #863970289) when it receives electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. Service must be supplied as specified by individual customer contract and the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service).

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at 12.5 kV.

METERING REQUIREMENTS

Customer shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$2,430.00			
per kW		$2.58		$1.86
per kWh		$0.00732	$0.00115	

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 15-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month.

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$154.15 per month
Meter Reading	$ 1.69 per month
Billing	$ 1.33 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

(CONTINUED ON REVERSE SIDE)

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customer is responsible for acquiring its own generation and any other required competitively supplied services from an ESP. T he Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

If Customer has on-site generation connected to the Company's electrical delivery grid, it shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

Exhibit A
DA-GS12

ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY	A.C.C. No. 5396
Phoenix, Arizona	Tariff or Schedule No. DA-GS12
Filed by: Alan Propper	Original Tariff
Title: Director, Pricing and Regulation	Effective: October 1, 1999

DIRECT ACCESS
BHP COPPER

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable only to BHP Copper (Site #774932285) when it receives electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. Service must be supplied as specified by individual customer contract and the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service).

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at 12.5 kV or higher.

METERING REQUIREMENTS

Customer shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution at Primary Voltage	Distribution at Transmission Voltage	System Benefits	Competitive Transition Charge
$/month	$2,430.00				
per kW		$2.35	$1.22		$1.54
per kWh		$0.00665	$0.00346	$0.00115	

PRIMARY AND TRANSMISSION LEVEL SERVICE:

Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25 kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 30-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month.

(CONTINUED ON REVERSE SIDE)

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

```
Meter             $154.15 per month
Meter Reading     $  1.69 per month
Billing           $  1.33 per month
```

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customer is responsible for acquiring its own generation and any other required competitively supplied services from an ESP. T he Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

If Customer has on-site generation connected to the Company's electrical delivery grid, it shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

Exhibit A
DA-GS13
ELECTRIC DELIVERY RATES

ARIZONA PUBLIC SERVICE COMPANY	A.C.C. No. 5397
Phoenix, Arizona	Tariff or Schedule No. DA-GS13
Filed by: Alan Propper	Original Tariff
Title: Director, Pricing and Regulation	Effective: October 1, 1999

DIRECT ACCESS
CYPRUS BAGDAD

AVAILABILITY

This rate schedule is available in all certificated retail delivery service territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable only to Cyprus Bagdad (Site #120932284) when it receives electric energy on a direct access basis from any certificated Electric Service Provider (ESP) as defined in A.A.C. R14-2-1603. Service must be supplied as specified by individual customer contract and the Company's Schedule #4 (Totalized Metering of Multiple Service Entrance Sections At a Single Premise for Standard Offer and Direct Access Service).

This rate schedule is not applicable to resale service.

This rate schedule shall become effective as defined in Company's Terms and Conditions for Direct Access (Schedule #10).

TYPE OF SERVICE

Service shall be three phase, 60 Hertz, at 115 kV or higher.

METERING REQUIREMENTS

Customer shall comply with the terms and conditions for hourly metering specified in Schedule #10.

MONTHLY BILL

The monthly bill shall be the greater of the amount computed under A. or B. below, including the applicable Adjustments.

A. RATE

	Basic Delivery Service	Distribution	System Benefits	Competitive Transition Charge
$/month	$2,430.00			
per kW		$1.05		$1.34
per kWh		$0.00298	$0.00115	

PRIMARY AND TRANSMISSION LEVEL SERVICE:

Pursuant to A.A.C. R14-2-1612.K.11, the Company shall retain ownership of Current Transformers (CT's) and Potential Transformers (PT's) for those customers taking service at voltage levels of more than 25 kV. For customers whose metering services are provided by an ESP, a monthly facilities charge will be billed, in addition to all other applicable charges shown above, as determined in the service contract based upon the Company's cost of CT and PT ownership, maintenance and operation.

DETERMINATION OF KW

The kW used for billing purposes shall be the greater of:

1. The kW used for billing purposes shall be the average kW supplied during the 30-minute period (or other period as specified by individual

customer's contract) of maximum use during the month, as determined from readings of the delivery meter.

2. The minimum kW specified in the agreement for service or individual customer contract.

B. MINIMUM

$2,430.00 per month plus $1.74 per kW per month, until June 30, 2004 when this minimum will no longer be applicable.

(CONTINUED ON REVERSE SIDE)

ADJUSTMENTS

1. When Metering, Meter Reading or Consolidated Billing are provided by the Customer's ESP, the monthly bill will be credited as follows:

Meter	$154.15 per month
Meter Reading	$ 1.69 per month
Billing	$ 1.33 per month

2. The monthly bill is also subject to the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric service sold and/or the volume of energy delivered or purchased for sale and/or sold hereunder.

SERVICES ACQUIRED FROM CERTIFICATED ELECTRIC SERVICE PROVIDERS

Customer is responsible for acquiring its own generation and any other required competitively supplied services from an ESP. T he Company will provide and bill its transmission and ancillary services on rates approved by the Federal Energy Regulatory Commission to the Scheduling Coordinator who provides transmission service to the Customer's ESP. The Customer's ESP must submit a Direct Access Service Request pursuant to the terms and conditions in Schedule #10.

ON-SITE GENERATION TERMS AND CONDITIONS

If Customer has on-site generation connected to the Company's electrical delivery grid, it shall enter into an Agreement for Interconnection with the Company which shall establish all pertinent details related to interconnection and other required service standards. The Customer does not have the option to sell power and energy to the Company under this tariff.

TERMS AND CONDITIONS

This rate schedule is subject to Company's Terms and Conditions for Standard Offer and Direct Access Service (Schedule #1) and the Company's Schedule #10. These schedules have provisions that may affect customer's monthly bill.

ARIZONA PUBLIC SERVICE COMPANY

Competitive Transition Charges
By Direct Access Rate Classes

Line #	Direct Access Rate Class	Competition Transition Charges Effective January 1 of 1999	2000	2001	2002	2003	2004
1	Residential, DA-R1 (per kWh)	$0.0093	$0.0084	$0.0063	$0.0056	$0.0050	$0.0036
2	Under 3 mW, DA-GS1, (per kW/mo.)	$ 2.43	$ 2.20	$ 1.66	$ 1.46	$ 1.30	$ 0.94
3	3 mW and Above, DA-GS10 (per kW/mo.)	$ 2.82	$ 2.55	$ 1.89	$ 1.72	$ 1.51	$ 1.09
4	BHP Copper (per kW/mo.)	$ 1.54	$ 1.53	$ 1.06	$ 0.95	$ 0.83	$ 0.61
5	Cyprus Copper (per kW/mo.)	$ 1.34	$ 1.46	$ 1.05	$ 0.94	$ 0.82	$ 0.61
6	Ralston Purina (per kW/mo.)	$ 1.86	$ 1.98	$ 1.50	$ 1.34	$ 1.18	$ 0.87
7	Average Retail (per kWh)	$0.0067	$0.0061	$0.0054	$0.0048	$0.0043	$0.0031

Charges are based upon recovery of $350 million NPV derived from APS' Compliance Filing of 8/21/98 as adjusted to synchronize Direct Access and Standard Offer revenue decreases.

ARIZONA PUBLIC SERVICE COMPANY
Distribution Charges
By Direct Access Rate Classes

Line #	Direct Access Rate Class	Distribution Charges Effective January 1 of 1999	2000	2001	2002	2003	2004(a)
	RESIDENTIAL, DA-R1						
1	Summer per kWh	$0.04158	$0.04041	$0.03934	$0.03837	$0.03748	$0.03689
2	Winter per kWh	$0.03518	$0.03419	$0.03329	$0.03247	$0.03172	$0.03122
	DA-GS1 (UNDER 3 MW)						
	Summer Rates						
3	per kW for all kW over 5	$ 0.721	$ 0.691	$ 0.663	$ 0.638	$ 0.615	$ 0.600
4	per kWh for the first 2,500 kWh	$0.04255	$0.04075	$0.03912	$0.03763	$0.03627	$0.03537
5	per kWh for the next 100 kWh per kW over 5	$0.04255	$0.04075	$0.03912	$0.03763	$0.03627	$0.03537
6	per kWh for the next 42,000 kWh	$0.02901	$0.02779	$0.02667	$0.02565	$0.02473	$0.02411
7	per kWh for all additional kWh	$0.01811	$0.01735	$0.01665	$0.01602	$0.01544	$0.01506
	Winter Rates						
8	per kW for all kW over 5	$ 0.652	$ 0.624	$ 0.599	$ 0.576	$ 0.555	$ 0.541
9	per kWh for the first 2,500 kWh	$0.03827	$0.03666	$0.03519	$0.03385	$0.03263	$0.03182
10	per kWh for the next 100 kWh per kW over 5	$0.03827	$0.03666	$0.03519	$0.03385	$0.03263	$0.03182
11	per kWh for the next 42,000 kWh	$0.02600	$0.02490	$0.02390	$0.02299	$0.02216	$0.02161
12	per kWh for all additional kWh	$0.01614	$0.01546	$0.01484	$0.01427	$0.01376	$0.01342
	Voltage Discounts						
13	Primary Voltage	11.6%	12.1%	12.6%	13.1%	13.6%	13.9%
14	Transmission Voltage	52.6%	54.9%	57.2%	59.5%	61.7%	63.3%
	DA-GS10 (3 MW AND ABOVE)						
15	per kW	$ 3.53	$ 3.33	$ 3.15	$ 2.98	$ 2.83	$ 2.73
16	per kWh	$0.00999	$0.00943	$0.00892	$0.00845	$0.00802	$0.00774
	Voltage Discounts						
17	Primary Voltage Discount	4.8%	5.1%	5.3%	5.6%	5.9%	6.2%
18	Transmission Voltage Discount	36.7%	38.9%	41.1%	43.4%	45.8%	47.4%
	DA-GS11 (RALSTON PURINA)						
19	per kW	$ 2.58	$ 2.71	$ 2.57	$ 2.44	$ 2.32	$ 2.25
20	per kWh	$0.00732	$0.00767	$0.00727	$0.00691	$0.00657	$0.00635
	DA-GS12 (BHP COPPER)						
21	Primary Voltage Delivery - per kW	$ 2.35	$ 2.30	$ 2.16	$ 2.07	$ 1.99	$ 1.93
22	per kWh	$0.00665	$0.00651	$0.00611	$0.00585	$0.00561	$0.00546
23	Transmission Voltage Delivery - per kW	$ 1.22	$ 1.17	$ 1.03	$ 0.94	$ 0.85	$ 0.80
24	per kWh	$0.00346	$0.00332	$0.00292	$0.00266	$0.00242	$0.00227
	DA-GS13 (CYPRUS BAGDAD)						
25	per kW	$ 1.05	$ 1.21	$ 1.03	$ 0.94	$ 0.85	$ 0.80
26	per kWh	$0.00297	$0.00343	$0.00292	$0.00266	$0.00242	$0.00227

(a) Transmission voltage customers will not pay Distribution Charges after June 30, 2004

Exhibit A 5/14/99 Schedule C

ARIZONA PUBLIC SERVICE COMPANY

Regulatory Asset Amortization Schedule
(Millions of Dollars)

1999	2000	2001	2002	2003	1/1 - 6/30 2004(1)	Total(2)
164	158	145	115	86	18	686

(1) Amortization ends 6/30/2004

(2) Includes the disallowance from Section 3.3

ARTICLE UT

PERIOD TYPE	9 MOS
PERIOD START	Jan 01 2000
FISCAL YEAR END	Dec 31 2000
PERIOD END	Sep 30 2000
BOOK VALUE	PER BOOK
TOTAL NET UTILITY PLANT	4,947,162
OTHER PROPERTY AND INVEST	615,543
TOTAL CURRENT ASSETS	1,038,526
TOTAL DEFERRED CHARGES	573,549
OTHER ASSETS	0
TOTAL ASSETS	7,174,780
COMMON	1,536,493
CAPITAL SURPLUS PAID IN	0
RETAINED EARNINGS	839,339
TOTAL COMMON STOCKHOLDERS EQ	2,375,832
PREFERRED MANDATORY	0
PREFERRED	0
LONG TERM DEBT NET	2,354,911
SHORT TERM NOTES	0
LONG TERM NOTES PAYABLE	0
COMMERCIAL PAPER OBLIGATIONS	1,984
LONG TERM DEBT CURRENT PORT	4,887
PREFERRED STOCK CURRENT	0
CAPITAL LEASE OBLIGATIONS	0
LEASES CURRENT	0
OTHER ITEMS CAPITAL AND LIAB	2,437,166
TOT CAPITALIZATION AND LIAB	7,174,780
GROSS OPERATING REVENUE	2,852,021
INCOME TAX EXPENSE	194,069
OTHER OPERATING EXPENSES	803,378
TOTAL OPERATING EXPENSES	2,298,596
OPERATING INCOME LOSS	553,425
OTHER INCOME NET	13,785
INCOME BEFORE INTEREST EXPEN	0
TOTAL INTEREST EXPENSE	113,121
NET INCOME	260,020
PREFERRED STOCK DIVIDENDS	0
EARNINGS AVAILABLE FOR COMM	260,020
COMMON STOCK DIVIDENDS	88,963
TOTAL INTEREST ON BONDS	68,491
CASH FLOW OPERATIONS	552,979
EPS BASIC	3.07
EPS DILUTED	3.06

End of Filing